DOMLEC GENERATION EXPANSION ASSESSMENT 2014 - 2033

June 13, 2014

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PREAMBLE

The preparation of the Integrated Resource Plan (IRP) spanned the period February to June 2014. Given the dynamic environment with which Dominica Electricity Services Limited operates, it should be noted that the information and data contained in the IRP is subject to review. One of the significant factors which informed the IRP's contents is the advent of the technology option utilising geothermal energy. Currently the information pertaining to the said option is not definitive in scope and timing. Consequently the IRP will be revised when concrete information is available.

1 Executive Summary

1.1 Background

The preparation of this Integrated Resource Plan (IRP) for the electricity sector of the Commonwealth of Dominica is being undertaken by the Dominica Electricity Services Limited (DOMLEC) supported by the Barbados Light and Power Company Limited (BLPC) project team in response to the requirement of the new Transmission, Distribution and Supply Licence which came into effect on the first day of January 2014 which mandated that within nine months of the commencement date of the licence DOMLEC should apply for a rate review. The Independent Regulatory Commission (IRC) mandated that as a precursor to the filing for a rate review an IRP should be filed.

The Commonwealth of Dominica is the third largest English speaking Caribbean island and has an area of 754 square kilometers of very mountainous terrain with very few tracts of level land, and has nine active volcanoes. Most of the population is centered within the towns of Roseau in the south and Portsmouth in the north and their environs. As such these are the two main centers of electrical load for the island. Approximately 95% of the island's inhabitants have access to electricity supply as every village on the island has electricity supplied by DOMLEC's grid.

Dominica Electricity Services Limited (DOMLEC) is a vertically integrated utility responsible for the generation, transmission, distribution and sale of electricity in the Commonwealth of Dominica. DOMLEC operates three hydro-electric power stations namely: Laudat, Trafalgar and Padu; and two diesel power stations at Fond Cole and Sugar Loaf. All generation sources are linked via 11kV inter-connectors and, in some instances, via 11kV distribution feeders. The secondary distribution voltage is 230/400V. The transmission and distribution (T&D) network, comprises 368 kilometers of 11kV and 922 kilometers of low voltage overhead lines.

In January 2014, the utility had 35,325 customers who used 88GWh of energy in 2013, while street lighting and other outdoor lighting used 1.7GWh in that same year. The customer base then consisted of 31,165 domestic customers using an average of 107kWh per month; 4,088 commercial customers using an average of 767kWh per month: 41 industrial customers who used an average of 16,156kWh per month and finally 30 hotel customers using an average 3,311kWh per month.

Table 1 shows the number of customers, the peak load and the energy produced by diesel generation, hydro generation, customer-owned renewable energy resources, and the total energy production over the period 2009-2013.

	2013	2012	2011	2010	2009
Number of Customers	35518	34870	34391	33986	30549
Peak Load (MW)	16.71	17.23	17.17	16.58	15.62
Gross diesel production (MWh)	63987	74807	64571	76033	69565
Gross hydro production (MWh)	36705	26748	35836	23132	23156
Gross purchased RE production (MWh)	60	117	76	16	0
Total gross energy production (MWh)	100752	101672	100483	99181	92721

Table 1: Selected DOMLEC system parameters (2009-2013)

1.2 Integrated Resource Planning

Integrated Resource Planning is an internationally recognized expansion planning process which is used by many utilities. This IRP was prepared with the strategic objective of seeking to reduce the importation and use of diesel fuel which drains the country of much-needed foreign exchange, and which increases the price of electricity through the fuel surcharge mechanism.

This IRP seeks to:

1. Project the electricity demand in Dominica from 2014 to 2033 based on previous load data and anticipated significant events for a low, base and high growth rate.
2. Review the age and reliability of the present fleet of generators, giving consideration to expected retirements.
3. Indicate potentially viable candidate plant for generation expansion for the period 2014 through 2033.
4. Determine when new capacity, if any, is required for the generating system to maintain reliability requirements for Dominica.
5. Determine performance constraints of the transmission and distribution system which may occur within the period of the plan, based on projected generation expansion.

1.3 Recommendation

An assessment was conducted into the generation expansion required over the planning period 2014 to 2033. This assessment sought to project the electricity demand in Dominica from 2014 to 2033 based on previous load data and anticipated significant events for low, base and high growth rates. A review of the age and reliability of the present fleet of generators was conducted, which gave consideration to expected retirements. Candidate plant for generation expansion for the planning period was identified and a determination of when new capacity, if any, is required for the generating system to maintain reliability requirements for Dominica was made. Additionally, the performance constraints of the transmission and distribution system which may occur within the period of the plan, based on projected generation expansion were assessed.

To take into account uncertainties due to input assumptions, a scenario planning approach was used in the assessment. The study considered three possible electricity demand growth backgrounds derived from the three electricity demand projections. Against these demand projections, four generation scenarios were considered during this assessment. These are summarized in Table 2.

Technology Options Considered	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Geothermal (7MW by 2018)	√	X	X	√
Geothermal (7MW by 2021)	X	√	X	X
Additional Geothermal capacity from	2020	2023	N/A	2020
Reciprocating Engines	√	√	√	√
Solar PV	√	√	√	√
Injection of 2MW demand in 2018	X	X	X	√

Table 2: Scenario Matrix of Unit Sizes and Technologies

In the first five years of the recommended least-cost plan, generation expansion is based on renewable energy technologies only, assuming that the anticipated timing of the introduction of the renewable energy technologies can be realized.

7.0MW of geothermal capacity is selected in 2018 when geothermal capacity becomes available to the model for selection. Two 0.5MW solar units are selected in 2017 representing 1.0MW of capacity with another 0.5MW of solar capacity being selected in 2018 for a total of 1.5MW of solar capacity across the planning period. The early introduction of renewable energy technologies provides the means by which the least cost plan is derived, as the contribution of fuel costs to the net present value of the plan are significantly lessened. Table 3 illustrates the recommended build schedule for the first five years of the recommended plan.

Year	Capacity Retired	Capacity Added		Total Installed	Peak Demand	Reserve Margin	N-2 Contingency
	(MW)	(MW)	Type	Capacity (MW)	(MWgross)	%	(MW)
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	17.4	77.8	6.5

Table 3: Recommended Build Schedule for 2014 – 2018 for Scenario 1 – Base Electricity Demand Projection

Beyond the initial five year outlook, another 3.5MW of geothermal capacity is added in 2020 and 2025 for a total of 14.0MW of geothermal capacity addition during the planning period. Reciprocating diesel engines are required from 2032, where 1.8MW of generating capacity is required to maintain the system reliability.

Sensitivity analysis to fuel prices indicated that generation scenario 3, which does not feature geothermal capacity as an expansion option is, as expected, the most sensitive to changes in fuel price over the planning period.

To accommodate the recommended generation expansion, the recommended transmission requirement includes a 33kV substation at Trafalgar, Padu, Fond Cole, and the geothermal generating stations with the stations connected in a ring configuration. Laudat is linked to the geothermal station 11kV bus and operated radially. This interconnection scenario satisfies the reliability, system losses, supply quality, minimized diesel usage, and hydro power requirements. The creation of the 33kV interconnectors from Fond Cole to Sugar Loaf and from Fond Cole to the new geothermal station would facilitate future generation expansion of the system and address voltage constraints that would otherwise compromise optimal generation dispatch.

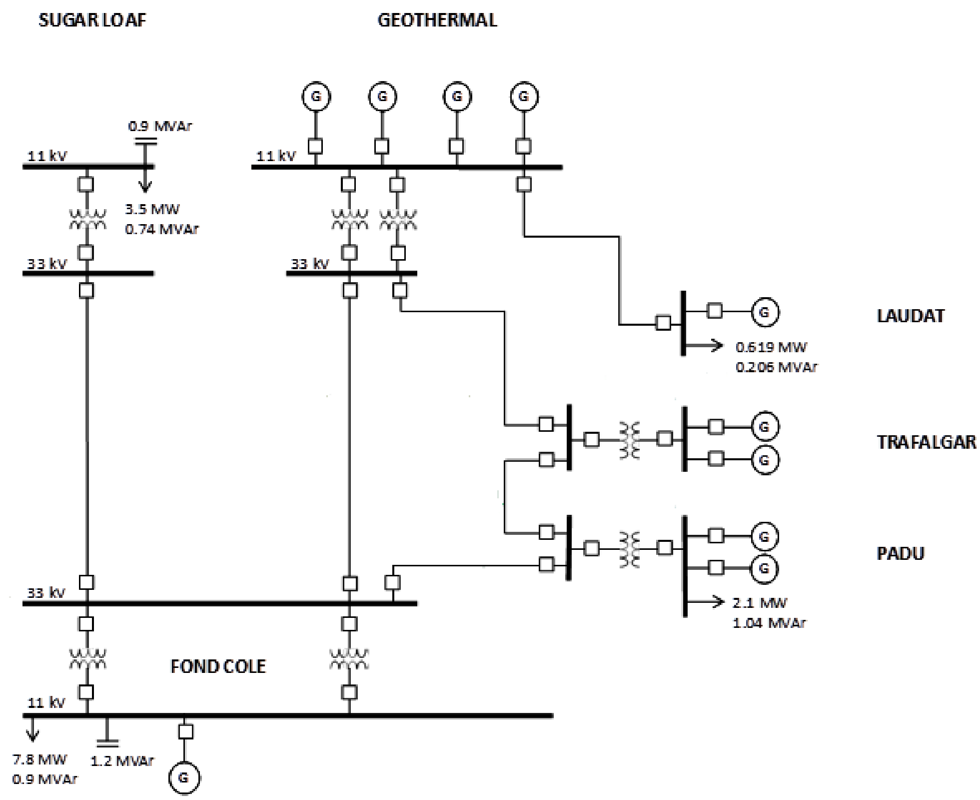

Figure 1: Recommended DOMLEC Transmission Interconnection Network

1.4 Structure of Report

This report consists of ten chapters. Chapter 1 is the Executive Summary which presents the background and gives some detail on the integrated resource planning process. The chapter also presents the recommended plan based on the results of the study. Finally, this chapter presents the structure of the report.

Chapter 2 details the planning parameters used in the study. The economic assumptions are presented followed by the electricity demand forecast for the planning period. Fuel assumptions are also critical to the study being undertaken. These are presented in this chapter. Finally, this chapter presents the system criteria and transmission and distribution assumptions used in the study.

Chapter 3 reviews the existing technologies used in the model. The cost and performance characteristics of the existing plant are presented.

Chapter 4 presents cost and performance characteristics for candidate plant used in the study.

Chapter 5 outlines the modeling methodology used in conducting the study. The scenarios used to model the options available are presented followed by information on how sensitivity analyses on the results were conducted. The chapter also presents information on the software model used in the study and the decision criteria used to evaluate the optimal plans produced by the software model.

Chapter 6 presents the results of the scenarios modeled with the base, high and low demand projections. Results are presented for the four scenarios for the base, high and low electricity demand projections. This chapter also presents the sensitivity results.

Chapter 7 presents information on DOMLEC’s existing transmission and distribution network as well as the recommended transmission and distribution upgrades required to support the recommended expansion plan.

Chapter 8 presents the conclusions of the study.

Chapter 9 presents the references used in the study.

The appendices in Chapter 10 provide containing further background information on study assumptions, and detailed model results.

2 Planning Parameters

2.1 Study Horizon and Reference Year

The study period is 20 years, from the reference year 2014 up to and including 2033.

All plant additions were assumed to take place at 00:00hrs on January 1 in the indicated year.

All plant retirements are assumed to take place at 00:00hrs on January 1 in the indicated year. For example, a retirement year of 2017 indicates that the plant is decommissioned at 00:00hrs on January 1, 2017.

2.2 Economic Assumptions

2.2.1 Discount Rate

The discount rate is an important factor in determining the optimal expansion plan due to the manner in which costs of the generation technologies are reflected in the modeling. The real WACC of 9.08% was assumed for this study and was derived using the Fisher Formula using a nominal WACC of 11.08% and an expected inflation of 2.0%. The real discount rate of 12.0% was assumed for this study and was derived using the Fisher Formula using the nominal discount rate of 14.0% and an expected inflation of 2%.

All discounting is done to January 1, 2014 and all expenditures are assumed to occur at the end of a calendar year.

2.2.2 Cost estimates

The IRP uses real 2014 Eastern Caribbean dollars (EC$) over the period of the study, i.e. inflation is not accounted for.

2.2.3 Capital Cost Estimates

Overnight capital cost is the cost of construction provided that no interest was incurred during construction (i.e. cost if the project was completed "overnight"). In reality however, the construction of new generating plant cannot be completed overnight. In this report, the capital cost assumptions for the candidate technologies are reported as overnight cost. The interest during construction is accounted for in the model and is also reported. The accumulated interest during construction for each technology is dependent on the technology build time. The interest rate during construction is assumed to be 5.75%.

2.2.4 Taxes and Duties

Local taxes and duties are not included in the model. These have not been included as the rates for taxes and duties over the planning period are unknown and could vary over time, therefore causing distortions to the true cost of technologies.

2.2.5 Currency & Exchange Rates

The United States dollar was the main currency for which cost estimates were denominated. The exchange rate of US$1 to EC$2.70 was used as the conversion for the United States dollar.

2.3 Demand Forecast

The twenty year electricity demand forecast is prepared by Dominica Electric Services Limited (DOMLEC) as an input into the development of its 2014 Integrated Resource Plan (IRP). The forecast covers the planning period 2014 through to 2033 and represents DOMLEC's estimate of the most probable outcome for load growth during the planning period. An econometric methodology was used to relate historical electricity demand to key economic, demographic and weather factors. This historic relationship is then used to project the future growth in demand for electricity within the Commonwealth of Dominica.

A forecast is inherently uncertain and therefore the actual future path the demand for electricity takes is unlikely to follow the exact track suggested by the base case load forecast. Two additional forecasts were therefore prepared, referred to as high and low load forecasts, to provide a range of possible future outcomes due to the variability of the key forecast drivers.

The forecasts incorporate the best available data and industry analysis obtained from the International Monetary Fund (IMF), Eastern Caribbean Central Bank (ECCB), Dominica's Meteorological Department and DOMLEC's internal records. Additional data sources as well as supporting statistical detail are described in the Chapter 10 Appendices.

2.3.1 Demand Forecast Assumptions

The customers served by DOMLEC were grouped into the three classes of commercial & industrial, residential and street lighting. The residential class consists of customers billed on the domestic tariff, commercial & industrial class includes customers on the hotels, commercial and industrial tariffs, while streetlights class consists of customers billed on the lighting and streetlights tariffs. Separate forecasts were developed for each of the three individual customer classes and these were aggregated to provide a forecast of total demand. An estimate of system losses based on the most recent three year annual average system losses (8.3%) and an expectation that losses will increase to 9.1% after 2015 was applied to total demand to derive the system load. Higher losses after 2015 are expected to be associated with scheduled infrastructural upgrades to the transmission and distribution network.

Economic growth, residential electricity prices and average daily temperatures were the main forecast drivers utilized in the econometric models. These variables were selected for inclusion in the models because of data availability and the degree to which these variables were able to explain the historical movements in electricity demand within the Commonwealth of Dominica.

Scenarios	Average Annual Values 2014-2033
Low Case Scenarios	
Temperature …………………………………………..…	27.4°C
Economic Growth ……………………………………..	0.1%
Residential Electricity Prices ……………..………..…	1.5%
Base Case Scenarios	
Temperature …………………………….…………..…	27.8°C
Economic Growth ………………………………..……..	1.6%
Residential Electricity Prices …………………………..…	-2.0%
High Case Scenarios	
Temperature …………………………….………...…	28.1°C
Economic Growth …………………….………..……..	3.1%
Residential Electricity Prices ……………………..……	-2.2%

Table 4: Key Forecast Assumptions

Real Gross Domestic Product (GDP) was employed as the economic growth variable in the models. The growth in electricity sales is influenced to a large extent by the growth in output within the economy. Growth in the economy was flat during 2013 after registering a marginal decline of 0.2% during 2012. Information published by the Eastern Caribbean Central Bank and the International Monetary Fund suggest that the economy could grow by an estimated 1.6% during 2014 supported by improvements in the Agriculture, Construction, and Tourism sectors. Average annual growth over the planning period is also projected to be 1.6%. High and low economic growth scenarios were constructed using a cone of ±1.5% (Table 4). Changes in electricity prices are also expected to influence the demand for electricity though its income and substitution effects. Geothermal resource development is anticipated to result in an average reduction in real residential electricity prices of 2% annually over the forecast period. In the high electricity price case where geothermal resources are absent, prices are projected to grow on an annual basis by 1.5%. Demand for electricity also varies with weather conditions such as daily temperatures. In the base case, average daily temperatures are assumed to continue at their twenty-year average of 27.8°C. Average daily temperatures in the low and high temperature scenarios are assumed to be 27.4°C and 28.1°C respectively.

2.3.2 Forecast Summary

In the base case scenario, Dominica Electric Services Limited's net generation is forecast to increase from 97,248MWh in the year 2014 to a load of 125,914MWh in 2033 (Figure 2). In the base case, net generation growth is projected to average 1.3% per year over the 20 years of the planning period (2014–2033). In the low case load scenario, net generation is forecasted to reach 83,657MWh at the end of the planning period, while in the high case scenario, net generation is projected to reach 172, 144MWh at the end of 2033. (See Table 5 & Appendices).

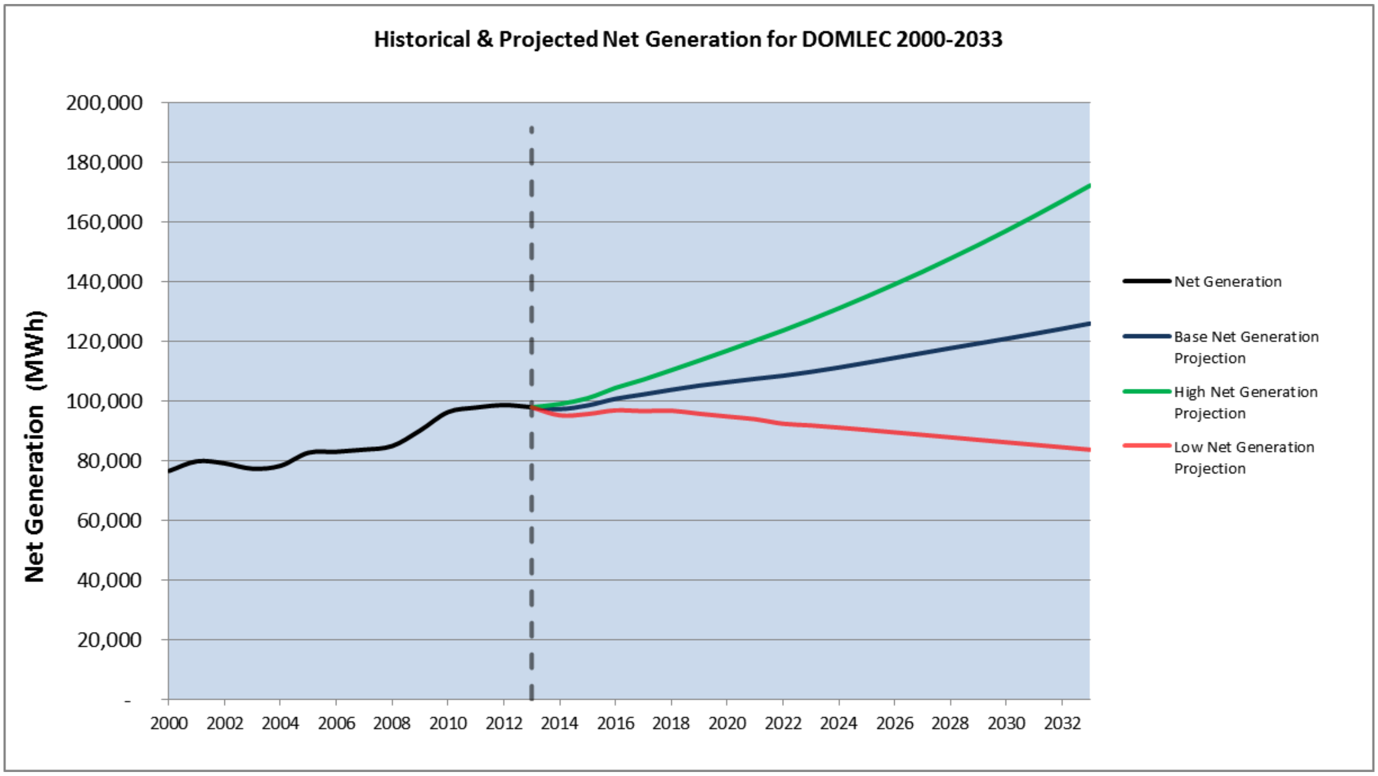

Figure 2: Historical & Projected Net Generation: 2000-2033

Year	Scenarios (MWh) High Case	Base Case	Low Case
2014	98,956	**97,248**	95,174
2020	116,823	**106,294**	94,769
2026	139,061	**114,415**	89,461
2033	172,144	**125,914**	83,657
Average Growth Rate (2014-2033)	*2.9%*	***1.3%***	*-0.8%*

Table 5: Net Generation Growth

System peak load is expected to grow to 19.5MW in 2033 from the 2013 actual system peak of 16.7 MW. In the base case scenario, DOMLEC's system peak increases at an average growth rate of 0.8% per year over the 20 years of the planning period (Table 6).

	Scenarios (MW)		
Year	**High Case**	**Base Case**	**Low Case**
2014	17.1	16.6	16.4
2020	19.8	17.6	16.8
2026	22.8	18.5	16.6
2033	27.1	19.5	16.2
Average Growth Rate (2014-2033)	*2.4%*	***0.8%***	*-0.2%*

Table 6: System Peak Load Growth Projections

The number of customers is projected to increase from 35,518 customers at the end of 2013 to just over 49,357 customers by 2033. Total usage per customer is expected to decline from 2,515 in 2013 to 2,330 by the end of the planning period.

2.3.3 Customer Class Forecasts

2.3.3.1 *Residential Forecast*

The base case residential load is projected to increase at an average annual rate of 1.7% from 40,402MWh in 2014 to 56,718MWh in 2033. In the high case scenario, residential load is anticipated to grow to 70,402MWh in 2033, to register an annual average growth of 2.8%. The residential load forecasts are reported in Table 7 and shown graphically in Figure 3.

	Scenarios (MWh)		
Year	**High Case**	**Base Case**	**Low Case**
2014	41,370	**40,402**	40,293
2020	47,231	**44,014**	38,794
2026	56,244	**49,233**	36,921
2033	70,402	**56,718**	34,809
Average Growth Rate (2014-2033)	*2.8%*	***1.7%***	*-0.8%*

Table 7: Residential Load Growth

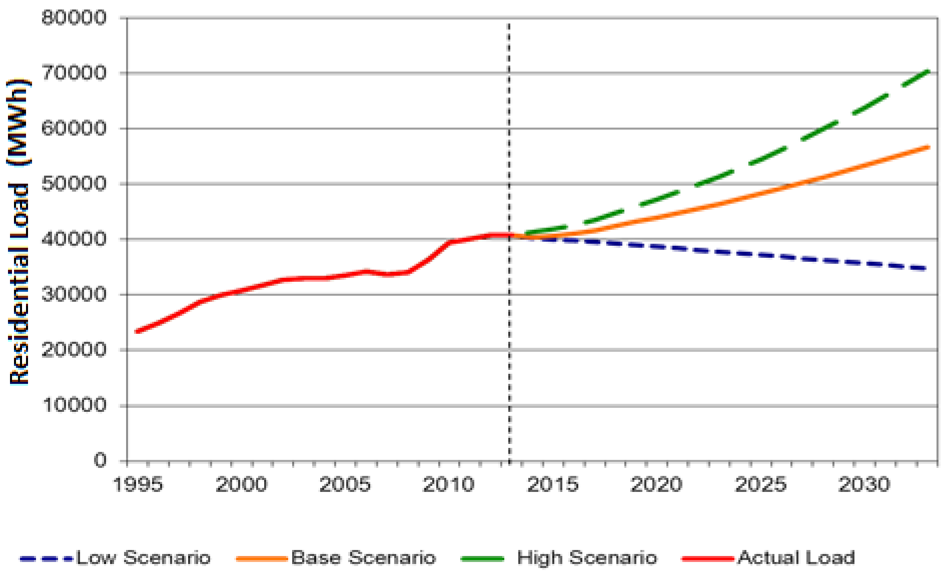

Figure 3: Residential Load Forecast

The residential customer class comprises customers that are billed on the domestic tariff whose demand for electricity is associated mainly with appliances and lighting loads. Energy within this customer class accounted for 52% of DOMLEC's load in 1995 and declined to 46% by the end of 2013. A marginal improvement in residential customers share to 47% of total load is however expected over the forecast period. Average usage per customer is projected to decline over the first five years of the forecast with some marginal growth anticipated thereafter (Figure 4). The total number of residential customers is expected to increase from 31,091 in 2013 to approximately 44,000 by the end of 2033.

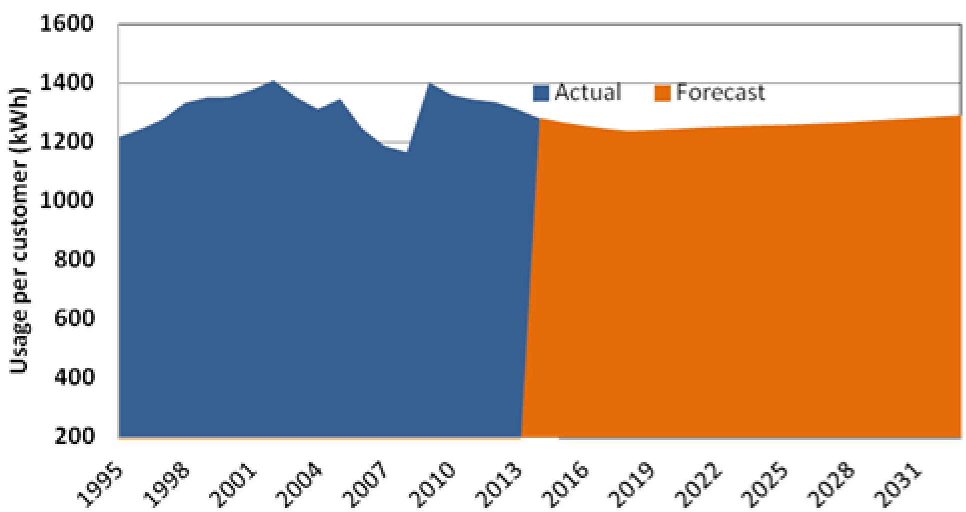

Figure 4: Historical & Projected Residential Usage per Customer

2.3.3.2 *Commercial & Industrial Forecast*

The Commercial & Industrial (C&I) class comprised customers that are served on the Commercial, Industrial and Hotel tariffs. In the base case scenario, commercial & industrial loads are projected to rise from 46,973MWh in 2014 to 55,766MWh in 2033 (Table 8). An average annual growth rate of 0.9% is expected over the forecast period.

	Scenarios (MWh)		
Year	**High Case**	**Base Case**	**Low Case**
2014	47,571	46,973	45,181
2020	57,008	50,653	45,398
2026	68,161	52,770	42,398
2033	84,106	55,766	39,262
Average Growth Rate (2014-2033)	*3.0%*	*0.9%*	*-0.9%*

Table 8: Commercial & Industrial Load Growth Projections

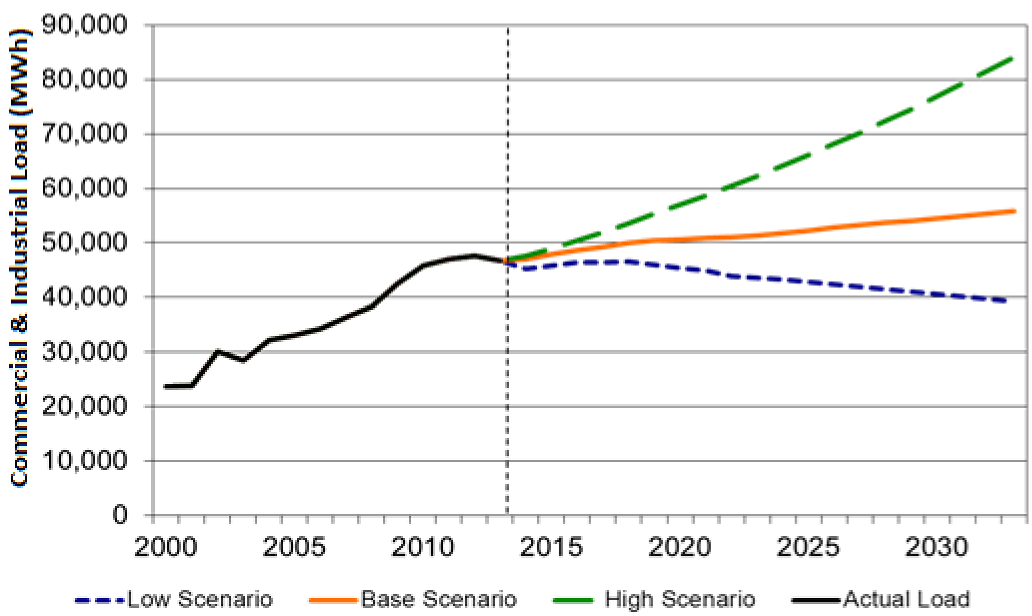

Figure 5: Commercial & Industrial Load Forecast

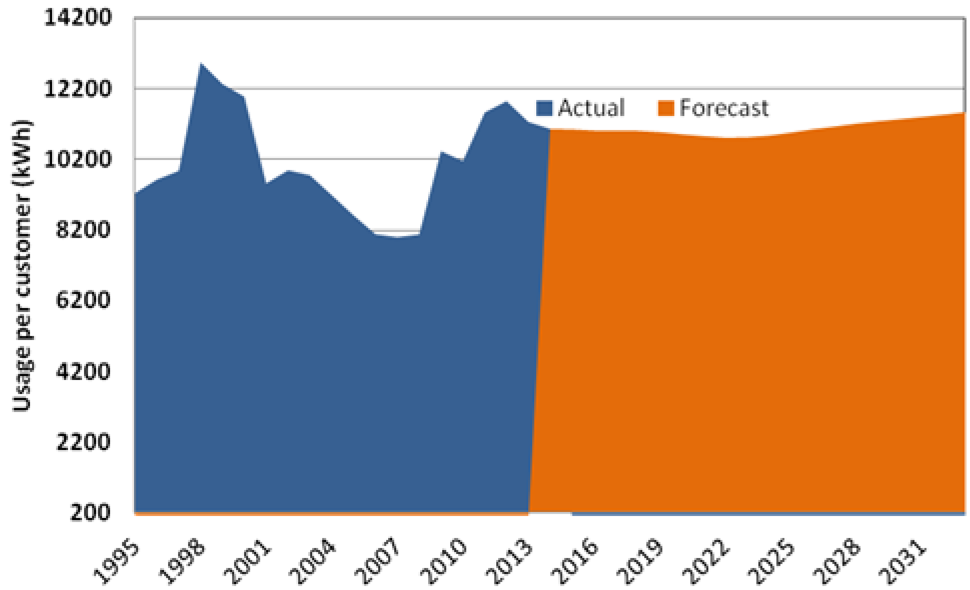

Figure 6: Historical & Projected Commercial & Industrial Usage per Customer

The total number of customers within the commercial & industrial class is expected to increase from 4,154 customers in 2013 to 4,835 by the end of 2033. Average usage per customer which grew on average by 7% in the past five years is expected to decline up to 2022, before recovering marginally towards the end of the planning period.

2.3.3.3 *Street lights Forecast*

Street lighting load is forecasted to increase from 1,801MWh in 2014 to 1,972MWh in 2033. The average annual growth rate for street lighting load is projected to be a modest 0.6% during the forecast period (Table 9).

Year	Base Case (MWh)
2014	**1,801**
2020	**1,953**
2026	**2,001**
2033	**1,972**
Average Growth Rate (2014-2033)	**0.6%**

Table 9: Street Lights Load Growth Projections

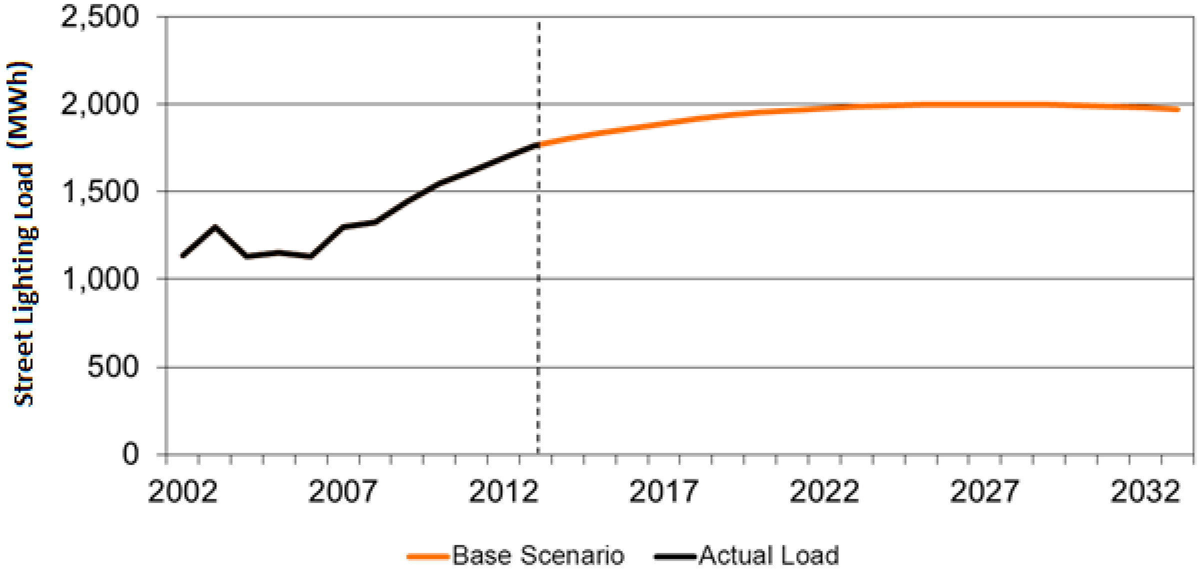

Figure 7: Street Lighting Load Forecast

2.3.3.4 *Total Sales Forecast*

Total sales are an aggregation of the load projections for the Residential, Streetlights and Commercial & Industrial customer classes. DOMLEC's total electricity demand is forecasted to increase from 89,177MWh in 2014 to register 114,456MWh by the end of 2033. The average annual growth rate over the planning period is projected to be 1.2% and the number of customers is forecasted to rise from 35,518 in 2013 to 49,120 by the end of the planning period (Table 10).

	Scenarios (MWh)		
Year	**High Case**	**Base Case**	**Low Case**
2014	90,742	89,177	87,275
2020	106,192	96,621	86,145
2026	126,406	104,004	81,320
2033	156,479	114,456	76,044
Average Growth Rate (2014-2033)	*2.8%*	*1.2%*	*-0.8%*

Table 10: Total Sales Growth Projections

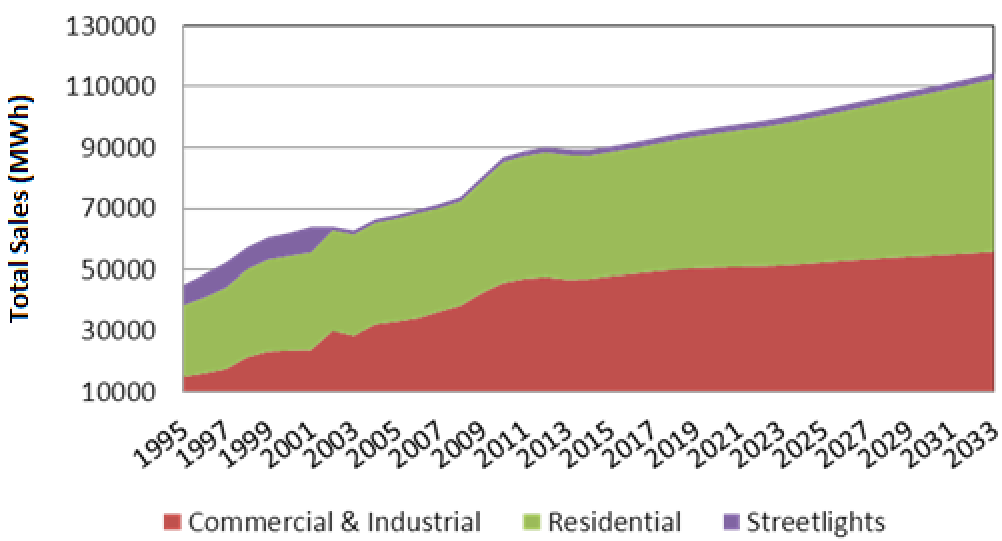

Figure 8: Total Sales Forecast

2.3.3.5 ***System Peak Forecast***

System peak fell from 17.2 MW in 2012 to 16.8 MW during 2013. Peak demand is forecasted to fall to 16.6 MW during 2014 while average annual growth of 0.8% in peak is projected over the planning period. System peak demand is forecasted to grow to 19.5 MW be the end of 2033 (Table 11, Figure 9).

	Scenarios (MW)		
Year	**High Case**	**Base Case**	**Low Case**
2014	17.1	16.6	16.4
2020	19.8	17.6	16.8
2026	22.8	18.5	16.6
2033	27.1	19.5	16.2
Average Growth Rate (2014-2033)	*2.4%*	***0.8%***	*-0.2%*

Table 11: System Peak Load Growth Projections

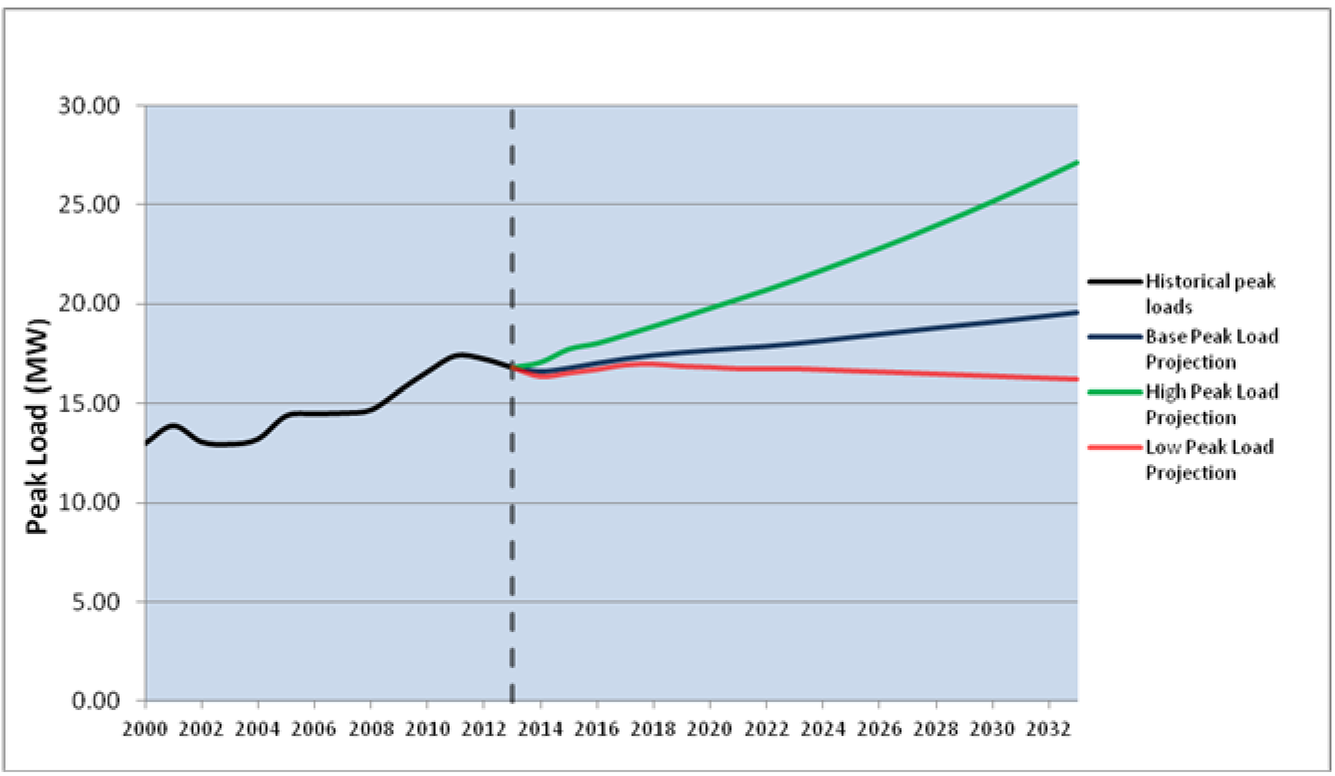

Figure 9: Historical & Projected System Peak Loads for DOMLEC: 2000-2033

2.4 Fuel Price Forecasts

2.4.1 Sources for Liquid Fuel Projections

Projections of long-term oil prices are performed regularly by third party oil market analyst groups and can show significant variation of results. In this report, the 2013 forecast produced by the U.S. Energy Information Administration (EIA) was used.

The EIA is the statistical and analytical agency within the U.S. Department of Energy (DOE). It collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets and public understanding of energy and its interaction with the economy and the environment. The EIA publishes two reports:

- **Short-Term Energy Outlook (STEO):** Energy projections for the next eighteen (18) months, updated monthly.
- **Annual Energy Outlook (AEO):** Projection and analysis of U.S. energy supply, demand and prices over a 25 to 30 year period based on the EIA's National Energy Modeling System.

The EIA's fuel price forecasts include Reference, High and Low fuel price scenarios which have been used in the IRP for sensitivity testing.

2.4.2 Liquid Fuel Forecast Methodology

In determining the fuel price forecast for diesel, the following methodology was used:

- A relationship was determined between the EIA's historical diesel fuel price and DOMLEC's delivered diesel price for the period 2010 to 2013. This was used to determine the delivered diesel price for the price forecast.
- The diesel price forecasts for 2014 to 2033 were derived from the Annual Energy Outlook 2013 report for April 2013.

Table 12 shows the reference, low and high fuel delivered price projections for diesel for 2014 – 2033 that are used in the model. These prices are expressed in real 2014 dollars.

Year	Reference Diesel Price		Low Diesel Price		High Diesel Price	
	EC$ /Imp. Gal.	EC$/mmbtu $_{LHV}$	EC$ /Imp. Gal.	EC$/mmbtu $_{LHV}$	EC$ /Imp. Gal.	EC$/mmbtu $_{LHV}$
2014	11.41	**72.45**	10.17	**64.56**	14.08	**89.38**
2015	11.48	**72.90**	9.76	**61.94**	15.29	**97.04**
2016	11.68	**74.13**	9.41	**59.75**	16.12	**102.30**
2017	11.93	**75.70**	9.05	**57.45**	16.39	**104.07**
2018	12.14	**77.09**	9.09	**57.69**	16.60	**105.39**
2019	12.38	**78.57**	9.09	**57.70**	16.91	**107.31**
2020	12.54	**79.57**	9.11	**57.82**	17.20	**109.19**
2021	12.79	**81.19**	9.20	**58.39**	17.56	**111.45**
2022	13.08	**83.03**	9.29	**58.97**	17.93	**113.80**
2023	13.26	**84.17**	9.35	**59.36**	18.24	**115.81**
2024	13.45	**85.38**	9.42	**59.79**	18.57	**117.87**
2025	13.66	**86.73**	9.47	**60.12**	18.91	**120.04**
2026	13.84	**87.87**	9.50	**60.30**	19.24	**122.10**
2027	14.02	**89.01**	9.53	**60.47**	19.59	**124.33**
2028	14.21	**90.19**	9.55	**60.59**	19.95	**126.67**
2029	14.39	**91.32**	9.56	**60.71**	20.30	**128.85**
2030	14.55	**92.38**	9.58	**60.83**	20.65	**131.07**
2031	14.72	**93.44**	9.60	**60.94**	21.00	**133.30**
2032	14.91	**94.66**	9.65	**61.27**	21.37	**135.64**
2033	15.15	**96.18**	9.66	**61.33**	21.75	**138.09**

Table 12: Fuel price projections for diesel for 2014 – 2033 in real 2014 dollars

2.4.3 Calorific values

A lower heating value (LHV) of 18,272Btu/lb, which is representative of the calorific value for diesel received by DOMLEC, was used in determining the fuel forecast for this study.

2.5 Generation System Reliability

2.5.1 Reliability Criterion

A system reliability criterion of having the firm capacity of the generation plants being greater than or equal to the expected peak load of the system has historically been used for expansion planning. Such criteria being applied ensures that service is uninterrupted in the event that the two largest generators on the system are out of service. Thus a reliability criterion of N-2 was adopted for this study.

2.5.2 Firm Capacity

The definition of firm capacity is the dry season capacity of the run-of-the-river hydro units plus the available capacity of the diesel units less the capacity of the two largest units.

2.6 Generation System Stability

2.6.1 Intermittent renewable energy penetration

Where intermittent renewable energy generators are utilized, an intermittent renewable energy penetration limit of 10% of annual peak demand was applied. This is consistent with intermittent renewable energy limits observed on other island grids.

2.6.2 Largest generating unit

Based on past operating experience, in order to maintain system frequency stability during a loss of generation event, it was determined that the maximum capacity of any generating unit on the network should not exceed 20% of the projected peak demand.

2.6.3 Generation spinning reserve

The spinning reserve policy states that the spinning reserve must exceed the dispatched unit with the largest output. The proportion of spinning reserve to system load ranges between 17% and 32% during the day due to the hydro-diesel generation mix.

For modeling purposes, a minimum of 3.0MW of spinning reserve was maintained throughout the period of study.

2.7 Transmission & Distribution System Stability

2.7.1 System losses

The five year average (2009-2013) for system losses is 9.47% of net generation. Any new transmission lines should not negatively affect the current level of system losses.

2.7.2 Voltage control in the North of Dominica (Generation maintained at Sugar Loaf)

Currently, high speed diesels at the Sugar Loaf station are operated continuously for the purpose of voltage control in the north of the island. This requirement will be required until the transmission link between Fond Cole and Sugar Loaf is upgraded. Generation out of Sugar Loaf was therefore constrained to a minimum of 2.4 MW until 2018 when the transmission network is assumed to be upgraded. Details on the planned transmission upgrades are presented in section 7.

3 Existing Generation Plant

The existing generating system is comprised of five power stations: Fond Cole, Sugar Loaf, Laudat, Padu and Trafalgar.

The Fond Cole Power Station is close to Roseau consisting of a mix of medium and high speed units (nine in total) with an installed capacity of 13.27MW and an available capacity of 12.30MW.

The Sugar Loaf Power Station, in the Portsmouth area, consists of five high speed units with an installed capacity of 6.75MW and an available capacity of 6.0MW.

The three cascading run-of-the-river hydro plants (Laudat, Trafalgar and Padu) are installed on the Roseau River with an installed capacity of 6.7MW and an available capacity of 6.0MW.

3.1 Diesel Power Stations

The operating and cost characteristics of the existing diesel -powered generating plant at Fond Cole and Sugar Loaf are shown in Table 13 and Table 14.

	Fond Colé								
	FC1	FC4	FC5	FC6	FC7	FC8	FC10	FC11	FC12
Manufacturer	Stork Wartsila	Stork Wartsila	Caterpillar	Caterpillar	Caterpillar	Caterpillar	MAN B + W	MAN B + W	MAN B + W
Technology	MSD	MSD	MSD	MSD	HSD	HSD	MSD	MSD	MSD
Model	6FHD-240	6FHD-240	3612	3608	3616B	3616B	7L28/32H	7L28/32H	7L28/32H
Installed (nameplate)Capacity (kW)	750	750	2840	1750	1400	1400	1460	1460	1460
Practical mimimum load (kW)	300	300	1200	875	500	700	730	730	730
Practical maximum load (kW)	600	600	2400	1750	1000	1400	1460	1460	1460
Installed Date	1986	1986	1996	1989	2003	2003	2009	2009	2009
Retirement Date	2019	2019	2038	2022	2028	2028	2040	2040	2040
Fuel Type	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel
Gross Heat Rate, LHV basis (Btu/kWh)	9340	10660	8752	8722	9867	9593	8635	8747	8807
Annual Maintenance rate (%)	0.86%	3.34%	2.95%	5.77%	7.29%	6.16%	7.03%	4.34%	6.38%
Mean time to repair:Planned outages (hrs)	12:00	12:00	72:00	48:00	24:00	24:00	72:00	72:00	72:00
Forced Outage rate (%)	0.61%	12.39%	10.38%	1.69%	2.22%	5.27%	7.06%	7.31%	3.64%
Mean time to repair:Forced outages (hrs)	2:00	2:00	6:00	4:00	2:00	2:00	4:00	4:00	4:00
Availability (%)	98.53%	84.27%	86.67%	92.54%	90.49%	88.57%	85.91%	88.34%	89.98%
Auxiliary Power Consumption (%)	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%
Variable O&M (EC$/MWh)	67.96	67.96	67.96	67.96	67.96	67.96	67.96	67.96	67.96

Table 13: Fond Cole - Existing Plant Characteristics

	Sugar Loaf				
	SL3	SL4	SL5	SL6	SL7
Manufacturer	Caterpillar	Caterpillar	Caterpillar	Caterpillar	Caterpillar
Technology	HSD	HSD	HSD	HSD	HSD
Model	3616	3516B	3516B	3516B	3516B
Installed (nameplate)Capacity (kW)	1350	1400	1400	1200	1400
Practical mimimum load (kW)	500	700	600	500	700
Practical maximum load (kW)	1000	1400	1200	1000	1400
Installed Date	1998	2003	2005	2007	2007
Retirement Date	2023	2028	2030	2032	2030
Fuel Type	Diesel	Diesel	Diesel	Diesel	Diesel
Gross Heat Rate, LHV basis (Btu/kWh)	9765	9210	9501	10030	9528
Annual Maintenance rate (%)	1.87%	8.90%	10.04%	5.95%	3.13%
Mean time to repair:Planned outages (hrs)	24:00	24:00	24:00	24:00	24:00
Forced Outage rate (%)	5.08%	7.35%	4.88%	0.94%	6.63%
Mean time to repair:Forced outages (hrs)	2:00	2:00	2:00	2:00	2:00
Availability (%)	93.05%	83.74%	85.08%	93.11%	90.23%
Auxiliary Power Consumption (%)	3.20%	3.20%	3.20%	3.20%	3.20%
Variable O&M (EC$/MWh)	49.86	49.86	49.86	49.86	49.86

Table 14: Sugar Loaf - Existing Plant Characteristics

3.2 Hydro-electric Power Stations

The average hourly load profile for the existing hydro-electric units for the period 2010 to 2013 was used to model the projected production. This allowed the seasonality of the output to be taken into consideration.

The operating and cost characteristics of the existing hydro-electric generating plant are tabulated in Table 15.

	Laudat	Trafalgar		Padu	
	LD1	NT1	NT2	PD1	PD2
Manufacturer	NOELL-PELTON	NOELL-PELTON	NOELL-PELTON	GILKES-TURGO IPM	GILKES-TURGO IPM
Technology	HYDRO	HYDRO	HYDRO	HYDRO	HYDRO
Model	Pelton Turbine	Pelton Turbine	Pelton Turbine	Turgo impulse, 22.5"	Turgo impulse, 22.5"
Installed (nameplate)Capacity (kW)	1300	1760	1760	940	940
Practical mimimum load (kW)	600	875	650	325	325
Practical maximum load (kW)	1200	1750	1750	650	650
Installed Date	1990	1991	1991	1967	1967
Retirement Date	2046	2047	2050	2029	2029
Annual maintenance rate (%)	0.69%	1.27%	0.75%	0.67%	4.34%
Mean time to repair:Planned outages (hrs)	8:00	12:00	12:00	8:00	8:00
Forced Outage rate (%)	0.42%	0.55%	16.69%	17.99%	34.71%
Mean time to repair:Forced outages (hrs:min)	1:30	2:00	2:00	1:30	1:30
Availability (%)	98.89%	98.18%	82.56%	81.34%	60.95%
Auxiliary Power Consumption (%)	0.20%	0.70%	0.70%	0.80%	0.80%
Variable O&M (EC$/MWh)	18.64	18.64	18.64	18.64	18.64

Table 15: Laudat, Padu & Trafalgar Existing Plant Characteristics

3.3 Present Generating Capacity Review

3.3.1 Retirement dates

At that time of the 2012 Integrated Resource Plan submission , the retirement schedule showed that all of DOMLEC's generating units were due to retire between 2012 and 2017, with most of them due to retire between 2012 and 2015.

However, the results of a 2013 Remaining Useful Life Study conducted by American Appraisal Associates Inc. suggests that the retirement of several units can be deferred due to the refurbishment of several units, namely:

- FC 5 has had its entire engine block, crankshaft, pistons, connecting rods and liners replaced in 2013. As a result, DOMLEC intends to apply for a life extension to 2037 for this unit.
- NT2's generator rotor was replaced and the stator was refurbished in 2013. The utility was granted a three (3) year life extension by the IRC based on this work.
- All turbines at Padu were completely refurbished.

The installation and commissioning of geothermal plant will allow the retirement of any diesel engines that are underperforming, whether through loss of efficiency or poor reliability. However, since the timeline for the installation of any geothermal plant is still unsure, no provision for the retirement of diesel units on this basis was made.

Expansion of the hydro-electric capacity of DOMLEC cannot ideally occur until the hydro-electric capacity can be replaced by another renewable source of electricity, e.g. geothermal capacity, to minimize the potential cost impact to customers. The expansion of the hydro-electric capacity will entail a minimum period of 18 months for which hydro-electric plant will be unavailable for production to carry out expansion works. Consequently, no expansion of the existing hydro-electric capacity was considered as part of this study.

The outcomes of the 2013 Remnant Life Study are tabulated below. All plant retirements take place at 00:00hrs on January 1 in the indicated year.

	Year In Service	Remaining Useful Life Beyond 2013	Date of last major refurbishment	Expected year of retirement
FC1	1986	5		2019
FC4	1986	5	25-Mar-2011	2019
FC5	1996	24	1-Aug-2013	2038
FC6	1989	8	4-Apr-2010	2022
FC7	2003	14	Mar - 2009	2028
FC8	2003	14	20-Nov-2013	2028
FC10	2009	26	30-Dec-2011	2040
FC11	2009	26	3-Oct-2011	2040
FC12	2009	26	15-Jun-2012	2040
SL3	1998	9	Jan - 2009	2023
SL4	2003	14	14-Sep-2012	2028
SL5	2005	16	30-Jun-2010	2030
SL6	2007	18	13-Feb-2011	2032
SL7	2007	16	5-Feb-2010	2030
LD1	1990	32	Mar - 2007	2046
NT1	1991	33	Mar - 2010	2047
NT2	1991	33	May - 2013	2050
PD1	1967	15	Oct - 2010	2029
PD2	1967	15	Oct - 2010	2029

Table 16: DOMLEC Remnant Life Study Outcomes

3.3.2 Heat rates

The heat rates for the units are based on the most recent five year average. The gross heat rate relates to the heat rate at the gross capacity of the plant using the lower heating value (LHV) of fuel.

3.3.3 Maintenance rate

Annual maintenance rate is the number of hours the unit is unavailable due to planned or corrective maintenance divided by the total number of hours in the year. The annual maintenance rates for the various generators are based on the most recent four year average.

3.3.4 Forced outage rate

Forced outage rate is the number of hours the unit is unavailable due to forced outages divided by the number of hours the unit is available. The forced outage rates for the various generators are based on the most recent four year average.

3.3.5 Auxiliary power consumption

The auxiliary power consumption is the amount of energy used in the plant for the production of electricity. The auxiliary power consumption for the existing units is based on the most recent five year average.

3.3.6 Fixed operating & maintenance cost

The fixed operating and maintenance costs are based on the most recent five year historical average corrected for annual inflation as reported by the International Monetary Fund.

3.3.7 Variable operating & maintenance cost

The variable operating and maintenance costs are based on the most recent five year historical average corrected for annual inflation as reported by the International Monetary Fund.

4 Candidate Generation Plant

The candidate plant that was considered during this assessment was as follows:-

- 1.8 MW Medium speed diesel units
- 3.5 MW Medium speed diesel units
- 0.5 MW Utility Scale PV Generators
- 3.5 MW Geothermal units
- 7.0 MW Geothermal units

Due to the timelines for construction, the earliest date for plant additions is assumed to be January 1, 2017.

4.1 Candidate diesel-based generating plant

The operating and cost characteristics of the candidate diesel-based generating plant used for the analysis are tabulated below. Medium speed diesel units were considered primarily based on the conventional fuel available, I.e. diesel. The cost assumptions are based on representative industry values across manufacturers for engines of similar capacity.

	MSD1.8	MSD3.5
Installed Capacity (MW)	1.80	3.45
Firm Capacity (MW)	1.73	3.32
Practical minimum load (MW)	0.90	1.50
Practical maximum load (MW)	1.80	3.45
Earliest Build Date	1/1/2017	1/1/2017
Economic life	20	20
Fuel Type	Diesel	Diesel
Gross Heat Rate, LHV basis (Btu/kWh)	9038.0	8769.0
Annual Maintenance rate (%)	8.0	8.0
Mean time to repair:Planned outages (hrs)	48:00	48:00
Forced Outage rate (%)	3.0	3.0
Mean time to repair:Forced outages (hrs)	6:00	6:00
Auxiliary Power Consumption (%)	4.0	4.0
Overnight Capital Cost ($/kW)	4709	4709
Capital Cost Incl. IDC ($/kW)	5574	5574
Variable O&M ($/MWh)	45.00	45.00

Table 17: Candidate Diesel Plant Characteristics

4.2 Candidate renewable energy-based generating plant

The operating and cost characteristics of the candidate renewable energy-based generating plant used for the analysis are tabulated below. Only solar PV technology and geothermal technology were considered.

The cost assumptions are based on estimates from the Lazard's Levelised Cost of Energy Analysis Report for 2013 while performance and operating characteristics are based on industry data.

	Solar	Geothermal	
Installed Capacity (MW)	0.5	3.5	7.0
Min Stable Capacity (MW)		2.5	5.0
Firm Capacity (MW)	-	-	-
Ramp Up Rate (MW/min)		0.5	0.5
Ramp Down Rate (MW/min)		0.5	0.5
Maximum capacity factor (%)		89	89
Earliest Build Date	1/1/2017	1/1/2018	1/1/2018
Economic life (yrs)	20	30	30
Configuration	Ground Mounted	-	-
Output	Modeled using solar profile	-	-
DC to AC conversion	85%	-	-
Annual Maintenance rate (%)	1.0	3.3	3.3
Mean time to repair:Planned outages (hrs)	24:00	140:00	140:00
Forced Outage rate (%)	-	0.6	0.6
Mean time to repair:Forced outages (hrs)	-	50:00	50:00
Auxiliary Power Consumption (%)		5.0	5.0
Overnight Capital Cost ($/kW)	5400	13500	13500
Capital Cost Incl. IDC ($/kW)	6319	15981	15981
Fixed O&M ($/kW/yr)	87.5	0.076	0.076
Variable O&M ($/MWh)	-	32.40	32.40

Table 18: Candidate Renewable Plant Characteristics

4.2.1 Renewable energy technology-based candidate plant

Only utility scale RE technologies are included as candidate plant in the IRP. A brief overview of each of these RE technologies is provided in the following sections.

4.2.1.1 *Solar Photovoltaic*

Solar photovoltaic (PV) panels are used to convert sunlight to electricity directly. Photovoltaic conversion is the direct conversion of sunlight into electricity with no intervening heat engine. When light photons of sufficient energy strike a solar cell, electrons move within the silicon crystal structure, resulting in a voltage between electrodes.

Solar photovoltaic panels are solid-state. At present, panels based on crystalline and polycrystalline silicon solar cells are the most common. Thin-film solar panels, especially cadmium telluride (CdTe) and copper indium gallium diselenide (CIGS) based cells, are gaining market share because of their lower costs and increased efficiencies. For example, the efficiencies of multi-junction cells and concentrating PV have been reported to be as high as 40% and most panels available in the market have efficiencies of the order of 15%.

Solar cells are arranged together in a solar module, which is installed on the roofs of houses or in large ground mounted installations. Solar modules generate Direct Current (DC) electricity, which needs to be converted into Alternating Current (AC) before it can be fed into the electricity grid and used in homes and businesses. The device used to convert DC to AC is called an inverter and thus, the two key components of PV generation are the modules and the inverter.

Utility grade installations of solar PV may be undertaken by private enterprise under a power purchase agreement facility, or developed by the electric utility.

4.2.1.2 *Geothermal Energy*

Geothermal power is generated by using steam or a hydrocarbon vapour to turn a turbine generator set to produce electricity. There are currently three main types of geothermal power plants:

- **Dry steam plants** using steam from underground wells to rotate a turbine, which activates a generator to produce electricity. Dry steam power plants systems were the first type of geothermal power generation plants built.
- **Flash steam plants** using hot-water resources, which are ‘flashed’ by reducing the pressure, to produce steam (normally in the 15% - 20% dryness range). Some plants use double and triple flash to improve the efficiency. The steam is then used to power a generator and any leftover water and condensed steam is returned to the reservoir.
- **Binary Cycle or Organic Rankine Cycle (ORC) plants** using the heat from lower temperature reservoirs to boil a working fluid, which is then vaporized in a heat exchanger and used to power a generator. Usually, a wet or dry cooling tower is used to condense the vapour after it leaves the turbine, to maximize the temperature and pressure drop between the incoming and outgoing vapour and thus increase the efficiency of the operation. The hot water, which never comes into direct contact with the working fluid, is then injected back into the ground to be reheated.

While the type of geothermal plant to be used has not been finalized, it is expected that the geothermal station will be sited at Laudat.

5 Modeling Methodology

5.1 Software

The software package used during the study was the PLEXOS 6.301R03 Utility Planning and Risk Management Software by Energy Exemplar. The Plexos software is used by utilities, ISO's, consulting firms and regulatory agents for operations, planning and market and transmission analyses. Plexos is a Mixed Integer Programming (MIP) energy market simulation and optimization software package, which is licensed in the United States, Europe, Asia-Pacific, Russia and Africa and used at over 100 sites.

The software seeks to minimize the net present value of forward-looking costs (i.e. capital and production costs), subject to fuel mix constraints including renewable energy targets, reliability and security of supply criteria and normal operating constraints.

The planning horizon, fuel and demand forecasts, typical load duration curve, existing plant and candidate plant data, reliability criteria as well as other criteria and constraints are inputted into the model and used in determining the least-cost plan.

5.2 Decision Criteria

The criterion used to determine the least-cost plan was the Net Present Value (NPV). The net present value of capital, fuel and operating and maintenance (O&M) costs for each plan over the 20-year planning horizon of the study was produced by the Plexos software model during the optimization process.

5.3 Electricity Demand Projections & Generation Expansion Scenarios

To take into account uncertainties due to input assumptions, a scenario planning approach was used in the assessment. The study considered three possible electricity growth projections described in Section 4.3. These are:

- High Demand
- Base Demand
- Low Demand

For each of these electricity demand projections, generation scenarios representing possible futures were evaluated. The planning model was then allowed to select the least-cost mix of resources for each combination of electricity demand and generation scenario.

Four (4) generation scenarios were considered during the assessment. The four generation scenarios selected for the IRP are defined by the technologies used in the generation of electricity, the timing of their implementation or changes to the initially projected demand profile.

1. Geothermal capacity addition of 7 MW in 2018, with additional geothermal capacity being available for selection from 2020, up to a maximum of 20MW of geothermal capacity being available for selection by the end of the planning period.
2. Geothermal capacity addition of 7 MW in 2021, with additional geothermal capacity being available for selection from 2023, up to a maximum of 20MW of geothermal capacity being available for selection by the end of the planning period.
3. Only reciprocating engines and utility scaled solar PV capacity being available for selection over the entire period of study.
4. Scenario 1 with the addition of a 2MW of load from 2018.

The four generation scenarios are tabulated below.

Technology Options Considered	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Geothermal (7MW by 2018)	√	X	X	√
Geothermal (7MW by 2021)	X	√	X	X
Additional Geothermal capacity from	2020	2023	N/A	2020
Reciprocating Engines	√	√	√	√
Solar PV	√	√	√	√
Injection of 2MW demand in 2018	X	X	X	√

Table 19: Scenario matrix

5.4 Sensitivity Analysis

5.4.1 Fuel Sensitivity Analysis

Sensitivity studies are usually undertaken to assess the impact of uncertainties that are inherent within the assumptions employed. This is especially relevant where projections for fuel price and for energy demand were used in modeling.

After determining the optimal plans for the base, high and low electricity growth demand projections, sensitivity analyses were performed on the optimal plans for each generation scenario in relation to fuel for the base, high and low fuel projections as identified in the Fuel Price Forecasts in Section 4.4.

The results for the sensitivity of the NPV to fuel price projections are reported in Section 9.5.

6 Generation Expansion Results

Table 20 below shows the net present value (NPV) results for the nine scenarios against the base, high and low electricity growth projections.

For the base electricity growth demand, Scenario 1 yielded the best NPV, followed by scenarios 4 then 2 and 3.

Electricity Demand	Scenarios	NPV ($ '000)
Base	Scenario 1	282,460
	Scenario 2	338,352
	Scenario 3	477,991
	Scenario 4	303,052
High	Scenario 1	331,186
	Scenario 2	397,414
	Scenario 3	561,581
	Scenario 4	363,221
Low	Scenario 1	253,577
	Scenario 2	298,924
	Scenario 3	396,839
	Scenario 4	273,794

Table 20: NPV results

The following sections detail the results of the generation scenarios for the base, low and high electricity growth demands. Additional results are available in the Appendices.

6.1 Base Electricity Demand

For base electricity demand projections, electricity demand is predicted to grow at an average of 1.6% per annum over the planning period.

6.1.1 Scenario 1- Capacity additions

Four 3.5MW geothermal units are selected in the planning period, representing 14.0MW of capacity. 7.0MW of geothermal capacity is selected in 2018 when it becomes available to the model. Another 3.5MW of geothermal capacity is added in 2020 and another 3.5MW of geothermal capacity is added in 2025. Two 0.5MW solar units are selected in 2017 representing 1.0 MW of capacity with another 0.5MW of solar capacity being selected in 2018.

Reciprocating diesel engines are required from 2032, where 1.8MW of generating capacity was required to maintain the system reliability.

The net present value of this plan is EC$282,460,208.

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	17.4	77.8	6.5
2019	1.50	0.0		33.7	17.5	69.9	5.2
2020	0.00	3.5	Geothermal - 1x3.5MW	37.2	17.6	88.3	8.5
2021	0.00	0.0		37.2	17.7	87.2	8.4
2022	1.75	0.0		35.5	17.8	76.4	6.6
2023	1.35	0.0		34.1	18.0	68.9	5.4
2024	0.00	0.0		34.1	18.1	68.0	5.3
2025	0.00	3.5	Geothermal - 1x3.5MW	37.6	18.3	84.8	8.4
2026	0.00	0.0		37.6	18.4	83.7	8.3
2027	0.00	0.0		37.6	18.6	81.7	8.1
2028	4.20	0.0		33.4	18.7	60.6	4.4
2029	1.88	0.0		31.5	18.9	51.9	2.9
2030	2.80	0.0		28.7	19.0	37.5	0.3
2031	0.00	0.0		28.7	19.2	36.0	0.1
2032	1.20	1.8	MSD - 1x1.8MW	29.3	19.3	39.4	0.8
2033	0.00	0.0		29.3	19.6	37.9	0.6

Table 21: Build Schedule for Scenario 1- Base sales forecast

6.1.2 Scenario 1- Reliability

The N-2 criterion for generation reliability is satisfied from 2014 throughout the planning period. The N-2 criterion translates to a minimum capacity reserve margin of 31%. The actual reserve margins are shown in Table 21.

6.1.3 Scenario2 - Capacity additions

Four 3.5MW geothermal units are selected in the planning period representing 14.0MW of capacity. 7.0MW of geothermal capacity is selected in 2021 when it becomes available to the model. Another 3.5MW of geothermal capacity is added in 2023 and another 3.5MW of geothermal capacity is added in 2025.

Two 0.5 MW solar units are selected in 2017 representing 1.0MW of capacity. 0.5MW of solar capacity is also selected in 2018.

Reciprocating diesel engines are required in 2019. In 2019, 1.8MW of diesel generating capacity is required to maintain the system reliability. No further reciprocating capacity is required for the remainder of the planning period.

The net present value of this plan is EC$338,352,151.

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	0.5	Solar - 1x0.5MW	28.2	17.4	38.4	2.4
2019	1.50	1.8	MSD - 1x1.8MW	28.5	17.5	40.9	2.9
2020	0.00	0.0		28.5	17.6	40.1	2.8
2021	0.00	7.0	Geothermal - 2x3.5MW	35.5	17.7	78.0	6.8
2022	1.75	0.0		33.8	17.8	67.2	5.0
2023	1.35	3.5	Geothermal - 1x3.5MW	35.9	18.0	78.8	7.1
2024	0.00	0.0		35.9	18.1	77.8	7.0
2025	0.00	3.5	Geothermal - 1x3.5MW	39.4	18.3	94.5	10.2
2026	0.00	0.0		39.4	18.4	93.4	10.1
2027	0.00	0.0		39.4	18.6	91.3	9.9
2028	4.20	0.0		35.2	18.7	70.1	6.1
2029	1.88	0.0		33.3	18.9	61.3	4.6
2030	2.80	0.0		30.5	19.0	46.9	2.0
2031	0.00	0.0		30.5	19.2	45.3	1.8
2032	1.20	0.0		29.3	19.3	39.4	0.8
2033	0.00	0.0		29.3	19.5	37.9	0.6

Table 22: Build Schedule for Scenario 2- Base sales forecast

6.1.4 Scenario2 - Reliability

The N-2 criterion for generation reliability is satisfied from 2014 throughout the planning period. The N-2 criterion translates to a minimum capacity reserve margin of 31%. The actual reserve margins are shown in Table 22.

6.1.5 Scenario 3- Capacity additions

Two 0.5 MW solar units are selected in 2017 representing 1.0MW of capacity. 0.5MW of solar capacity is also selected in 2018.

Reciprocating diesel engines are required from 2019. Over the planning period, three medium speed units of 1.8MW capacity each are required. Similarly, over the planning period, three medium speed units of 3.5MW capacity each are also required.

The net present value of this plan is EC$477,990,619.

Year	Capacity Retired (MW)	Capacity Added (MW)	Type	Total Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	0.5	Solar - 1x0.5MW	28.2	17.4	38.4	2.4
2019	1.50	1.8	MSD - 1x1.8MW	28.5	17.5	40.9	2.9
2020	0.00	0.0		28.5	17.6	40.1	2.8
2021	0.00	0.0		28.5	17.7	39.3	2.7
2022	1.75	3.5	MSD - 1x3.5MW	30.3	17.8	48.0	2.7
2023	1.35	0.0		28.9	18.0	40.8	1.5
2024	0.00	0.0		28.9	18.1	40.0	1.4
2025	0.00	0.0		28.9	18.3	38.4	1.2
2026	0.00	1.8	MSD - 1x1.8MW	30.7	18.4	47.3	2.8
2027	0.00	0.0		30.7	18.6	45.7	2.6
2028	4.20	3.5	MSD - 1x3.5MW	30.0	18.7	43.0	1.2
2029	1.88	3.5	MSD - 1x3.5MW	31.6	18.9	52.6	3.0
2030	2.80	0.0		28.8	19.0	38.2	0.4
2031	0.00	1.8	MSD - 1x1.8MW	30.6	19.2	45.9	2.0
2032	1.20	0.0		29.4	19.3	40.1	0.9
2033	0.00	0.0		29.4	19.5	38.6	0.7

Table 23: Build Schedule for Scenario 3- Base sales forecast

6.1.6 Scenario 3- Reliability

The N-2 criterion for generation reliability is satisfied from 2014 throughout the planning period. The N-2 criterion translates to a minimum capacity reserve margin of 38%. The actual reserve margins are shown in Table 23.

6.1.7 Scenario 4 - Capacity additions

For scenario 4, the 2MW load injection is allowed to occur in 2018, coincident with the introduction of geothermal electricity production in 2018.

Two 0.5 MW solar units are selected in 2017 representing 1.0MW of capacity. 0.5MW of solar capacity is also selected in 2018 and in 2027.

Four 3.5MW geothermal units are selected in the planning period, representing 14.0MW of capacity. 7.0MW of geothermal capacity is selected in 2018 when it becomes available to the model. Another 7.0MW of geothermal capacity is added in 2020.

Reciprocating diesel engines are required from 2030, where 1.8MW of generating capacity is required to maintain the system reliability.

The injection of additional load causes the installation of more geothermal capacity to occur earlier in the planning period than was observed in scenario 1. Further, an additional 0.5MW of solar capacity is required during the planning period, when compared to scenario 1.

The net present value of this plan is EC$303, 051, 576.

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.1	45.3	3.2
2015	0.00	0.0		26.7	16.3	43.5	3.0
2016	0.00	0.0		26.7	16.5	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	16.7	40.1	2.6
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	18.9	58.9	4.5
2019	1.50	0.0		33.7	19.0	52.0	3.2
2020	0.00	7.0	Geothermal - 2x3.5MW	40.7	19.1	86.0	9.8
2021	0.00	0.0		40.7	19.2	85.1	9.7
2022	1.75	0.0		39.0	19.3	75.4	7.9
2023	1.35	0.0		37.6	19.5	68.7	6.7
2024	0.00	0.0		37.6	19.6	67.8	6.6
2025	0.00	0.0		37.6	19.8	66.1	6.4
2026	0.00	0.0		37.6	19.9	65.3	6.3
2027	0.00	0.5	Solar - 1x0.5MW	38.1	20.1	63.6	6.1
2028	4.20	0.0		33.9	20.2	44.7	2.4
2029	1.88	0.0		32.0	20.4	37.0	0.9
2030	2.80	3.6	MSD - 2x1.8MW	32.8	20.5	41.0	1.8
2031	0.00	0.0		32.8	20.7	39.6	1.6
2032	1.20	0.0		31.6	20.8	34.3	0.5
2033	0.00	0.0		31.6	21.0	33.0	0.3

Table 24: Build Schedule for Scenario 4- Base sales forecast

6.1.8 Scenario 4 - Reliability

The N-2 criterion for generation reliability was satisfied from 2014 throughout the planning period. The N-2 criterion translated to a minimum capacity reserve margin of 33%, based on the size of the generators.

6.2 Low Electricity Demand

For low electricity demand projections, electricity demand is predicted to grow at an average of 0.1% per annum over the planning period. Additional information is detailed in the appendices.

6.2.1 Scenario 1

In scenario 1, 13.3MW of new capacity is required over the planning period. 1.0MW of solar capacity is installed in 2017. 10.5MW of geothermal capacity is installed between 2018 and 2020. A further 1.8MW of medium speed diesel capacity is added in 2030. The net present value of this plan is EC$ 253,576, 565.

6.2.2 Scenario 2

In scenario 2, 13.8MW of new capacity is required over the planning period. This plan features the installation of solar technology in 2017 and 2018. Medium speed diesel technology is added in 2019, just prior to the allowed introduction of geothermal technologies in 2021, and a subsequent geothermal installation in 2023. A total of 10.5MW of geothermal capacity, 1.5MW of solar technology and 1.8MW of medium speed diesel technology is required during the planning period. The net present value of this plan is EC$ 298,924,362.

6.2.3 Scenario 3

In scenario 3, 13.8MW of new capacity is required over the planning period. This generation scenario has only solar and medium speed diesel technologies available for selection. 1.5MW of solar technology is installed between 2017 and 2018. A total of 12.3MW of medium speed diesel capacity is installed between 2018 and 2030. The net present value of this plan is EC$ 396,838,959.

6.2.4 Scenario 4

In scenario 4, 15.5MW of new capacity is required over the planning period. 1.0MW of solar capacity is installed in 2017 and a further 0.5MW of solar capacity is added in 2018. 10.5MW of geothermal capacity is installed between 2018 and 2020 and a further 3.5MW of geothermal capacity is added in 2029. The net present value of this plan is EC$ 273,793,639.

6.3 High Electricity Demand

For high electricity demand projections, electricity demand is predicted to grow at an average of 3.1% per annum over the planning period. Additional information is detailed in the appendices.

6.3.1 Scenario 1

A total of 27.1MW of capacity is required over the planning period for scenario 1. 1.5MW of solar technology is installed between 2017 and 2018. A further 0.5MW of solar capacity is installed in 2022 and 2031. Four 3.5MW geothermal units are selected in the planning period, representing 14.0MW of capacity. 7.0MW of geothermal capacity is selected in 2018 when it becomes available to the model. Another 7.0MW of geothermal capacity is added in 2020. Reciprocating diesel engines are required from 2028. Over the planning period, two medium speed units of 1.8MW capacity each and two medium speed units of 3.5MW capacity each are also required. The net present value of this plan is EC$ 331,185,842.

6.3.2 Scenario 2

A total of 27.1MW of capacity is required over the planning period for scenario 2. 1.5MW of solar technology is installed between 2017 and 2018. A further 0.5MW of solar capacity is installed in 2022 and 2031. 7.0MW of geothermal capacity is selected in 2021 when it becomes available to the model. Another 7.0MW of geothermal capacity is added in 2023. Reciprocating diesel engines are required from 2019, prior to the allowed entry of geothermal capacity in 2021. Over the planning period, two medium speed units of 1.8MW capacity each and two medium speed units of 3.5MW capacity each are also required. The net present value of this plan is EC$397,413,615.

6.3.3 Scenario 3

A total of 27.2MW of capacity is required over the planning period for scenario 3. 1.5MW of solar technology is installed between 2017 and 2018. A further 0.5MW of solar capacity is installed in 2022 and 2031. Reciprocating diesel engines are required from 2018. Over the planning period, four medium speed units of 1.8MW capacity each and four medium speed units of 3.5MW capacity each are also required. The net present value of this plan is EC$ 56,158,1451.

6.3.4 Scenario 4

A total of 28.8W of capacity is required over the planning period for scenario 4. 2.0MW of solar technology is installed between 2017 and 2018. A further 0.5MW of solar capacity is installed in 2028. Four 3.5MW geothermal units are selected in the planning period, representing 14.0MW of capacity. 7.0MW of geothermal capacity is selected in 2018 when it becomes available to the model. Another 7.0MW of geothermal capacity is added in 2020. Reciprocating diesel engines are required from 2028. Over the planning period, one medium speed unit of 1.8MW capacity each and three medium speed units of 3.5MW capacity each are also required. The net present value of this plan is EC$ 363,220,502.

6.4 Generation Expansion Sensitivity Analysis

Table 25 shows the results of the sensitivity analysis performed on the optimal plans for each generation scenario in relation to fuel price.

Sensitivity	Base Demand World NPV ($ '000)			
	Scenario 1:	Scenario 2:	Scenario 3:	Scenario 4:
Base	282,460	338,352	477,991	303,052
Fuel - High	338,555	420,952	630,882	362,654
Fuel - Low	250,483	287,093	371,360	269,367

Sensitivity	High Demand World NPV ($ '000)			
	Scenario 1:	Scenario 2:	Scenario 3:	Scenario 4:
Base	331,186	397,414	561,581	363,221
Fuel - High	400,206	498,460	741,810	442,822
Fuel - Low	290,341	333,191	433,980	314,177

Sensitivity	Low Demand World NPV ($ '000)			
	Scenario 1:	Scenario 2:	Scenario 3:	Scenario 4:
Base	253,577	298,924	396,839	273,794
Fuel - High	304,826	372,434	520,975	329,902
Fuel - Low	225,645	254,875	312,322	241,991

Table 25: NPV sensitivity values

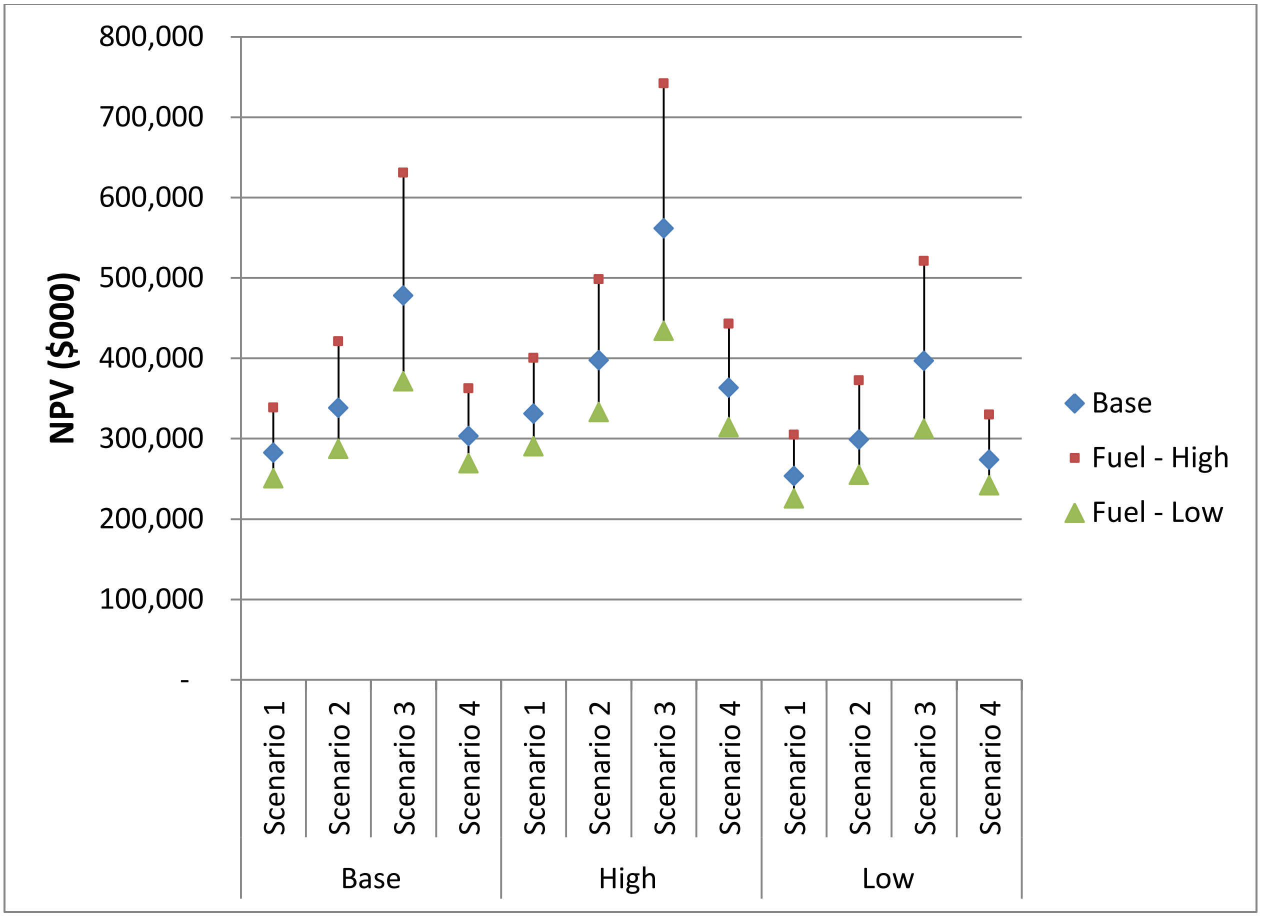

Figure 10: NPV Sensitivity chart

Scenario 3, which does not feature geothermal capacity as an expansion option was, as expected, the most sensitive to changes in fuel price over the planning period.

6.5 Generation Expansion Recommendation

The configuration that resulted in the lowest net present value over the planning period against a base sales background was generation scenario 1, which assumed the introduction of geothermal electricity production from 2018. Table 26 shows the build schedule for the recommended plan. The net present value for this plan was EC$ 282,460,208.

This early introduction of renewable energy technologies provides the means by which a least cost generation expansion plan was derived, as the contribution of fuel costs to the net present value of the plan are significantly lessened.

Further details on the energy and cost of the recommended plan can be found in Appendix 11.14.

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	17.4	77.8	6.5
2019	1.50	0.0		33.7	17.5	69.9	5.2
2020	0.00	3.5	Geothermal - 1x3.5MW	37.2	17.6	88.3	8.5
2021	0.00	0.0		37.2	17.7	87.2	8.4
2022	1.75	0.0		35.5	17.8	76.4	6.6
2023	1.35	0.0		34.1	18.0	68.9	5.4
2024	0.00	0.0		34.1	18.1	68.0	5.3
2025	0.00	3.5	Geothermal - 1x3.5MW	37.6	18.3	84.8	8.4
2026	0.00	0.0		37.6	18.4	83.7	8.3
2027	0.00	0.0		37.6	18.6	81.7	8.1
2028	4.20	0.0		33.4	18.7	60.6	4.4
2029	1.88	0.0		31.5	18.9	51.9	2.9
2030	2.80	0.0		28.7	19.0	37.5	0.3
2031	0.00	0.0		28.7	19.2	36.0	0.1
2032	1.20	1.8	MSD - 1x1.8MW	29.3	19.3	39.4	0.8
2033	0.00	0.0		29.3	19.6	37.9	0.6

Table 26: Build Schedule for Scenario 1- Base sales forecast

7 Transmission & Distribution Network Assessment

The current transmission and distribution system consists of two main load centers: Roseau (in the south) and Portsmouth (in the north). All the loads are fed through an 11kV distribution network. The existing network was reviewed and recommendations made for its upgrade based on the recommended generation expansion scenario.

7.1 Existing Transmission Network

DOMLEC's existing power transmission system contains an 11 kV transmission ring for reliable transfer of power from one station to another as shown in Figure 11 below.

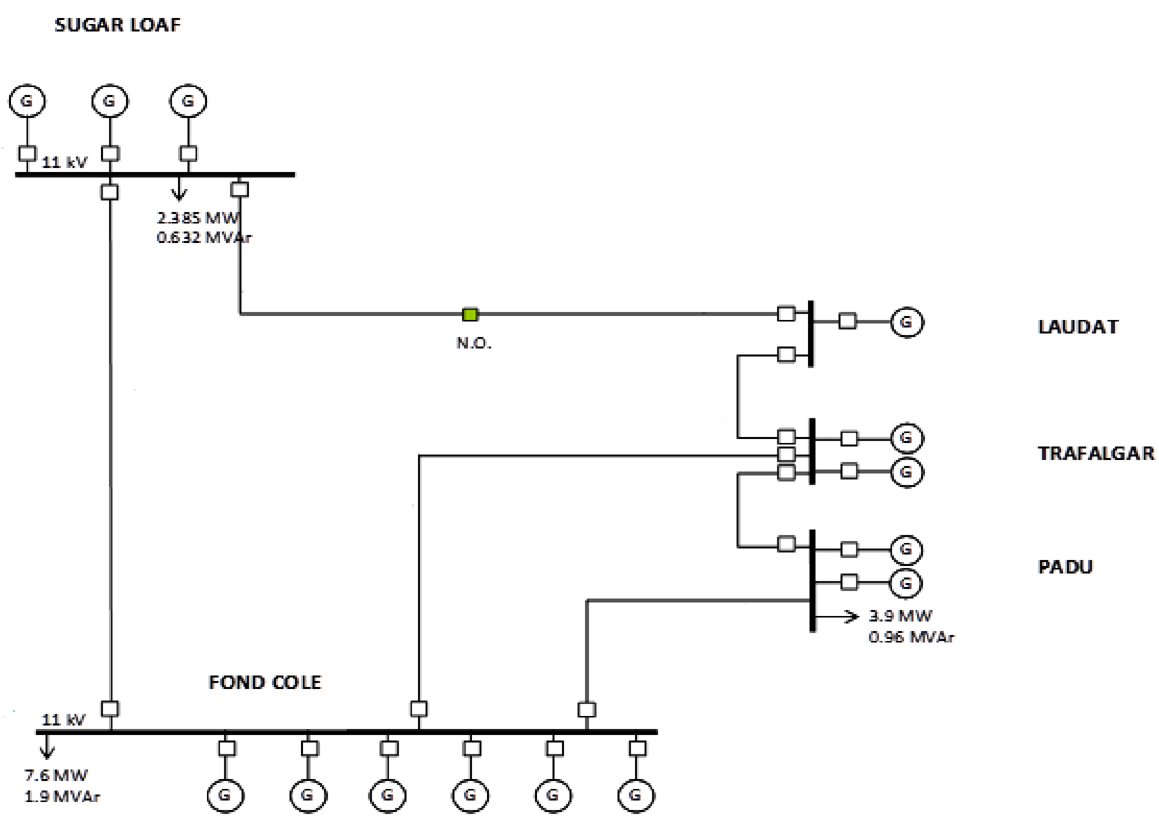

Figure 11: Existing DOMLEC Transmission Network

Included in this transmission ring are the Fond Cole, Padu, and Trafalgar power stations. This ring provides flexibility for the transfer of hydro power to Fond Cole, the largest distribution station on the network. The voltages on the 11kV buses are all acceptable when a minimum of 2.4MW is generated at Sugar Loaf. In the event of the failure of an inter-connector, another inter-connector is able to transfer the power required at the distribution stations. Table 27 shows the lengths of the station lines and routes.

The Sugar Loaf power station is normally linked to the grid via the Portsmouth Feeder, but has alternate links through the Belfast, Sugarloaf East, and East Coast feeders. The Laudat power station is normally linked to the grid via the Trafalgar-Laudat Inter-connector. Its alternate link is the interconnection of the East Coast and Belfast, or Sugarloaf East feeders.

The inter-connectors between Fond Cole, Padu, Trafalgar and Laudat are all capable of being upgraded to 33kV, and have an ampacity of approximately 500A.

From	To	Distance (km)	Line size
Fond Cole	Laudat	7.25	ACSR 170.5 (mm^2)
Fond Cole	Padu	5.63	ACSR 170.5 (mm^2)
Fond Cole	Trafalgar	6.04	ACSR 170.5 (mm^2)
Padu	Trafalgar	1.61	ACSR 170.5 (mm^2)
Trafalgar	Laudat	1.21	ACSR 170.5 (mm^2)
Fond Cole	Sugar Loaf	36.00	AAC 75 (mm^2)
Laudat	Sugar Loaf	61.48	ACSR 85.03 (mm^2)

Table 27: Physical characteristics of extant station lines and routes

7.2 Existing Distribution Network

The distribution system consists of nine feeders. Four of the heavily loaded feeders are supplied from the Fond Cole station, the main distribution station, while two are supplied from the Padu station, two from the Sugar Loaf station, and one from the Laudat station.

The Portsmouth Feeder is 36 km of 75 (mm^2)aluminum alloy conductor, required to carry a peak of 2.02MVA for distribution along its length plus 3.8 MVA to the consumers on the Sugarloaf East Feeder (21.12 km long) and the Sugar Loaf West Feeder (7.85 km long).

Due to the conductor size, feeder lengths, and growing load on the feeders, the power quality levels in the North of the island were initially unacceptable. As a result, the Sugar Loaf generating station was installed to provide stability on this portion of the network.

If the Sugar Loaf diesel units are removed from normal operation, due to retirement or proposed expansion plans, the load provided by the station must be replaced by other suitable means in order to maintain existing power quality levels.

Based on the current performance constraints of the transmission and distribution network, the transmission and distribution network will have to be strengthened to accommodate any new generation.

It is expected that any geothermal power station development will be sited at Laudat. The shortest line route between Laudat and Fond Cole (the main distribution center) is a cross country route approximately 7.25 km in length through steep mountains, river crossings and valleys covered with heavy vegetation. This makes the construction of an underground backup line for delivery of power from Laudat to Fond Cole a technical challenge and inordinately expensive, and, as such, this not considered.

The route of the Trafalgar-Padu inter-connector is not conducive to expansion by the construction of a parallel circuit, due to residential construction along the right-of-way (ROW). The construction of any other line from Padu to Trafalgar would require the establishment of an entirely new route traversing the terrain stated above. This construction would be 100% off-road so all materials would have to be transported without the aid of vehicles. This also presents a technical challenge and as such is not considered.

In addition, there is need for voltage control in the north of the island where generation is currently operated continuously for voltage stability.

7.3 Interconnection Scenarios

The following interconnection scenarios were evaluated for the interconnection of geothermal energy into the grid via overhead lines.

- **Interconnection Scenario 1:** Geothermal power station to extant network at 11 kV.
- **Interconnection Scenario 2:** Geothermal power station at 11 kV, Sugarloaf at 33 kV
- **Interconnection Scenario 3a:** Geothermal and Laudat station at 33kV, Sugarloaf at 33kV, Padu and Interconnection Trafalgar at 11kV
- **Interconnection Scenario 3b:** Geothermal power station and Sugarloaf at 33kV, Laudat, Padu, and Trafalgar at 11kV
- **Interconnection Scenario 4:** Geothermal power station, Fond Cole, Trafalgar and Padu in a 33kV ring, geothermal power station to Laudat station as an 11kV radial, Fond Cole to Sugar Loaf inter-connector at 33kV.
- **Interconnection Scenario 5:** All other stations at connected at 33kV in a ring configuration, Fond Cole to Sugar Loaf inter-connector at 33kV.

7.4 Transmission Interconnection Recommendation

The recommended plan is interconnection scenario 4 (Figure 12), which includes a 33kV substation at Trafalgar, Padu, Fond Cole, and the geothermal stations with the stations connected in a ring configuration. Laudat is linked to the geothermal station 11kV bus and operated radially. Fond Cole and Sugar Loaf are also interconnected at 33kV. This interconnection scenario satisfies the reliability, system losses, supply quality, minimized diesel usage, and hydro power requirements.

The creation of the 33kV interconnectors from Fond Cole to Sugar Loaf and from Fond Cole to the new geothermal station can be leveraged for the future generation expansion of the system. Components of the existing 11kV line in the Roseau Valley have been provisioned for 33kV, creating opportunities to reduce the projected line costs. The ability to estimate and control the planned investments is much better because it involves substation builds and not line builds. Due to the terrain and land constraints, interconnection scenarios that involve more line construction in the Roseau Valley are less predictable and have greater potential for cost overruns.

The benefits of the 33kV interconnectors include the following:

- Provision of room for future growth as this is the most cost effective solution for additional geothermal generation (beyond the 20 MW identified for the purposes of this study)
- Reduction of land issues by use of existing right of ways
- Lower losses with higher transmission voltage

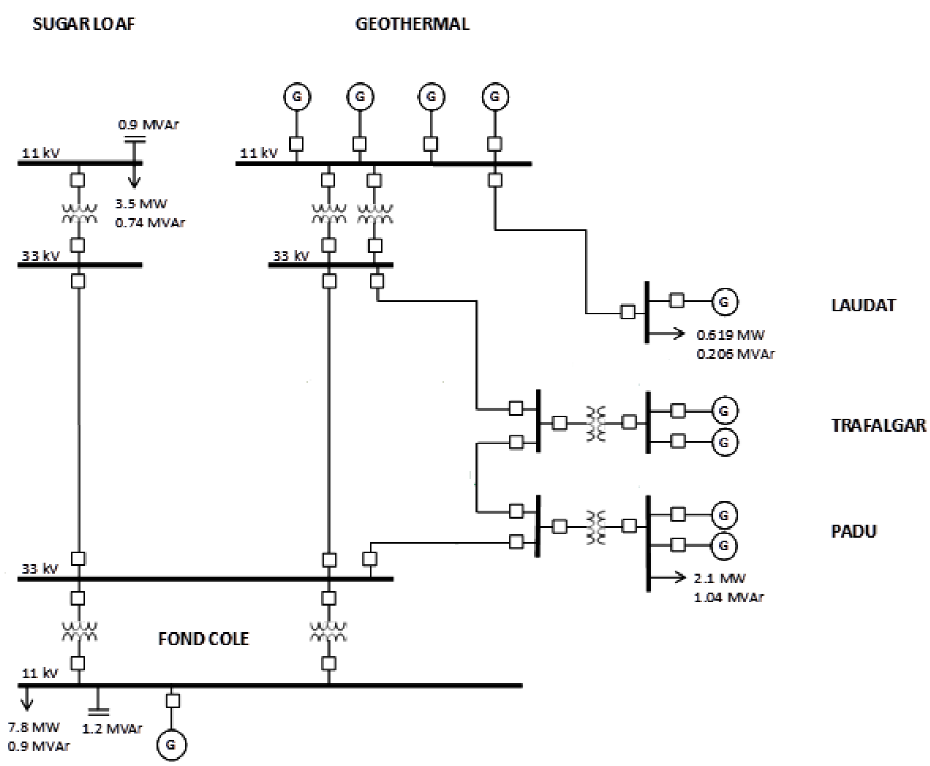

Figure 12: Recommended DOMLEC Transmission Interconnection Network

8 Conclusion

An assessment was conducted into the generation expansion required over the planning period 2014 to 2033. This assessment sought to project the electricity demand growth in Dominica from 2014 to 2033 based on previous load data and anticipated significant events for a low, base and high growth rate. A review of the age and reliability of the present fleet of generators, giving consideration to expected retirements was done. Potentially viable candidate plant for generation expansion for the period 2014 through 2033 was identified and a determination of when new capacity, if any, is required for the generating system to maintain reliability requirements for Dominica was made. Additionally, the performance constraints of the transmission and distribution system which may occur within the period of the plan, based on projected generation expansion were assessed. The four generation scenarios considered during this assessment are summarized in Table 28.

Technology Options Considered	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Geothermal (7MW by 2018)	√	X	X	√
Geothermal (7MW by 2021)	X	√	X	X
Additional Geothermal capacity from	2020	2023	N/A	2020
Reciprocating Engines	√	√	√	√
Solar PV	√	√	√	√
Injection of 2MW demand in 2018	X	X	X	√

Table 28: Scenario Matrix of Unit Sizes and Technologies

The generation configuration that resulted in the lowest net present value over the planning period against a base demand growth demand was scenario 1, which consisted of four 3.5MW geothermal units in the planning period, representing 14.0MW of capacity, three 0.5MW solar units representing 1.5 MW of capacity and 1.8MW of reciprocating diesel engine generating capacity. This plan assumed the introduction of geothermal electricity production from 2018. The net present value for this plan was EC$ 282,460,208.

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	17.4	77.8	6.5
2019	1.50	0.0		33.7	17.5	69.9	5.2
2020	0.00	3.5	Geothermal - 1x3.5MW	37.2	17.6	88.3	8.5
2021	0.00	0.0		37.2	17.7	87.2	8.4
2022	1.75	0.0		35.5	17.8	76.4	6.6
2023	1.35	0.0		34.1	18.0	68.9	5.4
2024	0.00	0.0		34.1	18.1	68.0	5.3
2025	0.00	3.5	Geothermal - 1x3.5MW	37.6	18.3	84.8	8.4
2026	0.00	0.0		37.6	18.4	83.7	8.3
2027	0.00	0.0		37.6	18.6	81.7	8.1
2028	4.20	0.0		33.4	18.7	60.6	4.4
2029	1.88	0.0		31.5	18.9	51.9	2.9
2030	2.80	0.0		28.7	19.0	37.5	0.3
2031	0.00	0.0		28.7	19.2	36.0	0.1
2032	1.20	1.8	MSD - 1x1.8MW	29.3	19.3	39.4	0.8
2033	0.00	0.0		29.3	19.6	37.9	0.6

Table 29: Build Schedule for Scenario 1- Base sales forecast

In the first five years of the recommended plan, assuming that the anticipated timing of the introduction of the renewable energy technologies can be realized, generation expansion based on only renewable energy technologies can be achieved. 7.0MW of geothermal capacity is selected in 2018 when it becomes available to the model and another 3.5MW of geothermal capacity is added in 2020. Two 0.5MW solar units are selected in 2017 representing 1.0 MW of capacity with another 0.5MW of solar capacity being selected in 2018. This early introduction of renewable energy technologies provides the means by which a least cost plan was derived, as the contribution of fuel costs to the net present value of the plan are significantly lessened.

Sensitivity analysis to fuel prices indicated that generation scenario 3, which does not feature geothermal capacity as an expansion option was, as expected, the most sensitive to changes in fuel price over the planning period.

To accommodate the recommended generation expansion, the recommended transmission requirement was interconnection scenario 4 (Figure 13), which includes a 33kV substation at Trafalgar, Padu, Fond Cole, and the geothermal stations with the stations connected in a ring configuration. Laudat is linked to the geothermal station 11kV bus and operated radially. This scenario satisfies the reliability, system losses, supply quality, minimized diesel usage, and hydro power requirements.

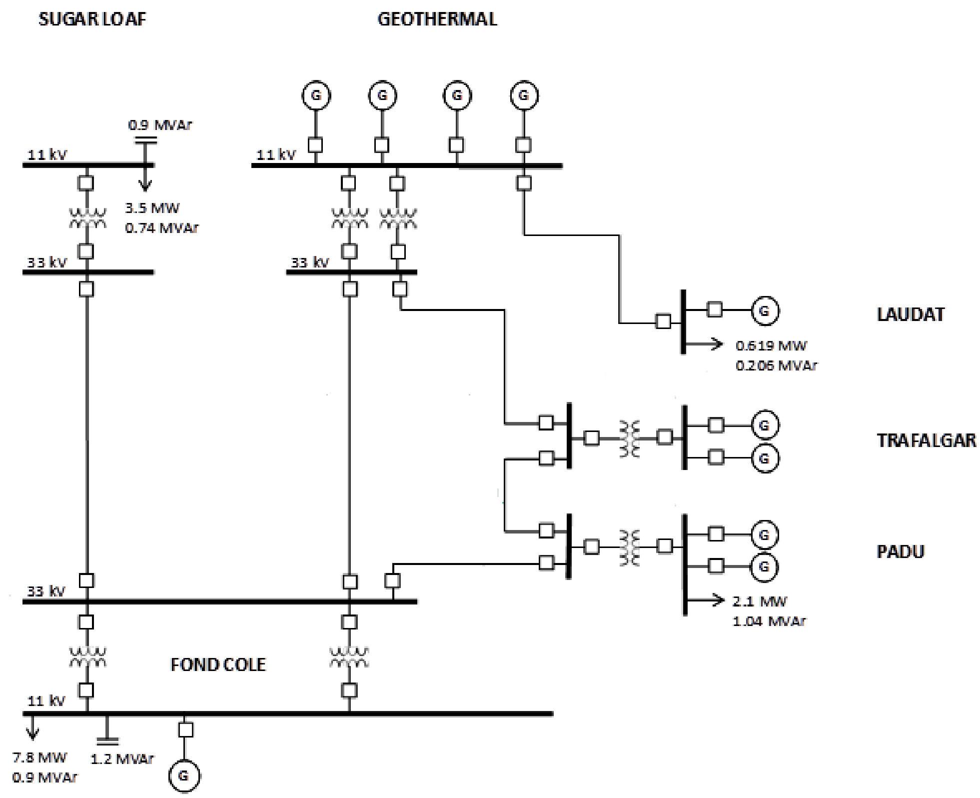

Figure 13: Recommended DOMLEC Transmission Interconnection Network

9 References

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10 Appendix

10.1 Demand Forecast Drivers & Models

Dominica Electricity Services (DOMLEC) prepared a forecast of energy demand and load as an input into the development of an Integrated Resource Plan (IRP). The demand and load forecast represents DOMLEC's best estimate of future demand for electricity given the impact of customer, demographic, weather and economic factors.

The forecast consists of a 20-year future energy demand and sales using econometric models that utilize a number of variables as drivers for individual customer classes' load. The demand forecasts were developed by utilizing partial adjustment econometric models to analyze and model the relationship between energy demand and the predictors of future demand. These predictors are referred to as forecast drivers. Gross Domestic Product (GDP), average temperatures, fuel prices and electricity prices are utilized as the key drivers for future electricity consumption.

Customer class specific econometric models are employed to model and forecast energy demand for the three main customer groups namely, Residential, Commercial & Industrial (commercial, industrial & hotel tariffs) and Streetlights (lighting & street lighting tariffs). Forecast estimates for each of the customer classes are aggregated to produce a forecast of annual demand.

Annual demand is used to derive net system load by applying the most recent three year annual average system losses (8.3%) to the first two years.

System losses are expected to increase to 9.1% after 2015 due to upgrades in transformers on the distribution system.

10.1.1 Forecast Drivers

Table 30 provides an overview of the key drivers for the base case forecast.

Forecast Component	Data
Residential Load	• Historical Domestic Service Tariff Sales • Historical & Forecasted GDP • Historical & Forecasted Electricity Prices
Commercial & Industrial Load	• Historical Commercial, Industrial and Hotel tariff Sales • Historical & Forecasted GDP • Historical & Forecasted Average Temperatures
Street Lighting	• Historical Street Lighting & Lighting Tariff Sales • Historical & Forecasted Customer Growth
Customer Growth	• Historical Customer Growth • Historical & Forecasted GDP
System Peak Demand	• Historical System Peak Demand • Historical & Forecasted System Load • Historical & Forecasted Temperatures

Table 30: Key Forecast Drivers

10.1.2 Data Sources

Table 31 provides an overview of the data sources for the variables included in the forecast.

Data	Data Source
Historical Sales	Billing Data – DOMLEC
Historical & Forecasted Average Temperatures	Meteorological Department
Historical & Forecasted GDP	Eastern Caribbean Central Bank International Monetary Fund
Historical & Forecasted Electricity Prices	Billing Data – DOMLEC DOMLEC Fuel Price Forecast
Historical and Forecasted Customer Growth	Billing Data – DOMLEC

Table 31: Data Sources

10.1.3 Residential Forecast Model

The econometric model for growth in residential load was estimated in logs as follows:

$$RES_{it} = \alpha_{ij} + \beta_{ij} RPRICE_{it} + \gamma_{ij} GDP_{it} + \varphi_{ij} RES_{i,t-j} + \nu_{ij}$$

Where:

- RES is residential class sales
- ν is the error associated with the model
- α, β, γ and φ are the regression coefficients from a time series regression of residential sales on a constant, average residential electricity price, real GDP, and past residential sales.

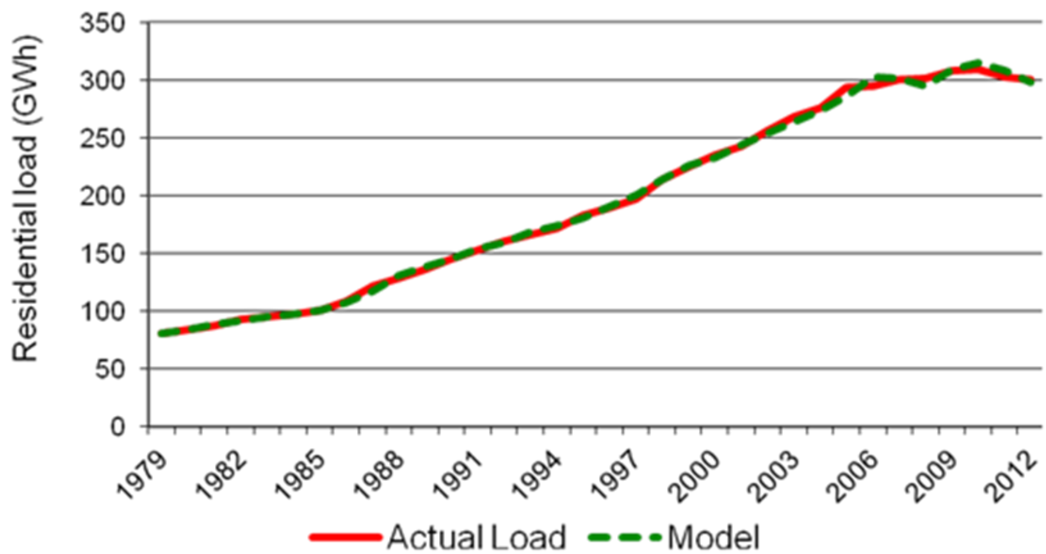

Figure 14: Residential Model Fit

10.1.4 Commercial & Industrial Forecast Model

The econometric model for growth in commercial & industrial load was estimated in logs as follows:

$$CI_{it} = \alpha_{ij} + \gamma_{ij} GDP_{it} + \delta_{ij} TEMP_{ti} + \varphi_{ij} CI_{i,t-j} + v_{ij}$$

Where:

- CI is Commercial & Industrial class sales
- v is the error associated with the model
- α, γ, δ and φ are the regression coefficients from a time series regression of commercial & industrial sales on a constant, real GDP, average temperature and past commercial & industrial sales.

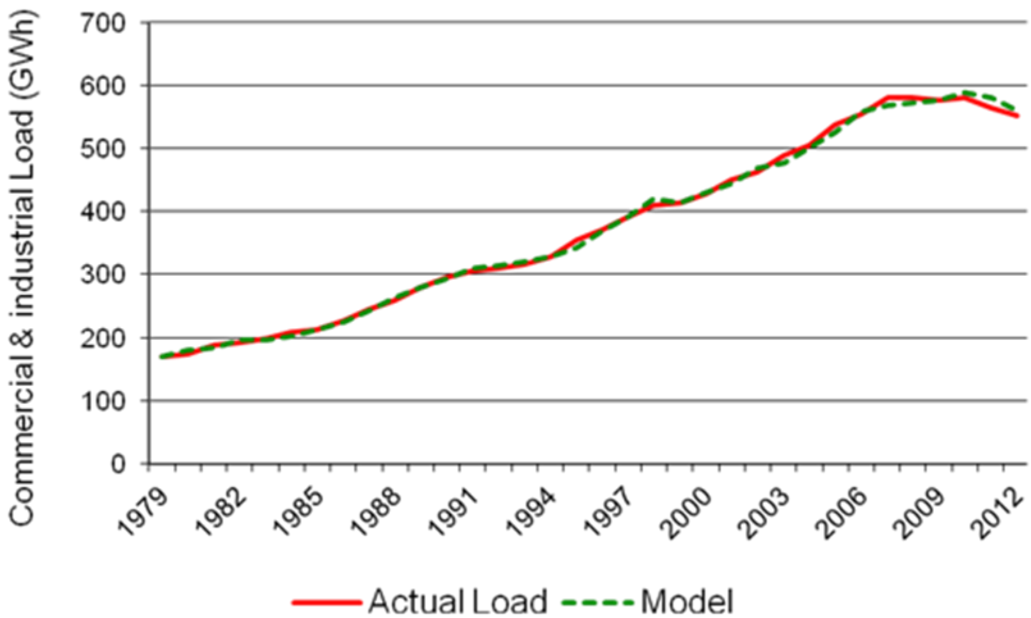

Figure 15: Commercial & Industrial Model Fit

10.1.5 Street Lighting Forecast

Simple time series trend analysis was employed to project electricity demand within the street lights customer group over the planning period.

10.1.6 System Peak Forecast Model

The econometric model for growth in system peak load was estimated in logs as follows:

$$SP_{it} = \alpha_{ij} + \beta_{ij} CI_{it} + \gamma_{ij} RES_{it} + \varphi_{ij} TEMP_{it} + v_{ij}$$

Where:

- SP is System Peak load
- v is the error associated with the model
- α, β, γ and φ are the regression coefficients from a time series regression of system peak on a constant, commercial & industrial load, residential load and average temperature.

10.1.7 Customer Number Growth Forecast

Regression models were employed to forecast the growth in the number of customers for each of the main customer classes. The models utilized GDP and moving average (MA) terms.

Base Case - Residential Historical and Projected: 1996 – 2033						
Year	Billed Sales (MWh)	Percent Change	Customers	Percent Change	kWh per Customer	Percent Change
1996	24,968	6.4%	20,062	4.1%	1,245	2.2%
1997	26,721	7.0%	20,903	4.2%	1,278	2.7%
1998	28,716	7.5%	21,528	3.0%	1,334	4.3%
1999	30,023	4.6%	22,196	3.1%	1,353	1.4%
2000	30,872	2.8%	22,802	2.7%	1,354	0.1%
2001	31,779	2.9%	23,069	1.2%	1,378	1.7%
2002	32,750	3.1%	23,210	0.6%	1,411	2.4%
2003	32,942	0.6%	24,333	4.8%	1,354	-4.1%
2004	33,062	0.4%	25,181	3.5%	1,313	-3.0%
2005	33,492	1.3%	24,851	-1.3%	1,348	2.6%
2006	34,176	2.0%	27,436	10.4%	1,246	-7.6%
2007	33,732	-1.3%	28,388	3.5%	1,188	-4.6%
2008	34,051	0.9%	29,183	2.8%	1,167	-1.8%
2009	36,369	6.8%	25,904	-11.2%	1,404	20.3%
2010	39,473	8.5%	28,984	11.9%	1,362	-3.0%
2011	40,149	1.7%	29,838	2.9%	1,346	-1.2%
2012	40,785	1.6%	30,512	2.3%	1,337	-0.7%
2013	40,800	0.0%	31,091	1.9%	1,312	-1.8%
2014	**40,402**	**-1.0%**	**31,529**	**1.4%**	**1,281**	**-2.4%**
2015	**40,638**	**0.6%**	**32,084**	**1.8%**	**1,267**	**-1.2%**
2016	**41,092**	**1.1%**	**32,745**	**2.1%**	**1,255**	**-0.9%**
2017	**41,678**	**1.4%**	**33,490**	**2.3%**	**1,244**	**-0.8%**
2018	**42,380**	**1.7%**	**34,264**	**2.3%**	**1,237**	**-0.6%**
2019	**43,197**	**1.9%**	**34,852**	**1.7%**	**1,239**	**0.2%**
2020	**44,014**	**1.9%**	**35,394**	**1.6%**	**1,244**	**0.3%**
2021	**44,822**	**1.8%**	**35,928**	**1.5%**	**1,248**	**0.3%**
2022	**45,616**	**1.8%**	**36,460**	**1.5%**	**1,251**	**0.3%**
2023	**46,454**	**1.8%**	**37,053**	**1.6%**	**1,254**	**0.2%**
2024	**47,339**	**1.9%**	**37,692**	**1.7%**	**1,256**	**0.2%**
2025	**48,268**	**2.0%**	**38,372**	**1.8%**	**1,258**	**0.2%**
2026	**49,233**	**2.0%**	**39,057**	**1.8%**	**1,261**	**0.2%**
2027	**50,230**	**2.0%**	**39,745**	**1.8%**	**1,264**	**0.3%**
2028	**51,253**	**2.0%**	**40,436**	**1.7%**	**1,268**	**0.3%**
2029	**52,292**	**2.0%**	**41,113**	**1.7%**	**1,272**	**0.3%**
2030	**53,357**	**2.0%**	**41,799**	**1.7%**	**1,277**	**0.4%**
2031	**54,455**	**2.1%**	**42,507**	**1.7%**	**1,281**	**0.4%**
2032	**55,576**	**2.1%**	**43,226**	**1.7%**	**1,286**	**0.4%**
2033	**56,718**	**2.1%**	**43,968**	**1.7%**	**1,290**	**0.3%**

Base Case -Commercial & Industrial Historical and Projected: 1996 – 2033						
Year	Billed Sales (MWh)	Percent Change	Customers	Percent Change	kWh per Customer	Percent Change
1996	16,133	7.3%	1,676	3.1%	9,626	4.1%
1997	17,518	8.6%	1,774	5.8%	9,875	2.6%
1998	21,427	22.3%	1,655	-6.7%	12,947	31.1%
1999	23,300	8.7%	1,889	14.1%	12,335	-4.7%
2000	23,626	1.4%	1,973	4.4%	11,975	-2.9%
2001	23,826	0.8%	2,503	26.9%	9,519	-20.5%
2002	30,097	26.3%	3,043	21.6%	9,891	3.9%
2003	28,496	-5.3%	2,923	-3.9%	9,749	-1.4%
2004	32,229	13.1%	3,509	20.0%	9,185	-5.8%
2005	33,146	2.8%	3,849	9.7%	8,612	-6.2%
2006	34,265	3.4%	4,241	10.2%	8,079	-6.2%
2007	36,390	6.2%	4,551	7.3%	7,996	-1.0%
2008	38,310	5.3%	4,746	4.3%	8,072	1.0%
2009	42,496	10.9%	4,074	-14.2%	10,431	29.2%
2010	45,755	7.7%	4,506	10.6%	10,154	-2.7%
2011	47,072	2.9%	4,084	-9.4%	11,526	13.5%
2012	47,631	1.2%	4,020	-1.6%	11,849	2.8%
2013	46,772	-1.8%	4,154	3.3%	11,260	-5.0%
2014	**46,973**	**0.4%**	**4,247**	**2.2%**	**11,061**	**-1.8%**
2015	**47,867**	**1.9%**	**4,332**	**2.0%**	**11,050**	**-0.1%**
2016	**48,577**	**1.5%**	**4,409**	**1.8%**	**11,017**	**-0.3%**
2017	**49,315**	**1.5%**	**4,479**	**1.6%**	**11,010**	**-0.1%**
2018	**49,988**	**1.4%**	**4,541**	**1.4%**	**11,008**	**0.0%**
2019	**50,420**	**0.9%**	**4,595**	**1.2%**	**10,972**	**-0.3%**
2020	**50,653**	**0.5%**	**4,642**	**1.0%**	**10,912**	**-0.6%**
2021	**50,832**	**0.4%**	**4,681**	**0.8%**	**10,858**	**-0.5%**
2022	**50,975**	**0.3%**	**4,714**	**0.7%**	**10,815**	**-0.4%**
2023	**51,294**	**0.6%**	**4,739**	**0.5%**	**10,824**	**0.1%**
2024	**51,731**	**0.9%**	**4,757**	**0.4%**	**10,874**	**0.5%**
2025	**52,261**	**1.0%**	**4,769**	**0.3%**	**10,958**	**0.8%**
2026	**52,770**	**1.0%**	**4,775**	**0.1%**	**11,051**	**0.9%**
2027	**53,255**	**0.9%**	**4,785**	**0.2%**	**11,130**	**0.7%**
2028	**53,714**	**0.9%**	**4,790**	**0.1%**	**11,214**	**0.7%**
2029	**54,097**	**0.7%**	**4,795**	**0.1%**	**11,282**	**0.6%**
2030	**54,480**	**0.7%**	**4,805**	**0.2%**	**11,338**	**0.5%**
2031	**54,896**	**0.8%**	**4,815**	**0.2%**	**11,401**	**0.6%**
2032	**55,314**	**0.8%**	**4,825**	**0.2%**	**11,464**	**0.6%**
2033	**55,766**	**0.8%**	**4,835**	**0.2%**	**11,534**	**0.6%**

Base Case - Street Lighting Historical and Projected: 1996 – 2033				
Year	**Billed Sales (MWh)**	**Percent Change**	**Customers**	**Percent Change**
1996	7,480	12.7%	1,278	6.7%
1997	8,054	7.7%	1,387	8.5%
1998	7,151	-11.2%	1,418	2.2%
1999	7,271	1.7%	1,520	7.2%
2000	7,507	3.2%	1,608	5.8%
2001	8,309	10.7%	1,093	-32.0%
2002	1,134	-86.4%	242	-77.9%
2003	1,297	14.4%	257	6.2%
2004	1,128	-13.0%	290	12.8%
2005	1,151	2.0%	325	12.1%
2006	1,130	-1.8%	331	1.8%
2007	1,299	15.0%	366	10.6%
2008	1,325	2.0%	432	18.0%
2009	1,443	8.9%	571	32.2%
2010	1,547	7.2%	496	-13.1%
2011	1,621	4.8%	469	-5.4%
2012	1,697	4.7%	338	-27.9%
2013	1,767	4.1%	273	-19.2%
2014	**1,801**	**1.9%**	**277**	**1.5%**
2015	**1,834**	**1.8%**	**280**	**1.0%**
2016	**1,865**	**1.7%**	**283**	**1.0%**
2017	**1,892**	**1.5%**	**285**	**0.9%**
2018	**1,916**	**1.3%**	**288**	**0.9%**
2019	**1,936**	**1.1%**	**290**	**0.9%**
2020	**1,953**	**0.9%**	**293**	**0.9%**
2021	**1,968**	**0.7%**	**296**	**0.9%**
2022	**1,979**	**0.6%**	**298**	**0.9%**
2023	**1,988**	**0.4%**	**300**	**0.6%**
2024	**1,994**	**0.3%**	**302**	**0.6%**
2025	**1,999**	**0.2%**	**304**	**0.6%**
2026	**2,001**	**0.1%**	**305**	**0.6%**
2027	**2,001**	**0.0%**	**307**	**0.6%**
2028	**2,000**	**-0.1%**	**309**	**0.6%**
2029	**1,997**	**-0.1%**	**311**	**0.5%**
2030	**1,992**	**-0.2%**	**312**	**0.5%**
2031	**1,987**	**-0.3%**	**314**	**0.5%**
2032	**1,980**	**-0.3%**	**315**	**0.5%**
2033	**1,972**	**-0.4%**	**317**	**0.5%**

Base Case- Total Sales Historical and Projected: 1996 – 2033						
Year	Billed Sales (MWh)	Percent Change	Customers	Percent Change	kWh per Customer	Percent Change
1996	48,581	7.7%	23,016	4.2%	2,111	3.3%
1997	52,293	7.6%	24,064	4.6%	2,173	3.0%
1998	57,294	9.6%	24,601	2.2%	2,329	7.2%
1999	60,594	5.8%	25,605	4.1%	2,366	1.6%
2000	62,005	2.3%	26,383	3.0%	2,350	-0.7%
2001	63,914	3.1%	26,665	1.1%	2,397	2.0%
2002	63,981	0.1%	26,495	-0.6%	2,415	0.7%
2003	62,735	-1.9%	27,513	3.8%	2,280	-5.6%
2004	66,419	5.9%	28,980	5.3%	2,292	0.5%
2005	67,789	2.1%	29,025	0.2%	2,336	1.9%
2006	69,571	2.6%	32,008	10.3%	2,174	-6.9%
2007	71,421	2.7%	33,305	4.1%	2,144	-1.3%
2008	73,686	3.2%	34,361	3.2%	2,144	0.0%
2009	80,308	9.0%	30,549	-11.1%	2,629	22.6%
2010	86,775	8.1%	33,986	11.3%	2,553	-2.9%
2011	88,842	2.4%	34,391	1.2%	2,583	1.2%
2012	90,113	1.4%	34,870	1.4%	2,584	0.0%
2013	89,339	-0.9%	35,518	1.9%	2,515	-2.7%
2014	**89,177**	**-0.2%**	**36,053**	**1.5%**	**2,473**	**-1.7%**
2015	**90,338**	**1.3%**	**36,696**	**1.8%**	**2,462**	**-0.5%**
2016	**91,534**	**1.3%**	**37,437**	**2.0%**	**2,445**	**-0.7%**
2017	**92,885**	**1.5%**	**38,254**	**2.2%**	**2,428**	**-0.7%**
2018	**94,283**	**1.5%**	**39,092**	**2.2%**	**2,412**	**-0.7%**
2019	**95,554**	**1.3%**	**39,737**	**1.7%**	**2,405**	**-0.3%**
2020	**96,621**	**1.1%**	**40,329**	**1.5%**	**2,396**	**-0.4%**
2021	**97,622**	**1.0%**	**40,905**	**1.4%**	**2,387**	**-0.4%**
2022	**98,570**	**1.0%**	**41,472**	**1.4%**	**2,377**	**-0.4%**
2023	**99,736**	**1.2%**	**42,091**	**1.5%**	**2,370**	**-0.3%**
2024	**101,064**	**1.3%**	**42,751**	**1.6%**	**2,364**	**-0.2%**
2025	**102,527**	**1.4%**	**43,445**	**1.6%**	**2,360**	**-0.2%**
2026	**104,004**	**1.4%**	**44,137**	**1.6%**	**2,356**	**-0.2%**
2027	**105,485**	**1.4%**	**44,837**	**1.6%**	**2,353**	**-0.2%**
2028	**106,966**	**1.4%**	**45,535**	**1.6%**	**2,349**	**-0.2%**
2029	**108,386**	**1.3%**	**46,218**	**1.5%**	**2,345**	**-0.2%**
2030	**109,829**	**1.3%**	**46,916**	**1.5%**	**2,341**	**-0.2%**
2031	**111,338**	**1.4%**	**47,635**	**1.5%**	**2,337**	**-0.2%**
2032	**112,870**	**1.4%**	**48,366**	**1.5%**	**2,334**	**-0.2%**
2033	**114,456**	**1.4%**	**49,120**	**1.6%**	**2,330**	**-0.2%**

System Load - Historical and Projected: 2001 - 2033						
Year	Low Case (MWh)	Percent Change	Base Case (MWh)	Percent Change	High Case (MWh)	Percent Change
2001	-	-	79,770	4.3%	-	-
2002	-	-	79,079	-0.9%	-	-
2003	-	-	77,289	-2.3%	-	-
2004	-	-	78,261	1.3%	-	-
2005	-	-	82,642	5.6%	-	-
2006	-	-	82,939	0.4%	-	-
2007	-	-	83,686	0.9%	-	-
2008	-	-	84,868	1.4%	-	-
2009	-	-	90,079	6.1%	-	-
2010	-	-	96,243	6.8%	-	-
2011	-	-	97,769	1.6%	-	-
2012	-	-	98,597	0.8%	-	-
2013	-	-	97,873	-0.7%	-	-
2014	**95,174**	**-2.8%**	**97,248**	**-0.6%**	**98,956**	**1.1%**
2015	**95,607**	**0.5%**	**98,479**	**1.3%**	**100,885**	**1.9%**
2016	**96,835**	**1.3%**	**100,697**	**2.3%**	**104,342**	**3.4%**
2017	**96,577**	**-0.3%**	**102,184**	**1.5%**	**107,142**	**2.7%**
2018	**96,700**	**0.1%**	**103,722**	**1.5%**	**110,278**	**2.9%**
2019	**95,693**	**-1.0%**	**105,119**	**1.3%**	**113,512**	**2.9%**
2020	**94,769**	**-1.0%**	**106,294**	**1.1%**	**116,823**	**2.9%**
2021	**93,876**	**-0.9%**	**107,395**	**1.0%**	**120,185**	**2.9%**
2022	**92,348**	**-1.6%**	**108,438**	**1.0%**	**123,585**	**2.8%**
2023	**91,774**	**-0.6%**	**109,721**	**1.2%**	**127,209**	**2.9%**
2024	**91,059**	**-0.8%**	**111,182**	**1.3%**	**131,014**	**3.0%**
2025	**90,275**	**-0.9%**	**112,791**	**1.4%**	**134,972**	**3.0%**
2026	**89,461**	**-0.9%**	**114,415**	**1.4%**	**139,061**	**3.0%**
2027	**88,633**	**-0.9%**	**116,046**	**1.4%**	**143,257**	**3.0%**
2028	**87,797**	**-0.9%**	**117,675**	**1.4%**	**147,730**	**3.1%**
2029	**86,961**	**-1.0%**	**119,236**	**1.3%**	**152,245**	**3.1%**
2030	**86,129**	**-1.0%**	**120,824**	**1.3%**	**156,981**	**3.1%**
2031	**85,302**	**-1.0%**	**122,484**	**1.4%**	**161,900**	**3.1%**
2032	**84,478**	**-1.0%**	**124,170**	**1.4%**	**166,959**	**3.1%**
2033	**83,657**	**-1.0%**	**125,914**	**1.4%**	**172,144**	**3.1%**

System Peak - Historical and Projected: 2001 - 2033						
Year	Low Case (MW)	Percent Change	Base Case (MW)	Percent Change	High Case (MW)	Percent Change
2001	-	-	13.9	6.9%	-	-
2002	-	-	13.0	-5.9%	-	-
2003	-	-	12.9	-0.9%	-	-
2004	-	-	13.2	2.1%	-	-
2005	-	-	14.4	8.9%	-	-
2006	-	-	14.5	0.7%	-	-
2007	-	-	14.5	0.2%	-	-
2008	-	-	14.7	1.1%	-	-
2009	-	-	15.6	6.5%	-	-
2010	-	-	16.6	6.1%	-	-
2011	-	-	17.2	3.5%	-	-
2012	-	-	17.2	0.3%	-	-
2013	-	-	16.8	-2.6%	-	-
2014	**16.4**	**-2.5%**	**16.6**	**-1.2%**	**17.1**	**1.6%**
2015	**16.5**	**1.0%**	**16.8**	**1.0%**	**17.7**	**3.9%**
2016	**16.7**	**1.0%**	**17.0**	**1.5%**	**18.0**	**1.6%**
2017	**16.9**	**1.3%**	**17.2**	**1.3%**	**18.4**	**2.4%**
2018	**17.0**	**0.3%**	**17.4**	**1.0%**	**18.9**	**2.4%**
2019	**16.9**	**-0.6%**	**17.5**	**0.8%**	**19.3**	**2.4%**
2020	**16.8**	**-0.3%**	**17.6**	**0.6%**	**19.8**	**2.4%**
2021	**16.7**	**-0.4%**	**17.8**	**0.6%**	**20.2**	**2.3%**
2022	**16.7**	**0.0%**	**17.9**	**0.5%**	**20.7**	**2.3%**
2023	**16.7**	**0.0%**	**18.0**	**0.7%**	**21.2**	**2.4%**
2024	**16.7**	**-0.3%**	**18.1**	**0.8%**	**21.7**	**2.4%**
2025	**16.6**	**-0.3%**	**18.3**	**0.9%**	**22.3**	**2.5%**
2026	**16.6**	**-0.3%**	**18.5**	**0.9%**	**22.8**	**2.5%**
2027	**16.5**	**-0.3%**	**18.6**	**0.9%**	**23.4**	**2.5%**
2028	**16.5**	**-0.3%**	**18.8**	**0.8%**	**24.0**	**2.5%**
2029	**16.4**	**-0.3%**	**18.9**	**0.8%**	**24.6**	**2.5%**
2030	**16.4**	**-0.3%**	**19.1**	**0.8%**	**25.2**	**2.5%**
2031	**16.3**	**-0.3%**	**19.2**	**0.8%**	**25.8**	**2.5%**
2032	**16.3**	**-0.3%**	**19.4**	**0.8%**	**26.5**	**2.5%**
2033	**16.2**	**-0.3%**	**19.5**	**0.8%**	**27.1**	**2.5%**

10.2 Scenario 1 Results –Base Sales

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	17.4	77.8	6.5
2019	1.50	0.0		33.7	17.5	69.9	5.2
2020	0.00	3.5	Geothermal - 1x3.5MW	37.2	17.6	88.3	8.5
2021	0.00	0.0		37.2	17.7	87.2	8.4
2022	1.75	0.0		35.5	17.8	76.4	6.6
2023	1.35	0.0		34.1	18.0	68.9	5.4
2024	0.00	0.0		34.1	18.1	68.0	5.3
2025	0.00	3.5	Geothermal - 1x3.5MW	37.6	18.3	84.8	8.4
2026	0.00	0.0		37.6	18.4	83.7	8.3
2027	0.00	0.0		37.6	18.6	81.7	8.1
2028	4.20	0.0		33.4	18.7	60.6	4.4
2029	1.88	0.0		31.5	18.9	51.9	2.9
2030	2.80	0.0		28.7	19.0	37.5	0.3
2031	0.00	0.0		28.7	19.2	36.0	0.1
2032	1.20	1.8	MSD - 1x1.8MW	29.3	19.3	39.4	0.8
2033	0.00	0.0		29.3	19.6	37.9	0.6

Table 32: Build Schedule for Scenario 1 – Base Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC $million			Total Operating Cost	Total Cost EC$ million
					Fuel	O&M			
	Diesel	Geothermal	Solar		Diesel	Fixed	Variable		
2014	-	-	-	**-**	45.5	-	4.9	**50.5**	**50.5**
2015	-	-	-	**-**	46.6	-	5.0	**51.7**	**51.7**
2016	-	-	-	**-**	48.9	-	5.2	**54.0**	**54.0**
2017	-	-	6.3	**6.3**	49.9	0.1	5.2	**55.1**	**61.5**
2018	-	111.9	3.2	**115.0**	19.0	0.1	3.6	**22.7**	**137.7**
2019	-	-	-	**-**	15.4	0.1	3.8	**19.3**	**19.3**
2020	-	55.9	-	**55.9**	2.7	0.1	3.2	**6.0**	**61.9**
2021	-	-	-	**-**	3.1	0.1	3.3	**6.6**	**6.6**
2022	-	-	-	**-**	3.6	0.1	3.3	**7.1**	**7.1**
2023	-	-	-	**-**	4.3	0.1	3.4	**7.8**	**7.8**
2024	-	-	-	**-**	4.8	0.1	3.5	**8.4**	**8.4**
2025	-	55.9	-	**55.9**	0.0	0.1	3.3	**3.5**	**59.4**
2026	-	-	-	**-**	0.0	0.1	3.4	**3.5**	**3.5**
2027	-	-	-	**-**	0.0	0.1	3.4	**3.6**	**3.6**
2028	-	-	-	**-**	0.1	0.1	3.5	**3.7**	**3.7**
2029	-	-	-	**-**	1.1	0.1	3.7	**4.9**	**4.9**
2030	-	-	-	**-**	1.4	0.1	3.8	**5.3**	**5.3**
2031	-	-	-	**-**	2.0	0.1	3.8	**6.0**	**6.0**
2032	10.0	-	-	**10.0**	2.5	0.1	3.9	**6.5**	**16.6**
2033	-	-	-	**-**	3.4	0.1	4.0	**7.6**	**7.6**
NPV 12%	**-**	**-**	**-**	**80.2**	**170.7**	**0.6**	**30.9**	**202.3**	**282.5**

Table 33: NPV for Scenario 1 – Base Sales

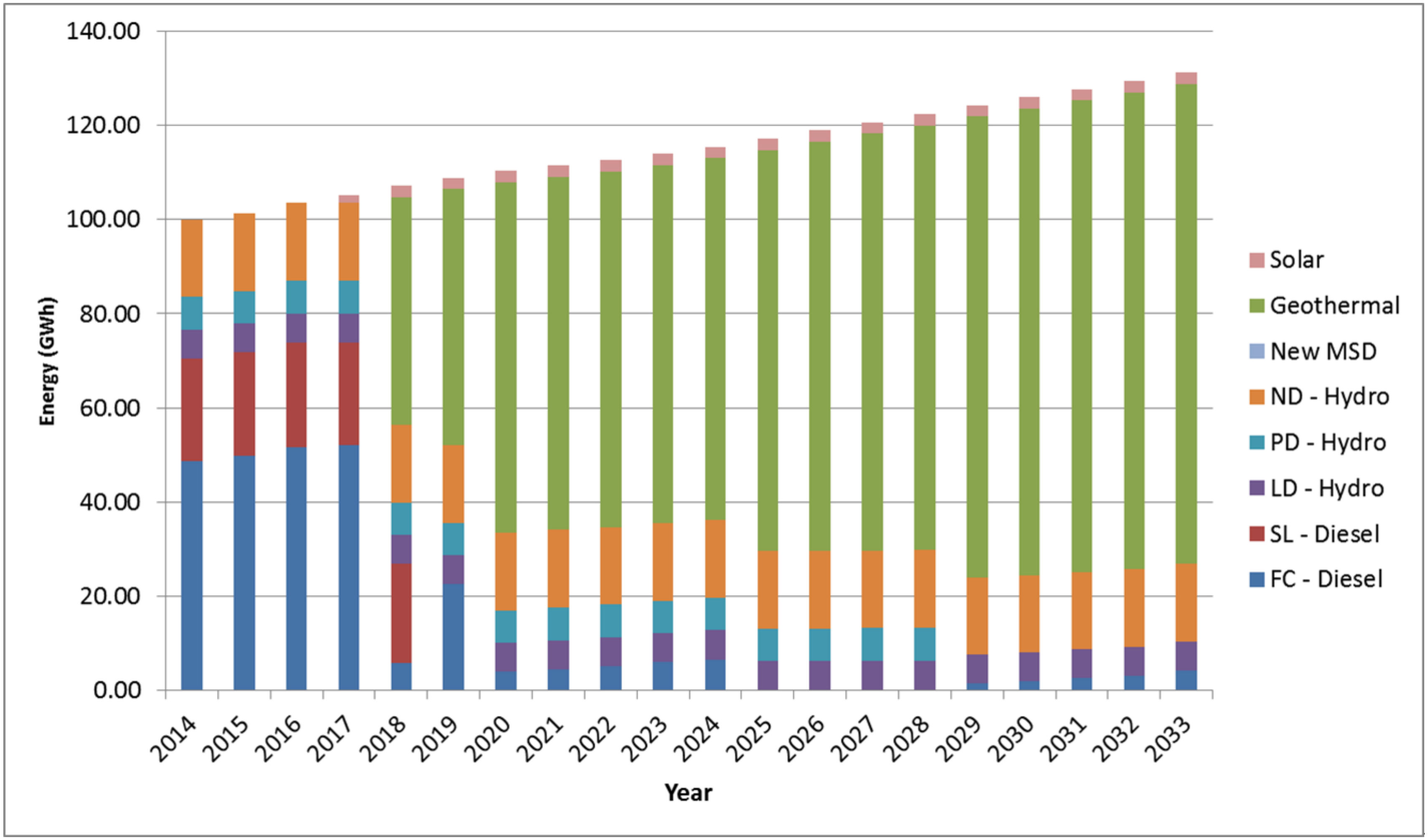

Figure 16: Generation by Technology / Location for Scenario 1 – Base Sales

10.3 Scenario 2 Results – Base Sales

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	0.5	Solar - 1x0.5MW	28.2	17.4	38.4	2.4
2019	1.50	1.8	MSD - 1x1.8MW	28.5	17.5	40.9	2.9
2020	0.00	0.0		28.5	17.6	40.1	2.8
2021	0.00	7.0	Geothermal - 2x3.5MW	35.5	17.7	78.0	6.8
2022	1.75	0.0		33.8	17.8	67.2	5.0
2023	1.35	3.5	Geothermal - 1x3.5MW	35.9	18.0	78.8	7.1
2024	0.00	0.0		35.9	18.1	77.8	7.0
2025	0.00	3.5	Geothermal - 1x3.5MW	39.4	18.3	94.5	10.2
2026	0.00	0.0		39.4	18.4	93.4	10.1
2027	0.00	0.0		39.4	18.6	91.3	9.9
2028	4.20	0.0		35.2	18.7	70.1	6.1
2029	1.88	0.0		33.3	18.9	61.3	4.6
2030	2.80	0.0		30.5	19.0	46.9	2.0
2031	0.00	0.0		30.5	19.2	45.3	1.8
2032	1.20	0.0		29.3	19.3	39.4	0.8
2033	0.00	0.0		29.3	19.5	37.9	0.6

Table 34: Build Schedule for Scenario 2 – Base Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC $million			Total Operating Cost	Total Cost EC$ million
	Diesel	Geothermal	Solar		Fuel	O&M			
					Diesel	Fixed	Variable		
2014	-	-	-	**-**	45.5	-	4.9	**50.5**	**50.5**
2015	-	-	-	**-**	46.6	-	5.0	**51.7**	**51.7**
2016	-	-	-	**-**	48.9	-	5.2	**54.0**	**54.0**
2017	-	-	6.3	**6.3**	49.9	0.1	5.2	**55.1**	**61.5**
2018	-	-	3.2	**3.2**	51.3	0.1	5.2	**56.7**	**59.8**
2019	10.0	-	-	**10.0**	52.7	0.1	5.4	**58.3**	**68.3**
2020	-	-	-	**-**	54.2	0.1	5.5	**59.8**	**59.8**
2021	-	111.9	-	**111.9**	17.5	0.1	4.0	**21.6**	**133.5**
2022	-	-	-	**-**	18.7	0.1	4.1	**22.9**	**22.9**
2023	-	55.9	-	**55.9**	4.3	0.1	3.4	**7.8**	**63.8**
2024	-	-	-	**-**	4.8	0.1	3.5	**8.4**	**8.4**
2025	-	55.9	-	**55.9**	0.0	0.1	3.3	**3.5**	**59.4**
2026	-	-	-	**-**	0.0	0.1	3.4	**3.5**	**3.5**
2027	-	-	-	**-**	0.0	0.1	3.4	**3.6**	**3.6**
2028	-	-	-	**-**	0.1	0.1	3.5	**3.7**	**3.7**
2029	-	-	-	**-**	1.1	0.1	3.7	**4.9**	**4.9**
2030	-	-	-	**-**	1.4	0.1	3.8	**5.3**	**5.3**
2031	-	-	-	**-**	2.0	0.1	3.8	**6.0**	**6.0**
2032	-	-	-	**-**	2.5	0.1	3.9	**6.5**	**6.5**
2033	-	-	-	**-**	3.4	0.1	4.0	**7.6**	**7.6**
NPV 12%	**-**	**-**	**-**	**60.9**	**242.5**	**0.6**	**34.2**	**277.4**	**338.4**

Table 35: NPV for Scenario 2 – Base Sales

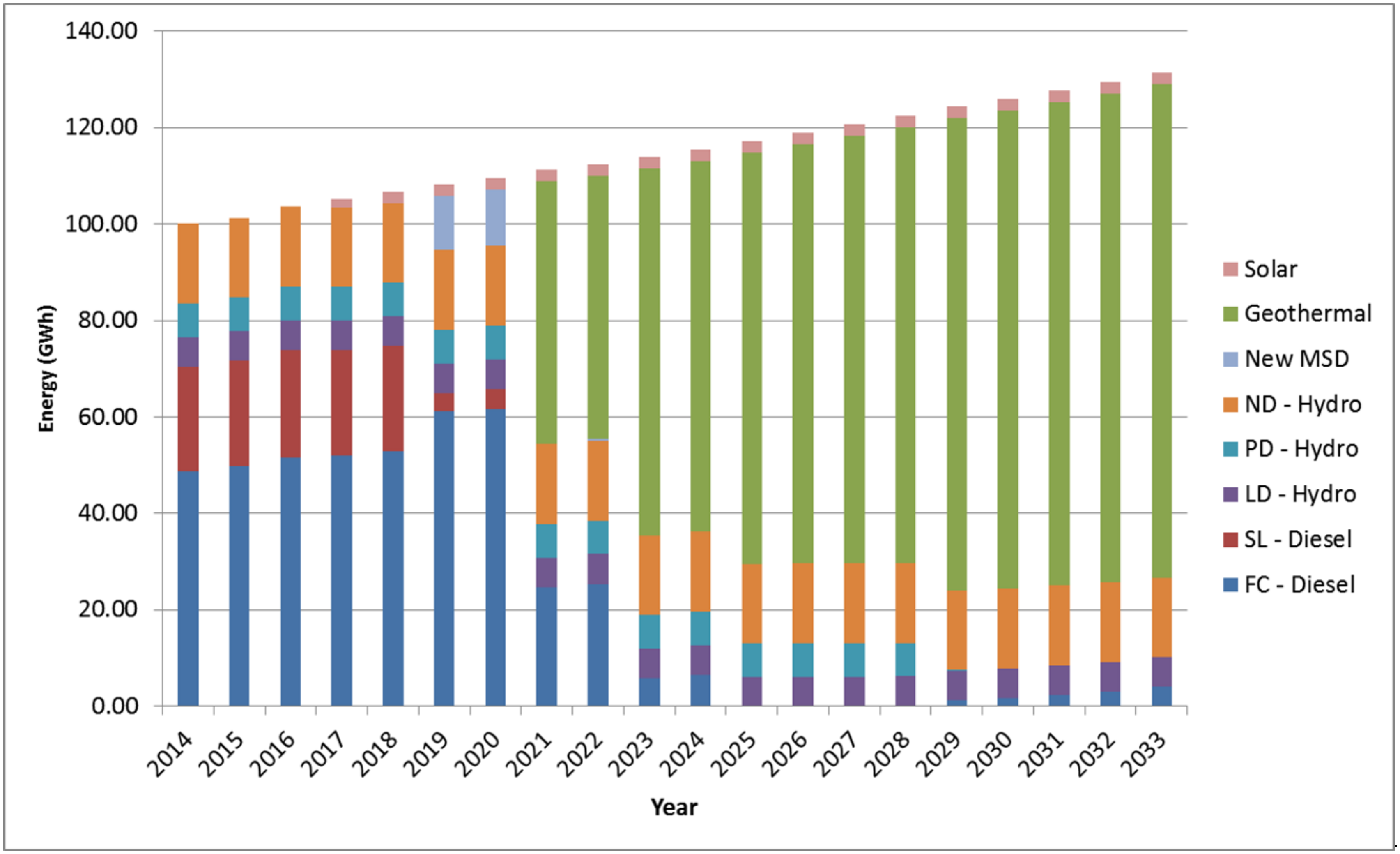

Figure 17: Generation by Technology / Location for Scenario 2 – Base Sales

10.4 Scenario 3 Results – Base Sales

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	0.5	Solar - 1x0.5MW	28.2	17.4	38.4	2.4
2019	1.50	1.8	MSD - 1x1.8MW	28.5	17.5	40.9	2.9
2020	0.00	0.0		28.5	17.6	40.1	2.8
2021	0.00	0.0		28.5	17.7	39.3	2.7
2022	1.75	3.5	MSD - 1x3.5MW	30.3	17.8	48.0	2.7
2023	1.35	0.0		28.9	18.0	40.8	1.5
2024	0.00	0.0		28.9	18.1	40.0	1.4
2025	0.00	0.0		28.9	18.3	38.4	1.2
2026	0.00	1.8	MSD - 1x1.8MW	30.7	18.4	47.3	2.8
2027	0.00	0.0		30.7	18.6	45.7	2.6
2028	4.20	3.5	MSD - 1x3.5MW	30.0	18.7	43.0	1.2
2029	1.88	3.5	MSD - 1x3.5MW	31.6	18.9	52.6	3.0
2030	2.80	0.0		28.8	19.0	38.2	0.4
2031	0.00	1.8	MSD - 1x1.8MW	30.6	19.2	45.9	2.0
2032	1.20	0.0		29.4	19.3	40.1	0.9
2033	0.00	0.0		29.4	19.5	38.6	0.7

Table 36: Build Schedule for Scenario 3 – Base Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC $million			Total Operating Cost	Total Cost EC$ million
					Fuel	O&M			
	Diesel	Geothermal	Solar		Diesel	Fixed	Variable		
2014	-	-	-	**-**	45.5	-	4.9	**50.5**	**50.5**
2015	-	-	-	**-**	46.6	-	5.0	**51.7**	**51.7**
2016	-	-	-	**-**	48.9	-	5.2	**54.0**	**54.0**
2017	-	-	6.3	**6.3**	49.9	0.1	5.2	**55.1**	**61.5**
2018	-	-	3.2	**3.2**	51.3	0.1	5.2	**56.7**	**59.8**
2019	10.0	-	-	**10.0**	52.7	0.1	5.4	**58.3**	**68.3**
2020	-	-	-	**-**	54.2	0.1	5.5	**59.8**	**59.8**
2021	-	-	-	**-**	56.2	0.1	5.5	**61.9**	**61.9**
2022	19.2	-	-	**19.2**	58.2	0.1	5.1	**63.4**	**82.7**
2023	-	-	-	**-**	60.0	0.1	5.2	**65.3**	**65.3**
2024	-	-	-	**-**	61.9	0.1	5.3	**67.3**	**67.3**
2025	-	-	-	**-**	64.3	0.1	5.4	**69.8**	**69.8**
2026	10.0	-	-	**10.0**	66.5	0.1	5.4	**72.0**	**82.0**
2027	-	-	-	**-**	68.7	0.1	5.5	**74.3**	**74.3**
2028	19.2	-	-	**19.2**	70.5	0.1	5.3	**76.0**	**95.2**
2029	19.2	-	-	**19.2**	78.5	0.1	5.3	**83.9**	**103.2**
2030	-	-	-	**-**	80.8	0.1	5.4	**86.3**	**86.3**
2031	10.0	-	-	**10.0**	83.1	0.1	5.5	**88.7**	**98.8**
2032	-	-	-	**-**	85.6	0.1	5.5	**91.3**	**91.3**
2033	-	-	-	**-**	88.6	0.1	5.7	**94.4**	**94.4**
NPV 12%	**-**	**-**	**-**	**19.5**	**418.7**	**0.6**	**39.2**	**458.5**	**478.0**

Table 37: NPV for Scenario 3– Base Sales

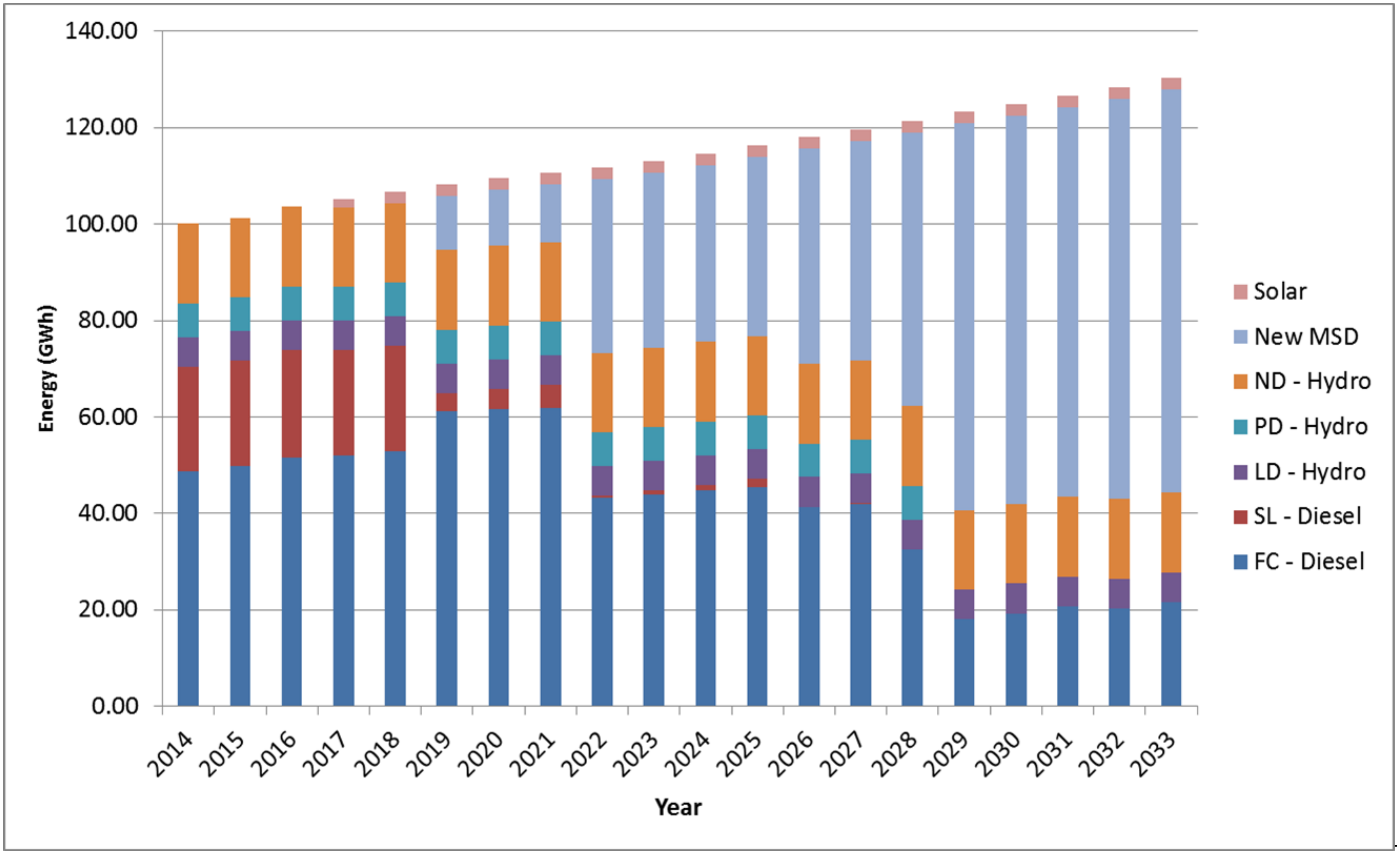

Figure 18: Generation by Technology / Location for Scenario 3 – Base Sales

10.5 Scenario 4 Results – Base Sales

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.1	45.3	3.2
2015	0.00	0.0		26.7	16.3	43.5	3.0
2016	0.00	0.0		26.7	16.5	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	16.7	40.1	2.6
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	18.9	58.9	4.5
2019	1.50	0.0		33.7	19.0	52.0	3.2
2020	0.00	7.0	Geothermal - 2x3.5MW	40.7	19.1	86.0	9.8
2021	0.00	0.0		40.7	19.2	85.1	9.7
2022	1.75	0.0		39.0	19.3	75.4	7.9
2023	1.35	0.0		37.6	19.5	68.7	6.7
2024	0.00	0.0		37.6	19.6	67.8	6.6
2025	0.00	0.0		37.6	19.8	66.1	6.4
2026	0.00	0.0		37.6	19.9	65.3	6.3
2027	0.00	0.5	Solar - 1x0.5MW	38.1	20.1	63.6	6.1
2028	4.20	0.0		33.9	20.2	44.7	2.4
2029	1.88	0.0		32.0	20.4	37.0	0.9
2030	2.80	3.6	MSD - 2x1.8MW	32.8	20.5	41.0	1.8
2031	0.00	0.0		32.8	20.7	39.6	1.6
2032	1.20	0.0		31.6	20.8	34.3	0.5
2033	0.00	0.0		31.6	21.0	33.0	0.3

Table 38: Build Schedule for Scenario 4 – Base Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC $million			Total Operating Cost	Total Cost EC$ million
					Fuel	O&M			
	Diesel	Geothermal	Solar		Diesel	Fixed	Variable		
2014	-	-	-	**-**	45.5	-	4.9	**50.5**	**50.5**
2015	-	-	-	**-**	46.6	-	5.0	**51.7**	**51.7**
2016	-	-	-	**-**	48.9	-	5.2	**54.0**	**54.0**
2017	-	-	6.3	**6.3**	49.9	0.1	5.2	**55.1**	**61.5**
2018	-	111.9	3.2	**115.0**	25.0	0.1	4.3	**29.4**	**144.4**
2019	-	-	-	**-**	23.7	0.1	4.7	**28.5**	**28.5**
2020	-	111.9	-	**111.9**	0.3	0.1	3.5	**4.0**	**115.8**
2021	-	-	-	**-**	0.4	0.1	3.6	**4.1**	**4.1**
2022	-	-	-	**-**	0.5	0.1	3.6	**4.2**	**4.2**
2023	-	-	-	**-**	0.7	0.1	3.6	**4.5**	**4.5**
2024	-	-	-	**-**	0.9	0.1	3.7	**4.7**	**4.7**
2025	-	-	-	**-**	1.3	0.1	3.8	**5.2**	**5.2**
2026	-	-	-	**-**	1.6	0.1	3.8	**5.6**	**5.6**
2027	-	-	3.2	**3.2**	1.7	0.2	3.9	**5.7**	**8.9**
2028	-	-	-	**-**	2.0	0.2	3.9	**6.1**	**6.1**
2029	-	-	-	**-**	6.2	0.2	4.3	**10.6**	**10.6**
2030	20.1	-	-	**20.1**	6.9	0.2	4.4	**11.5**	**31.6**
2031	-	-	-	**-**	7.9	0.2	4.5	**12.6**	**12.6**
2032	-	-	-	**-**	8.8	0.2	4.6	**13.5**	**13.5**
2033	-	-	-	**-**	10.1	0.2	4.7	**15.0**	**15.0**
NPV 12%	**-**	**-**	**-**	**91.3**	**178.0**	**0.7**	**33.1**	**211.7**	**303.1**

Table 39: NPV for Scenario 4 – Base Sales

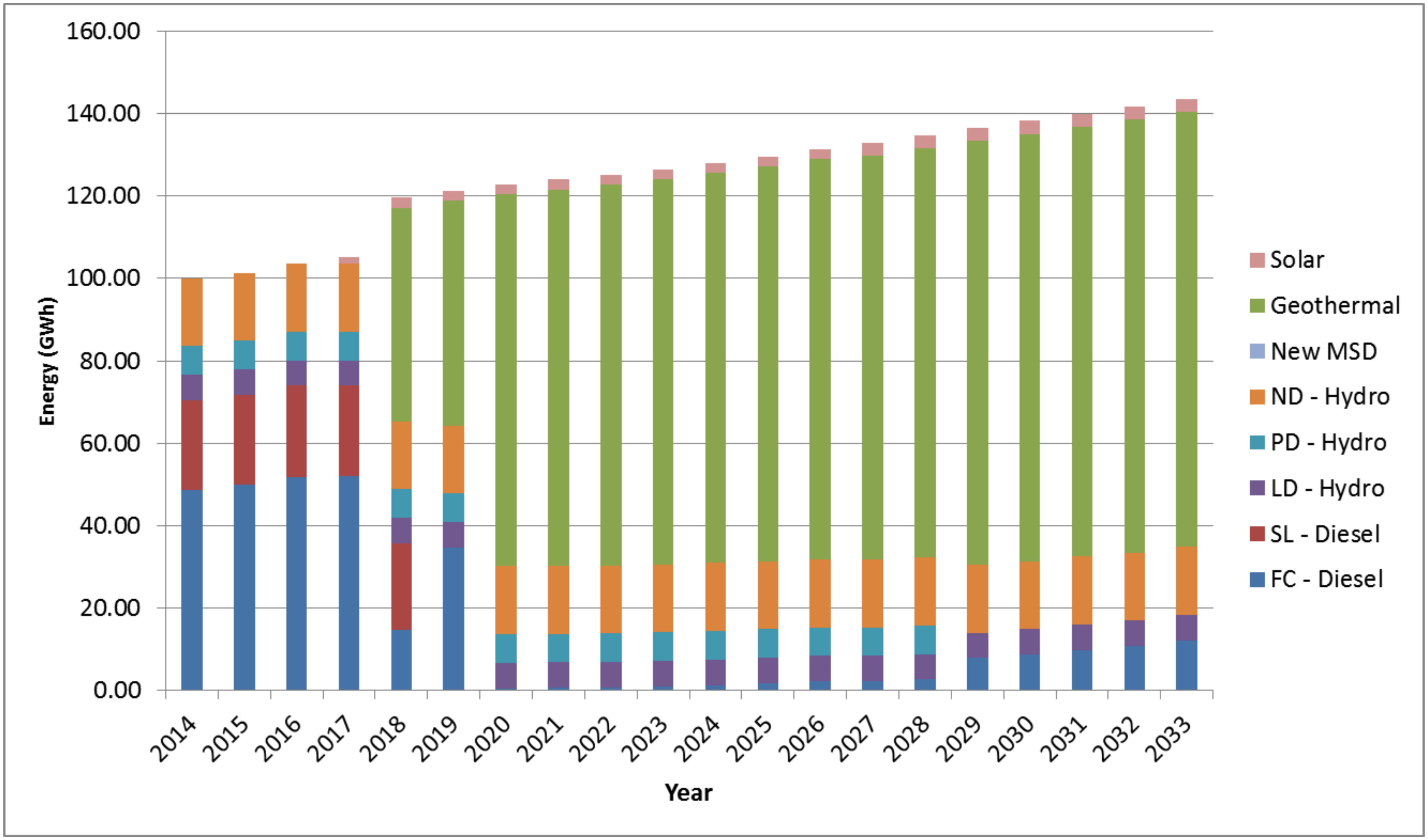

Figure 19: Generation by Technology / Location for Scenario 4 – Base Sales

	Unit Name																							
	FC1	FC10	FC11	FC12	FC4	FC5	FC6	FC7	FC8	LD1	SL3	SL4	SL5	SL6	SL7	MSD1.8	MSD 3.5	Geo3.5	Geo 7.0	Solar	PD1	PD2	ND1	ND2
2014	0.05	10.99	9.50	3.32	-	10.83	14.04	-	-	6.15	0.01	10.27	8.94	-	2.49	-	-	-	-	-	3.97	2.97	8.96	7.54
2015	0.09	10.99	9.69	3.80	-	11.17	14.09	-	-	6.16	0.02	10.27	8.94	-	2.65	-	-	-	-	-	3.97	2.97	8.96	7.54
2016	0.13	11.02	10.18	4.40	-	11.73	14.18	-	0.00	6.18	0.03	10.30	8.97	-	2.98	-	-	-	-	-	3.98	2.98	8.99	7.56
2017	0.07	10.99	10.48	4.25	-	12.09	14.17	-	-	6.15	0.01	10.27	8.94	-	2.65	-	-	-	-	1.60	3.96	2.97	8.96	7.53
2018	-	7.07	1.36	-	-	0.11	6.12	-	-	6.15	-	10.27	8.94	-	1.81	-	-	51.94	-	2.40	3.96	2.97	8.96	7.53
2019	-	10.70	6.89	0.29	-	5.62	11.17	-	-	6.15	-	0.01	-	-	-	-	-	54.57	-	2.40	3.96	2.97	8.96	7.53
2020	-	0.45	-	-	-	-	0.02	-	-	6.17	-	-	-	-	-	-	-	90.30	-	2.41	3.98	2.98	8.99	7.56
2021	-	0.54	-	-	-	-	0.02	-	-	6.16	-	-	-	-	-	-	-	91.44	-	2.40	3.97	2.97	8.96	7.54
2022	-	0.68	0.03	-	-	-	-	-	-	6.15	-	-	-	-	-	-	-	92.43	-	2.40	3.96	2.97	8.96	7.53
2023	-	0.93	0.06	-	-	0.00	-	-	-	6.15	-	-	-	-	-	-	-	93.49	-	2.40	3.96	2.97	8.96	7.53
2024	-	1.10	0.08	-	-	0.00	-	-	-	6.17	-	-	-	-	-	-	-	94.74	-	2.41	3.98	2.98	8.98	7.55
2025	-	1.63	0.11	-	-	0.00	-	-	-	6.15	-	-	-	-	-	-	-	95.95	-	2.40	3.97	2.97	8.96	7.54
2026	-	1.98	0.15	-	-	0.00	-	-	-	6.16	-	-	-	-	-	-	-	97.25	-	2.40	3.97	2.97	8.96	7.54
2027	-	2.02	0.13	-	-	0.00	-	-	-	6.16	-	-	-	-	-	-	-	98.10	-	3.20	3.97	2.97	8.96	7.54
2028	-	2.42	0.17	-	-	0.00	-	-	-	6.17	-	-	-	-	-	-	-	99.30	-	3.21	3.97	2.98	8.98	7.55
2029	-	5.58	2.06	-	-	0.14	-	-	-	6.15	-	-	-	-	-	-	-	103.02	-	3.20	0.01	0.01	8.96	7.53
2030	-	6.02	2.49	-	-	0.17	-	-	-	6.15	-	-	-	-	-	-	-	103.80	-	3.20	-	-	8.96	7.53
2031	-	6.37	3.14	-	-	0.30	-	-	-	6.15	-	-	-	-	-	0.00	-	104.39	-	3.20	-	-	8.96	7.54
2032	-	6.59	3.69	-	-	0.38	-	-	-	6.17	-	-	-	-	-	0.01	-	105.21	-	3.21	-	-	8.99	7.56
2033	-	6.93	4.53	-	-	0.66	-	-	-	6.15	-	-	-	-	-	0.01	-	105.66	-	3.20	-	-	8.96	7.53

Table 40: Generation (GWh) by unit for Scenario 4 – Base Sales

10.6 Scenario 1 Results – Low Sales

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.4	47.1	3.4
2015	0.00	0.0		26.7	16.6	45.3	3.2
2016	0.00	0.0		26.7	16.7	44.4	3.1
2017	0.00	1.0	Solar - 2x0.5MW	27.7	16.9	42.6	2.9
2018	0.00	7.0	Geothermal - 2x3.5MW	34.7	17.0	82.1	6.9
2019	1.50	0.0		33.2	16.9	76.1	5.8
2020	0.00	3.5	Geothermal - 1x3.5MW	36.7	16.8	97.6	9.3
2021	0.00	0.0		36.7	16.8	97.6	9.3
2022	1.75	0.0		35.0	16.8	87.3	7.6
2023	1.35	0.0		33.6	16.8	81.4	6.6
2024	0.00	0.0		33.6	16.7	82.5	6.7
2025	0.00	0.0		33.6	16.7	82.5	6.7
2026	0.00	0.0		33.6	16.6	83.6	6.8
2027	0.00	0.0		33.6	16.6	83.6	6.8
2028	4.20	0.0		29.4	16.5	61.9	3.3
2029	1.88	0.0		27.5	16.5	53.9	2.0
2030	2.80	1.8	MSD - 1x1.8MW	26.5	16.4	50.0	1.3
2031	0.00	0.0		26.5	16.4	50.0	1.3
2032	1.20	0.0		25.3	16.3	44.8	0.4
2033	0.00	0.0		25.3	16.3	44.8	0.4

Table 41: Build Schedule for Scenario 1 – Low Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC$ million			Total Operating Cost	Total Cost EC$ million
	Diesel	Geothermal	Solar		Fuel	O&M			
					Diesel	Fixed	Variable		
2014	-	-	-	**-**	44.1	-	4.8	**48.9**	**48.9**
2015	-	-	-	**-**	44.7	-	4.8	**49.5**	**49.5**
2016	-	-	-	**-**	46.2	-	4.9	**51.1**	**51.1**
2017	-	-	6.3	**6.3**	46.0	0.1	4.8	**50.9**	**57.2**
2018	-	111.9	-	**111.9**	17.6	0.1	3.3	**20.9**	**132.8**
2019	-	-	-	**-**	10.5	0.1	3.3	**13.8**	**13.8**
2020	-	55.9	-	**55.9**	0.8	0.1	2.8	**3.7**	**59.6**
2021	-	-	-	**-**	0.8	0.1	2.7	**3.6**	**3.6**
2022	-	-	-	**-**	0.8	0.1	2.7	**3.6**	**3.6**
2023	-	-	-	**-**	0.8	0.1	2.7	**3.5**	**3.5**
2024	-	-	-	**-**	0.7	0.1	2.6	**3.4**	**3.4**
2025	-	-	-	**-**	0.7	0.1	2.6	**3.4**	**3.4**
2026	-	-	-	**-**	0.6	0.1	2.6	**3.3**	**3.3**
2027	-	-	-	**-**	0.6	0.1	2.5	**3.2**	**3.2**
2028	-	-	-	**-**	0.5	0.1	2.5	**3.1**	**3.1**
2029	-	-	-	**-**	1.8	0.1	2.6	**4.5**	**4.5**
2030	10.0	-	-	**10.0**	1.6	0.1	2.6	**4.3**	**14.3**
2031	-	-	-	**-**	1.6	0.1	2.6	**4.2**	**4.2**
2032	-	-	-	**-**	1.4	0.1	2.5	**4.0**	**4.0**
2033	-	-	-	**-**	1.4	0.1	2.5	**4.0**	**4.0**
NPV 12%	**-**	**-**	**-**	**70.6**	**155.5**	**0.4**	**27.1**	**183.0**	**253.6**

Table 42: NPV for Scenario 1 – Low Sales

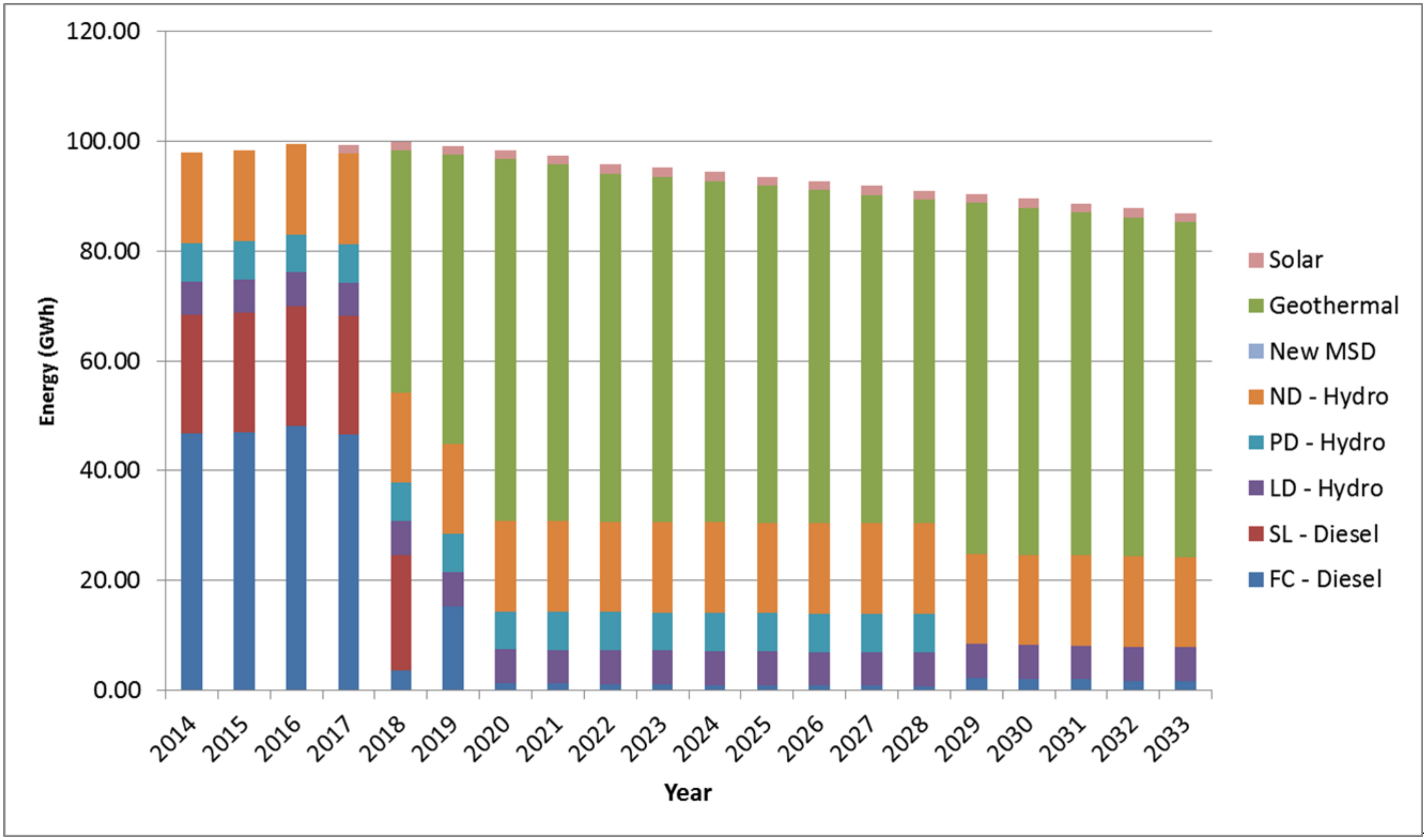

Figure 20: Generation by Technology / Location for Scenario 1 – Low Sales

10.7 Scenario 2 Results – Low Sales

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.4	47.1	3.4
2015	0.00	0.0		26.7	16.6	45.3	3.2
2016	0.00	0.0		26.7	16.7	44.4	3.1
2017	0.00	1.0	Solar - 2x0.5MW	27.7	16.9	42.6	2.9
2018	0.00	0.5	Solar - 1x0.5MW	28.2	17.0	41.8	2.8
2019	1.50	1.8	MSD - 1x1.8MW	28.5	16.9	46.1	3.5
2020	0.00	0.0		28.5	16.8	47.0	3.6
2021	0.00	7.0	Geothermal - 2x3.5MW	35.5	16.8	87.8	7.7
2022	1.75	0.0		33.8	16.8	77.5	6.0
2023	1.35	3.5	Geothermal - 1x3.5MW	35.9	16.8	92.0	8.3
2024	0.00	0.0		35.9	16.7	93.2	8.4
2025	0.00	0.0		35.9	16.7	93.2	8.4
2026	0.00	0.0		35.9	16.6	94.4	8.5
2027	0.00	0.0		35.9	16.6	94.4	8.5
2028	4.20	0.0		31.7	16.5	72.7	5.0
2029	1.88	0.0		29.8	16.5	64.7	3.7
2030	2.80	0.0		27.0	16.4	50.0	1.3
2031	0.00	0.0		27.0	16.4	50.0	1.3
2032	1.20	0.0		25.8	16.3	44.8	0.4
2033	0.00	0.0		25.8	16.3	44.8	0.4

Table 43: Build Schedule for Scenario 2 – Low Sales

Year	Capital Expenditure EC$ million			**Total Capex**	**Operating Cost EC$ million**			**Total Operating Cost**	**Total Cost EC$ million**
	Diesel	Geothermal	Solar		**Fuel**	**O&M**			
					Diesel	**Fixed**	**Variable**		
2014	-	-	-	**-**	44.1	-	4.8	**48.9**	**48.9**
2015	-	-	-	**-**	44.7	-	4.8	**49.5**	**49.5**
2016	-	-	-	**-**	46.2	-	4.9	**51.1**	**51.1**
2017	-	-	6.3	**6.3**	46.0	0.1	4.8	**50.9**	**57.2**
2018	-	-	3.2	**3.2**	46.4	0.1	4.7	**51.2**	**54.4**
2019	10.0	-	-	**10.0**	45.8	0.1	4.9	**50.8**	**60.9**
2020	-	-	-	**-**	45.7	0.1	4.8	**50.6**	**50.6**
2021	-	111.9	-	**111.9**	9.4	0.1	3.1	**12.6**	**124.5**
2022	-	-	-	**-**	9.0	0.1	3.1	**12.2**	**12.2**
2023	-	55.9	-	**55.9**	0.6	0.1	2.6	**3.3**	**59.3**
2024	-	-	-	**-**	0.5	0.1	2.6	**3.2**	**3.2**
2025	-	-	-	**-**	0.5	0.1	2.6	**3.2**	**3.2**
2026	-	-	-	**-**	0.4	0.1	2.5	**3.1**	**3.1**
2027	-	-	-	**-**	0.4	0.1	2.5	**3.0**	**3.0**
2028	-	-	-	**-**	0.3	0.1	2.5	**2.9**	**2.9**
2029	-	-	-	**-**	1.4	0.1	2.6	**4.1**	**4.1**
2030	-	-	-	**-**	1.3	0.1	2.6	**3.9**	**3.9**
2031	-	-	-	**-**	1.2	0.1	2.5	**3.9**	**3.9**
2032	-	-	-	**-**	1.1	0.1	2.5	**3.7**	**3.7**
2033	-	-	-	**-**	1.1	0.1	2.5	**3.7**	**3.7**
NPV 12%	**-**	**-**	**-**	**52.6**	**215.9**	**0.6**	**29.8**	**246.3**	**298.9**

Table 44: NPV for Scenario 2 – Low Sales

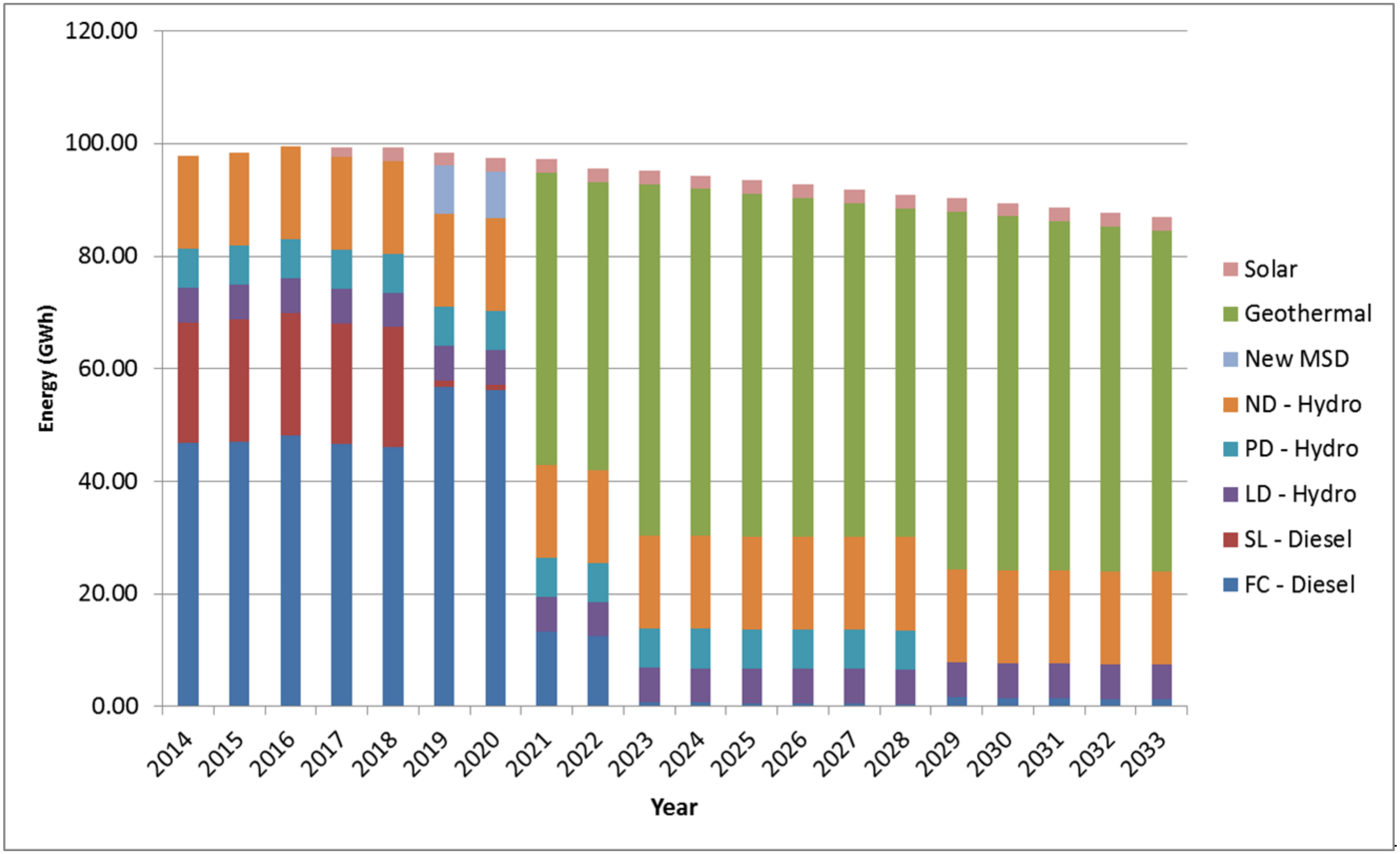

Figure 21: Generation by Technology / Location for Scenario 2 – Low Sales

10.8 Scenario 3 Results – Low Sales

Year	Capacity Retired (MW)	Capacity Added		Total Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
		(MW)	Type				
2014	0.00	0.0		26.7	16.4	47.1	3.4
2015	0.00	0.0		26.7	16.6	45.3	3.2
2016	0.00	0.0		26.7	16.7	44.4	3.1
2017	0.00	1.0	Solar - 2x0.5MW	27.7	16.9	42.6	2.9
2018	0.00	2.3	Solar - 1x0.5MW MSD - 1x1.8MW	30.0	17.0	52.2	4.6
2019	1.50	0.0		28.5	16.9	46.1	3.5
2020	0.00	0.0		28.5	16.8	47.0	3.6
2021	0.00	0.0		28.5	16.8	47.0	3.6
2022	1.75	3.5	MSD - 1x3.5MW	30.3	16.8	57.1	3.7
2023	1.35	0.0		28.9	16.8	51.2	2.7
2024	0.00	0.0		28.9	16.7	52.1	2.8
2025	0.00	0.0		28.9	16.7	52.1	2.8
2026	0.00	0.0		28.9	16.6	53.0	2.9
2027	0.00	0.0		28.9	16.6	53.0	2.9
2028	4.20	3.5	MSD - 1x3.5MW	28.2	16.5	51.9	1.7
2029	1.88	0.0		26.3	16.5	43.9	0.4
2030	2.80	3.5	MSD - 1x3.5MW	27.0	16.4	49.9	1.3
2031	0.00	0.0		27.0	16.4	49.9	1.3
2032	1.20	0.0		25.8	16.3	44.7	0.4
2033	0.00	0.0		25.8	16.3	44.7	0.4

Table 45: Build Schedule for Scenario 3 – Low Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC$ million			Total Operating Cost	Total Cost EC$ million
	Diesel	Geothermal	Solar		Fuel	O&M			
					Diesel	Fixed	Variable		
2014	-	-	-	**-**	44.1	-	4.8	**48.9**	**48.9**
2015	-	-	-	**-**	44.7	-	4.8	**49.5**	**49.5**
2016	-	-	-	**-**	46.2	-	4.9	**51.1**	**51.1**
2017	-	-	-	**-**	46.0	0.1	4.8	**50.9**	**50.9**
2018	10.0	-	3.2	**13.2**	46.5	0.1	4.6	**51.2**	**64.4**
2019	-	-	-	**-**	45.8	0.1	4.9	**50.8**	**50.8**
2020	-	-	-	**-**	45.7	0.1	4.8	**50.6**	**50.6**
2021	-	-	-	**-**	46.0	0.1	4.7	**50.9**	**50.9**
2022	19.2	-	-	**19.2**	45.8	0.1	4.1	**50.1**	**69.3**
2023	-	-	-	**-**	46.0	0.1	4.1	**50.2**	**50.2**
2024	-	-	-	**-**	46.1	0.1	4.0	**50.2**	**50.2**
2025	-	-	-	**-**	46.2	0.1	4.0	**50.3**	**50.3**
2026	-	-	-	**-**	46.2	0.1	3.9	**50.2**	**50.2**
2027	-	-	-	**-**	46.1	0.1	3.9	**50.1**	**50.1**
2028	19.2	-	-	**19.2**	46.0	0.1	3.4	**49.5**	**68.7**
2029	-	-	-	**-**	51.6	0.1	3.7	**55.4**	**55.4**
2030	19.2	-	-	**19.2**	51.6	0.1	3.3	**55.1**	**74.3**
2031	-	-	-	**-**	51.5	0.1	3.3	**54.9**	**54.9**
2032	-	-	-	**-**	51.4	0.1	3.2	**54.8**	**54.8**
2033	-	-	-	**-**	51.6	0.1	3.2	**54.9**	**54.9**
NPV 12%	**-**	**-**	**-**	**18.0**	**344.9**	**0.6**	**33.3**	**378.8**	**396.8**

Table 46: NPV for Scenario 3 – Low Sales

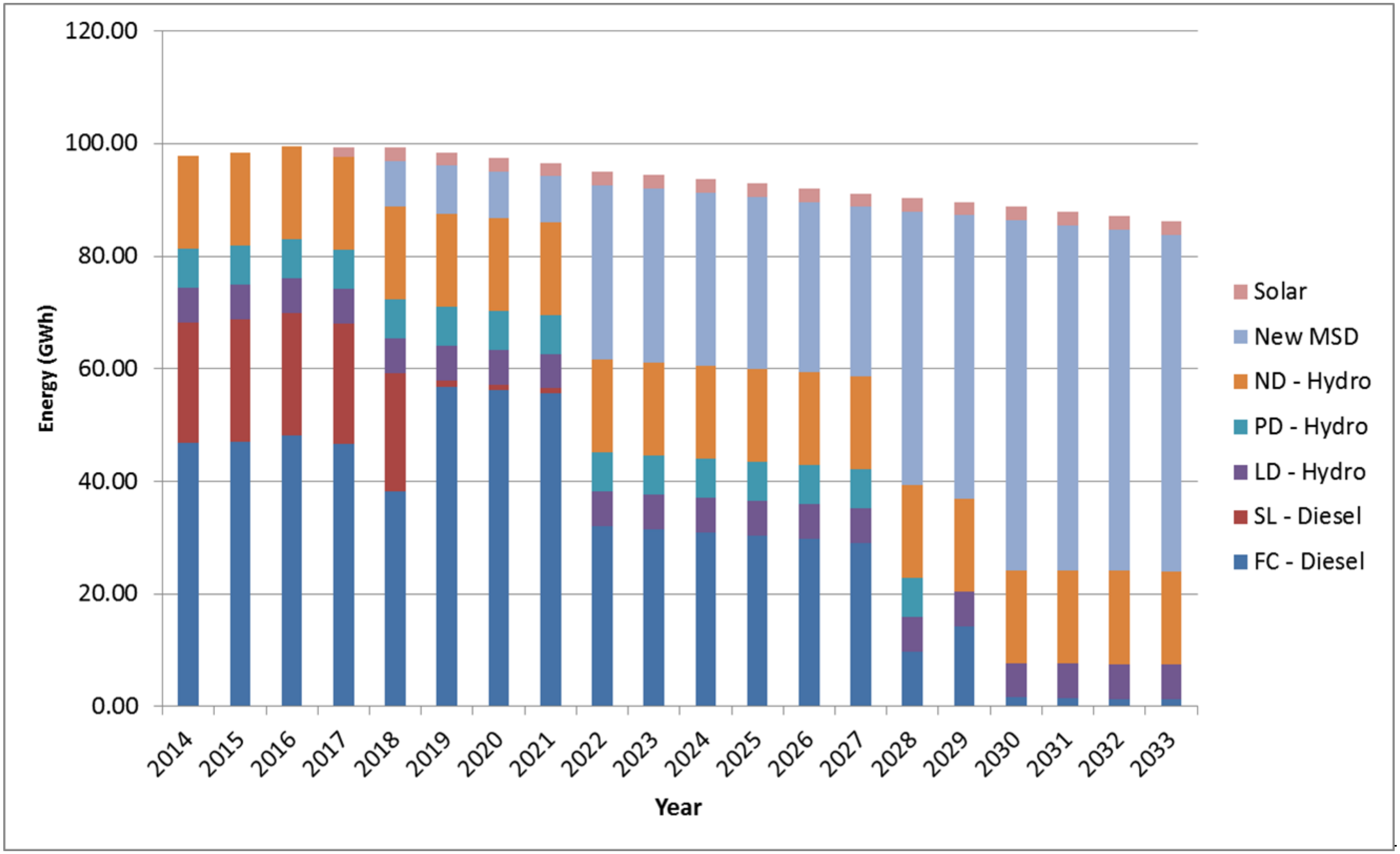

Figure 22: Generation by Technology / Location for Scenario 3 – Low Sales

10.9 Scenario 4 Results – Low Sales

Year	Capacity Retired (MW)	Capacity Added		Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
		(MW)	Type				
2014	0.00	0.0		26.7	16.4	47.1	3.4
2015	0.00	0.0		26.7	16.6	45.3	3.2
2016	0.00	0.0		26.7	16.7	44.4	3.1
2017	0.00	1.0	Solar - 2x0.5MW	27.7	16.9	42.6	2.9
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	19.0	62.4	4.9
2019	1.50	0.0		33.7	18.9	57.0	3.8
2020	0.00	3.5	Geothermal - 1x3.5MW	37.2	18.8	76.0	7.3
2021	0.00	0.0		37.2	18.8	76.0	7.3
2022	1.75	0.0		35.5	18.8	66.8	5.6
2023	1.35	0.0		34.1	18.8	61.6	4.6
2024	0.00	0.0		34.1	18.7	62.4	4.7
2025	0.00	0.0		34.1	18.7	62.4	4.7
2026	0.00	0.0		34.1	18.6	63.3	4.8
2027	0.00	0.0		34.1	18.6	63.3	4.8
2028	4.20	0.0		29.9	18.5	43.9	1.3
2029	1.88	3.5	Geothermal - 1x3.5MW	31.5	18.5	55.3	3.3
2030	2.80	0.0		28.7	18.4	42.1	0.9
2031	0.00	0.0		28.7	18.4	42.1	0.9
2032	1.20	0.0		27.5	18.3	37.5	0.0
2033	0.00	0.0		27.5	18.3	37.5	0.0

Table 47: Build Schedule for Scenario 4 – Low Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC$ million			Total Operating Cost	Total Cost EC$ million
	Diesel	Geothermal	Solar		Fuel	O&M			
					Diesel	Fixed	Variable		
2014	-	-	-	**-**	44.1	-	4.8	**48.9**	**48.9**
2015	-	-	-	**-**	44.7	-	4.8	**49.5**	**49.5**
2016	-	-	-	**-**	46.2	-	4.9	**51.1**	**51.1**
2017	-	-	6.3	**6.3**	46.0	0.1	4.8	**50.9**	**57.2**
2018	-	111.9	3.2	**115.0**	22.1	0.1	3.9	**26.1**	**141.1**
2019	-	-	-	**-**	17.2	0.1	4.0	**21.4**	**21.4**
2020	-	55.9	-	**55.9**	4.1	0.1	3.3	**7.6**	**63.5**
2021	-	-	-	**-**	4.1	0.1	3.3	**7.5**	**7.5**
2022	-	-	-	**-**	3.9	0.1	3.2	**7.2**	**7.2**
2023	-	-	-	**-**	3.8	0.1	3.2	**7.1**	**7.1**
2024	-	-	-	**-**	3.6	0.1	3.1	**6.8**	**6.8**
2025	-	-	-	**-**	3.5	0.1	3.1	**6.8**	**6.8**
2026	-	-	-	**-**	3.3	0.1	3.1	**6.5**	**6.5**
2027	-	-	-	**-**	3.2	0.1	3.0	**6.4**	**6.4**
2028	-	-	-	**-**	3.0	0.1	3.0	**6.1**	**6.1**
2029	-	55.9	-	**55.9**	0.2	0.1	3.0	**3.3**	**59.2**
2030	-	-	-	**-**	0.2	0.1	2.9	**3.2**	**3.2**
2031	-	-	-	**-**	0.2	0.1	2.9	**3.2**	**3.2**
2032	-	-	-	**-**	0.2	0.1	2.9	**3.2**	**3.2**
2033	-	-	-	**-**	0.2	0.1	2.8	**3.1**	**3.1**
NPV 12%	**-**	**-**	**-**	**75.2**	**168.6**	**0.6**	**29.4**	**198.6**	**273.8**

Table 48: NPV for Scenario 4 – Low Sales

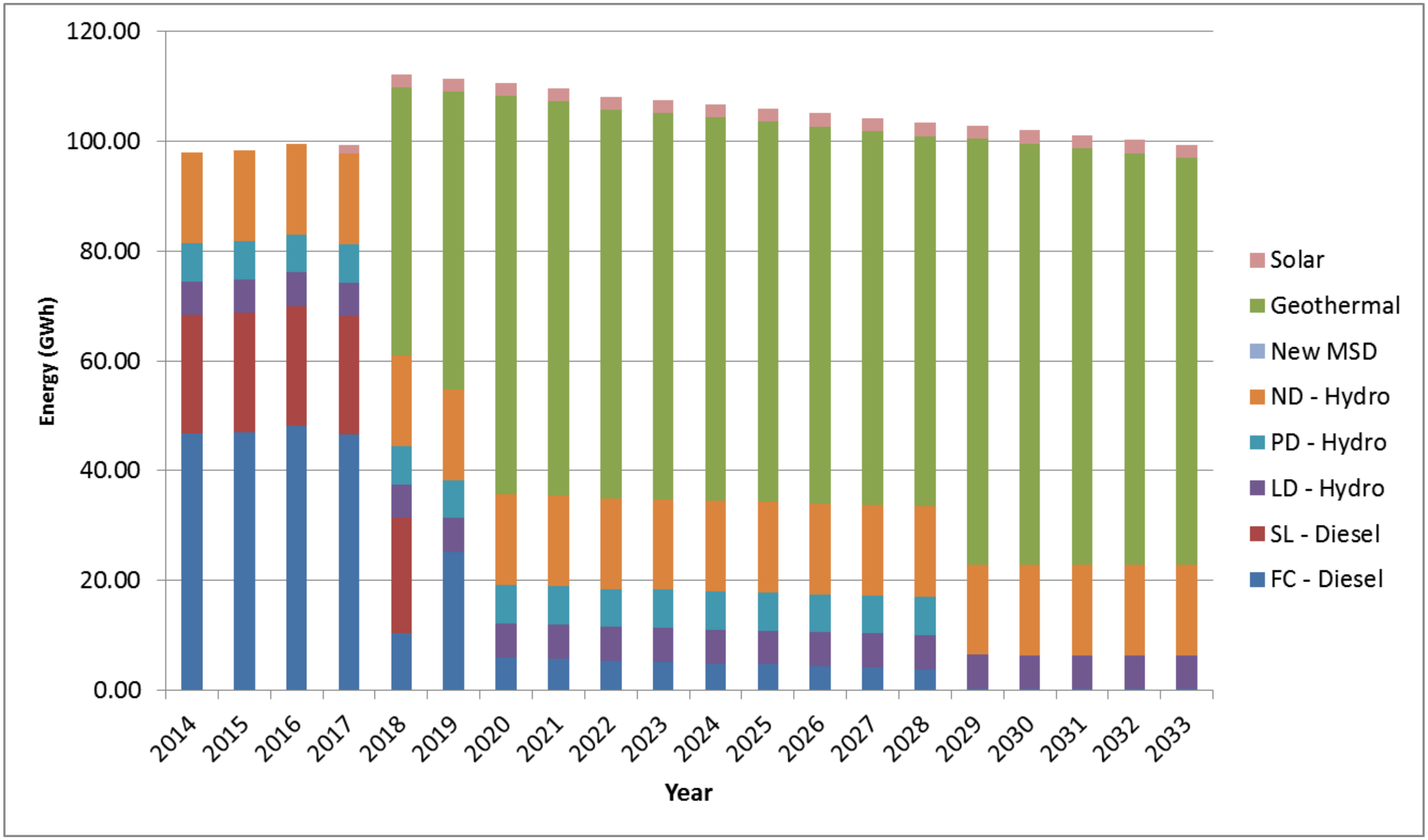

Figure 23: Generation by Technology / Location for Scenario 4 – Low Sales

10.10 Scenario 1 Results – High Sales

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	17.1	40.9	2.7
2015	0.00	0.0		26.7	17.7	36.0	2.1
2016	0.00	0.0		26.7	18.0	33.7	1.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	18.4	30.7	1.4
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	18.8	64.2	5.1
2019	1.50	0.0		33.7	19.3	53.6	3.4
2020	0.00	7.0	Geothermal - 2x3.5MW	40.7	19.8	85.1	9.7
2021	0.00	0.0		40.7	20.3	80.4	9.2
2022	1.75	0.5	Solar - 1x0.5MW	39.5	20.7	68.4	7.1
2023	1.35	0.0		38.1	21.2	59.7	5.6
2024	0.00	0.0		38.1	21.7	55.9	5.1
2025	0.00	0.0		38.1	22.2	52.3	4.6
2026	0.00	0.0		38.1	22.8	48.2	4.0
2027	0.00	0.0		38.1	23.4	44.9	3.5
2028	4.20	3.5	MSD - 1x3.5MW	37.4	24.0	39.7	2.6
2029	1.88	0.0		35.5	24.5	31.4	0.8
2030	2.80	3.5	MSD - 1x3.5MW	36.2	25.2	30.9	0.9
2031	0.00	0.5	Solar - 1x0.5MW	36.7	25.8	27.8	0.3
2032	1.20	1.8	MSD - 1x1.8MW	37.3	26.4	27.8	0.5
2033	0.00	1.8	MSD - 1x1.8MW	39.1	27.2	31.0	1.5

Table 49: Build Schedule for Scenario 1 – High Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC$ million			Total Operating Cost	Total Cost EC$ million
	Diesel	Geothermal	Solar		Fuel	O&M			
					Diesel	Fixed	Variable		
2014	-	-	-	**-**	46.7	-	5.1	**51.7**	**51.7**
2015	-	-	-	**-**	48.3	-	5.2	**53.5**	**53.5**
2016	-	-	-	**-**	51.4	-	5.4	**56.8**	**56.8**
2017	-	-	6.3	**6.3**	53.4	0.1	5.5	**59.0**	**65.3**
2018	-	111.9	3.2	**115.0**	22.4	0.1	4.0	**26.5**	**141.6**
2019	-	-	-	**-**	21.3	0.1	4.4	**25.8**	**25.8**
2020	-	111.9	-	**111.9**	0.3	0.1	3.5	**3.9**	**115.8**
2021	-	-	-	**-**	0.8	0.1	3.6	**4.5**	**4.5**
2022	-	-	3.2	**3.2**	1.1	0.2	3.7	**5.0**	**8.1**
2023	-	-	-	**-**	2.1	0.2	3.9	**6.1**	**6.1**
2024	-	-	-	**-**	3.3	0.2	4.1	**7.6**	**7.6**
2025	-	-	-	**-**	5.1	0.2	4.3	**9.5**	**9.5**
2026	-	-	-	**-**	7.2	0.2	4.5	**11.9**	**11.9**
2027	-	-	-	**-**	9.5	0.2	4.8	**14.4**	**14.4**
2028	19.2	-	-	**19.2**	12.2	0.2	4.7	**17.1**	**36.3**
2029	-	-	-	**-**	19.8	0.2	5.2	**25.2**	**25.2**
2030	19.2	-	-	**19.2**	23.7	0.2	5.3	**29.1**	**48.4**
2031	-	-	3.2	**3.2**	27.2	0.2	5.5	**32.9**	**36.0**
2032	10.0	-	-	**10.0**	31.5	0.2	5.7	**37.4**	**47.4**
2033	10.0	-	-	**10.0**	36.8	0.2	6.0	**43.0**	**53.1**
NPV 12%	**-**	**-**	**-**	**94.0**	**201.6**	**0.8**	**34.8**	**237.2**	**331.2**

Table 50: NPV for Scenario 1 – High Sales

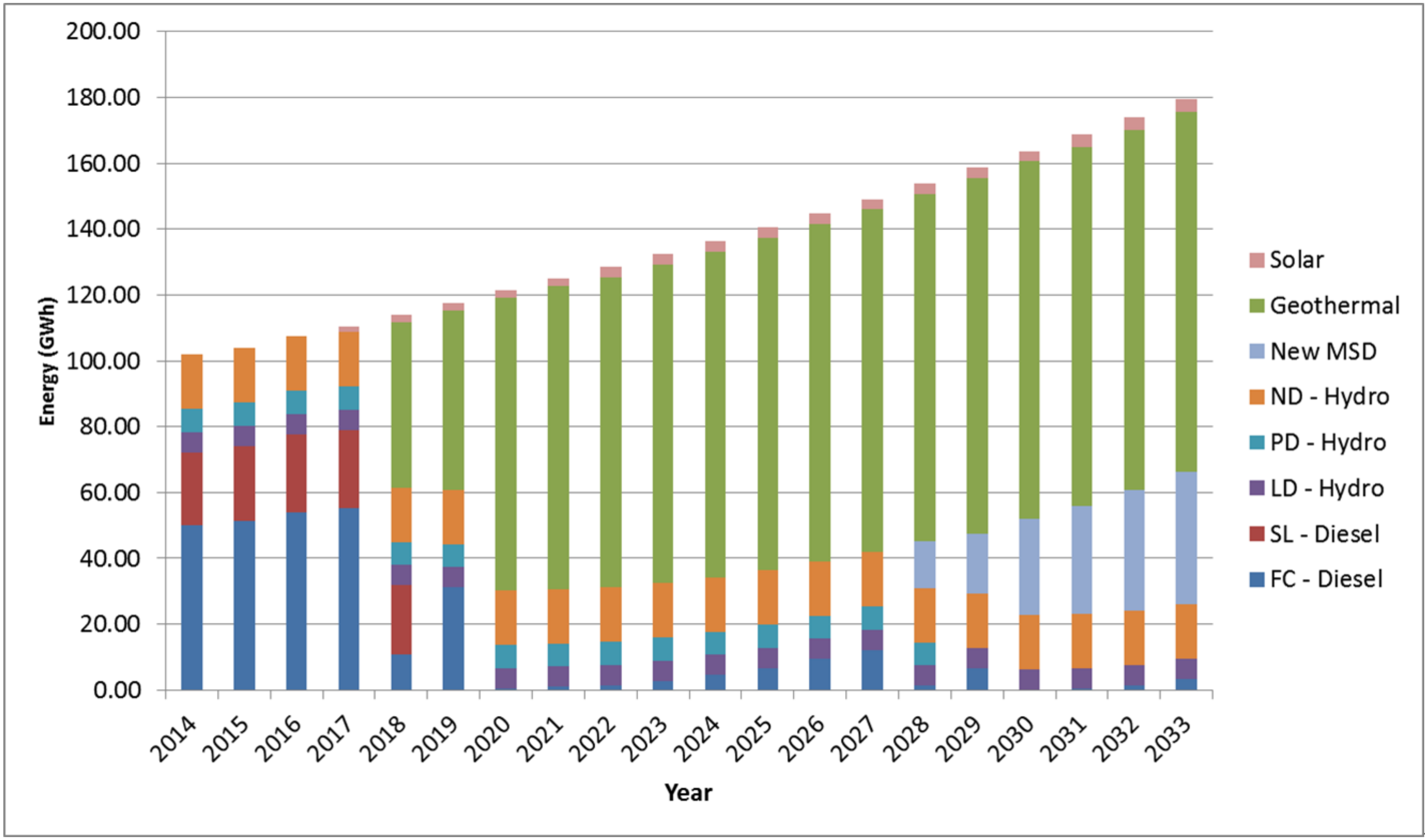

Figure 24: Generation by Technology / Location for Scenario 1 – High Sales

10.11 Scenario 2 Results – High Sales

Year	Capacity Retired (MW)	Capacity Added		Total Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
		(MW)	Type				
2014	0.00	0.0		26.7	17.1	40.9	2.7
2015	0.00	0.0		26.7	17.7	36.0	2.1
2016	0.00	0.0		26.7	18.0	33.7	1.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	18.4	30.7	1.4
2018	0.00	0.5	Solar - 1x0.5MW	28.2	18.8	27.8	1.0
2019	1.50	3.5	MSD - 1x3.5MW	30.2	19.3	35.9	1.1
2020	0.00	0.0		30.2	19.8	33.1	0.7
2021	0.00	7.0	Geothermal - 2x3.5MW	37.2	20.3	63.5	5.9
2022	1.75	0.5	Solar - 1x0.5MW	36.0	20.7	51.8	3.8
2023	1.35	7.0	Geothermal - 2x3.5MW	41.6	21.2	75.8	9.0
2024	0.00	0.0		41.6	21.7	71.6	8.5
2025	0.00	0.0		41.6	22.2	67.6	8.0
2026	0.00	0.0		41.6	22.8	63.1	7.4
2027	0.00	0.0		41.6	23.4	59.5	6.9
2028	4.20	0.0		37.4	24.0	39.7	2.6
2029	1.88	0.0		35.5	24.5	31.4	0.8
2030	2.80	3.5	MSD - 1x3.5MW	36.2	25.2	30.9	0.9
2031	0.00	0.5	Solar - 1x0.5MW	36.7	25.8	27.8	0.3
2032	1.20	1.8	MSD - 1x1.8MW	37.3	26.4	27.8	0.5
2033	0.00	1.8	MSD - 1x1.8MW	39.1	27.2	31.0	1.5

Table 51: Build Schedule for Scenario 2 – High Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC$ million			Total Operating Cost	Total Cost EC$ million
					Fuel	O&M			
	Diesel	Geothermal	Solar		Diesel	Fixed	Variable		
2014	-	-	-	**-**	46.7	-	5.1	**51.7**	**51.7**
2015	-	-	-	**-**	48.3	-	5.2	**53.5**	**53.5**
2016	-	-	-	**-**	51.4	-	5.4	**56.8**	**56.8**
2017	-	-	6.3	**6.3**	53.4	0.1	5.5	**59.0**	**65.3**
2018	-	-	3.2	**3.2**	56.1	0.1	5.6	**61.9**	**65.0**
2019	19.2	-	-	**19.2**	58.5	0.1	5.7	**64.3**	**83.5**
2020	-	-	-	**-**	61.7	0.1	5.9	**67.6**	**67.6**
2021	-	111.9	-	**111.9**	27.0	0.1	4.4	**31.5**	**143.3**
2022	-	-	3.2	**3.2**	29.6	0.2	4.5	**34.3**	**37.4**
2023	-	111.9	-	**111.9**	2.1	0.2	3.8	**6.1**	**117.9**
2024	-	-	-	**-**	3.4	0.2	4.0	**7.5**	**7.5**
2025	-	-	-	**-**	5.1	0.2	4.1	**9.4**	**9.4**
2026	-	-	-	**-**	7.3	0.2	4.3	**11.8**	**11.8**
2027	-	-	-	**-**	9.6	0.2	4.5	**14.2**	**14.2**
2028	-	-	-	**-**	12.2	0.2	4.7	**17.1**	**17.1**
2029	-	-	-	**-**	19.8	0.2	5.2	**25.2**	**25.2**
2030	19.2	-	-	**19.2**	23.7	0.2	5.3	**29.1**	**48.4**
2031	-	-	3.2	**3.2**	27.2	0.2	5.5	**32.9**	**36.0**
2032	10.0	-	-	**10.0**	31.5	0.2	5.7	**37.4**	**47.4**
2033	10.0	-	-	**10.0**	36.8	0.2	6.0	**43.0**	**53.1**
NPV 12%	**-**	**-**	**-**	**70.5**	**288.2**	**0.8**	**37.9**	**326.9**	**397.4**

Table 52: NPV for Scenario 2 – High Sales

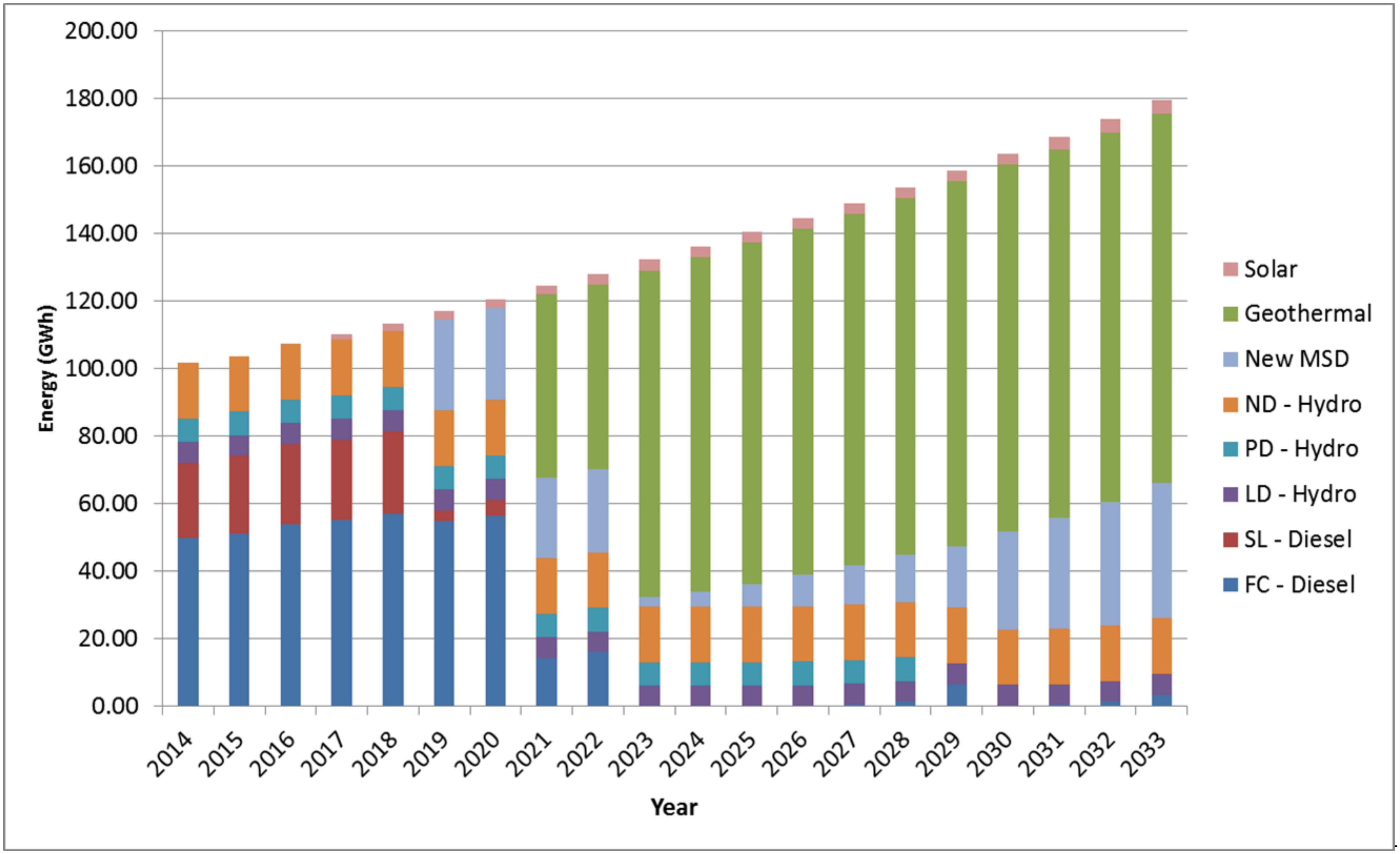

Figure 25: Generation by Technology / Location for Scenario 2 – High Sales

10.12 Scenario 3 Results – High Sales

Year	Capacity Retired (MW)	Capacity Added		Total Capacity	Peak Demand	Reserve Margin	N-2 Contingency (MW)
		(MW)	Type	(MW)	(MWgross)	%	
2014	0.00	0.0		26.7	17.1	40.9	2.7
2015	0.00	0.0		26.7	17.7	36.0	2.1
2016	0.00	0.0		26.7	18.0	33.7	1.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	18.4	30.7	1.4
2018	0.00	4.0	Solar - 1x0.5MW MSD - 1x3.5MW	31.7	18.8	46.0	3.3
2019	1.50	0.0		30.2	19.3	35.9	1.1
2020	0.00	0.0		30.2	19.8	33.1	0.7
2021	0.00	0.0		30.2	20.3	29.7	0.2
2022	1.75	4.0	Solar - 1x0.5MW MSD - 1x3.5MW	32.5	20.7	35.3	0.5
2023	1.35	3.5	MSD - 1x3.5MW	34.6	21.2	43.4	2.3
2024	0.00	0.0		34.6	21.7	40.0	1.8
2025	0.00	0.0		34.6	22.2	36.8	1.3
2026	0.00	0.0		34.6	22.8	33.1	0.7
2027	0.00	0.0		34.6	23.4	30.2	0.2
2028	4.20	5.3	MSD - 1x1.8MW MSD - 1x3.5MW	35.7	24.0	32.8	1.0
2029	1.88	1.8	MSD - 1x1.8MW	35.6	24.5	31.9	1.0
2030	2.80	3.5	MSD - 1x3.5MW	36.3	25.2	31.4	1.1
2031	0.00	0.5	Solar - 1x0.5MW	36.8	25.8	28.3	0.5
2032	1.20	1.8	MSD - 1x1.8MW	37.4	26.4	28.3	0.6
2033	0.00	1.8	MSD - 1x1.8MW	39.2	27.2	31.4	1.7

Table 53: Build Schedule for Scenario 3 – High Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC$ million			Total Operating Cost	Total Cost EC$ million
	Diesel	Geothermal	Solar		Fuel	O&M			
					Diesel	Fixed	Variable		
2014	-	-	-	**-**	46.7	-	5.1	**51.7**	**51.7**
2015	-	-	-	**-**	48.3	-	5.2	**53.5**	**53.5**
2016	-	-	-	**-**	51.4	-	5.4	**56.8**	**56.8**
2017	-	-	6.3	**6.3**	53.4	0.1	5.5	**59.0**	**65.3**
2018	19.2	-	3.2	**22.4**	55.9	0.1	5.1	**61.2**	**83.5**
2019	-	-	-	**-**	58.5	0.1	5.7	**64.3**	**64.3**
2020	-	-	-	**-**	61.7	0.1	5.9	**67.6**	**67.6**
2021	-	-	-	**-**	65.6	0.1	6.1	**71.7**	**71.7**
2022	19.2	-	3.2	**22.4**	68.9	0.2	5.7	**74.8**	**97.2**
2023	19.2	-	-	**19.2**	72.6	0.2	5.4	**78.2**	**97.5**
2024	-	-	-	**-**	76.6	0.2	5.7	**82.4**	**82.4**
2025	-	-	-	**-**	81.0	0.2	5.9	**87.1**	**87.1**
2026	-	-	-	**-**	85.3	0.2	6.2	**91.7**	**91.7**
2027	-	-	-	**-**	89.8	0.2	6.5	**96.5**	**96.5**
2028	29.3	-	-	**29.3**	94.7	0.2	6.3	**101.1**	**130.4**
2029	10.0	-	-	**10.0**	105.4	0.2	6.9	**112.5**	**122.5**
2030	19.2	-	-	**19.2**	110.7	0.2	6.8	**117.7**	**136.9**
2031	-	-	3.2	**3.2**	115.4	0.2	7.1	**122.7**	**125.9**
2032	10.0	-	-	**10.0**	121.3	0.2	7.3	**128.8**	**138.9**
2033	10.0	-	-	**10.0**	127.9	0.2	7.7	**135.7**	**145.8**
NPV 12%	**-**	**-**	**-**	**30.0**	**488.4**	**0.8**	**42.4**	**531.6**	**561.6**

Table 54: NPV for Scenario 3 – High Sales

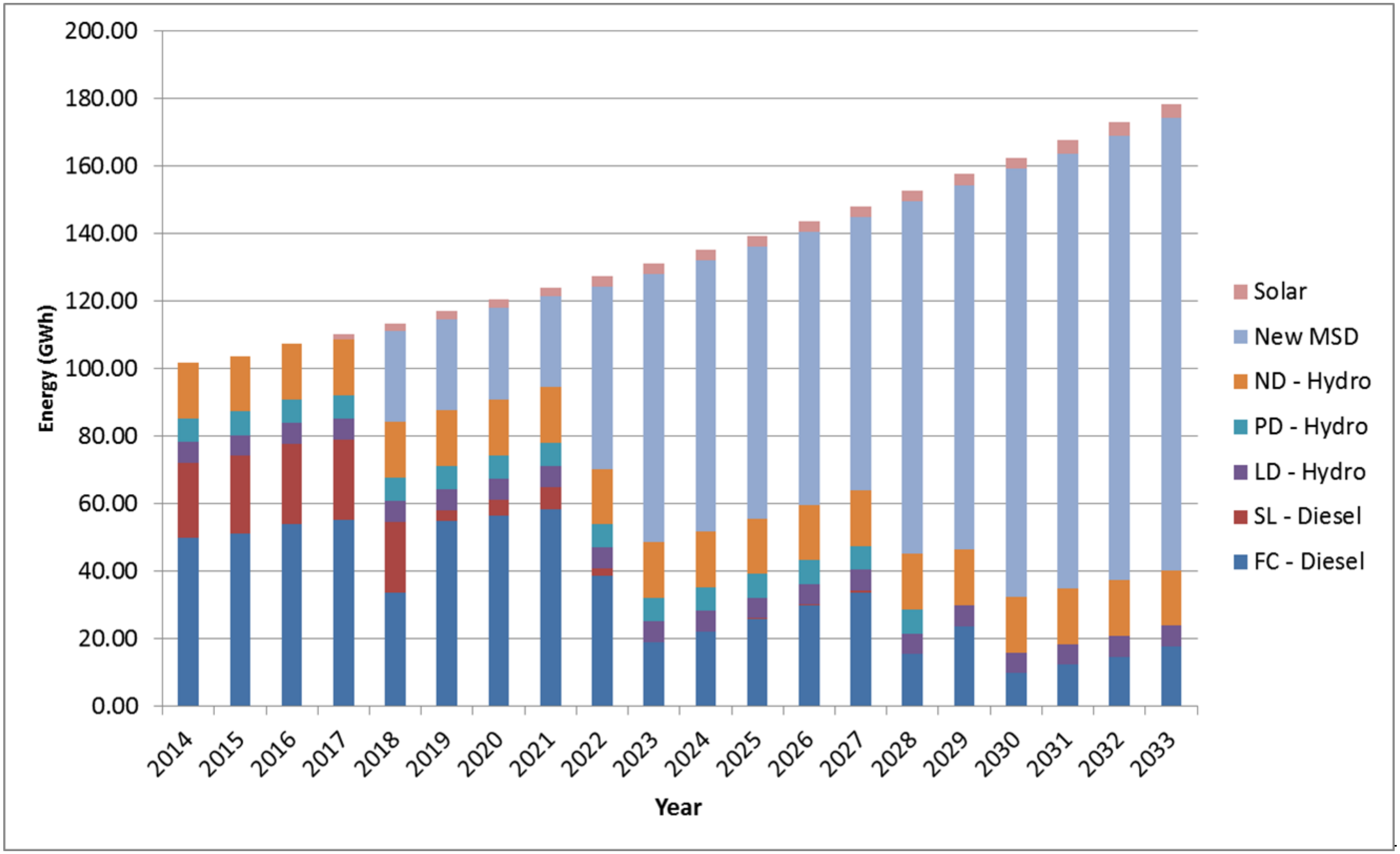

Figure 26: Generation by Technology / Location for Scenario 3 – High Sales

10.13 Scenario 4 Results – High Sales

Year	Capacity Retired (MW)	Capacity Added		Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
		(MW)	Type				
2014	0.00	0.0		26.7	17.1	40.9	2.7
2015	0.00	0.0		26.7	17.7	36.0	2.1
2016	0.00	0.0		26.7	18.0	33.7	1.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	18.4	30.7	1.4
2018	0.00	8.0	Geothermal - 2x3.5MW Solar - 2x0.5MW	35.7	20.9	48.0	3.1
2019	1.50	0.0		34.2	21.4	38.8	1.4
2020	0.00	7.0	Geothermal - 2x3.5MW	41.2	21.8	67.6	7.7
2021	0.00	0.0		41.2	22.3	63.7	7.2
2022	1.75	0.0		39.5	22.7	53.2	5.1
2023	1.35	0.0		38.1	23.3	45.5	3.6
2024	0.00	0.0		38.1	23.8	42.4	3.1
2025	0.00	0.0		38.1	24.3	39.4	2.6
2026	0.00	0.0		38.1	24.9	35.9	2.0
2027	0.00	0.0		38.1	25.4	33.2	1.5
2028	4.20	4.0	Solar - 1x0.5MW MSD - 1x3.5MW	37.9	26.0	28.7	0.6
2029	1.88	3.5	MSD - 1x3.5MW	39.5	26.5	34.1	2.1
2030	2.80	1.8	MSD - 1x1.8MW	38.5	27.3	27.6	0.7
2031	0.00	0.0		38.5	27.9	24.8	0.1
2032	1.20	3.5	MSD - 1x3.5MW	40.8	28.5	30.6	1.8
2033	0.00	0.0		40.8	29.2	27.4	1.1

Table 55: Build Schedule for Scenario 4 – High Sales

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC$ million			Total Operating Cost	Total Cost EC$ million
	Diesel	Geothermal	Solar		Fuel	O&M			
					Diesel	Fixed	Variable		
2014	-	-	-	**-**	46.7	-	5.1	**51.7**	**51.7**
2015	-	-	-	**-**	48.3	-	5.2	**53.5**	**53.5**
2016	-	-	-	**-**	51.4	-	5.4	**56.8**	**56.8**
2017	-	-	6.3	**6.3**	53.4	0.1	5.5	**59.0**	**65.3**
2018	-	111.9	6.3	**118.2**	28.4	0.2	4.7	**33.2**	**151.4**
2019	-	-	-	**-**	29.2	0.2	5.2	**34.5**	**34.5**
2020	-	111.9	-	**111.9**	2.8	0.2	4.0	**6.9**	**118.8**
2021	-	-	-	**-**	4.2	0.2	4.2	**8.5**	**8.5**
2022	-	-	-	**-**	5.6	0.2	4.3	**10.1**	**10.1**
2023	-	-	-	**-**	7.4	0.2	4.5	**12.1**	**12.1**
2024	-	-	-	**-**	9.3	0.2	4.7	**14.2**	**14.2**
2025	-	-	-	**-**	11.7	0.2	5.0	**16.8**	**16.8**
2026	-	-	-	**-**	14.3	0.2	5.2	**19.7**	**19.7**
2027	-	-	-	**-**	17.0	0.2	5.5	**22.6**	**22.6**
2028	19.2	-	3.2	**22.4**	19.3	0.2	5.3	**24.9**	**47.2**
2029	19.2	-	-	**19.2**	28.4	0.2	5.6	**34.2**	**53.4**
2030	10.0	-	-	**10.0**	32.6	0.2	5.8	**38.7**	**48.7**
2031	-	-	-	**-**	37.1	0.2	6.1	**43.4**	**43.4**
2032	19.2	-	-	**19.2**	41.7	0.2	6.2	**48.1**	**67.4**
2033	-	-	-	**-**	47.2	0.2	6.5	**54.0**	**54.0**
NPV 12%	**-**	**-**	**-**	**95.9**	**228.8**	**0.9**	**37.6**	**267.4**	**363.2**

Table 56: NPV for Scenario 4 – High Sales

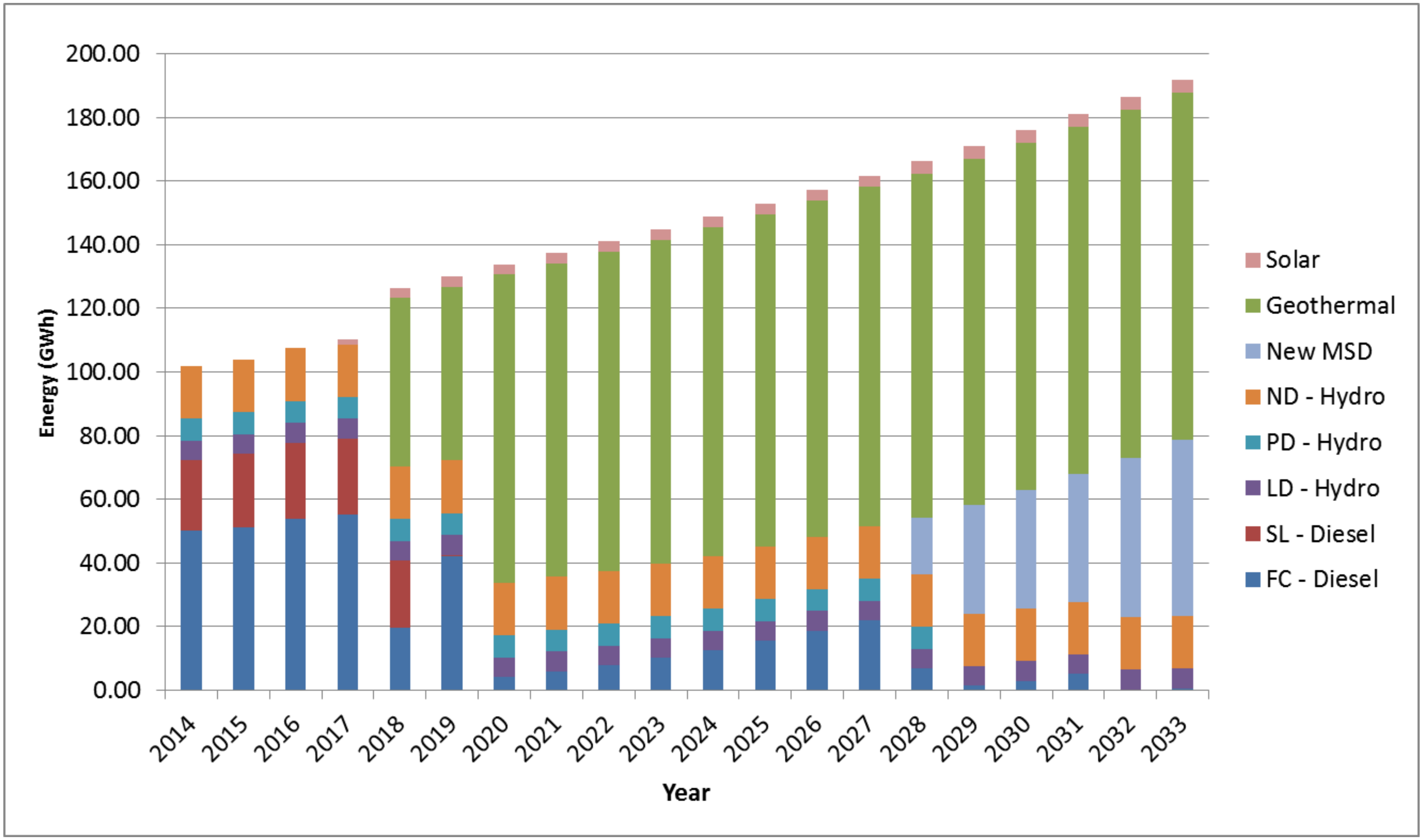

Figure 27: Generation by Technology / Location for Scenario 4 – High Sales

10.14 Recommended Plan Results

Year	Capacity Retired (MW)	Capacity Added (MW)	Capacity Added Type	Total Installed Capacity (MW)	Peak Demand (MWgross)	Reserve Margin %	N-2 Contingency (MW)
2014	0.00	0.0		26.7	16.6	45.3	3.2
2015	0.00	0.0		26.7	16.8	43.5	3.0
2016	0.00	0.0		26.7	17.0	41.8	2.8
2017	0.00	1.0	Solar - 2x0.5MW	27.7	17.2	40.1	2.6
2018	0.00	7.5	Geothermal - 2x3.5MW Solar - 1x0.5MW	35.2	17.4	77.8	6.5
2019	1.50	0.0		33.7	17.5	69.9	5.2
2020	0.00	3.5	Geothermal - 1x3.5MW	37.2	17.6	88.3	8.5
2021	0.00	0.0		37.2	17.7	87.2	8.4
2022	1.75	0.0		35.5	17.8	76.4	6.6
2023	1.35	0.0		34.1	18.0	68.9	5.4
2024	0.00	0.0		34.1	18.1	68.0	5.3
2025	0.00	3.5	Geothermal - 1x3.5MW	37.6	18.3	84.8	8.4
2026	0.00	0.0		37.6	18.4	83.7	8.3
2027	0.00	0.0		37.6	18.6	81.7	8.1
2028	4.20	0.0		33.4	18.7	60.6	4.4
2029	1.88	0.0		31.5	18.9	51.9	2.9
2030	2.80	0.0		28.7	19.0	37.5	0.3
2031	0.00	0.0		28.7	19.2	36.0	0.1
2032	1.20	1.8	MSD - 1x1.8MW	29.3	19.3	39.4	0.8
2033	0.00	0.0		29.3	19.6	37.9	0.6

Table 57: Build Schedule for recommended plan

Year	Capital Expenditure EC$ million			Total Capex	Operating Cost EC $million			Total Operating Cost	Total Cost EC$ million
					Fuel	O&M			
	Diesel	Geothermal	Solar		Diesel	Fixed	Variable		
2014	-	-	-	**-**	45.5	-	4.9	**50.5**	**50.5**
2015	-	-	-	**-**	46.6	-	5.0	**51.7**	**51.7**
2016	-	-	-	**-**	48.9	-	5.2	**54.0**	**54.0**
2017	-	-	6.3	**6.3**	49.9	0.1	5.2	**55.1**	**61.5**
2018	-	111.9	3.2	**115.0**	19.0	0.1	3.6	**22.7**	**137.7**
2019	-	-	-	**-**	15.4	0.1	3.8	**19.3**	**19.3**
2020	-	55.9	-	**55.9**	2.7	0.1	3.2	**6.0**	**61.9**
2021	-	-	-	**-**	3.1	0.1	3.3	**6.6**	**6.6**
2022	-	-	-	**-**	3.6	0.1	3.3	**7.1**	**7.1**
2023	-	-	-	**-**	4.3	0.1	3.4	**7.8**	**7.8**
2024	-	-	-	**-**	4.8	0.1	3.5	**8.4**	**8.4**
2025	-	55.9	-	**55.9**	0.0	0.1	3.3	**3.5**	**59.4**
2026	-	-	-	**-**	0.0	0.1	3.4	**3.5**	**3.5**
2027	-	-	-	**-**	0.0	0.1	3.4	**3.6**	**3.6**
2028	-	-	-	**-**	0.1	0.1	3.5	**3.7**	**3.7**
2029	-	-	-	**-**	1.1	0.1	3.7	**4.9**	**4.9**
2030	-	-	-	**-**	1.4	0.1	3.8	**5.3**	**5.3**
2031	-	-	-	**-**	2.0	0.1	3.8	**6.0**	**6.0**
2032	10.0	-	-	**10.0**	2.5	0.1	3.9	**6.5**	**16.6**
2033	-	-	-	**-**	3.4	0.1	4.0	**7.6**	**7.6**
NPV 12%	**-**	**-**	**-**	**80.2**	**170.7**	**0.6**	**30.9**	**202.3**	**282.5**

Table 58: NPV for recommended plan

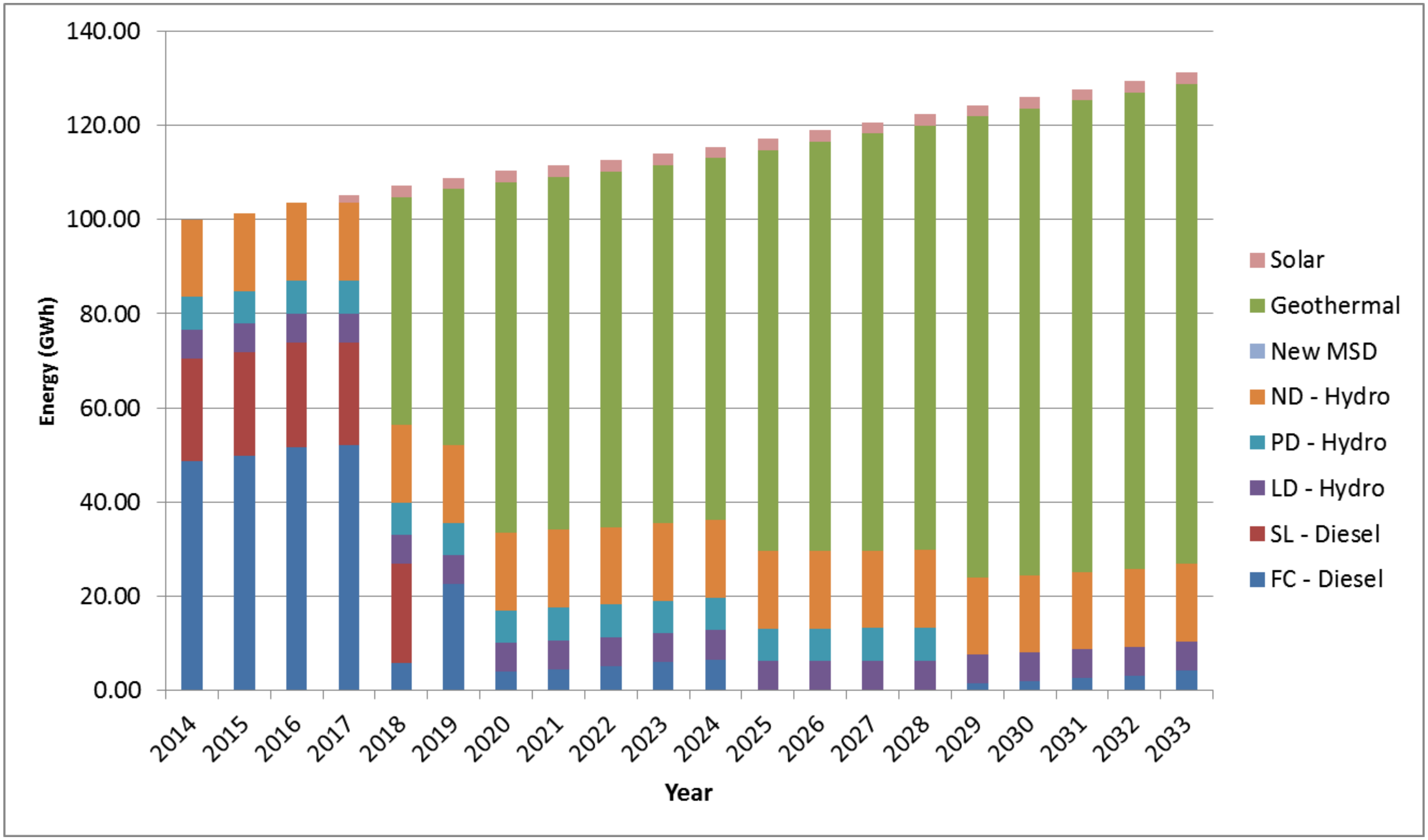

Figure 28: Generation by Technology / Location for recommended plan

	Unit Name																							
	FC1	**FC10**	**FC11**	**FC12**	**FC4**	**FC5**	**FC6**	**FC7**	**FC8**	**LD1**	**SL3**	**SL4**	**SL5**	**SL6**	**SL7**	**MSD 1.8**	**MSD 3.5**	**Geo3.5**	**Geo 7.0**	**Solar**	**PD1**	**PD2**	**ND1**	**ND2**
2014	0.05	10.99	9.50	3.32	-	10.83	14.04	-	-	6.15	0.01	10.27	8.94	-	2.49	-	-	-	-	-	3.97	2.97	8.96	7.54
2015	0.09	10.99	9.69	3.80	-	11.17	14.09	-	-	6.16	0.02	10.27	8.94	-	2.65	-	-	-	-	-	3.97	2.97	8.96	7.54
2016	0.13	11.02	10.18	4.40	-	11.73	14.18	-	0.00	6.18	0.03	10.30	8.97	-	2.98	-	-	-	-	-	3.98	2.98	8.99	7.56
2017	0.07	10.99	10.48	4.25	-	12.09	14.17	-	-	6.15	0.01	10.27	8.94	-	2.65	-	-	-	-	1.60	3.96	2.97	8.96	7.53
2018	-	4.55	0.01	-	-	-	1.17	-	-	6.15	-	10.27	8.94	-	1.81	-	-	48.50	-	2.40	3.96	2.97	8.96	7.53
2019	-	9.33	3.77	0.00	-	0.53	8.86	-	-	6.15	-	-	-	-	-	-	-	54.43	-	2.40	3.96	2.97	8.96	7.53
2020	-	3.39	0.00	-	-	-	0.47	-	-	6.17	-	-	-	-	-	-	-	74.41	-	2.41	3.98	2.98	8.99	7.56
2021	-	3.88	0.00	-	-	-	0.59	-	-	6.16	-	-	-	-	-	-	-	75.03	-	2.40	3.97	2.97	8.96	7.54
2022	-	4.27	0.76	-	-	0.02	-	-	-	6.15	-	-	-	-	-	-	-	75.57	-	2.40	3.96	2.97	8.96	7.53
2023	-	4.74	1.11	-	-	0.04	-	-	-	6.15	-	-	-	-	-	-	-	76.08	-	2.40	3.96	2.97	8.96	7.53
2024	-	5.10	1.37	-	-	0.05	-	-	-	6.17	-	-	-	-	-	-	-	76.88	-	2.41	3.98	2.98	8.98	7.55
2025	-	0.02	-	-	-	-	-	-	-	6.15	-	-	-	-	-	-	-	85.23	-	2.40	3.97	2.97	8.96	7.54
2026	-	0.02	-	-	-	-	-	-	-	6.16	-	-	-	-	-	-	-	86.93	-	2.40	3.97	2.97	8.96	7.54
2027	-	0.04	0.00	-	-	-	-	-	-	6.16	-	-	-	-	-	-	-	88.62	-	2.40	3.97	2.97	8.96	7.54
2028	-	0.07	0.00	-	-	-	-	-	-	6.17	-	-	-	-	-	-	-	90.24	-	2.41	3.97	2.98	8.98	7.55
2029	-	1.30	0.05	-	-	0.00	-	-	-	6.15	-	-	-	-	-	-	-	97.90	-	2.40	0.01	0.01	8.96	7.53
2030	-	1.73	0.07	-	-	0.00	-	-	-	6.15	-	-	-	-	-	-	-	99.13	-	2.40	-	-	8.96	7.53
2031	-	2.36	0.10	-	-	0.00	-	-	-	6.15	-	-	-	-	-	-	-	100.20	-	2.40	-	-	8.96	7.54
2032	-	2.86	0.16	-	-	0.00	-	-	-	6.17	-	-	-	-	-	-	-	101.33	-	2.41	-	-	8.99	7.56
2033	-	3.81	0.31	-	-	0.00	-	-	-	6.15	-	-	-	-	-	-	-	102.15	-	2.40	-	-	8.96	7.53

Table 59: Generation (GWh) by unit for recommended plan