2018 Integrated Resource Plan Proposal

Bermuda Electric Light Company Limited

February 15, 2018

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EXECUTIVE SUMMARY

As the sole transmission, distribution and retail ("TD&R") licensee for the Bermuda electric system, BELCO prepared this integrated resource plan proposal ("IRP") as requested by the Regulatory Authority of Bermuda ("Authority") on November 17, 2017 pursuant to Section 40 of the Electricity Act 2016 ("EA 2016"). The primary objective of the IRP process is to perform a holistic evaluation of quantitative and qualitative factors with respect to alternative fuels, power supply-side resources and demand-side resources leading to a preferred plan ("Preferred Plan") that will meet the electric energy needs of Bermuda for the 20 year period January 1, 2018 to December 31, 2037 (the "Study Period").

An examination of the trend of declining electric system load over the past eight years revealed that the main driver for system load level is the economic performance of Bermuda as measured by the gross domestic product ("GDP"). Without firm economic indicators pointing to a consistent recovery, the best estimate is that the economic performance, and thus the system load, will display an average of zero growth during the Study Period. Based on this assumed zero load growth, it is clear that the need for additional resources will be driven by the retirement schedule for the existing generating units.

In its capacity as a bulk generation licensee, BELCO intends to construct replacement generation consisting of engines referred to as the North Power Station ("NPS") along with a battery energy storage system ("BESS") together known as the "Replacement Generation" which are included as the baseload power supply.

During the IRP process, resources and fuels were selected for levelized cost of energy ("LCOE") screening on the basis of suitability for deployment in Bermuda. Both supply-side and demand-side resources were included in the screening and the results were used to compile a list of resources to develop four feasible planning scenarios for detailed quantitative and qualitative evaluation, summarized as follows:

- Scenario 1 – A reference scenario that reflects expansion with the continued use of Fuel Oil as the primary fuel for power generation with no (i) additional renewable resources, (ii) energy efficiency ("EE") or (iii) electric vehicles ("EV").
- Scenario 2 – A revised version of Scenario 1 with the addition of (i) cost effective utility-scale renewables, (ii) EE and (iii) EVs.
- Scenario 3 – Full conversion of the NPS engines, that are planned for installation in 2020, as well as other existing assets where suitable, to natural gas ("NG") operation as soon as NG can be made available, and future expansion with (i) all thermal resources operating on NG, (ii) cost effective utility-scale renewables, (iii) EE and (iv) EVs.
- Scenario 4 – Future expansion with thermal resources operating on liquefied petroleum gas ("LPG") beginning when the next installation of thermal resources is required and conversion of suitable existing thermal resources to

operate on LPG plus (i) cost effective utility-scale renewables, (ii) EE and (iii) EVs.

A summary of the key findings from the IRP process is as follows:

1. Based on the overall scoring from the production cost dispatch analysis and the qualitative evaluation of base cases for the four scenarios, the full conversion to NG (Scenario 3) ranked highest. Additionally, the scores for all four base cases were tightly grouped, falling within 2.1 percent of each other.
2. The net present value ("NPV") from the production cost dispatch analysis for the high fuel cost and carbon monetization pricing sensitivity cases show Scenario 3 to be the most robust scenario in terms of cost impact due to high fuel price.
3. The current fuel duties payable to the Collector of Customs pursuant to the Custom's Tariff Act 1970 ("Custom's Duty") on NG result in a significant reduction in the NPV for Scenario 3. Continued application of the current Custom's Duty on NG versus the higher level that is normalized on a $/MMBtu basis to the Custom's Duty on HFO would make Scenario 3 more attractive for selection as the Preferred Plan for Bermuda.
4. In the conversion to LPG scenario (Scenario 4), only partial conversion is achieved because only some of the existing generating units are suitable for conversion to LPG fuel and the practical opportunity for conversion is presented when the first thermal resource expansion is required during the second half of the Study Period. This results in an overall relatively low percentage of HFO being displaced by LPG.
5. The formula for calculating the planning reserve margin ("PRM") factors in the unavailability of intermittent and non-firm generating resources. An analysis of the estimated loss of load hours ("LOLH") based on the adopted PRM shows that Scenario 3 is projected to achieve the common industry LOLH target of under 1 day in ten years.
6. The alternative scenarios are each based on the adoption of an identical amount of cost-effective renewable resources in the form of utility-scale solar photovoltaic energy ("PV"). In addition, amounts of distributed small scale PV and solar thermal are included based on the expected continued adoption by customers. Also, based on work performed by independent subject matter experts, projected uptakes for a commercial EE program, and an EV program are included in each scenario.

Based on the findings above, implementation of the Preferred Plan outlined in Scenario 3 will address key objectives related to cost of power, reliability of supply, exposure to high fuel cost, increased renewable resources, capability to burn diverse fuels and reduced carbon footprint.

Assumptions and analyses contained in this IRP should be revisited on a recurring basis in order to reexamine changes in fuel price forecasts and technologies over time. The IRP process will be internalized within BELCO TD&R and viewed as a tool to determine whether any revisions to the long-term course of action suggested by the prior iteration are warranted as a result of changes to fuel prices, infrastructure and generating unit costs, changes in load expectations, or other key factors influencing the IRP results.

GLOSSARY OF TERMS

This Glossary includes definitions of acronyms and terms that are used within the IRP.

Ln. No.	TERM	DEFINITION
1	**AEO**	Annual Energy Outlook; an annual projection of key fuel and market prices prepared by the United States Energy Information Administration for purposes of informing energy analysis.
2	**Assumptions Document**	Compilation of assumptions used as a basis for this IRP and summarized as Appendix I of this IRP.
3	**Authority**	Regulatory Authority of Bermuda
4	**BAU**	Business As Usual
5	**BELCO**	Bermuda Electric Light Company Limited - Utility company operating under a transmission, distribution and retail licence and a bulk generation licence.
6	**BELCO BG**	BELCO in its capacity as the holder of a Bulk Generation Licence
7	**BELCO TD&R**	BELCO in its capacity as the holder of a Transmission, Distribution and Retail Licence
8	**BELCO Team**	BELCO IRP Project Team
9	**BESS**	Battery Energy Storage System
10	**BOP**	Balance of Plant
11	**BSSR**	Battery Support for Spinning Reserve
12	**BTU**	British Thermal Unit
13	**CC**	Combined Cycle
14	**CCHP**	Combined Cooling Heat and Power
15	**CDD**	Cooling Degree Day
16	**Central Plant**	BELCO Thermal Power Plant located at Hamilton, Bermuda
17	**CHP**	Combined Heat and Power

Ln. No.	TERM	DEFINITION
18	**Conservation**	A premeditated behavioral adjustment associated with a conscious decision to adjust an end-user's utility or comfort in order to reduce energy consumption; examples include adjusting the thermostat at the expense of temperature comfort, and turning off lights when not in the room; contrast with energy efficiency (defined herein).
19	**CO2**	Carbon Dioxide
20	**CT**	Combustion Turbine (Same as gas turbine)
21	**Custom's Duty**	Custom's Tariff Act 1970
22	**DF**	Dual Fuel (Fuel Oil/NG)
23	**DG**	Distributed Generation; resources that generate electricity that are "distributed" across the power delivery grid or installed to serve the load of a specific end-user or customer; examples include rooftop solar generation and CCHP/CHP units that serve a single load; DG resources typically avoid transmission cost associated with traditional large scale grid-based resources.
24	**DOE**	Department of Energy (U.S.)
25	**DR**	Demand Response - Programs that target reductions in demand during key peak hours of utility load through direct intervention to curtail certain end-uses; example: water heater direct load control that cycles water heaters to limit their utilization during anticipated critical peak load events at the utility level.
26	**DSM**	Demand Side Management; an umbrella of measures, programs, and incentives that attempt to control energy demand in lieu of serving that demand with generating resources that are grid connected in the traditional centrally controlled utility framework; the key components of DSM include demand response, energy efficiency, and conservation (defined herein).
27	**EA 2016**	Bermuda Electricity Act 2016
28	**EE**	Energy Efficiency; deriving the same utility from a given end-use using a less energy-intensive device that does not require a change in user behavior or intervention to conserve energy, and/or programs and incentives that encourage end-use switch-outs to more efficient units; example: Energy Star dishwasher incentive programs.

Ln. No.	TERM	DEFINITION
29	**EIA**	U.S. Energy Information Administration
30	**EPC**	Engineering, Procurement and Construction
31	**EV**	Electric Vehicle
32	**°F**	Degrees Fahrenheit
33	**FEED**	Feasibility and Front End Engineering Design
34	**FTE**	Full-Time Equivalent
35	**Fuel Cell**	A technology that converts chemical energy directly into electricity from natural gas, or hydrogen, and air vapor and produces heat and water vapor as by products.
36	**GDP**	Gross Domestic Product
37	**GT**	Gas Turbine (same as CT)
38	**HDD**	Heating Degree Day
39	**HHV**	Higher Heating Value
40	**HFO**	Heavy Fuel Oil
41	**HRSG**	Heat Recovery Steam Generator
42	**IC**	Internal Combustion
43	**IPP**	Independent Power Producer
44	**IRP**	Integrated Resource Plan Proposal
45	**ISO**	International Organization of Standardization
46	**kW**	Kilowatt
47	**kWh**	Kilowatt hour
48	**Leidos**	Leidos Engineering, LLC
49	**LCOE**	Levelized Cost of Energy
50	**LED**	Light Emitting Diode
51	**LHV**	Lower Heating Value
52	**LFO**	Light Fuel Oil
53	**LNG**	Liquefied Natural Gas
54	**Load Forecast**	Load Forecast for Study Period
55	**LOLH**	Loss of Load Hours
56	**LPG**	Liquefied Petroleum Gas–

Ln. No.	TERM	DEFINITION
57	**MMBtu**	One Million British Thermal Units
58	**MSD**	Medium Speed Diesel
59	**MW**	Megawatt
60	**MWh**	Megawatt hour
61	**National Economic Report 2015**	Bermuda Government Ministry of Finance 2015 National Economic Report dated February 2016
62	**NCDC**	National Climatic Data Center
63	**NEL**	Net Energy for Load
64	**NG**	Natural Gas
65	**NPS**	North Power Station
66	**NPV**	Net Present Value
67	**NREL**	National Renewable Energy Laboratory
68	**O&M**	Operation & Maintenance
69	**OEM**	Original Equipment Manufacturer
70	**ORC**	Organic Rankine Cycle
71	**Policy**	National Electricity Sector Policy of Bermuda June 2015
72	**PPA**	Power Purchase Agreement
73	**Pre-Budget Report 2018**	Bermuda Government 2018 Pre-Budget Report dated January 2018
74	**Preferred Plan**	The expansion plan selected as a result of the holistic evaluation of quantitative and qualitative factors with respect to alternative fuels, power supply-side resources and demand-side resources
75	**PRM**	Planning Reserve Margin
76	**PV**	Photovoltaic
77	**RET Screen**	An Excel-based clean energy project analysis software tool that helps decision makers quickly and inexpensively determine the technical and financial viability of potential renewable energy, energy efficiency and cogeneration projects.
78	**RFI**	Request for Information
79	**RFP**	Request for Proposals

Ln. No.	TERM	DEFINITION
80	**RPS**	Renewable Portfolio Standards
81	**RICE**	Reciprocating Internal Combustion Engine
82	**S&P**	Standard and Poor's
83	**SAM**	System Analyzer Model
84	**SC**	Simple-Cycle
85	**SME**	Subject Matter Expert
86	**SSD**	Slow Speed Diesel
87	**STG**	Steam Turbine Generator
88	**Study Period**	20-year IRP study period beginning January 1, 2018 to December 31, 2037
89	**Synapse Report**	Synapse 2016 CO_2 Price Forecast
90	**TD&R**	Transmission, Distribution and Retail
91	**T&D**	Transmission and Distribution
92	**Tg/QBtu**	Tera Grams per Quadrillion Btu
93	**TMY**	Typical Meteorological Year
94	**Tynes Bay**	Tynes Bay Waste-to-Energy Facility
95	**UCSB Report**	Offshore Wind Energy Feasibility Study by University of California, Santa Barbara
96	**U.S.**	United States
97	**W**	Watt
98	**WACC**	Weighted Average Cost of Capital
99	**WT**	Wind Turbine

Section 1
IRP PROPOSAL METHODOLOGY

1.1 Project Overview

BELCO TD&R has engaged Leidos to prepare a rigorous, holistic, and comprehensive IRP for Bermuda in compliance with the EA 2016 and the BELCO TD&R licence. The IRP analysis covers the Study Period. This IRP is focused on the projected cost of producing the net energy to serve Bermuda's electric system load over the Study Period, and does not reflect the translation of estimated production costs into retail rates for any of BELCO TD&R's rate sectors. Such efforts typically follow the final IRP activities and are predicated upon the selected expansion plan, which includes the cost of both generating (central plant and distributed) resources that serve load and demand-side management initiatives that cost-effectively abate load.

Bermuda is faced with a series of significant challenges and opportunities as it navigates its energy future. The Bermuda electric system load is declining as a result of sustained contraction of the local economy. The Bermuda electric system is comprised of an aging generation asset base composed mainly of oil-fired reciprocating internal combustion engine ("RICE") resources. The IRP process includes an evaluation of a variety of power generation technologies and fuels as well as demand-side technologies and programs that are feasible for application in Bermuda with the aim of developing a plan that incorporates a blend of resources and carefully balances the objectives of the National Electricity Sector Policy of Bermuda June 2015 ("Policy").

The main elements of the IRP process are as follows:

I. Develop the system load forecast
II. Develop a list of candidate fuels and associated price forecast
III. Develop a list of candidate supply-side and demand-side resources along with the technical and economic parameters required for analysis
IV. Conduct a Bermuda electric system capacity gap analysis using the load forecast and existing resource retirement schedule
V. Conduct a Levelized Cost of Energy ("LCOE") screening of the candidate resources to create a shortlist for use in a dispatch analysis
VI. Develop a number of feasible expansion plan scenarios using an optimal blend of supply-side and demand-side resources
VII. Conduct detailed economic analyses of the expansion plan scenarios based on an hourly energy dispatch model
VIII. Conduct a qualitative assessment of the resource planning scenarios
IX. Determine the planning scenario that best meets the objectives of the Policy

1.2 Description of IRP Goals

Throughout the course of the IRP process, BELCO TD&R partnered with Leidos to ensure that the overarching Policy objectives were addressed. The development of the IRP was strategically aligned with the Policy objectives by utilizing the following goals:

- ***The IRP process will engage in a holistic evaluation of both quantitative and qualitative factors***. Historically, resource planning has been focused on finding the "least cost" expansion path as defined by the NPV of production cost over a prescribed study period. This approach, while efficient, fails to recognize that there may be additional, non-monetary or difficult to quantify benefits of alternative expansion paths or portfolios. These alternatives may very well serve to meet the needs of today in a more sustainable manner, help to support renewable portfolio standards, encourage economic investment, or be logistically advantageous given Bermuda's island terrain. Engaging in a qualitative evaluation of resource options and pairing this review with detailed financial modeling of options can serve to ensure a more holistic perspective when taking downstream action.
- ***The IRP process will engage in a concurrent evaluation of supply-side and demand-side options.*** The term "integrated" in integrated resource plan implies that the plan will engage in an equally rigorous evaluation of demand-side resource options as it does with traditional supply-side resources. As described elsewhere in this IRP, BELCO TD&R and Leidos have developed detailed estimates of costs, energy impacts, and peak demand impacts of a series of distributed generation resources and demand-side management options. Leidos has evaluated these in the load dispatch modeling in order to carefully examine the cost implications to system generation requirements as a result of abating load through distributed generation or demand-side options. BELCO TD&R has provided estimates of uptake potential (based on independent studies) for each of the distributed generation or demand-side resource options and where information gaps exist, Leidos has provided supplementary input from its subject matter experts.
- ***The IRP process will build upon considerable work already done by BELCO TD&R.*** Throughout the IRP process, care was taken to leverage existing data developed by BELCO TD&R whenever possible. This was particularly true for data from manufacturers or Engineering, Procurement, and Construction ("EPC") contractors, inputs regarding uptake for distributed generation or demand-side management options, supportive insights on the load forecast, operating costs and performance characteristics of existing assets and associated retirement dates, and existing feasibility studies on certain resource options that were previously commissioned by the BELCO TD&R. This information exchange between BELCO TD&R and Leidos helped to expedite the planning process and shed light on the areas of focus in terms of data gaps.
- ***The IRP will be designed as a recurring process, and will serve as the main precursor to detailed feasibility studies.*** Leidos has worked extensively with BELCO TD&R to design a series of input models to capture key IRP assumptions. An LCOE screening model was constructed with a series of repeatable steps and criteria for qualitative analysis of resource options. A load forecast was prepared

and infused along with the existing Bermuda electric system resources into a production cost model. All of the inputs to the analysis have been codified in detail in Appendix I to this IRP. Through the construction of a living resource planning process, it is ensured that as additional information becomes available and/or as the passage of time warrants additional analysis, the underpinnings of this IRP architecture can again be leveraged in lieu of starting over. This living/recurring process is one of the primary goals of the IRP, and at its core is the ability to revisit the assumptions as detailed in Appendix I or any one of the existing suite of input files and models to make adjustments, additions, or deletions as deemed warranted. This is preferable to a more short-term focus on obtaining results for this iteration of the process that would sacrifice the detailed documentation necessary to render the process repeatable.

1.3 Load Forecast

Leidos has reviewed BELCO TD&R's NEL and system peak demand data, generally over the period 2005 through 2017. We have also reviewed the 2015 Ministry of Finance National Economic Report and the Ministry of Finance 2018-19 Pre-Budget Report, which is the most recent such report issued by the Bermuda Government. In addition, we reviewed economic forecast for Bermuda as prepared by an international firm that specializes in preparing country economic forecasts. Our review has comprised two parallel efforts, namely (i) weather normalization of historical data in an effort to quantify the impact of weather variability on the Bermuda electric system load and (ii) review of economic data and projections to develop a perspective regarding the Load Forecast for the Study Period ("Load Forecast"), including the determination of assumptions related to uncertainty over the Study Period. The Load Forecast is predicated upon a reasonable approach underpinned by an econometric analysis framework that has produced monthly econometric models for the Bermuda electric system's NEL and a methodology for characterizing load uncertainty. For purposes of the IRP analysis the Load Forecast has been adjusted to reflect the discrete impacts of EE and EV. Appendix I of this IRP contains more specific details regarding the range of activities involved in developing the Load Forecast.

Figures 1.1 and 1.2 below summarize the results of the load forecasting process.

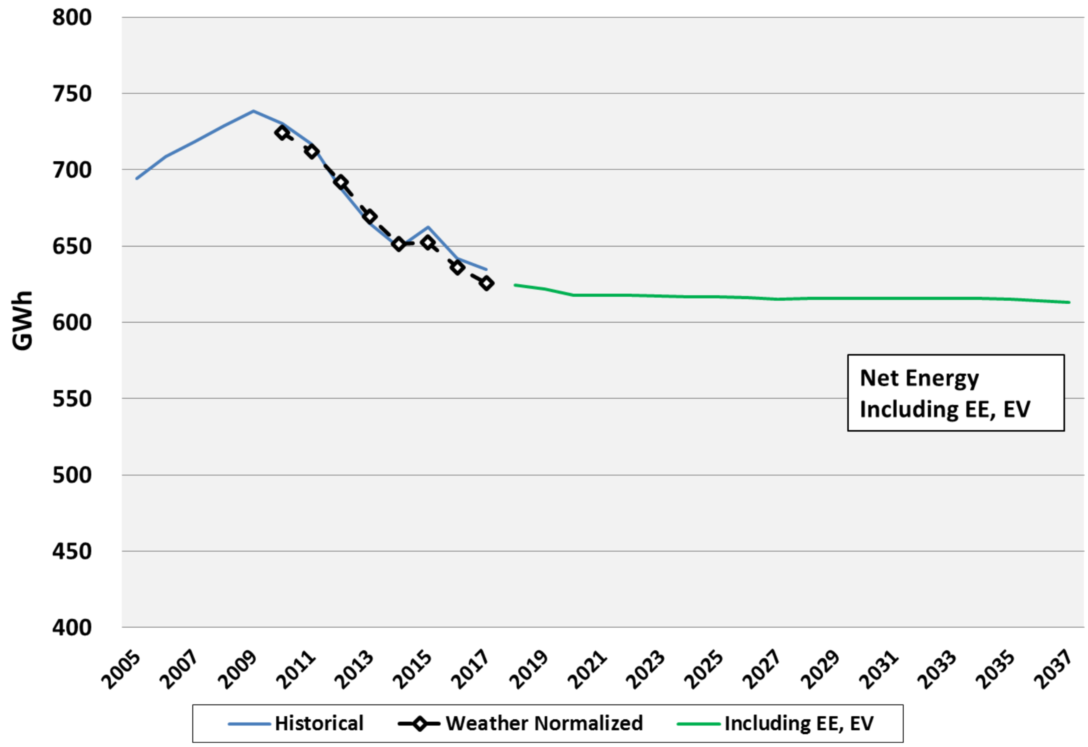

Figure 1.1 – Base Case Energy Forecast (Net of EE and EV) (GWh)

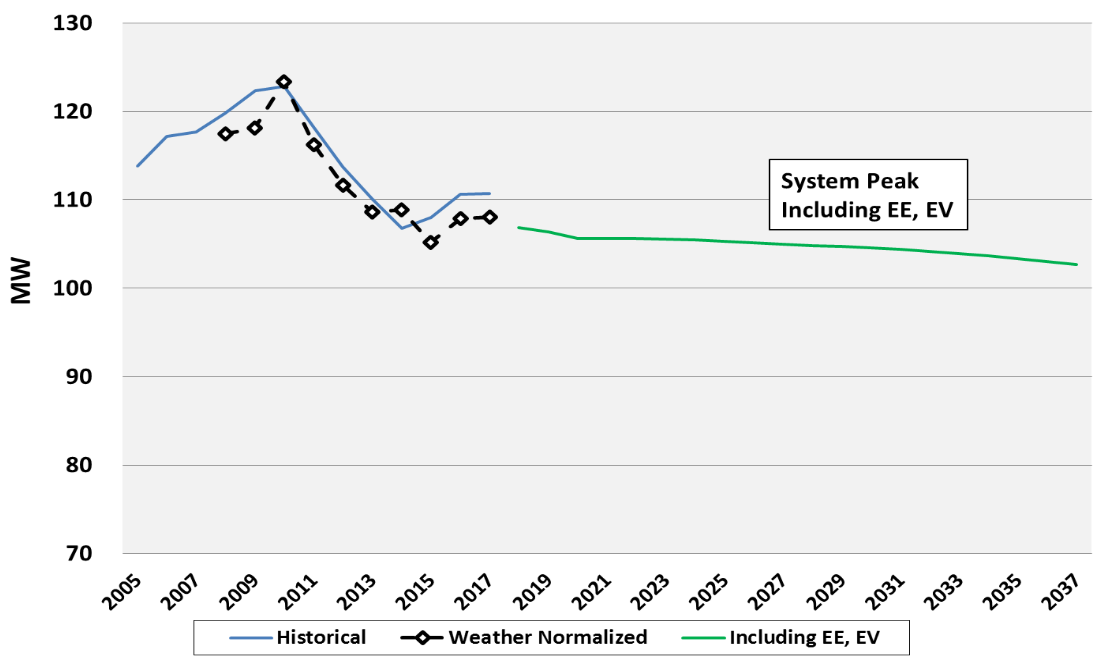

Figure 1.2 – Base Case Peak Demand Forecast (Net of EE and EV) (MW)

Figures 1-1 and 1-2, depict the base case Load Forecast of NEL and peak demand, both reflecting the discrete adjustment for impacts of EE and EV. The base case Load Forecast for both NEL and peak demand reflects a long term growth rate of approximately -0.1 percent per year and -0.2 percent per year, respectively. It should be noted that while the base case Load Forecast reflects a continued decline in Bermuda's electric system requirements, the Load Forecast before the impacts of EE and EV demonstrates a very modest long-term year over year growth rate of 0.1 percent for both NEL and peak demand. The Load Forecast before the impacts of EE and EV includes the organic uptake in the application of demand side resources by customers as evidenced in the historical load data. A high and low case Load Forecast, which are intended to capture the majority of the potential future range of economic activity in Bermuda based on an analysis of historical errors in representative economic forecasts, are presented in Appendix I of this IRP. Refer to Appendix I for further details regarding the Load Forecast methodology, data sources, and assumptions.

1.4 Reserve Margin Planning Criteria

In the context of an operating electric utility, PRM is a measure of the available generating capacity in excess of the capacity required to meet the projected annual system peak demand. It is one of the most important resource planning parameters as it impacts the level of installed capacity and the level of supply reliability. With the increase of non-dispatchable and intermittent resources such as solar PV and wind energy, the formula used by small utilities to calculate the target PRM has become more complex.

In the case of the Bermuda electric system, both dispatchable and intermittent resources were considered in developing the formula for calculating the target PRM for production cost modeling purposes as follows:

Target Planning Reserve Margin = dependable capacity of the two highest capacity output traditional generating resources

+ the dependable capacity of the Tynes Bay plant
+ the dependable capacity of the planned utility scale solar PV PPA (6 MW located at the Airport Finger site)
+ the aggregate dependable capacity of small scale solar PV resources

Additional details regarding the PRM criteria and its development are provided in Appendix I of this IRP.

1.5 Fuel Forecast

Leidos developed a detailed delivered fuel price forecast model for each fuel that was selected as a candidate based on cost, sustainability, and logistical feasibility for application in Bermuda. The purpose of this detailed fuel price model is to expand and enhance the transparency of the fuel forecast and compartmentalize the components of the build-out, so as to allow BELCO TD&R a platform for review and in-depth itemization of the pricing aspects. Appendix IIC of this IRP contains the by-year fuel price forecast for all candidate fuels, including the fuel adders necessary to establish the cost delivered for each fuel. Leidos prepared detailed price forecasts for the following fuels:

- Heavy Fuel Oil ("HFO") – It was assumed that HFO would continue to be sourced and transported to BELCO's existing thermal power plant ("Central Plant") in a manner similar to the present.
- Light Fuel Oil ("LFO") - It was assumed that LFO would continue to be sourced and transported to the Central Plant in a manner similar to the present.
- NG – Pricing was developed by an independent consultant based on the following key assumptions:
  - Bulk liquefied natural gas ("LNG") would be sourced in the United States ("U.S.") and transported to Bermuda.
  - Necessary offloading, storage and regasification infrastructure would be constructed at a location in St. Georges, Bermuda in the vicinity of the existing Fuel Oil storage depots.
  - A new NG pipeline would be constructed along the route of the existing Fuel Oil pipeline to the Central Plant for use in baseload and peaking generating units.
  - For candidate resources by future bulk generation licensees such as IPPs, the capital cost for an additional 1.5 mile pipeline was added to support the physical transportation requirements for fuel delivery from the existing Fuel Oil depot locations to the assumed thermal power plant development site at Marginal Wharf.
- LPG – Pricing was developed by an independent consultant based on the following key assumptions:
  - Bulk LPG would be sourced in the U.S. and transported to Bermuda.
  - Necessary offloading and storage infrastructure would be constructed at a location in St. Georges, Bermuda in the vicinity of the existing Fuel Oil storage depots.
  - LPG will be transported by road tanker to the Central Plant for use in suitable CT generating units.
  - New generating resources by IPPs would be located at the Marginal Wharf site and the capital cost for a 1.5 mile pipeline was added to support the physical transportation requirements for fuel delivery.

Figures 1.3 and 1.4 below contain a summary of the core commodity component (<u>without any adders for items such as transportation, Custom's Duty and storage</u>), as well as the all-in delivered price (<u>with adders</u>), respectively, associated with all of the fuel forecasts prepared for evaluation purposes.

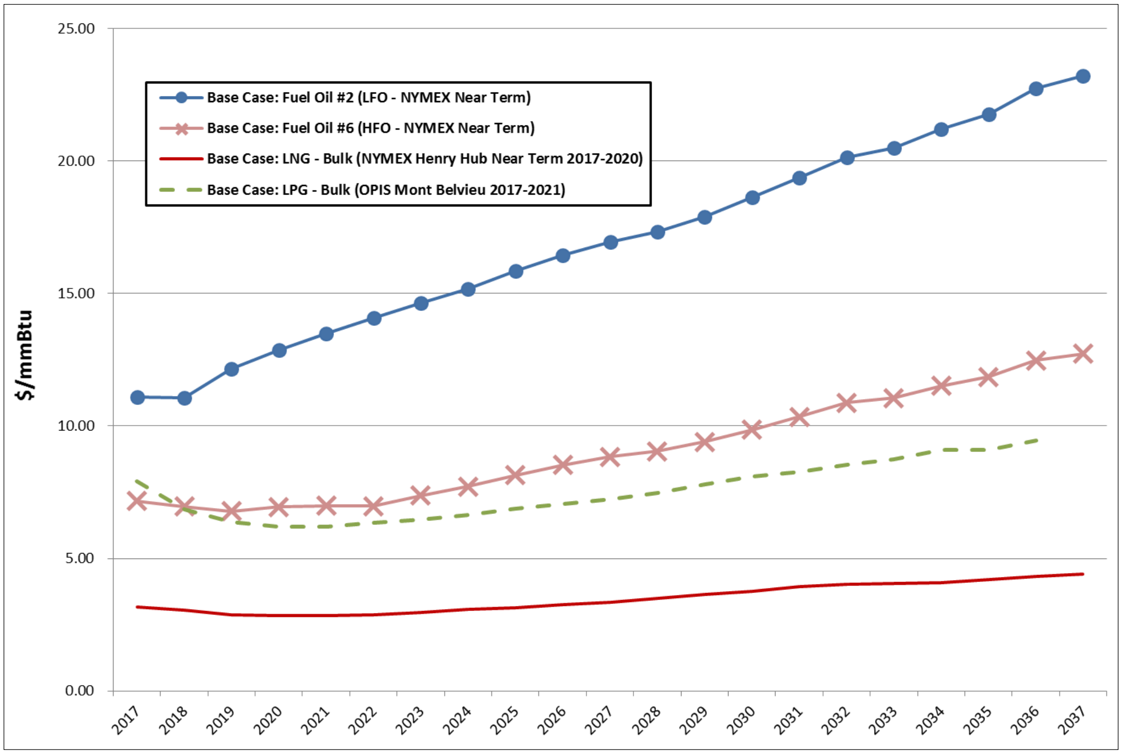

Figure 1.3 – Base Case Commodity Price Forecast

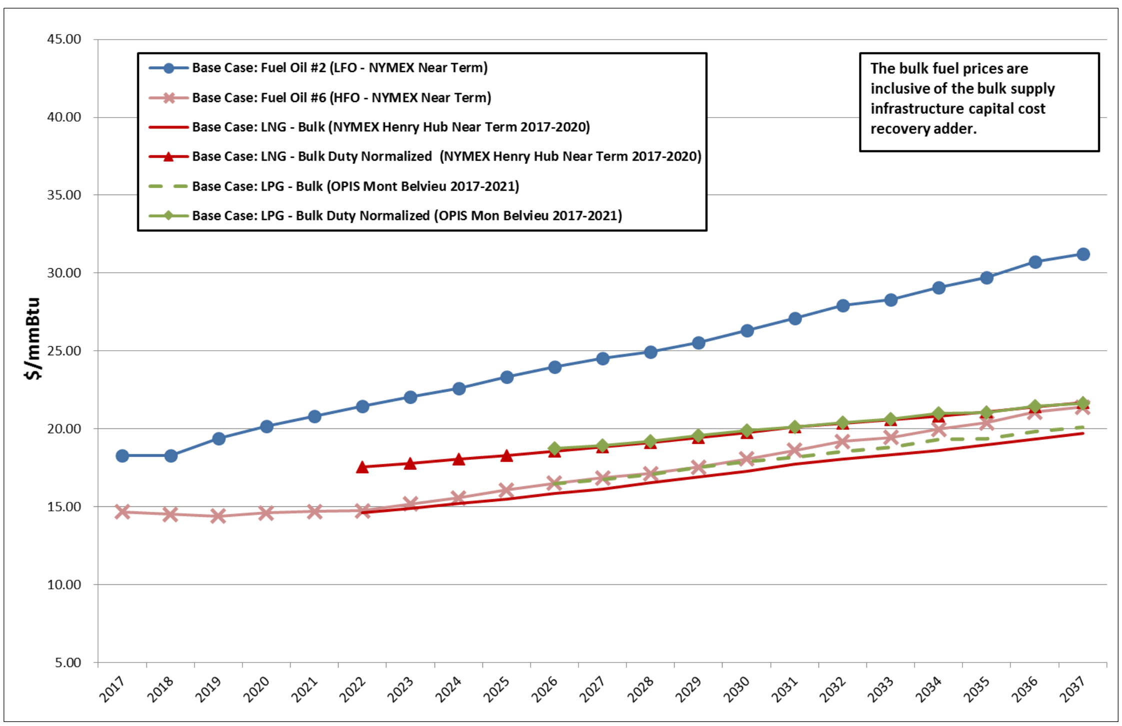

Figure 1.4 – Base Case Delivered Cost Forecast

1.6 Financial and Other Planning Criteria

In collaboration with BELCO TD&R, the following key financial factors were selected for use in the production cost analysis:

- Inflation – 2.00 percent.
- Weighted Average Cost of Capital (“WACC”)
  - 8.00 percent for traditional baseload projects developed by BELCO BG and renewable energy projects by potential bulk renewable energy licensees;
  - 10.00 percent for traditional baseload projects and associated infrastructure developed by potential bulk generation licensees such as IPPs.

It should be noted that discounted cash flow calculations across the IRP are based upon escalation of nominal dollars over the course of the Study Period, and that production costs are discounted back to today’s (year 2018) dollars using the WACC. The escalation adder used for future capital costs is equal to inflation for the duration of the Study Period.

Escalation of the capital cost for the LNG storage and regasification infrastructure is developed by the same independent consultant that supported the initial feasibility study. The escalation adder used for future capital costs is equal to inflation for the duration of the Study Period.

1.7 Existing Resources

In developing modeling input parameters for the existing power generating resources of BELCO BG, fuel conversion of existing units, and the timing of the availability of alternative fuels Leidos reviewed information and data gathered as a part of a previous resource planning exercise. Where necessary, data was updated and new data was obtained. Appendix II.B appended herein, summarizes all cost, operational, and performance characteristics for the electric system’s existing resources.

Pursuant to BELCO’s bulk generation licence, BELCO has previously submitted a proposal for the construction of replacement generation consisting of engines at the NPS and a BESS together known as the “Replacement Generation”. Such Replacement Generation falls outside the scope of this IRP.

Figure 1.5 below summarizes the electric system’s base case Load Forecast net of the impacts of EE and EV (with and without reserve margin requirements) versus the existing electric system power supply resources, reflecting projected retirement dates, including Tynes Bay. The retirements are assumed to occur after the summer peak season of the year stated in the text boxes within the graph. Table 1-1 summarizes the electric system’s estimated capacity gaps, using the base case Load Forecast with reserve margin requirements as a basis.

Additional details regarding the existing resources can be found in Appendix I of this IRP.

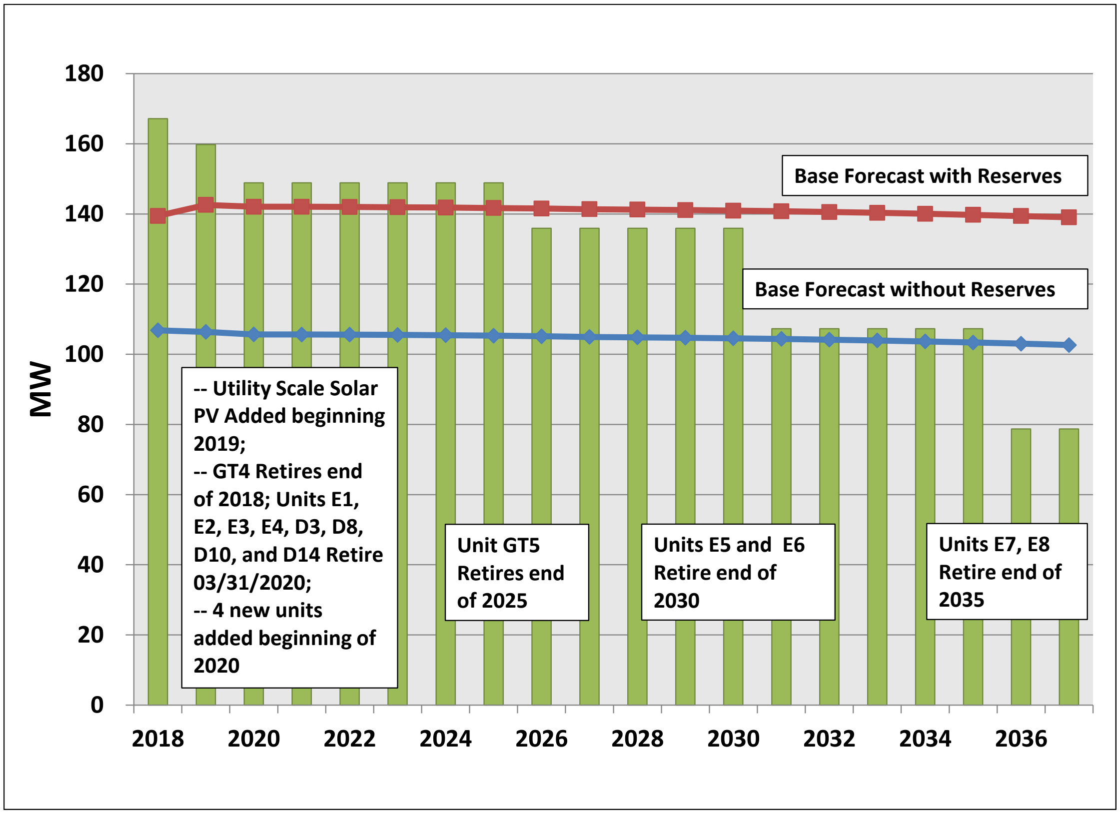

Figure 1.5 – Capacity vs. Load

Table 1-1
Capacity Gap Analysis
(Base Load Forecast with Planning Reserves)

Year	Capacity Gap (MW)	Year	Capacity Gap (MW)
2018	27.8	**2028**	(5.3)
2019	17.2	**2029**	(5.2)
2020	6.8	**2030**	(5.1)
2021	6.9	**2031**	(33.5)
2022	6.9	**2032**	(33.3)
2023	7.0	**2033**	(33.0)
2024	7.1	**2034**	(32.8)
2025	7.2	**2035**	(32.5)
2026	(5.6)	**2036**	(60.7)
2027	(5.5)	**2037**	(60.3)

1.8 Demand-Side Resource Options

DSM resource options can include a variety of measures, including distributed generation, demand response (which can involve certain rate mechanisms such as time of use rates), conservation/behavioral programs, EE, and direct load control. Leidos has worked with BELCO TD&R to parameterize a residential solar-thermal water heater option that is paired with PV, residential and commercial rooftop solar PV, and distributed cogeneration resources.

Appendix IIB of this IRP provides a complete set of assumptions related to the solar thermal water heater system. The peak demand and energy impact of this system has been netted out from the Load Forecast prior to dispatch against supply-side resources in a scenario involving DSM. While the costs were evaluated for purposes of the LCOE analysis, the costs have not been included with the dispatch analysis. Uptake of the program is based on information provided by BELCO TD&R.

In addition to the solar thermal and PV pairing above, Leidos will consider a generic DSM option comprised of an as yet undefined bundle of EE measures and the forecast adoption of EV.

The EE measures result in an incremental DSM abatement (or reduction in both peak demand and energy). EE measures, whose energy impact averages a 17.3 percent increase (and thus decrease in load) per year over the Study Period, have been derived from an October 2017 Applied Energy Group report commissioned by BELCO detailing the realistic achievable potential of a wide variety of commercial EE measures.

The forecast EV adoption results in an incremental DSM addition (or addition in energy). EV adoption, and the resulting contribution to load energy requirements, is forecast to increase an average 34.9 percent per year over the Study Period. It is noted that due to the anticipated EV charging and usage behaviors that no measurable impact to peak demand is anticipated. EV adoption projections were developed from a July 2017 report produced by Bloomberg New Energy Finance that provided a long term outlook on worldwide EV sales.

Implementation of both the EE and EVs are anticipated to be external to BELCO TD&R and as a result do not result in direct program costs to BELCO TD&R.

1.9 Supply-Side Resource Options

The approach to estimating cost and performance characteristics of the range of feasible supply-side resource options for the IRP consisted of the following overarching activities:

- Leidos assumed that any new LFO-fired resources will be supplied with fuel from existing oil storage facilities at the Central Plant.
- Based on the conceptual LNG regasification facility and NG delivery pipeline design, it is anticipated that gas compressors will not be required for the CT options.

- Due to the scarcity of fresh water on Bermuda, Leidos assumed an air-cooled condenser system in place of a traditional condenser and wet cooling tower configuration for all combined cycle ("CC") resource options.
- The CT and CC generating unit performance characteristics were developed based on the average high temperatures observed in Bermuda during the summer peak months of approximately 86°F.
- The construction cost estimates in the base case of each scenario are based on the assumption that no land costs or other site infrastructure improvements such as fire/water supply lines or significant site remediation requirements are necessary.
- Under the IPP development of future traditional generation sensitivity case for each scenario, Leidos included a WACC of 10 percent, included assumptions for the cost of land at approximately $5,000 per acre per annum, and interconnection costs based on information from BELCO TD&R. Under the LPG scenario, it is assumed that all future traditional generation will occur off site of the Central Plant and therefore these adjustments apply to the base case of this scenario.
- Leidos' existing relationships with vendors was leveraged to obtain up-to-date resource cost estimates and performance information.
- The NPS and BESS option technical and cost parameters are based on data provided from the procurement process.
- Missing or otherwise unavailable cost and performance assumptions were developed either by BELCO or by the Leidos independent engineering team, the latter estimates being predicated upon our prior industry experience with similar technologies.
- For any conversions of existing assets to alternative fuel types, Leidos relied upon the information provided from the procurement process as well as our prior industry experience with similar technologies.

Appendix I of this IRP provides a resource-by-resource description of the approach to development of assumptions for each of the supply-side resource options considered in the IRP.

1.10 Levelized Cost of Energy Screening

As an initial step in the IRP quantitative analysis process, Leidos performed an LCOE screening to assess, on a preliminary basis, the economic competitiveness of the DSM, supply-side resources (including renewable energy), and conversion of existing generating units as power supply technology options that are considered to be feasible candidates for the Bermuda electric system. The LCOE analysis is a "current snapshot" of the approximate economic competitiveness based on the information we know today about costs and performance. This approach is intended to help compare various resource options using the costs today. The results are calculated as a stream of equal $/MWh payments, normalized over the expected energy production period for the resource, that would result in the recovery of all production costs, including financing and a specified return on investment, over an assumed financial life.

The three basic cost components of the LCOE calculation are as follows:

- Fixed costs, such as initial project investment and fixed operations and maintenance costs. These costs are provided in the tables of Appendix IIB.
- Variable costs, such as variable operations and maintenance and fuel costs. Variable operations and maintenance costs are provided in the tables of Appendix IIB. Fuel costs are provided in Appendix IIC. The fuel costs used in the LCOE calculations include normalized Custom's Duty.
- Financing costs, such as the cost of debt and the cost of capital. Capital costs for resource options can be found in Appendix IIB of this IRP.

In addition, the expected annual energy production is required as a fourth component of the LCOE calculation. For each resource, the LCOE is calculated over the range of capacity factors (in 5 percent increments) that the resource is expected to operate.

The results of the LCOE screening exercise are presented in graphical form for ease of making comparison among the resources. The results of the LCOE screening informed the construction of the production cost scenarios described further below in this section. Refer to Section 2 results of this IRP for graphical output summarizing the results of the LCOE screening.

1.11 Production Cost Modeling

The dispatch to load modeling was performed using the PROMOD© platform. The PROMOD© production cost model simulates the dispatch of generating resources using an hourly chronological dispatch algorithm to meet system energy requirements. PROMOD© incorporates generator operating characteristics such as heat rates, O&M costs, hourly production profiles of renewable resources, ramp rates, and minimum operating and shutdown times, among others, to provide a realistic projection of unit operations. In addition, system level constraints such as operating reserve requirements are modeled to more accurately reflect the expected dispatch of generating units.

PROMOD© determines the hourly least-cost dispatch of active generating units in its database over the Study Period but does not add or retire units to optimize costs. Unit retirements are made based on the BELCO unit retirement schedule and unit additions are made to meet the annual peak load forecast and PRM requirement.

The analysis focused on a series of pre-defined scenarios, which are delineated fully further below in this subsection.

The dispatch to load modeling utilized as inputs the cost and performance characteristics of existing resources as well as all of the candidate resources which were made available to serve load for the respective scenarios evaluated. As appropriate for a given scenario, peak demand was represented as net of all DSM impacts, including combined heat and power ("CHP") in those scenarios where CHP is included as a resource, after which the resource expansion path inclusive of DSM was finalized. The model added resources to serve load as a function of capacity and energy needs given the anticipated retirement schedule for existing resources, as well as meeting the reserve margin requirement discussed previously in this section. The costs associated with the battery option were added to the production cost simulation results as discrete costs.

Candidate utility scale renewable energy resources were “forced in” to the dispatch profile as “as available” energy based on dispatch profile estimates. Transmission and distribution (“T&D”) costs associated with renewable integration and resources not located at the Central Plant were included in the cost estimate for these specific scenarios, as appropriate. Refer to Appendix I and Appendix II of this IRP for further details regarding cost assumptions and the specific resources included in a given scenario.

1.11.1 Production Cost Modeling Scenarios

Scenario Definitions

Based on discussions with BELCO and the sum total of work conducted as delineated in this IRP, the following scenarios are the subject of the production cost modeling, as predicated on Base Case assumptions across each of the inputs to the IRP (e.g., load, fuel).

Table 1-2
BELCO TD&R 2018 IRP
Production Cost Modeling Scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scenario Name	Central Plant Expansion on Fuel Oil with the Planned Phase 1 Solar IPP at Finger (Reference Scenario)	Central Plant Expansion on Fuel Oil with the Planned Phase 1 Solar IPP at Finger, IPP Renewable Energy & DSM. (Reference Scenario plus Renewables & DSM)	Central Plant Conversion to NG and future Fossil Fuel Expansion , IPP Renewable Energy & DSM	Central Plant Resources Remain on Fuel Oil Until Retirement, IPP Fossil Fuel Expansion on LPG Fuel, IPP Renewable Energy & DSM
Summary Description	Resource Plan is based on utilizing same generating technologies and fuels as in the past except for those installations that are already planned.	Resource Plan is based on utilizing the same generating technologies and fuels as in the past (except for those installations that are already planned) with the addition of renewables (utility scale and distributed), EE and EV to the portfolio.	Resource Plan is based on utilizing same generating technologies and fuels as in the past (except for those installations that are already planned) with the addition of renewables (utility scale and distributed), EE and EV to the portfolio. Additionally, install the infrastructure to import, store and regassify LNG and provide piped NG to the Central Plant as soon as possible, to serve as the primary fuel type for planned and candidate resources.	Resource Plan is based on utilizing same generating technologies and fuels as in the past (except for those installations that are already planned) with the addition of renewables (utility scale and distributed), EE and EV to the portfolio. Additionally, install the infrastructure to import and store liquefied petroleum gas as soon as possible, to serve as the primary fuel type for candidate resources.
Plant Retirements	Defined by TD&R	Defined by TD&R	Defined by TD&R	Defined by TD&R
Planned Fossil Fuel Resources	North Power Station comprising 4 x 14 MW MSD units in (Q1 2020).	North Power Station comprising 4 x 14 MW MSD units in (Q1 2020).	North Power Station comprising 4 x 14 MW MSD units in (Q1 2020). Convert from HFO to NG operation when NG becomes available.	North Power Station comprising 4 x 14 MW MSD units in (Q1 2020). CT-CHP
Planned Renewable Resources	6 MW (Phase I) Solar PV PPA at the Airport Finger site	6 MW (Phase I) Solar PV PPA at the Airport Finger site	6 MW (Phase I) Solar PV PPA at the Airport Finger site	6 MW (Phase I) Solar PV PPA at the Airport Finger site
Planned BESS	Central Power Plant location	Central Power Plant location	Central Power Plant location	Central Power Plant location

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Candidate Fuels	HFO for MSD and LFO for CTs for planning period	HFO for MSD and LFO for CTs for planning period	LNG. HFO & LFO to be phased out as non-converted existing plant is retired. Apply Custom's Duty level that is "normalized" to HFO on a $ per MMBtu basis	LPG. HFO & LFO to be phased out as non-converted existing plant is retired. Apply Custom's Duty level that is "normalized" to HFO on a $ per MMBtu basis
Resource Fuel Conversions	None required	None required	Convert planned MSDs (adding steam turbine for combined cycle operation) and capable existing resources at central plant to NG operation.	Convert capable CT's at Central Plant to LPG operation
Candidate Fossil Fuel Resources	• MSDs on HFO (located at Central Power Plant) • CTs on LFO (located at Central Power Plant)	• MSDs on HFO (located at Central Power Plant) • CTs on LFO (located at Central Power Plant)	• MSDs on NG (located at Central Power Plant) • CTs on NG (located at Central Power Plant) • RICE – CHP (NG)	• MSDs on LPG (located at/near LPG fuel storage site) • CTs on LPG (located at/near LPG fuel storage site) • CT – CCHP (LPG)
Candidate Renewable Fuel Resources	None (no new additions after the planned Solar Finger Phase 1)	Solar (Up to 18 MW) • 12 MW (Phase II) Solar PV PPA at Finger. • 6 MW aggregate PPAs (Phase III) from other sites. Off-shore Wind (Up to 25 MW PPA	Solar (Up to 18 MW) • 12 MW (Phase II) Solar PV PPA at Finger. • 6 MW aggregate PPAs (Phase III) from other sites. Off-shore Wind (Up to 25 MW PPA	Solar (Up to 18 MW) • 12 MW (Phase II) Solar PV PPA at Finger. • 6 MW aggregate PPAs (Phase III) from other sites. Off-shore Wind (Up to 25 MW PPA
Candidate BESS Resources	None	As needed to support renewable resources	As needed to support renewable resources	As needed to support renewable resources
Candidate EE	Defined Realistic Achievable Potential.	Defined Realistic Achievable Potential.	Defined Realistic Achievable Potential.	Defined Realistic Achievable Potential.
Candidate EV	Defined EV Program	Defined EV Program	Defined EV Program	Defined EV Program
Distributed Renewables	None (organic growth already embedded in forecast	Solar • Solar PV rooftop (residential and commercial) • Solar thermal water heating	Solar • Solar PV rooftop (residential and commercial) • Solar thermal water heating	Solar • Solar PV rooftop (residential and commercial) • Solar thermal water heating

The sensitivities applied to the selected planning scenarios are defined as follows:

1. **Fuel Cost** (based on 2017 EIA AEO range) – High Fuel Price and Low Fuel Price Forecasts have been developed based on AEO scenarios that represent the highest and lowest commodity price for each commodity that underpins the fuel in question. As discussed further in Section 4.8, the scenario that represents the High Fuel Price Case for LFO, HFO, LPG, and LNG is the 2017 AEO High Oil Case; the Low Fuel Price Case is based on the AEO Low Oil Case for HFO, LFO, and LPG but is based on the AEO High Resource Case for LNG.
2. **Carbon Monetization** – Leidos has researched an updated March 2016 report from Synapse that captures a revised view on potential carbon prices – this report's pricing is applied to each production cost model's results on the back end, in addition to reporting the actual tons of carbon emitted for each scenario.
3. **High and Low Load Forecast** – The IRP evaluated a "High" and "Low" forecast. The High Case reflects a long-term growth rate of 0.9 percent per year, while the Low Case reflects a resumption of the recent contraction in load, with a long-term rate of decline of 0.4 percent per year.
4. **Non-Normalized Custom's Duty on LPG and LNG** – The amount of Custom's Duty applied to LPG and LNG is adjusted (lowered) to reflect the current rate applied by the Bermuda Government for import of those fuels.
5. **IPP Development of Future Fossil Fuel Resources** – The estimated cost of future fossil fuel resources is adjusted as necessary to reflect the development by an IPP at an east end site near the existing bulk fuel storage facilities.

1.12 Qualitative Analysis of Candidate Resources

In order to provide a holistic evaluation of the supply-side and demand-side resources, and to ensure that non-monetary factors that are critical to the success of the IRP but not quantified in the load dispatch modeling are carefully considered, the IRP process includes a qualitative evaluation of each candidate resource. The qualitative assessment criteria used as a basis for the evaluation and the maximum scores that are allocated to each criterion have been developed specifically for this IRP and reflect BELCO TD&R's interpretation of their significance. The results of the qualitative evaluation were considered together with the results from the quantitative analysis in arriving at the recommendations for the action plan arising from this IRP exercise. The importance of the qualitative assessment is highlighted in the consideration of renewable energy resources for the Preferred Plan to address a sustainability objective, since the least cost plan based on the quantitative analysis may exclude these resources. Descriptions of the criteria used for the qualitative assessment along with the maximum scores allocated to each one is provided in Table 1-3.

Table 1-3
Qualitative Assessment Criteria

	Qualitative Factor	Factor Description	Maximum Score
1	Supply Quality	Evaluate the degree to which the asset enhances or reinforces system reliability as a firm resource.	20
2	Environmental Sustainability	Evaluate the degree to which the asset will cause a reduction in the emission of Green House Gases (GHG) from electricity generation	20
3	Security and Cost Resilience	Evaluate the degree to which the asset contributes to resource/fuel diversity to make Bermuda resilient to shocks caused by dramatic changes in the cost and availability of fuel.	20
4	Logistics	Evaluate the degree to which the asset provides for ease of logistics and implementation.	20
5	Economic Development	Evaluate the degree to which the asset contributes to the economic development of Bermuda with a focus on job creation.	20
	Total Maximum Score		100

The results of the qualitative analysis are presented in Section 2 of this IRP. The total scores gleaned from the qualitative analysis will be combined with the direct financial implications of the dispatch scenarios and LCOE screening to inform the findings in this IRP in terms of the resource plan that is deemed to be most attractive overall for Bermuda.

2.1 LCOE Results

Figure 2.1 below summarizes the results, on a NPV basis over the Study Period, of the LCOE analysis and include the Custom's Duty in the fuel cost projections. The NG resource options evaluated in the LCOE analysis are based on the full conversion of the BELCO generating fleet to operate on NG.

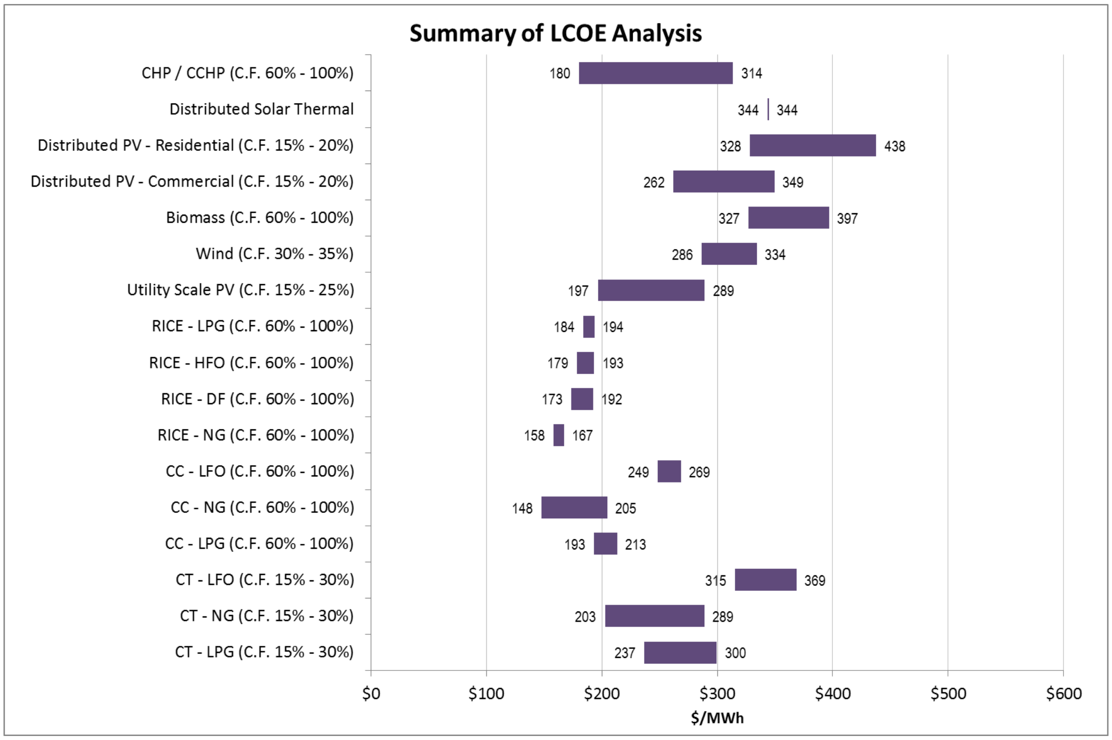

Figure 2.1 – NPV Summary of LCOE Analysis Results

As evidenced by Figure 2-1, baseload gas resources are generally less costly than baseload oil resources and are comparable to existing resources that are converted from oil to gas operation. Additionally, renewable energy resources are comparable in cost to traditional peaking thermal assets as the assumed capacity factor increases, which is in part a function of the fact that such resources do not have any variable costs of production. Utility-scale renewable resources were found, in general, to be more cost-effective in this analysis than customer-sited renewables, primarily as a function of the economies of scale inherent in larger installations. However, customer-sited distributed PV resources were included in the dispatch scenarios as they would be developed by customers with no cost impact to the utility. Biomass and offshore wind resources were screened out from further consideration because of cost and logistical uncertainties that require addressing in a feasibility study.

2.2 Production Cost Modeling Results

Production cost modeling results are presented in Figure 2-2, Figure 2-3 and Table 2-1 below. Figure 2-2 depicts the annual "all-in" $/MWh cost of each production cost scenario (Scenarios 1 through 4 as defined in Section 1) over the Study Period. Table 2-1 summarizes the NPV of each scenario, and computes the difference (either positive or negative) between the NPV and Scenario 1 (or the Reference Scenario). Figure 2.3 compiles the sum total (Tons) and intensity (kg/kWh) of all carbon emissions associated with each scenario over the entire Study Period into a bar chart comparison. Note that MWh and kWh values are inclusive of energy abated, as applicable.

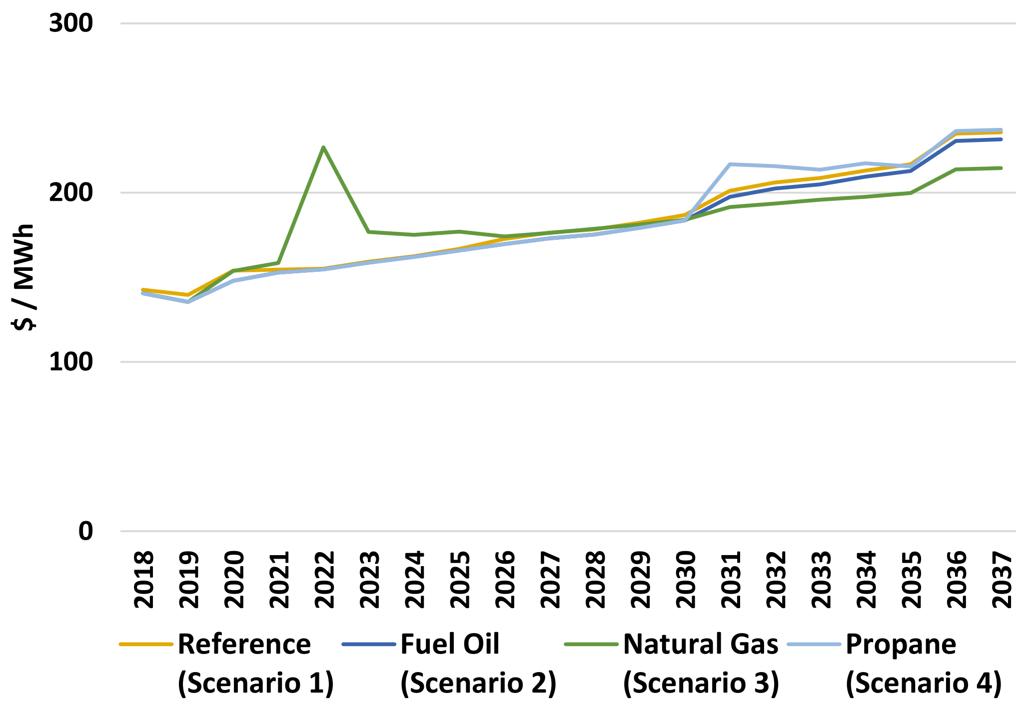

Figure 2.2 – Summary of Annual $/MWh Costs by Scenario

Table 2-1
Summary of Estimated Levelized Cost by Scenario ($/MWh)

Scenario	Levelized Cost ($/MWh)	Difference from Scenario 1 ($/MWh)	Difference from Scenario 1 (%)
Reference (Scenario 1)	170.80		
Fuel Oil + DSM + Renewables (Scenario 2)	168.08	(2.72)	(1.6)%
NG + DSM + Renewables (Scenario 3)	174.87	4.07	2.4%
LPG + DSM + Renewables (Scenario 4)	169.99	(0.80)	(0.5)%

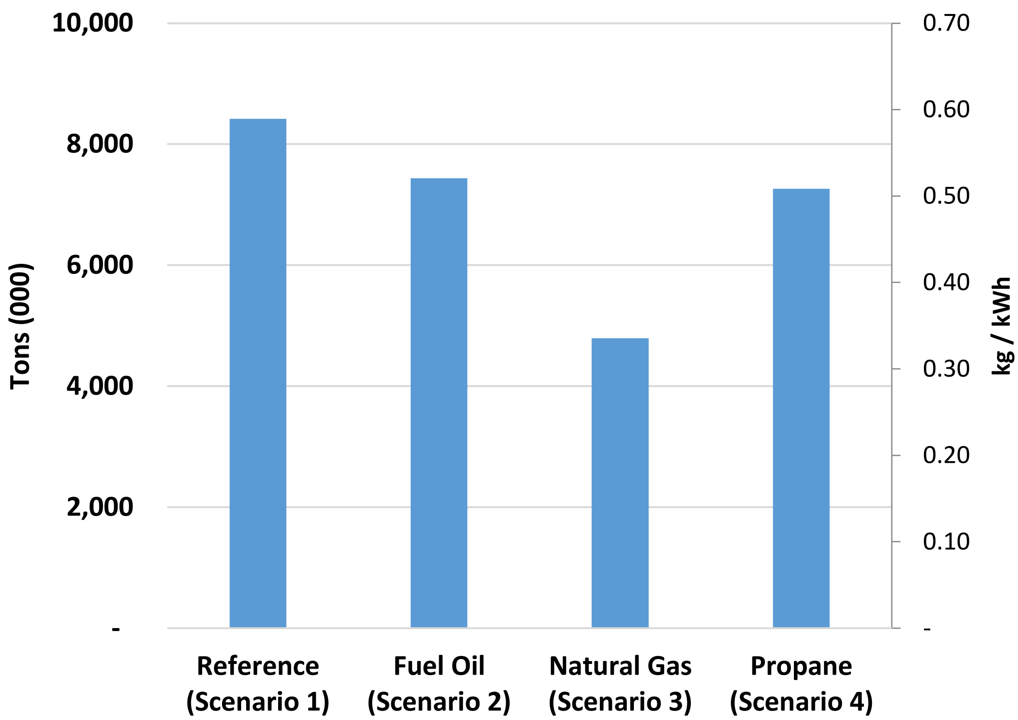

Figure 2.3 – Summary of Carbon Emissions by Scenario During Study Period

As evidenced by the Base Case results above:

- The least cost scenario is the Fuel Oil Scenario, Scenario 2, although the NPVs over the Study Period for all scenarios are in a relatively narrow range between $168/MWh and $175/MWh.

- Costs for the Fuel Oil (Scenario 2) and LPG (Scenario 4) scenarios are similar. Energy in both scenarios is primarily supplied by Fuel Oil resources until new LPG resources are required to meet system capacity requirements in 2031 after which costs in the LPG scenario increase relative to Fuel Oil.

- The NG scenario, Scenario 3, is the highest cost scenario over the course of the Study Period owing to higher capital costs, both LNG infrastructure costs and costs to convert existing generation resources to LNG which can be seen in the 2022 cost spike, but Scenario 3 becomes the least cost scenario by 2031 as lower fuel costs offset the higher capital costs.

- The NG scenario, Scenario 3, has the lowest carbon footprint over the course of the Study Period and following the installation of LNG infrastructure on the island, Scenario 3 CO_2 emissions are less than half of the Reference scenario. CO_2 emissions in the LPG scenario are not significantly lower than the Fuel Oil scenario since LPG is only introduced on a limited basis in 2031 and Fuel Oil remains a prominent fuel in Scenario 4.

The energy mix of the four Scenarios is presented in Tables 2-2 through 2-5 below.

Table 2-2
Energy Supply Mix – Reference (Scenario 1)

Resource / Fuel Type	2018	2023	2028	2033	2037	Study Period Total
Fuel Oil	96.9%	92.9%	92.0%	91.5%	90.6%	92.4%
NG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LPG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Renewables	2.8%	5.1%	5.0%	4.8%	4.7%	4.8%
EE / EV	0.3%	2.0%	3.0%	3.7%	4.7%	2.8%

Table 2-3
Energy Supply Mix – Fuel Oil (Scenario 2)

Resource / Fuel Type	2018	2023	2028	2033	2037	Study Period Total
Fuel Oil	95.3%	79.7%	79.4%	79.5%	79.1%	81.4%
NG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LPG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Renewables	4.4%	18.3%	17.5%	16.7%	16.2%	15.8%
EE / EV	0.3%	2.0%	3.0%	3.7%	4.7%	2.8%

Table 2-4
Energy Supply Mix – Natural Gas (Scenario 3)

Resource / Fuel Type	2018	2023	2028	2033	2037	Study Period Total
Fuel Oil	95.3%	0.0%	0.0%	0.0%	0.0%	17.6%
NG	0.0%	79.8%	79.5%	79.6%	79.2%	63.8%
LPG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Renewables	4.4%	18.2%	17.5%	16.7%	16.2%	15.8%
EE / EV	0.3%	2.0%	3.0%	3.7%	4.7%	2.8%

Table 2-5
Energy Supply Mix – Liquefied Petroleum Gas (Scenario 4)

Resource / Fuel Type	2018	2023	2028	2033	2037	Study Period Total
Fuel Oil	95.3%	79.7%	79.4%	62.8%	41.4%	73.3%
NG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LPG	0.0%	0.0%	0.0%	16.8%	37.9%	8.1%
Renewables	4.4%	18.3%	17.5%	16.7%	16.0%	15.8%
EE / EV	0.3%	2.0%	3.0%	3.7%	4.6%	2.8%

The resource expansion plans for the four scenarios are provided in Tables 2-6 through 2-9. The tables show the annual asset expansion and retirement plans by year and include the surplus capacity balance and reserve margins that guided the development of the expansion plans. These tables can be paired with the detailed operations and cost data supplied in Appendix II.D for each scenario.

Table 2-6
Reference (Scenario 1) Annual Expansion Plan Summary (MW)

	Supply Side Resources								Demand Side Resources						
	Existing Capacity			New Capacity (Dependable)				New Demand Side						
	Existing Capacity Retired		Existing Capacity Remaining	Resources Added		Total New Capacity	Total Supply Side Capacity	Resource Added		Total Demand Side Resources	Peak Demand	Peak Demand (Net of DSM)	Reserve Margin	Surplus Capacity
Year	(MW)	(Type)	(MW)	(MW)	(Type)	(MW)	(MW)	(MW)	(Type)	(MW)	(MW)	(MW)	(MW)	(MW)
2018			167.2		BESS-Spin (10 MW)	-	167.2	0.36	EE / EV	0.4	107.2	106.8	32.6	27.8
2019	11.0	GT4	156.2	3.6	Utility PV (6 MW)	3.6	159.8	0.39	EE / EV	0.8	107.1	106.4	36.2	17.2
2020	7.0 4.5 7.0 7.0 12.2 11.2 10.1 9.5	D10 D14 D3 D8 E1 E2 E3 E4	87.7	13.8 13.8 13.8 13.8	IC_MSD (DF) NPS1 IC_MSD (DF) NPS2 IC_MSD (DF) NPS3 IC_MSD (DF) NPS4	58.9	146.6	0.85	EE / EV	1.6	107.3	105.7	36.2	4.7
2021			87.7			58.9	146.6	0.18	EE / EV	1.8	107.5	105.7	36.1	4.7
2022			87.7			58.8	146.5	0.20	EE / EV	2.0	107.6	105.6	36.1	4.8
2023			87.7			58.8	146.5	0.23	EE / EV	2.2	107.8	105.6	36.1	4.8
2024			87.7			58.8	146.5	0.25	EE / EV	2.5	108.0	105.5	36.1	4.9
2025			87.7			58.7	146.4	0.28	EE / EV	2.8	108.1	105.4	36.0	5.1
2026	13.0	GT5	74.7	12.8	GT_New (LFO)	71.5	146.2	0.32	EE / EV	3.1	108.3	105.2	36.0	5.0
2027			74.7			71.5	146.2	0.35	EE / EV	3.4	108.5	105.0	36.0	5.2
2028			74.7			71.5	146.2	0.27	EE / EV	3.7	108.6	104.9	35.9	5.3
2029			74.7			71.4	146.1	0.29	EE / EV	4.0	108.8	104.8	35.9	5.4
2030			74.7			71.4	146.1	0.31	EE / EV	4.3	109.0	104.7	35.9	5.6
2031	14.3 14.3	E5 E6	46.1	14.0 14.0	IC_MSD New (HFO) IC_MSD New (HFO)	99.4	145.5	0.34	EE / EV	4.6	109.1	104.5	35.9	5.1
2032			46.1			99.3	145.4	0.37	EE / EV	5.0	109.3	104.3	35.8	5.3
2033			46.1			99.3	145.4	0.39	EE / EV	5.4	109.5	104.1	35.8	5.6
2034			46.1			99.3	145.4	0.42	EE / EV	5.8	109.6	103.8	35.8	5.8
2035			46.1			99.3	145.4	0.46	EE / EV	6.3	109.8	103.5	35.7	6.1
2036	14.3 14.3	E7 E8	17.5	14.0 14.0	IC_MSD New (HFO) IC_MSD New (HFO)	127.2	144.7	0.49	EE / EV	6.8	110.0	103.2	35.1	6.4
2037			17.5			127.2	144.7	0.53	EE / EV	7.3	110.1	102.8	35.1	6.8

Notes:
PV - Dependable capacity is 60% of installed nameplate capacity and degrades at 0.8% annually
Battery for spinning reserve backup and battery for renewable support are not counted toward dependable capacity

Table 2-7
Fuel Oil (Scenario 2) Annual Expansion Plan Summary (MW)

	Supply Side Resources								Demand Side Resources						
	Existing Capacity			New Capacity (Dependable)				New Demand Side						
	Existing Capacity Retired		Existing Capacity Remaining	Resources Added		Total New Capacity	Total Supply Side Capacity	Resource Added		Total Demand Side Resources	Peak Demand	Peak Demand (Net of DSM)	Reserve Margin	Surplus Capacity
Year	(MW)	(Type)	(MW)	(MW)	(Type)	(MW)	(MW)	(MW)	(Type)	(MW)	(MW)	(MW)	(MW)	(MW)
2018			167.2		BESS-Spin (10 MW)	-	167.2	1.10	EE / EV / PV	1.1	107.2	106.1	33.0	28.1
2019	11.0	GT4	156.2	3.6	Utility PV (6 MW)	3.6	159.8	1.13	EE / EV / PV	2.2	107.1	104.9	37.0	17.8
2020	7.0	D10	87.7	13.8	IC_MSD (DF) NPS1	58.9	146.6	1.59	EE / EV / PV	3.8	107.3	103.5	37.4	5.7
	4.5	D14		13.8	IC_MSD (DF) NPS2									
	7.0	D3		13.8	IC_MSD (DF) NPS3									
	7.0	D8		13.8	IC_MSD (DF) NPS4									
	12.2	E1												
	11.2	E2												
	10.1	E3												
	9.5	E4												
2021			87.7	3.6	Utility PV (12 MW)	69.7	157.4	0.92	EE / EV / PV	4.7	107.5	102.7	37.8	16.8
				7.2	Utility PV (6 MW)									
					BESS-Renew (10 MW)									
2022			87.7			69.6	157.3	0.62	EE / EV / PV	5.3	107.6	102.3	38.2	16.9
2023			87.7			69.6	157.3	0.21	EE / EV / PV	5.6	107.8	102.2	38.1	16.9
2024			87.7			69.6	157.3	0.24	EE / EV / PV	5.8	108.0	102.2	38.1	17.0
2025			87.7			69.5	157.2	0.27	EE / EV / PV	6.1	108.1	102.1	38.0	17.1
2026	13.0	GT5	74.7			69.5	144.2	0.30	EE / EV / PV	6.4	108.3	101.9	38.0	4.3
2027			74.7			69.5	144.2	0.34	EE / EV / PV	6.7	108.5	101.8	38.0	4.5
2028			74.7			69.5	144.2	0.25	EE / EV / PV	7.0	108.6	101.7	37.9	4.6
2029			74.7			69.4	144.1	0.28	EE / EV / PV	7.2	108.8	101.6	37.9	4.7
2030			74.7			69.4	144.1	0.30	EE / EV / PV	7.5	109.0	101.4	37.8	4.9
2031	14.3	E5	46.1	14.0	IC_MSD New (HFO)	97.4	143.5	0.32	EE / EV / PV	7.8	109.1	101.3	37.8	4.4
	14.3	E6		14.0	IC_MSD New (HFO)									
2032			46.1			97.3	143.4	0.35	EE / EV / PV	8.2	109.3	101.1	37.7	4.6
2033			46.1			97.3	143.4	0.38	EE / EV / PV	8.6	109.5	100.9	37.7	4.9
2034			46.1			97.3	143.4	0.41	EE / EV / PV	9.0	109.6	100.6	37.6	5.1
2035			46.1			97.3	143.4	0.44	EE / EV / PV	9.4	109.8	100.4	37.6	5.4
2036	14.3	E7	17.5	14.0	IC_MSD New (HFO)	125.2	142.7	0.48	EE / EV / PV	9.9	110.0	100.0	37.0	5.7
	14.3	E8		14.0	IC_MSD New (HFO)									
2037			17.5			125.2	142.7	0.52	EE / EV / PV	10.4	110.1	99.7	36.9	6.1

Notes:
Assumes PV - Dependable capacity is 60% of installed nameplate capacity and degrades at 0.8% annually
Battery for spinning reserve backup and battery for renewable support are not counted toward dependable capacity

Table 2-8
Natural Gas (Scenario 3) Annual Expansion Plan Summary (MW)

	Supply Side Resources							Demand Side Resources						
	Existing Capacity			New Capacity (Dependable)				New Demand Side						
	Existing Capacity Retired		Existing Capacity Remaining	Resources Added		Total New Capacity	Total Supply Side Capacity	Resource Added		Total Demand Side Resources	Peak Demand	Peak Demand (Net of DSM)	Reserve Margin	Surplus Capacity
Year	(MW)	(Type)	(MW)	(MW)	(Type)	(MW)	(MW)	(MW)	(Type)	(MW)	(MW)	(MW)	(MW)	(MW)
2018			167.2		BESS-Spin (10 MW)	-	167.2	1.10	EE / EV / Dist PV	1.1	107.2	106.1	33.0	28.1
2019	11.0	GT4	156.2	3.6	Utility PV (6 MW)	3.6	159.8	1.13	EE / EV / Dist PV	2.2	107.1	104.9	37.0	17.8
2020	7.0	D10	87.7	13.8	IC_MSD (DF) NPS1 *	58.9	146.6	1.59	EE / EV / Dist PV	3.8	107.3	103.5	37.4	5.7
	4.5	D14		13.8	IC_MSD (DF) NPS2 *									
	7.0	D3		13.8	IC_MSD (DF) NPS3 *									
	7.0	D8		13.8	IC_MSD (DF) NPS4 *									
	12.2	E1												
	11.2	E2												
	10.1	E3												
	9.5	E4												
2021			87.7	3.6	Utility PV (12 MW)	69.7	157.4	0.92	EE / EV / PV / CHP	4.7	107.5	102.7	37.8	16.8
				7.2	Utility PV (6 MW)									
					BESS-Renew (10 MW)									
2022	14.3	E5 - Refuel	4.0	13.4	IC_MSD Refuel (NG) E5	157.0	161.0	3.09	EE / EV / PV / CHP	7.8	107.6	99.8	39.3	21.9
	14.3	E6 - Refuel		13.4	IC_MSD Refuel (NG) E6									
	14.3	E7 - Refuel		13.4	IC_MSD Refuel (NG) E7									
	14.3	E8 - Refuel		14.0	IC_MSD Refuel (NG) E8									
	13.0	GT5 - Refuel		12.8	GT_Refuel (NG) GT5									
	4.5	GT6 - Refuel		5.2	GT_Refuel (NG) GT6									
	4.5	GT7 - Refuel		5.2	GT_Refuel (NG) GT7									
	4.5	GT8 - Refuel		5.2	GT_Refuel (NG) GT8									
				1.1	NPS1 switch to NG									
				1.1	NPS2 switch to NG									
				1.1	NPS3 switch to NG									
				1.1	NPS4 switch to NG									
2023			4.0			157.0	161.0	0.21	EE / EV / PV / CHP	8.0	107.8	99.8	39.3	21.9
2024			4.0			157.0	161.0	2.71	EE / EV / PV / CHP	10.7	108.0	97.2	39.2	24.5
2025			4.0			156.9	160.9	0.27	EE / EV / PV / CHP	11.0	108.1	97.1	39.2	24.6
2026			4.0	-12.7	GT_Retire (NG) GT5	144.1	148.1	2.77	EE / EV / PV / CHP	13.8	108.3	94.5	39.2	14.4
2027			4.0			144.1	148.1	0.34	EE / EV / PV / CHP	14.1	108.5	94.4	39.1	14.6
2028			4.0			144.1	148.1	0.25	EE / EV / PV / CHP	14.4	108.6	94.3	39.1	14.7
2029			4.0			144.0	148.0	0.28	EE / EV / PV / CHP	14.6	108.8	94.2	39.0	14.9
2030			4.0			144.0	148.0	0.30	EE / EV / PV / CHP	14.9	109.0	94.0	39.0	15.0
2031			4.0	-13.4	IC_MSD Retire (NG) E5	131.2	135.2	0.32	EE / EV / PV / CHP	15.3	109.1	93.9	38.9	2.4
				-13.4	IC_MSD Retire (NG) E6									
				14.0	IC_MSD New (NG)									
2032			4.0			131.1	135.1	0.35	EE / EV / PV / CHP	15.6	109.3	93.7	38.9	2.6
2033			4.0			131.1	135.1	0.38	EE / EV / PV / CHP	16.0	109.5	93.5	38.8	2.8
2034			4.0			131.1	135.1	0.41	EE / EV / PV / CHP	16.4	109.6	93.2	38.8	3.1
2035			4.0			131.1	135.1	0.44	EE / EV / PV / CHP	16.8	109.8	92.9	38.8	3.4
2036			4.0	-14.0	IC_MSD Retire (NG) E7	131.0	135.0	0.48	EE / EV / PV / CHP	17.3	110.0	92.6	38.7	3.7
				-14.0	IC_MSD Retire (NG) E8									
				14.0	IC_MSD New (NG)									
				14.0	IC_MSD New (NG)									
2037			4.0			131.0	135.0	0.52	EE / EV / PV / CHP	17.8	110.1	92.3	38.7	4.0

Notes:

* Converted to natural gas in 2022

Assumes PV - Dependable capacity is 60% of installed nameplate capacity and degrades at 0.8% annually

Battery for spinning reserve backup and battery for renewable support are not counted toward dependable capacity

Table 2-9
Liquefied Petroleum Gas (Scenario 4) Annual Expansion Plan Summary (MW)

	Supply Side Resources							Demand Side Resources						
	Existing Capacity			New Capacity (Dependable)				New Demand Side						
	Existing Capacity Retired		Existing Capacity Remaining	Resources Added		Total New Capacity	Total Supply Side Capacity	Resource Added		Total Demand Side Resources	Peak Demand	Peak Demand (Net of DSM)	Reserve Margin	Surplus Capacity
Year	(MW)	(Type)	(MW)	(MW)	(Type)	(MW)	(MW)	(MW)	(Type)	(MW)	(MW)	(MW)	(MW)	(MW)
2018			167.2		BESS-Spin (10 MW)	-	167.2	1.10	EE / EC / PV / CCHP	1.1	107.2	106.1	33.0	28.1
2019	11.0	GT4	156.2	3.6	Utility PV (6 MW)	3.6	159.8	1.13	EE / EC / PV / CCHP	2.2	107.1	104.9	37.0	17.8
2020	7.0	D10	87.7	13.8	IC_MSD (DF) NPS1	58.9	146.6	1.59	EE / EC / PV / CCHP	3.8	107.3	103.5	37.4	5.7
	4.5	D14		13.8	IC_MSD (DF) NPS2									
	7.0	D3		13.8	IC_MSD (DF) NPS3									
	7.0	D8		13.8	IC_MSD (DF) NPS4									
	12.2	E1												
	11.2	E2												
	10.1	E3												
	9.5	E4												
2021			87.7	3.6	Utility PV (12 MW)	69.7	157.4	0.92	EE / EC / PV / CCHP	4.7	107.5	102.7	37.8	16.8
				7.2	Utility PV (6 MW)									
					BESS-Renew (10 MW)									
2022			87.7			69.6	157.3	0.62	EE / EC / PV / CCHP	5.3	107.6	102.3	38.2	16.9
2023			87.7			69.6	157.3	0.21	EE / EC / PV / CCHP	5.6	107.8	102.2	38.1	16.9
2024			87.7			69.6	157.3	0.24	EE / EC / PV / CCHP	5.8	108.0	102.2	38.1	17.0
2025			87.7			69.5	157.2	0.27	EE / EC / PV / CCHP	6.1	108.1	102.1	38.0	17.1
2026	13.0	GT5	74.7			69.5	144.2	0.30	EE / EC / PV / CCHP	6.4	108.3	101.9	38.0	4.3
2027			74.7			69.5	144.2	0.34	EE / EC / PV / CCHP	6.7	108.5	101.8	38.0	4.5
2028			74.7			69.5	144.2	0.25	EE / EC / PV / CCHP	7.0	108.6	101.7	37.9	4.6
2029			74.7			69.4	144.1	0.28	EE / EC / PV / CCHP	7.2	108.8	101.6	37.9	4.7
2030			74.7			69.4	144.1	0.30	EE / EC / PV / CCHP	7.5	109.0	101.4	37.8	4.9
2031	4.5	GT6 - Refuel	32.6	5.2	GT_Refuel (NG) GT6	117.4	150.0	2.55	EE / EC / PV / CCHP	10.1	109.1	99.0	41.6	9.4
	4.5	GT7 - Refuel		5.2	GT_Refuel (NG) GT7									
	4.5	GT8 - Refuel		5.2	GT_Refuel (NG) GT8									
	14.3	E5		16.2	CC_New (LPG)									
	14.3	E6		16.2	CC_New (LPG)									
2032			32.6			117.3	149.9	0.35	EE / EC / PV / CCHP	10.4	109.3	98.9	41.5	9.6
2033			32.6			117.3	149.9	2.61	EE / EC / PV / CCHP	13.0	109.5	96.4	41.5	12.0
2034			32.6			117.3	149.9	0.41	EE / EC / PV / CCHP	13.4	109.6	96.2	41.4	12.3
2035			32.6			117.3	149.9	2.67	EE / EC / PV / CCHP	16.1	109.8	93.7	41.4	14.8
2036	14.3	E7	4.0	16.2	CC_New LPG	133.4	137.4	0.48	EE / EC / PV / CCHP	16.6	110.0	93.4	41.4	2.7
	14.3	E8												
2037			4.0			133.4	137.4	0.52	EE / EC / PV / CCHP	17.1	110.1	93.0	41.3	3.1

Notes:
PV - Dependable capacity is 60% of installed nameplate capacity and degrades at 0.8% annually
Battery for spinning reserve backup and battery for renewable support are not counted toward dependable capacity

2.3 Reliability Analysis

As described in Section 1 of this IRP, the production cost modeling was performed assuming a PRM that accounts for the loss of the two largest generating resources and allows additional reserves to cover the loss of intermittent resources during peak demand periods. This PRM level is intended to maintain system reliability at industry standard levels. While the scope of this IRP did not include a robust PRM study that would account for the variability in load, intermittent generation and generator outages, an analysis of the impact of unplanned outages on system reliability was performed.

The analysis was performed by running PROMOD© for Scenarios 2 and 3 (top two ranked scenarios) using 20 random unplanned outage draws to calculate LOLH for the Study Period. LOLH is a count of the number of hours in which load exceeds available generation in a given year. A common LOLH reliability target used in the industry is 1 day in 10 years, meaning on average that the system would not expect to have demand exceed available resources for more than an average of 2.4 hours per year (24 hours in 10 years). Table 2-10 below depicts the results of the reliability analysis conducted for Scenarios 2 and 3.

Table 2-10
Average Loss of Load Hours (LOLH)

Scenario	LOLH
Fuel Oil (Scenario 2)	2.9
NG (Scenario 3)	1.4

Scenario 3 LOLH is better than the industry standard of 2.4 hours per year while Scenario 2 is slightly above target. Reliability in Scenario 3 is improved relative to Scenario 2 due to the additional capacity and lower outage rates of the existing oil-fired units following their conversion to NG in 2022. This analysis did not consider the variability of load and intermittent generation but does support the PRM levels, described previously in this section, that were used in the IRP analysis.

2.4 Sensitivity Analysis Results

Production costs for Scenarios 2, 3 and 4 were modeled using sensitivities to key assumptions defined in Section 1 to quantify the effect of the assumptions on each scenario. Figure 2-4 presents the levelized cost in "$/MWh" over the Study Period for each sensitivity grouped by scenario with the Base Case for each scenario identified by the solid marker. Table 2-11 summarizes the change in levelized costs resulting from each of the sensitivities that were applied to three base scenarios (2, 3 and 4) relative to the levelized cost estimated of the Reference Scenario (Scenario 1).

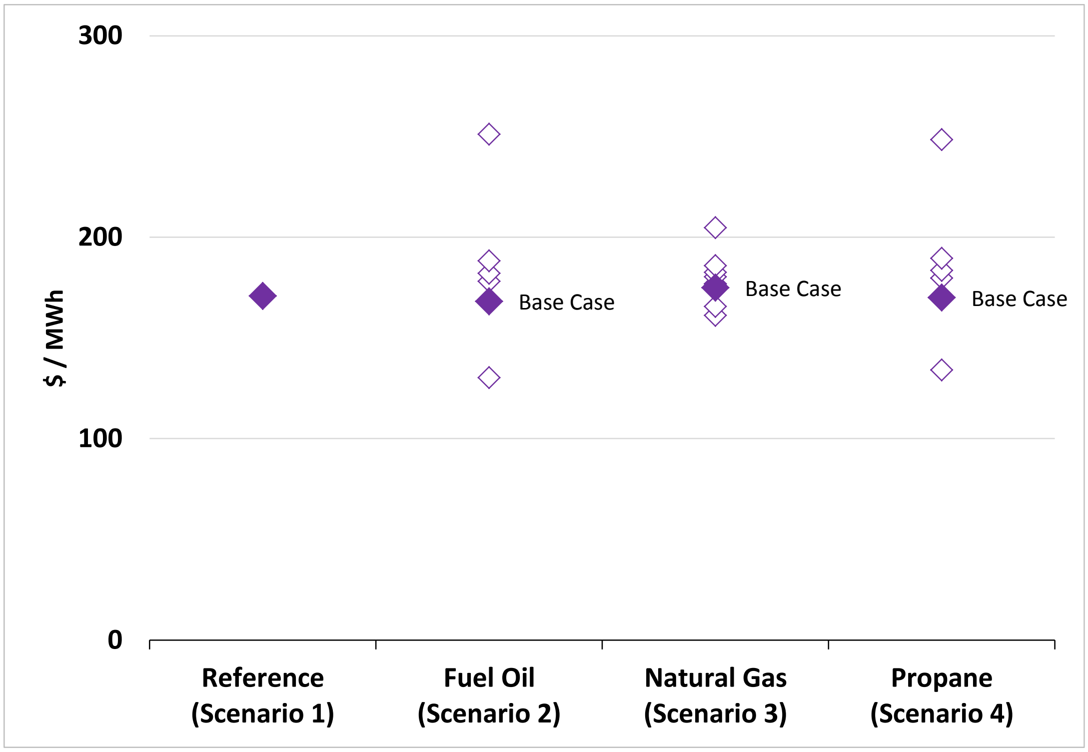

Figure 2-4 – Summary of Levelized Costs by Scenario and Sensitivity

Table 2-11
Summary of Sensitivity Analysis Results for Base Scenarios
(Percent Cost Deltas from Reference Scenario)

Sensitivity	Fuel Oil (Scenario 2)	NG (Scenario 3)	LPG (Scenario 4)
Base Case	-1.6%	2.2%	-0.5%
High Fuel	47.0%	19.9%	45.4%
Low Fuel	-23.7%	-5.7%	-21.5%
Non-Normalized Fuel Custom's Duty	NA	-3.1%	-0.8%
High Load Forecast	-1.4%	1.1%	-1.3%
Low Load Forecast	-1.5%	3.5%	-1.1%
IPP Future Traditional Resources	-1.0%	3.5%	NA
Low Carbon Monetization	5.8%	3.2%	5.7%
Mid Carbon Monetization	8.1%	4.5%	7.9%
High Carbon Monetization	11.8%	6.4%	11.4%

The high and low fuel price sensitivities represent the upper and lower bounds of cost, respectively, for each scenario. The NG scenario, Scenario 3, has the lowest variance in outcomes due to the narrower range of projected NG prices suggesting Scenario 3 is associated with less cost risk than Scenarios 2 and 4. Additionally, Appendix II.D contains detailed graphical and tabular results for each defined scenario as well as the sensitivities applied, including capacity and energy mix balance, pro forma summaries of system cost, as well as by-unit operations and cost summaries for both existing and new resources.

2.5 Qualitative Evaluation Results

Figure 2-5 below depicts the results of the qualitative analysis for the candidate resource categories. A detailed qualitative evaluation matrix is provided in Appendix II.E.

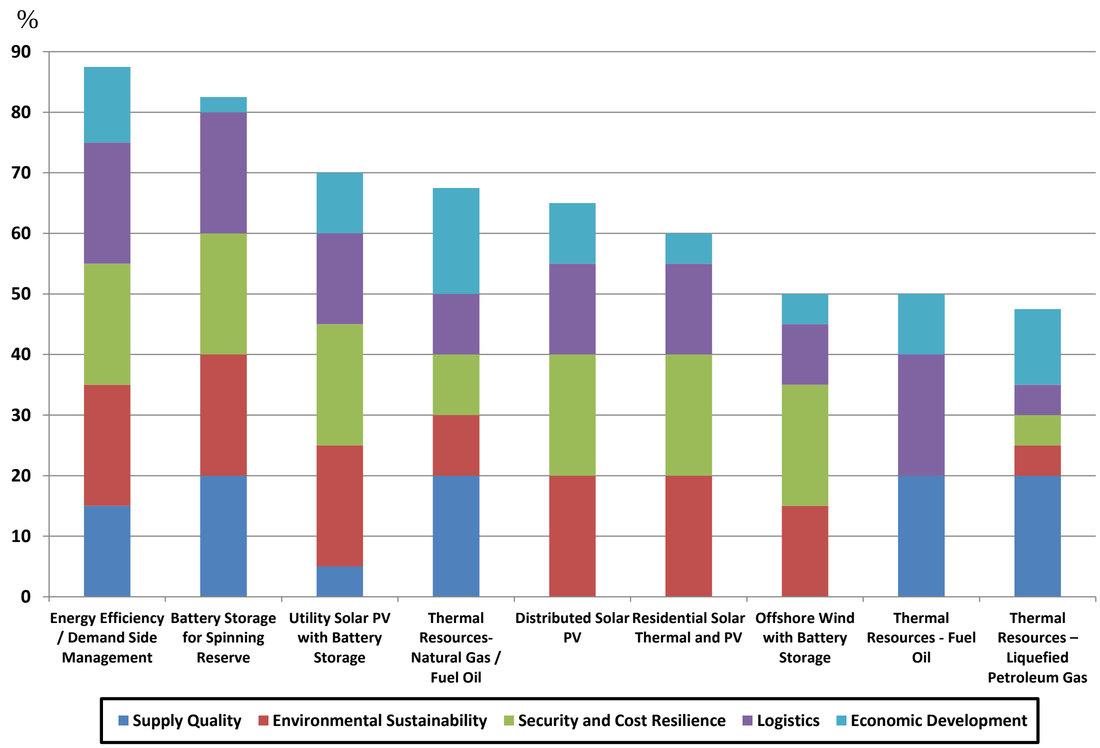

Figure 2-5 – Qualitative Scoring Results

The key takeaways from the results of the qualitative analysis are as follows:

- The generic EE/DSM resource scored highest at 87.5 percent among all resource categories. This is a function of the fact that the measures contemplated are environmentally sustainable, promote energy security and cost resilience and are relatively easy to implement. Additionally, energy efficiency can help to engender trust and goodwill between BELCO TD&R and its customers.

- The block of battery storage for spinning reserve has the next highest qualitative score at 82.5 percent, as a result of very high marks across all evaluation factors, other than economic development.

- The block of utility solar PV, thermal resources utilizing NG as the primary fuel, distributed solar PV, and residential solar thermal and PV have the next highest qualitative scores, ranging between 60 and 70 percent.

- Offshore wind, thermal resources operating on Fuel Oil, and the same burning LPG fuel scored 50, 50, and 47.5 percent, respectively. The offshore wind scored low due to poor supply quality and low economic development. Thermal resources scored poorly because of the increased handling and transportation risks and the reduced infrastructure requirement associated with LPG when compared with LNG, along with low environmental sustainability.

2.6 Scoring and Findings

2.6.1 Evaluation Methodology

Leidos worked with BELCO TD&R to develop a method for computing a single ranking score for each scenario composed of a quantitative and qualitative attribute. The quantitative attribute is based on the economic analysis and is represented by the NPV result from the PROMOD© analysis. The qualitative attribute is based on the results of the qualitative evaluation. Both methods are discussed in detail earlier in this section of the IRP. The following discussion describes the methodology for computing a single ranking score using a weighted scoring mechanism. The resulting scenario rankings are also presented.

The quantitative attribute is computed by applying a percentage score to the results of the economic evaluation. The scenario with the lowest base case NPV cost is assigned a score of 100 percent and the scores assigned to the other scenarios are scaled based on the respective NPV cost relative to the lowest base case scenario cost. This score constitutes the "Raw Quantitative Score".

The qualitative attribute is comprised of two factors: (i) the proportion of energy generated over the Study Period by fuel/resource type and (ii) the qualitative score of the respective resource type. For each scenario, the long term average of the annual percent of energy generation by resource type is computed over the Study Period. The sum-product of the long term averages and the respective qualitative scores is then computed. The qualitative scores of the scenarios are then normalized by computing the ratio of the qualitative scores against the highest qualitative score. These normalized values represent the "Raw Qualitative Cost of each Scenario".

The Raw Quantitative Score and the Raw Qualitative Score are then combined using a weighting of 80 percent and 20 percent, respectively. The resulting weighted score is the scenario "rank". The scenario rank is the comparative value used to identify the performance of each scenario as compared to all other scenarios. Table 2-12 demonstrates the scenario rank across all base scenarios. A detailed overall scoring table is provided in Appendix II.E.

Table 2-12
Summary of Scenario Overall Ranking

Scenario	Weighted Quantitative Score	Weighted Qualitative Score	Total Combined Score	Rank
Reference (Scenario 1)	78.7%	16.1%	94.8%	4
Fuel Oil (Scenario 2)	80.0%	16.4%	96.4%	2
NG (Scenario 3)	76.9%	20.0%	96.9%	1
LPG (Scenario 4)	79.1%	16.6%	95.5%	3

In order to provide an indication regarding the sensitivity of the overall results to these weights, Table 2-13 provides alternative scenario rankings reflecting varying weighting factors for quantitative versus qualitative scoring, relative to the Base Scenario results. As shown below, the NG scenario scores at the top across all weights shown. Overall, the rankings are not particularly sensitive to the weights.

Table 2-13
Sensitivity of Overall Ranking to Weighting Factors

	Quantitative / Qualitative Weight			
Scenario	80/20	70/30	60/40	50/50
Reference (Scenario 1)	4	4	4	4
Fuel Oil (Scenario 2)	2	2	2	2
NG (Scenario 3)	1	1	1	1
LPG (Scenario 4)	3	3	3	2

2.6.2 Findings

Based on the totality of evaluations, assumptions, and dispatch analyses conducted for purposes of the IRP, the details of which should be reviewed carefully, the following is a list of findings and conclusions in the form of recommended actions and next steps relative to the results:

1. The top ranked scenario reflects NG conversion (Scenario 3) as well as renewables, DSM and BESS. While the NG scenario is more capital intensive than the other scenarios, it is less sensitive to increasing fuel commodity prices when compared to LPG or Fuel Oil scenarios. In addition, the NG scenario introduces the potential for NG to serve other uses in Bermuda via a piped distribution network.
2. The differential in levelized cost across the scenarios relates primarily to: (i) commodity price forecast for the candidate fuels; (ii) estimated cost of fuel transportation, storage and processing as necessary; and (iii) estimated capital and operating cost for candidate resources.
3. EE programs should be pursued and implemented to realize the efficiency projections that were estimated by an independent subject matter expert as factored into the Load Forecast.
4. Based on the qualitative performance of utility-scale solar, as well as the more advantageous cost estimated for utility-scale solar as compared to the residential solar thermal and commercial distributed PV options, Bermuda should continue to pursue utility scale solar resources to the extent suitable sites in addition to the one at the Airport Finger can be located.
5. As part of the evaluation of the Scenarios, CHP distributed generation utilizing a reciprocating engine was evaluated. The sizing of the generating unit was based upon the electric demand load requirements of a generic customer and the thermal recovery equipment sized to maximize the thermal energy of the exhaust for providing domestic hot water heating. The NG and LPG scenarios both included the use of CHP resources. Scenario specific studies should be performed to assess the full range of benefits this type of resource may provide.
6. With regard to the sensitivities performed, the following are the main implications of such additional scenarios:
    - Fuel Commodity Price Sensitivities: The high fuel commodity cost sensitivity resulted in Scenario 3 becoming the lowest cost and highest ranked scenario on a quantitative basis. For the low commodity cost sensitivity, the ranking remained unchanged from the base case ranking.
    - Custom's Duty Sensitivities: The base scenarios assume the Custom's Duty associated with LPG and NG will increase and be "normalized" at levels consistent with HFO in order to offset the Bermuda Government revenue losses associated with switching to NG or LPG. The "Non-Normalized" sensitivities for NG and LPG assume current duties remain effective throughout the Study Period. Under this sensitivity, the lower cost of NG results in scenario 3 becoming the lowest cost scenario. "Non-Normalized" LPG did not affect the scenario ranking due to the relatively lower consumption of LPG compared with NG.
    - Carbon Monetization Sensitivities: These sensitivities do not change the quantitative ranking of the three base scenarios due to the relatively low additional cost imposed by the monetization of carbon relative to the total

production costs except in the high Carbon Monetization sensitivity in which the NG scenario becomes the lowest cost due to the lower CO_2 emissions in that scenario.

- Based on the initial reliability analysis that measured LOLH for Scenarios 2 and 3 using 20 random forced outage draws, reliability in terms of LOLH is better than the industry standard of 2.4 hours per year in Scenario 3 and slightly worse than the standard for Scenario 2. The additional capacity and lower outage rates of units converted to NG improve reliability in Scenario 3. The analysis did not consider the variability of load and intermittent generation but does support the PRM levels used in the IRP.

2.7 Procurement Plan

2.7.1 Procurement Plan Overview

The IRP is dependent on the Authority's approval followed by the successful acquisition and integration of resources in accordance with the Preferred Plan. This 5-year procurement plan outlines a potential series of activities related to the procurement approach on a resource basis and the steps that can be followed as a function of the resources within the Preferred Plan as indicated by the entirety of the analyses comprising this IRP (LCOE screening, production cost modeling of scenarios, and qualitative evaluation).

2.7.2 Natural Gas Supply

In March 2016, Castalia Strategic Advisers completed the Viability of LNG in Bermuda report for the Bermuda Government. This report determined that it was feasible to develop a project to import bulk LNG and provide NG in the required volume to the Central Plant via a pipeline from an existing petroleum bulk storage facility in Bermuda. Capital and operating cost estimates for the associated facilities were used in developing the projected delivered cost of NG in the IRP.

The estimated duration for the development of the LNG offloading, storage and regasification facilities project is approximately 3.5 years from the commencement of front end engineering design ("FEED") activities. FEED activities should commence once a decision has been made to transition to NG, including the development of a detailed schedule of activities and project plan based on current information. BELCO is currently undertaking a Request for Proposal ("RFP") for LNG to assess the market pricing to validate previous feasibility reports for the delivered cost of NG.

2.7.3 Liquefied Petroleum Gas Supply

Under the LPG scenario, LPG would be delivered to Bermuda in bulk ocean tankers and stored at an existing petroleum products bulk storage facility. A detailed feasibility study has not been undertaken to develop a conceptual plan along with project development cost estimates. Should the decision be made to give this option further consideration, the first order of business would be to perform such a study.

2.7.4 Thermal Resources

With the planned addition of the NPS, no additional thermal resources are forecasted until 2031 and are subject to approval by the Authority.

2.7.5 Battery Energy Storage

BELCO engaged the services of an engineering consultant with subject matter expertise in BESS to facilitate the procurement of the battery system to serve as "spinning" reserve for the electric system instead of operating a thermal unit for that purpose. Additionally, a BESS for renewable support is contemplated. The procurement process for the BESS that will be installed as support for spinning reserve capacity include:

- Review information compiled by the BELCO working group
- Prepare BESS technical specifications and RFP package
- Prequalify bidders
- Facilitate RFP process
- Prepare proposal evaluation criteria
- Evaluation of proposals

The EPC contract execution period is estimated to be ten to twelve months. This process will be repeated for BESS to be installed for intermittent energy resource support.

2.7.6 Combined Heat & Power and Combined Cooling, Heat & Power

It is anticipated that investments in CHP facilities would be made by customers directly; however, BELCO may partner with customers if approved by the Authority.

2.7.7 Energy Efficiency and Energy Conservation/Demand Side Management

The typical activities that are necessary to support the development of an EE & EC/DSM Program Plan include the following:

- Identification of a Program Implementation Partner
- Data Gathering and Goal Refinement
- Demand Response System Interface Requirements (to the extent demand response is considered as a portfolio item)
- EE & EC/DSM Program Measure Assessment
- Funding Analysis
- Monitoring and Verification

- Additional Resources and Change Management Plan
- Communication & Stakeholder Engagement Activities
- Final Program Plan
- Ongoing Implementation Support

2.7.8 Distributed Solar PV

Residential and commercial solar PV should be acquired through customer-driven developments and utilize the Standard Contract, as defined in the EA 2016, should the system size fall below the licence threshold as determined by the Minister responsible for energy.

2.7.9 Utility Scale Solar PV

The procurement and negotiation of a PPA for utility scale solar PV, should generally comprise the following key activities:

- A Request for Information ("RFI") or equivalent outreach process should be engaged that will help BELCO TD&R identify interested potential bidders to the RFP process. This RFI will afford BELCO TD&R and other stakeholders the opportunity to raise several high level questions that can help filter out credible bidders based on their responses to technical, logistical, siting, and financial terms and conditions that would need to be considered when negotiating an actual contract for output.

- A technical specification should be developed that highlights the available and/or preferred siting and other key technical nuances related to third party construction that falls outside of the terms and conditions of the PPA arrangement.

- A PPA template will be prepared that outlines BELCO TD&R's preferred terms and conditions for pricing and scheduling of energy delivery, as well as the key legal and financial terms and conditions associated with the agreement, including damages in the event of default, force majeure conditions, and all other standard terms and conditions. Starting with a PPA template will help bidders understand how they can best align their products and pricing with the desired terms, and is a relatively standard approach to procurement. While this is not a guarantee that the ultimate terms will completely align with the template, it will serve as an appropriate starting point for discussions.

- A detailed RFP document should be prepared that includes such information as: desired timelines for project delivery; detailed bid forms; the aforementioned draft PPA template, as well as any other terms and conditions related to communications; questions related to the RFP; the availability or possibility of pre-bid meetings; and the desired path towards interviews with potential proponents (if deemed necessary).

- The RFP responses should then be reviewed for completeness and compliance. Typically, minimum compliance standards related to the documentation provided as requested in the RFP as well as the criteria for a complete and credible bid may result in certain bids being deemed non-responsive. BELCO TD&R can reserve the right to engage in follow-up questions with bidders as part of the evaluation process. In parallel, the RFP responses can be reviewed based on evaluation criteria (which are likely to extend beyond mere pricing considerations and should carefully evaluate bidder credibility and ability to deliver on promised outcomes based on a holistic evaluation). The evaluation criteria may or may not be specified to bidders as part of the RFP submittal.

A general timeline for the procurement process is estimated to be six months, with the actual contract negotiation and execution phase taking no more than an additional 12 months.