REGULATORY AUTHORITY
OF BERMUDA

Integrated Resource Plan (IRP) Proposal Invitation to Comment

Invitation to Comment Document
Matter Number: 20240729
Date: 29 July 2024
Responses Due: 30 September 2024

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I. INTRODUCTION

1. The purpose of this Invitation to Comment Document is for the Regulatory Authority of Bermuda (the **RA**) to: (i) invite comments on the Integrated Resource Plan (**IRP**) Proposal submitted by the Transmission, Distribution and Retail Licensee (**TD&R Licensee**), set forth in Appendix A; and (ii) request submission of proposals for bulk generation or demand side resources.

2. The RA is responsible for the regulation of the electricity sector in Bermuda and its overarching responsibilities are to:

    - regulate tariffs and the quality-of-service provision to end-users;
    - ensure that access to electricity infrastructure by current and prospective generators in Bermuda is transparent, fair, reasonable, and non-discriminatory;
    - investigate and respond to complaints from end-users as regards the provision of electricity.

3. Section 40(1) of the Electricity Act (**EA**) requires the RA to request that the TD&R Licensee prepares an IRP Proposal within two years of the commencement of the EA, and every five years or less.

4. For the first IRP, the RA issued the respective Notice of Request for the IRP Proposal (the **Notice**) on the 17 November 2017, which required the TD&R Licensee to submit an IRP Proposal by 17 February 2018. The TD&R Licensee then submitted its IRP Proposal on the 15 February 2018.

5. As per Section 42, the RA shall publish the IRP Proposal for public comment and request submissions of proposals for bulk generation or demand side resources, upon acceptance of the IRP Proposal by the RA.

6. The RA published the Consultation Document on 2 May 2018, which closed on 2 July 2018.

7. After review of responses and consideration of alternative proposals, the RA published its first IRP on 30 June 2019.

8. Since the last IRP was published in 2019, and as Section 40(1) of the EA requires the RA to request the TD&R to prepare an IRP Proposal every five years or less, the RA issued the Notice of Request with IRP Guidelines to the TD&R Licensee on 17 November 2022. This request required the TD&R Licensee to submit an IRP Proposal to the RA by 17 November 2023.

9. The TD&R Licensee submitted its IRP Proposal to the RA on the 17 November 2023.

10. Thereafter, the RA reviewed the IRP Proposal and provided feedback to the TD&R Licensee to improve the alignment between the IRP Proposal and the Notice and Guidelines provided by the RA. The TD&R Licensee considered the feedback and resubmitted their IRP Proposal on 19 March 2024, and thereafter, on 9 May 2024.

11. Now, the RA is issuing this Invitation to Comment Document, in line with Section 42 of the EA, to (i) consult on the IRP Proposal submitted by the TD&R Licensee, set forth in Appendix A; and (ii) request submissions of proposals for bulk generation or demand side resources. The IRP Proposal set forth in Appendix A is published on the RA's website in accordance with the EA. However, the publication of the IRP Proposal, prepared by the TD&R Licensee, does not constitute an endorsement by the RA of the IRP Proposal.

12. The Invitation to Comment Document is structured as follows:

    a. Chapter II outlines the process for public engagement on the IRP Proposal and submission of Alternative Proposals;

    b. Chapter III discusses the next steps;

    c. Chapter VI lists the consultation questions;

    d. Appendix A provides the IRP Proposal;

    e. Appendix B provides the RA's assessment of the TD&R Licensee's IRP Proposal;

    f. Appendix C outlines IRP Proposal Notice and Guidance.

    g. Appendix D outlines the procedure, sets out the legislative context and , discusses the background.

    h. Appendix E provides a list of the main definitions.

II. IRP PROPOSAL AND REQUEST FOR ALTERNATIVE PROPOSALS

13. This section outlines the process for the public engagement on the IRP Proposal and submission of Alternative Proposals.

II.1 IRP Proposal

14. The IRP Proposal is published on the RA's official website in accordance with the EA. However, the publication of the IRP Proposal, prepared by the TD&R Licensee, does not constitute an endorsement by the RA of the IRP Proposal.

15. The EA requires the IRP Proposal to contain (i) a resource plan that includes the expected demand for the IRP Period and the state of the TD&R Licensee's existing resources; and (ii) a procurement plan that details how the TD&R Licensee proposes to meet the demand.[1] The IRP Proposal must also comply with the Notice and the Guidelines Order and meet the requirements set forth in Section 40 of the EA.

16. In preparing the IRP Proposal, the TD&R Licensee should consider (i) all possible resources, including new generation capacity, demand side resources (including demand response and energy efficiency), and retirement of generation capacity; and (ii) a range of renewable energy and efficient generation options, and a prudent diversification of the generation portfolio.[2] The IRP Proposal should also (i) prioritise actions that most meet the purposes of the EA, conform to Ministerial directions, and be reasonably likely to supply electricity at the least cost, subject to trade-offs contained in the Ministerial directions or instructions from the RA; (ii) include recommendations on whether any resources should be procured through competitive bidding; and (iii) propose limits for total distributed generation capacity over the planning period.[3]

17. The Proposal Requirements provided the guidelines on what is expected to be included in the IRP Proposal to ensure that the RA is able to meet its obligations under the EA.

18. After assessing the IRP Proposal's compliance with the Proposal Requirements and accepting the IRP Proposal, the RA is required to publish the IRP Proposal for public consultation.

19. The RA's assessment of the TD&R Licensee's IRP Proposal can be found in Appendix B, which highlights some differences with the high-level independent analysis conducted. Nevertheless, the RA has accepted the IRP Proposal for public consultation to understand the public's opinion on the Proposal.

20. While the RA has accepted the IRP Proposal for public consultation, it will, concurrent with this Invitation to Comment Document, undertake a further detailed analysis of the IRP Proposal to

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[1] Electricity Act 2016, Section 40(1)
[2] Electricity Act 2016, Section 40(2)(a)
[3] Electricity Act 2016, Section 40(2)(b)-(d)

determine whether the proposal represents the capacity expansion plan that best balances the different priorities for the electricity market of Bermuda.

21. The RA welcomes comments from the public on the IRP Proposal submitted by the TD&R Licensee.

Box 1: Questions regarding the IRP Proposal

- *Q1: Do you have any concerns with the IRP Proposal? Please elaborate, provide reasoning and evidence in your answer.*
- *Q2: The table below provides a list of the technologies, and respective capacities, installed in the TD&R's preferred scenario in 2050. Please complete the table below and comment on whether you believe each of the projects should be competitively procured or not with a justification.*

Projects in the TD&R's preferred scenario in 2050	Procurement strategy (competitively procured or not?)	Justification
20MW of biomass		
60MW of offshore wind		
20MW of onshore solar		
70MW of floating solar		
260MW of battery storage		

- *Q3: To select a preferred scenario, it is important to balance and consider different priorities for the electricity sector in Bermuda. Therefore, could you please rank the metrics in the table below, from most important to least important to consider (i.e. where 1 = most important and 6 = least important).*

Metric	Ranking (1-6)
Compound annual electricity rate growth (annual % over the next 20 years)	
Carbon emission reductions in 2050, relative to 2025 (%)	
Renewable energy generation of total energy requirements (including self-generation) in 2050 (%)	
Dispatchable capacity of total installed capacity in 2050 (%)	
Resource diversity in 2050	

Operational risks[4]	

- *Q4: Are there any other metrics that you think should be added and considered under Q3? Please justify your response and provide a new ranking considering the additions.*
- *Q5: Do you agree with the generation technologies, and relative assumptions, considered in the IRP Proposal? Please justify your answer.*

II.2 Alternative Proposals

22. The RA also invites interested parties to provide their views on alternative scenarios that should be considered in the IRP, as well as any other aspect of the assumptions, assessment methodology, and conclusions set out by the TD&R Licensee. These alternatives may provide for an electricity generation mix that is more consistent with the purposes of the EA (e.g. least-cost provision of reliable electricity).

23. In particular, this Invitation to Comment Document requests submissions of detailed proposals for bulk generation or demand side resources for potential inclusion in the IRP. The Alternative Proposal should demonstrate (i) how its inclusion in the IRP would result in an electricity supply that is more consistent with the purposes of the EA and Ministerial directions; and (ii) how it uses technology that is in commercial operation in another jurisdiction.

Box 2: Questions regarding Alternative Proposals

- *Q6: Do you have any additional views on the assumptions, assessment methodology, and conclusions set out in the IRP Proposal? Please justify your answer and provide alternative assumptions if you disagree with any of the assumptions with accompanied reasoning.*
- *Q7: Do you have any Alternative Proposals for bulk generation or demand side resources that should be considered in the IRP? Please provide details and demonstrate points raised in paragraph 56.*

[4] Operation risk is meant to reflect the risks associated with potentially running engines at less optimal conditions, in particular due to higher renewable generation (e.g. more frequent start-ups and shut downs, etc). This could potentially lead to higher operating and maintenance costs, higher emissions, etc.

III. NEXT STEPS IN THE IRP PROCESS

24. The RA will hold at least one public consultation for every Alternative Proposal received before the deadline set forth in this Invitation to Comment Document, whether alone or together with other Alternative Proposals. The RA will also hold as many meetings as it deems necessary with the proponent of each Alternative Proposal, the TD&R Licensee and any other persons that the RA considers relevant in order to assess the Alternative Proposals.

25. The RA will, concurrent with this consultation, undertake a further detailed analysis of the IRP Proposal in order to determine whether the proposal best balances the different priorities for the electricity market of Bermuda.

26. The TD&R Licensee will then prepare a draft final IRP (**Draft IRP**) for the review and approval of the RA. The Draft IRP will take any public comments and Alternative Proposals into consideration and will implement any comments of the RA.

27. The RA will review the Draft IRP and may approve it if, acting in accordance with regulatory principles and any administrative determinations, the RA considers the Draft IRP to be the best approach to meeting the purposes of the EA and complying with any Ministerial directions. This may be an iterative process, as the RA may require the TD&R Licensee to modify the Draft IRP until it is in a form that can meet the RA's approval.

28. The RA will then publish the approved IRP on its official website.

IV. QUESTIONS

29. Interested parties are invited to comment on the IRP Proposal from the TD&R Licensee, in particular in relation to the following questions:

Box 3: Considerations pertaining to the IRP Proposal and Alternative Proposals

- *Q1: Do you have any concerns with the IRP Proposal? Please elaborate, provide reasoning and evidence in your answer.*
- *Q2: The table below provides a list of the technologies, and respective capacities, installed in the TD&R's preferred scenario in 2050. Please complete the table below and comment on whether you believe each of the projects should be competitively procured or not with a justification.*

Projects in the TD&R's preferred scenario in 2050	Procurement strategy (competitively procured or not?)	Justification
20MW of biomass		
60MW of offshore wind		
20MW of onshore solar		
70MW of floating solar		
260MW of battery storage		

- *Q3: To select a preferred scenario, it is important to balance and consider different priorities for the electricity sector in Bermuda. Therefore, could you please rank the metrics in the table below, from most important to least important to consider (i.e. where 1 = most important and 6 = least important).*

Metric	Ranking (1-6)
Compound annual electricity rate growth (annual % over the next 20 years)	
Carbon emission reductions in 2050, relative to 2025 (%)	
Renewable energy generation of total energy requirements (including self-generation) in 2050 (%)	
Dispatchable capacity of total installed capacity in 2050 (%)	
Resource diversity in 2050	

Operational risks[5]	

- *Q4: Are there any other metrics that you think should be added and considered under Q3? Please justify your response and provide a new ranking considering the additions.*
- *Q5: Do you agree with the generation technologies, and relative assumptions, considered in the IRP Proposal? Please justify your answer.*
- *Q6: Do you have any additional views on the assumptions, assessment methodology, and conclusions set out in the IRP Proposal? Please justify your answer and provide alternative assumptions if you disagree with any of the assumptions with accompanied reasoning.*
- *Q7: Do you have any Alternative Proposals for bulk generation or demand side resources that should be considered in the IRP? Please provide details and demonstrate points raised in paragraph 56.*

[5] Operation risk is meant to reflect the risks associated with potentially running engines at less optimal conditions, in particular due to higher renewable generation (e.g. more frequent start-ups and shut downs, etc). This could potentially lead to higher operating and maintenance costs, higher emissions, etc.

APPENDIX A: BELCO'S IRP PROPOSAL

30. The document linked below contains BELCO's IRP Proposal:

    a. BELCO's IRP Proposal

2023 Integrated Resource Plan Proposal

Submitted: 17 November 2023

Revised: 9 May 2024

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Table of Acronyms

AEO	Annual Energy Outlook
AFUDC	Allowance for Funds Used During Construction
BAU	Business as Usual
BELCO	Bermuda Electric Light Company Limited
BELCO BG	BELCO in its capacity as a holder of a Bulk Generation Licence
BG	Bulk Generation
BESS	Battery Energy Storage System
BFB	Bubbling Fluidized Bed
BTM	Behind-the-meter
BTU	British Thermal Unit
CAGR	Compound Annual Growth Rate
CapEx	Capital Expenditure
CF	Capacity Factor
CO_2	Carbon Dioxide
C.O.D.	Commercial Operation Date
CRA	Charles River Associates (IRP Consultants)
CT	Combustion Turbine
DER	Distributed Energy Resource
DLC	Direct Load Control
DOE	Department of Energy
DR	Demand Response
DSM	Demand-side Management
EA	Electricity Act 2016
EE	Energy Efficiency
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capability
EPS	East Power Station
EV	Electric Vehicle
GIVE	Greenhouse Gas Impact Value Estimator
GDP	Gross Domestic Product
HCP	High Commodity Price
HFO	Heavy Fuel Oil
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Installed Capacity
IRP	Integrated Resource Plan
IRP Proposal	Integrated Resource Plan Proposal
ISO	International Organization for Standardization

LCE	Life Cycle Extension
LCOE	Levelised Cost of Electricity/Energy
LCU	Life Cycle Upgrade
LFO	Light Fuel Oil
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LOLE	Loss of Load Expectation
LOLEv	Loss of Load Events
NESP	National Electricity Sector Policy 2015
NFP	National Fuels Policy 2018
NGCT	Natural Gas Combustion Turbine
NPS	North Power Station
NPV	Net Present Value
NPVRR	Net Present Value of Revenue Requirements
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OpEx	Operational Expenditures
OSW	Offshore Wind
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PV	Photovoltaic
RA	Regulatory Authority
RA Guidance	Regulatory Authority's Integrated Resource Plan (IRP) Proposal Guidance
REF	Reference Scenario
RET	Renewable Energy Target
RFF	Resources For the Future
SCC	Social Cost of Carbon
SDR	Social Discount Rate
T&D	Transmission and Distribution
TDD	Technology Driven Decarbonisation
TD&R	Transmission, Distribution, and Retail
TD&R	BELCO in its capacity as the sole holder of a Transmission, Distribution,
TRN	Total Reliability Need
TMY	Typical Meteorological Year
UCAP	Unforced Capacity
VOM	Variable Operating and Maintenance

1. Executive Summary

This 2023 Integrated Resource Plan Proposal (IRP Proposal), prepared by the Transmission, Distribution and Retail (TD&R) Licensee, provides an update to the energy plan for the supply of electricity in Bermuda that best meets a range of legislative, regulatory, sectoral policy and external drivers and seeks to continue to transition Bermuda's electricity supply toward a balanced portfolio that is affordable, reliable, and sustainable. Today, electricity in Bermuda is largely generated by resources burning fuel oil leading to a very reliable supply, however it is vulnerable to global fuel prices and has a high carbon intensity. This IRP Proposal identifies resource plans that maintain the high level of reliability the country has become accustomed to whilst balancing affordability and sustainability.

To do so, this IRP Proposal explores a set of supply-side and demand-side options for Bermuda's evolving resource portfolio through 2043 and beyond to 2050. The supply-side options included a combination of renewable energy, storage, and thermal technologies. The demand-side options included energy efficiency, demand side management, and distributed energy resources. Portfolios were evaluated for their performance against a range of scorecard objectives. The preferred portfolio achieves an 82 percent reduction in carbon emissions by 2043 and includes near-term investments in solar, storage, and offshore wind. This portfolio was chosen for its ability to support system reliability while charting a sustainable path forward at a reasonable cost.

1.1. Bermuda's Electricity System

The TD&R Licensee transmits and distributes electricity to more than 36,000 customers in Bermuda. Bermuda Electric Light Company Limited (BELCO) is the sole holder of the TD&R licence on the island and is also licensed to supply bulk generation (BG). The TD&R Licensee supplies its customers with energy from a set of BELCO-owned and third-party power generation resources. BELCO's central power station, located in Pembroke, includes a mix of reciprocating engines and gas turbines running on fuel oil with a total nameplate capacity of 141.3 megawatts (MW). Additionally, the TD&R Licensee contracts a small amount of energy and capacity from a solar plant and waste-to-energy (WTE) facility via power purchase agreements (PPAs).

1.2. IRP Proposal Objectives

This IRP Proposal developed a variety of resource portfolios with many renewable energy options coupled with new fuel strategies for the existing thermal fleet. The preferred portfolio is objectively selected using a scorecard that reflects the purposes of the Electricity Act 2016 (EA), the Regulatory Authority's Integrated Resource Plan (IRP) Proposal Guidance (RA Guidance), consideration of the objectives in the National Electricity Sector Policy 2015 (NESP) and consideration of goals of the National Fuels Policy 2018 (NFP).

The EA purposes, objectives of the NESP, goals of the NFP and the RA Guidance were used to develop scorecard objectives to assess the portfolios. These scorecard objectives are described below:

- **Customer Affordability** – represents in aggregate, the system costs over the planning period, considering the time value of money. The costs may be passed down to customers, so lower overall portfolio costs lead to lower overall rates.
- **Rate Stability** – represents the range of possible portfolio costs given several future states of the world. Lower values for these metrics represent lower overall portfolio cost risk, thereby reducing customer exposure to future cost disruptions.
- **Environmental Stewardship** – is defined by the carbon reductions from 2022 emissions. This metric evaluates how close Bermuda is to meeting its renewable energy targets.
- **Resource Adequacy** – is defined as the amount of dispatchable capacity to ensure the system is always capable of meeting demand.
- **Resource Diversity** – is defined using the Herfindahl–Hirschman index (HHI) and is calculated by weighing the shares of different types of resources with their overall system capacity. This metric highlights the ability of the grid to diversify its resources and hedge against risks associated with supply chain issues.
- **Minimise Curtailment** – is defined by how much renewable energy is not being used when it produces energy. This metric is important to understand whether the system has optimized its generation capabilities and if it can accommodate the generation from these resources.

- **Land Use** – is defined by the total acreage to accommodate the different resource buildouts. Since Bermuda is land-constrained, offshore resources were necessary to supplement load when existing engines come offline.
- **Executional Risk** – is defined by risks associated with infrastructure, stranded assets, and public sentiment. This metric is a qualitative evaluation of different portfolio components that may delay buildout.

1.3. Portfolio Options and Modelling

The portfolio options evaluate pathways toward a balanced energy mix that is affordable, reliable, and sustainable. This IRP Proposal evaluates 11 portfolios to determine how cleaner technologies can significantly lower emissions at a reasonable cost, whilst maintaining reliability. Based on existing infrastructure the portfolios are separated into four fuel strategies:

1. Current fuel strategy
2. Switch to LFO with a 10-year Life Cycle Extension
3. Switch to LFO with a 30-year Life Cycle Upgrade
4. Switch to LNG with a 30-year Life Cycle Upgrade

All four fuel strategies are evaluated against an economic target to minimise the cost to customers. The fuel strategies that switch fuel types and have life cycle extensions and upgrades are also used to evaluate sustainability improvements such as renewable energy penetration and decarbonisation. The sustainability improvements were driven by setting two targets, 85 percent of renewable energy generation by 2040 and Net Zero by 2050. The Net Zero target was evaluated to better understand the required glide paths to any future decarbonisation targets, and make sure that decisions to 2040 were not short sighted of potential policy changes such as a requirement to be Net Zero by 2050.

Figure 1 illustrates how the portfolio options were selected to evaluate a range of economic and decarbonisation targets for a variety of fuel strategies. For a given fuel strategy, a modelling simulation that optimised portfolio additions and retirements subject to a sustainability or economic target was run and compared to current fuel strategy portfolios P1 (stay the course) and P2F (economic).

Figure 1: Portfolio Analysis Approach

Fuel Strategies	Economic & Decarbonisation Targets: Stay the Course	Economic	85% RET by 2040	Net Zero by 2050
Current fuel strategy	P1	P2F	-	-
Switch to LFO with a 10-year Life Cycle Extension	-	P2L	P4L	P5L
Switch to LFO with a 30-year Life Cycle Upgrade	-	P2LL	P4LL	P5LL
Switch to LNG with a 30-year Life Cycle Upgrade	-	P2N	P4N	P5N

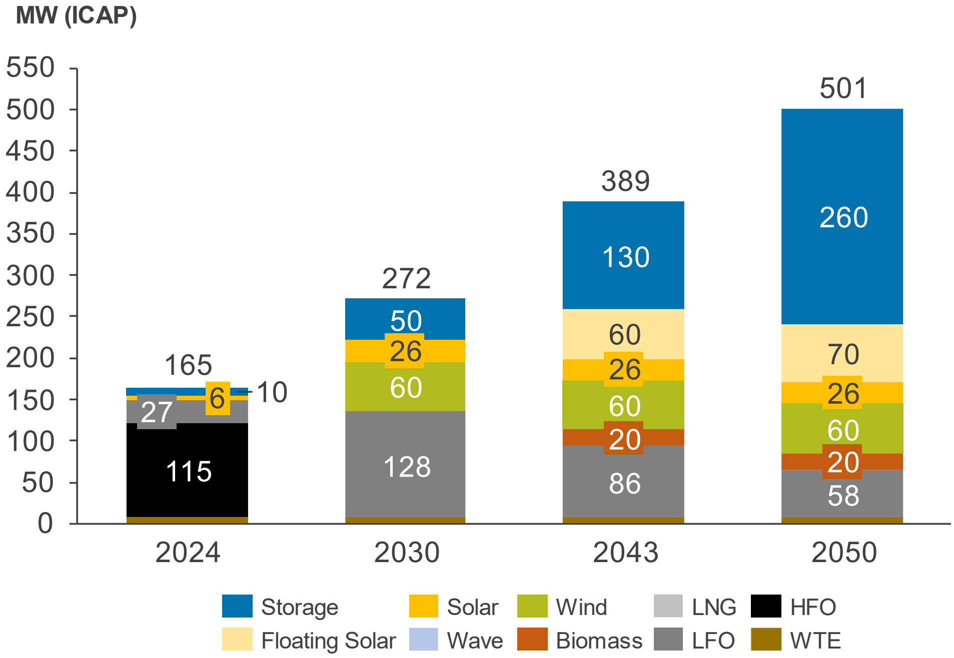
1.4. Preferred Portfolio

The preferred portfolio, P4L (highlighted above), achieves an 82 percent carbon emissions reduction by 2043 and includes near-term investments in solar, storage, and offshore wind. This portfolio supports system reliability whilst pursuing a more sustainable path at a reasonable cost to customers.

Within the five-year procurement window, the portfolio installs wind, solar, and storage to reduce CO_2 emissions by 52 percent by 2030. The portfolio requires a fuel switch from Heavy Fuel Oil (HFO) to Light Fuel Oil (LFO) and a 10-year life cycle extension (LCE) of the East Power Station (EPS) engines. The LCE is possible due to the reduced run hours of baseload generation as more renewable energy comes online. A replacement gas turbine (GT) is also required within the procurement window to meet contingency reserve requirements.

To further reduce CO_2 emissions beyond the procurement window, the portfolio installs more solar and storage, and requires energy production from floating solar and a dispatchable renewable resource such as biomass.

Figure 2: Preferred Portfolio P4L Installed Capacity (ICAP) (MW)



The preferred portfolio significantly decarbonises Bermuda's generation resources without significant increases in customer rates compared to other portfolios. The portfolio achieves 85 percent renewable energy by 2040 and reduces carbon emissions by 82 percent by 2043 when compared to 2022 levels. To achieve this decarbonisation, customer rates increase at a 4.7 percent compound annual growth rate (CAGR) over the 20-year forecast period, which includes inflation. The portfolio is also easier to implement compared to other carbon-constrained portfolios and does not require engine upgrades at the EPS.

1.5. Near Term Actions

The following actions comprise the key outputs of the IRP Proposal. The procurement window actions can be expected to be executed by 2030. The longer-term strategy will evolve based on how market conditions change in the near term.

- **Life cycle extension (LCE) of the EPS:** Perform a LCE on the EPS engines which are set to retire in 2030 (E5 and E6) and 2035 (E7 and E8). The preferred portfolio assumes a 10-yr life extension of these engines to ensure that sufficient baseload capacity exists. With the extension, the EPS engines will operate until 2040 for E5 and E6 and 2045 for E7 and E8. The extension will not require any additional capital expenditures (CapEx) and is a result of reduced operation with greater renewable generation.

- **Retire and replace GT5:** Retire GT5 at the end of 2025. The TD&R Licensee relies on this resource for contingency reserves. The IRP Proposal recommends commissioning a replacement of this gas turbine in 2026 to continue providing reserves and to support resiliency.
- **Bring new renewable energy resources and storage online:** To reduce carbon emissions and invest in clean generation early, the IRP Proposal recommends that the following resources be built in the procurement window (Figure 3):

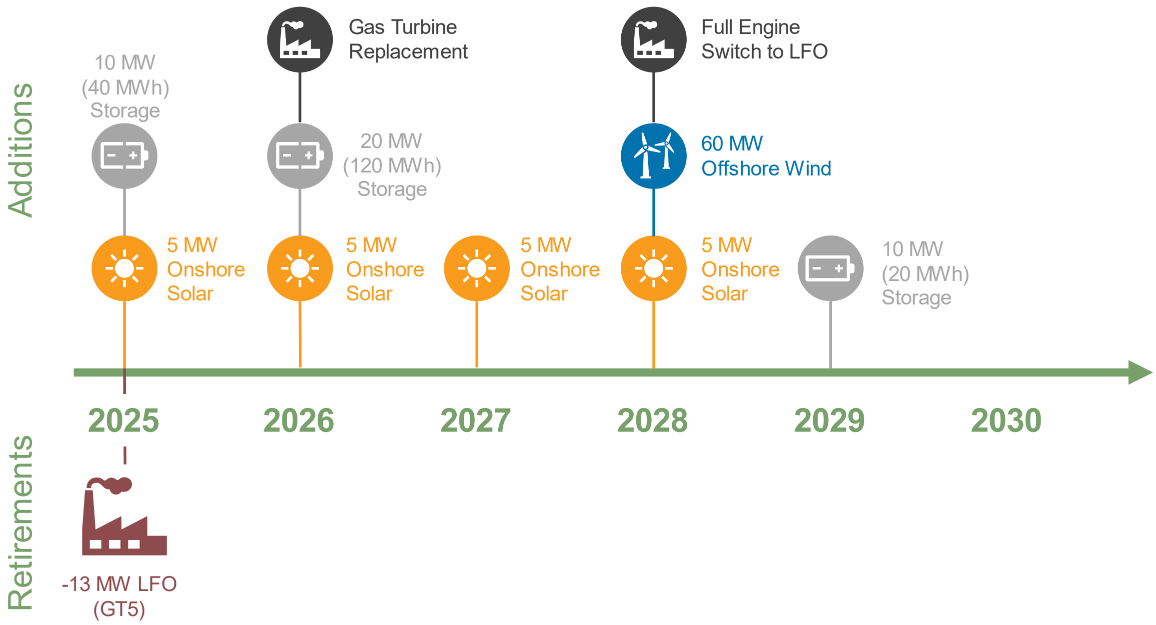
– 20 MW of Onshore Solar

– 60 MW of OSW

– 40 MW, 180MWh of Storage

To complete the near-term buildouts on schedule, permitting and procurement processes for the new builds must commence as soon as possible. For example, to build 60 MW of Offshore Wind (OSW) in 2028, the wind resource characterisation study should be commissioned as soon as possible.

Figure 3. Procurement Window Builds and Retirements[1]



[1] GT5 is replaced in 2026 but has no capacity credit. It is being solely built to support contingency reserves.

- **Integration of behind-the-meter (BTM) solar resources:** Monitor the build-out of customer-sited solar, which could total 21 MW_{AC} by 2030. The TD&R Licensee should perform a distribution hosting capacity analysis to ensure that adequate distribution capacity is available to support the integration of distributed solar. It is also recommended to consider developing funding mechanisms to improve the hosting capacity of the distribution network and preparing for system impacts through more flexible generation.
- **Grid impact analysis:** As Bermuda's resource mix transitions to a mix with less synchronous generation capacity, the TD&R Licensee should evaluate what additional resources or grid improvements will be required to address steady state criteria violations and maintain grid stability.
- **Facilitate energy efficiency (EE) programme implementation:** The IRP Proposal analysis found that EE programmes have significant impacts on decreasing the overall demand. However, the TD&R Licensee does not currently have any existing programmes. The IRP Proposal recommends 29 measures in Section 6 that can be implemented between 2025 through 2037. This requires a new way of operating Bermuda's grid, including potential upgrades of technology, dedicated staff to optimally create the programmes, and customer training and outreach.
- **Analyse demand response programmes:** The TD&R Licensee should perform additional analyses of demand response programmes and gain experience in conducting such programmes. The TD&R Licensee may want to collect and assess market characterisation data to have more complete information upon which to estimate costs and savings.
- **Plan for longer term new resource builds:** Adhering to the timeline laid out in this IRP Proposal is important to reducing emissions. Continued analysis of market changes will be required as medium term (2030-2040) build plans are assessed.
- **Plan for a clean, dispatchable resource:** It is clear from this IRP Proposal that a clean, dispatchable resource will be necessary for the retirement of thermal units and to reach Net Zero. In this IRP Proposal, biomass with a maximum of 20MW is modelled to represent such a dispatchable resource. This resource is recommended to be built in the 2030s. It is recommended that further studies are completed that continue to evaluate emergent technologies such as green hydrogen.

1.6. Signposts and Pivot Strategies

Given significant future uncertainty in many of the key drivers of the portfolio analysis, including technology costs, commodity costs, customer loads, and government policies, Bermuda must be positioned to pivot its resource strategy. A major component of the preferred portfolio is OSW, which is expected to be in service by 2028. If headwinds are faced in the pursuit of OSW, one alternative strategy as shown in

Table 1 is to pivot to an LNG strategy. Similarly, if battery implementation is challenged, flexible peaking technology using hydrogen could be a potential solution.

Table 1. Signposts for Pivot Strategies

Signpost	Strategy
Headwinds against the development of offshore wind projects	Consider an LNG strategy to get closer to carbon targets
LFO commodity costs increase materially	Explore fuel price hedging mechanisms
Headwinds against the development of onshore solar projects	Pivot to floating solar when technically feasible
Floating solar technology matures more rapidly than expected	Reevaluate the earliest commissioning date of floating solar
Floating solar decreases in CapEx and/or OpEx	Reevaluate the capacity expansion offering solar at lower costs
Inverter based technology is challenged to provide adequate virtual inertia	Limit buildout of battery energy storage and invest in flexible gas turbines with the option to burn hydrogen or biofuels in the future
Hydrogen technologies mature in cost and become more widely available	Consider building new gas turbines running on green hydrogen and scale back on battery energy storage deployment
Biomass cannot be permitted	Explore the use of an alternative clean dispatchable resource or cleaner fuels in the EPS, NPS or new gas turbines

2. Introduction

The 2023 IRP Proposal for BELCO identifies the amount, timing, and type of supply- and demand-side resources required to ensure affordable and reliable energy for Bermuda. The EA requires the Regulatory Authority (RA) to request an IRP Proposal from BELCO as TD&R Licensee at least every five years that contains "a resource plan that includes the expected demand for the period and the state of the TD&R Licensee's existing resources; and a procurement plan that details how the Licensee proposes to meet this demand." The RA Guidance reflects established practices and precedents for the development of IRPs and similar capacity planning exercises seen in relevant regulatory jurisdictions.

The TD&R Licensee participated in an invitation to comment on preliminary RA Guidance issued by the RA on 16 July 2021. The final 2023 RA Guidance annexed to the Notice from the RA requesting the proposal was published on 17 November 2022, that gave the TD&R Licensee one year to submit this IRP Proposal. Although the EA requires a deadline of no greater than 90 days, on 16 November 2022, the Minister of Home Affairs issued a Direction extending the deadline to 17 November 2023.[2] This IRP Proposal represents a significant step forward in developing a long-range plan for the island.

The TD&R Licensee engaged Charles River Associates (CRA), an international economic and management consulting firm, with extensive capabilities in integrated resource planning, to help develop the IRP Proposal. CRA's experts possess deep energy sector expertise and experience working with North American and island-based utilities on integrated resource planning. More information on CRA's energy practice and experience can be found in Appendix A.

CRA worked closely with the TD&R Licensee to help frame, develop, and communicate the IRP Proposal. CRA brought extensive capabilities in developing scenarios and modelling resource options within Aurora, an Energy Exemplar software for capacity expansion modelling of energy portfolios.[3] CRA also brought extensive capabilities in forecasting financial metrics and customer rates with their revenue requirement model. BELCO contributed information on key input assumptions, coupled with information gathered from the engagement of other stakeholders within the renewable energy sector.

2 https://www.gov.bm/theofficialgazette/notices/gn10712022
3 https://www.energyexemplar.com/aurora

This report is organised as follows:

- **Section 3** provides an overview of Bermuda and its challenges as an island jurisdiction.
- **Section 4** lays out the key objectives of the IRP Proposal.
- **Section 5** presents a summary of the expected demand and how it is impacted by different factors.
- **Section 6** presents a summary of demand-side resources that Bermuda may use to impact future load.
- **Section 7** presents a summary of Bermuda's existing supply resources and the supply-demand outlook.
- **Section 8** describes the key planning assumptions to assess the reliability of the system.
- **Section 9** describes the setup of Bermuda's resources in the model.
- **Section 10** provides a detailed summary of the scenario development process, including an overview of the major scenario concepts and documentation of key assumptions and modelling outcomes.
- **Section 11** provides a summary of the portfolio development process, which includes the identification of major resource alternatives and a series of analyses to identify portfolio options for Bermuda.
- **Section 12** presents the portfolio analysis in support of the preferred plan selected by the TD&R Licensee and the near-term portfolio decisions.
- **Section 13** assesses the risks associated with the portfolios developed.
- **Section 14** provides an overview of the financial treatment of existing and new resources and the financial impacts on ratepayers for each portfolio produced by modelling.
- **Section 0** provides the high-level scenario and sensitivity results commenting on future uncertainties.
- **Section 0** presents a summary of the overall conclusions and recommendations including considerations for future IRP proposals.

This IRP Proposal covers the processes, assumptions, results, and provides recommendations. The results are based on the best available information at the time of preparation, but changes that may affect its results can, and will occur without notice. Therefore, commitments to specific resources and actions remain subject to further review and consideration.

3. BELCO Overview

BELCO was formed in 1904 and today generates, transmits, and distributes electricity to more than 36,000 customers in Bermuda. BELCO is a wholly owned subsidiary of Liberty Group Limited, an Algonquin Power & Utilities Corp. company.

3.1. BELCO Electricity Grid

BELCO's electricity grid comprises more than 250 miles of underground cables and 900 miles of overhead distribution lines that deliver electricity from the generating sources to over 36,000 metered connections.

The TD&R Licensee currently supplies power to its customers from a set of BELCO-owned and third party-owned power generation resources. A central power station has a mix of reciprocating engines and gas turbines running on fuel oil. The NPS and EPS make up 114.8 MW of generation capacity. This capacity consists of eight (8) baseload reciprocating engines with four (4) dual-fuel fired engines (NPS) and four (4) fuel-oil fired engines (EPS). The four gas turbines running on LFO make up 26.5 MW of added capacity. BELCO also owns and operates a 10 MW, 5.5 MWh lithium-ion battery.

The TD&R Licensee also purchases energy from the 6 MW Solar Plant known as "The Finger" and the 7.3 MW Tynes Bay WTE facility. There is also approximately 11 MW_{AC} of BTM solar capacity on the island (as of October 2023). More information on existing resources can be found in Section 7.1.

3.2. Island System Challenges

Island electric systems like Bermuda's must ensure customers are reliably served by electric generating resources that are present on or near the island. Unlike many mainland systems, island systems cannot rely on a vast and diverse network of interconnected resources to maintain reliability. In this light, resource planning takes on a critical importance for a system like Bermuda's.

Bermuda also faces challenges related to the island's land constraints. Because Bermuda is approximately 21 square miles with much of the island populated, acreage for new-generation development is limited. Moreover, Bermuda faces the challenge of a supply chain that can be slowed or disrupted. If fuel or critical materials are delayed for instance, Bermuda can face energy supply risks.

4. IRP Proposal Framework

The IRP Proposal studies how Bermuda can reliably, sustainably**,** and affordably meet the future electrical demand required of its people. The TD&R Licensee developed a "scorecard" to determine how alternative portfolios performed. The scorecard objectives were developed to meet the purposes of the EA, consider the NESP objectives, and consider the NFP goals as per the RA Guidance.

The Electricity Act 2016

The IRP Proposal seeks a future energy plan that aligns with the purposes set forth in section 6 of the EA which are to seek:

- to ensure the adequacy, safety, sustainability and reliability of electricity supply in Bermuda so that Bermuda continues to be well positioned to compete in the international business and global tourism markets;
- to encourage electricity conservation and the efficient use of electricity;
- to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources;
- to promote and encourage innovation in the electricity sector;
- to provide sectoral participants and end-users with non-discriminatory interconnection to transmission and distribution systems;
- to protect the interests of end-users with respect to prices and affordability, and the adequacy, reliability and quality of electricity service;
- to promote economic efficiency and sustainability in the generation, transmission, distribution, and sale of electricity.

The National Electricity Sector Policy

The proposal also considers the NESP which lays out 4 clear objectives for the electricity sector, stating that the electricity service should be: (1) least cost and high quality, (2) environmentally sustainable, (3) secure, and (4) affordable. The IRP Proposal assumed the following definitions of these four NESP objectives:

- **Least Cost and High Quality** – Electricity service that is delivered at the lowest possible financial cost, without compromising safety standards or failing end users' expectations for reliability and customer service.

- **Environmentally Sustainable** - Electricity service that, over time, does not cause economic harm to Bermuda's sensitive natural environment, or cause economic harm to the global environment.
- **Secure** – Electricity service that is provided using a mix of primary energy options that are procured from reliable sources and under terms that make Bermuda resilient to shocks (such as dramatic changes in the availability or price of fuels, or the introduction of binding commitments to reduce greenhouse gas emissions).
- **Affordable** – Electricity service that allows all Bermudians to pay for at least a basic supply, while preserving (where cross-subsidies for ensuring basic supply are involved) the competitiveness of Bermuda's productive sector.

The National Fuels Policy

The NFP lists the eight goals identified by the Government of Bermuda to guide the specific measures within the policy. They are:

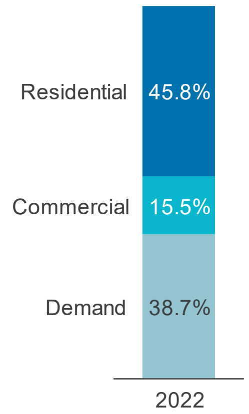
- safeguarding fuel security,
- making fuels least cost,
- guaranteeing public safety and fuel quality,
- promoting environmental sustainability,
- fostering economic growth,
- maintaining affordability,
- upholding national values, and
- increasing administrative effectiveness.

5. Load Forecast

A primary output of an IRP process is determining the set of demand-side and supply-side resources that are best able to meet the utility's load requirements over time. This section describes Bermuda's load forecast requirements and some of the key uncertainties that could contribute to higher or lower load levels.

The load forecast was developed through a bottom-up approach. Separate forecasts were developed for the number of customers and energy use at each customer group (class) level. The forecasts were aggregated to the system level of total energy sales, total energy requirements, and peak demand. Monthly forecasts were developed using a combination of multivariate regression models and trending techniques.

Figure 4. The TD&R Licensee's 2022Retail Electric Sales



The TD&R Licensee's 2022 retail energy sales by class are presented in Figure 4. The residential class is the largest with nearly 33,000 customers, comprising 46 percent of 2022 total retail sales. The Demand metered class comprised roughly 40 percent of 2022 retail sales, but included just over 200 large customers. Smaller businesses are included in the commercial class with over 3,000 businesses that account for 15 percent of the TD&R Licensee's 2022 retail electric sales. Customers with BTM renewable energy systems and subject to the Feed-In-Tariff are embedded within these three classes for forecasting purposes.

The following sections detail the data sources, methodologies, and forecast results at a class level and for the total energy system. The forecasts presented here exclude the impacts of BTM solar output from customer-owned solar installations (Section: 5.7.2), electric vehicles (Section: 5.7.1), and any newly implemented demand-side management (DSM) programmes (Section: 6), which is incorporated separately into the IRP Proposal analyses.

5.1. Load Forecast Inputs

To develop an accurate load forecast, extensive data was collected. Historical information was required for weather, gross domestic product (GDP), tourism, actual system energy requirements and peak demand. The following key information for January 2012 to October 2022 was provided:

- The monthly number of customers, energy sales, and revenues by customer class.
- The number of customers and average usage per class – residential, commercial, demand, and customers with DERs.[4]
- Monthly total system energy requirements (including estimated losses, own use, and miscellaneous) and system peak demand including date and hour for January 2012 to September 2022.
- Historical data for the monthly number of BTM solar installations and energy impacts from installation.
- Key economic, demographic, and related data, including:
  - Quarterly GDP data from the Department of Statistics under Bermuda's Ministry of Economy and Labour[5] and Moody's Analytics
  - Tourism value index from the Department of Statistics under Bermuda's Ministry of Economy and Labour[5]
  - Population, housing, and related data from Bermuda Census data and related reports from government sources
  - Appliance efficiency information from the U.S. Department of Energy – Energy Information Administration.
- Weather data from Virtual Crossing[6] data source.

5.2. Load Forecast by Class

Each customer class has specific considerations that impact how the load forecast is performed. Detailed information on each class forecast can be found in Appendix B.

5.2.1. Residential Class

The residential class includes nearly 33,000 customers. Total sales to the residential class were approximately 239 GWh in 2022, slightly less than the 250 GWh of sales in 2012. The number of residential customers over the past decade has remained stable, however electricity usage per customer has declined, driven by more

[4] Customers with DERs were broken down and backed into the main three classes: residential, commercial, and demand.
[5] https://www.gov.bm/bermuda-economic-statistics
[6] https://www.visualcrossing.com/

efficient appliances and lighting along with solar installations by over 1000 residential customers as of late October 2023. The residential customer forecast is correlated to Bermuda's population change.

Residential electric sales decrease at an average annual rate of 0.2 percent from 2023 to 2042 excluding the impacts of BTM solar, which are incorporated separately in the IRP Proposal analysis.

5.2.2. Commercial Class

The TD&R Licensee serves over 3,000 commercial customers, including a wide variety of small to medium-sized businesses and other non-residential accounts. Energy sales to the commercial class have declined over the past decade due to economic factors, EE, and BTM solar impacts. The influence of the COVID-19 Pandemic (the Pandemic) on commercial electricity sales is evident in 2020 and 2021, with some rebound in 2022 that is expected to carry into 2023 and 2024 before stabilising.

Excluding BTM solar impacts, commercial sales rebound slightly in 2023 and 2024 due to the continued recovery from the Pandemic impacts before remaining flat through the remainder of the forecast horizon, as driven by the flat real GDP forecast.

5.2.3. Demand Class

The TD&R Licensee serves 210 customers that are metered and billed on peak demand as well as energy consumption. These customers are generally larger than the businesses and other non-residential accounts that are included in the commercial class. This class comprised nearly 40 percent of the TD&R Licensee's retail electric sales in 2022 with the average annual electric use per customer near one million kWh.

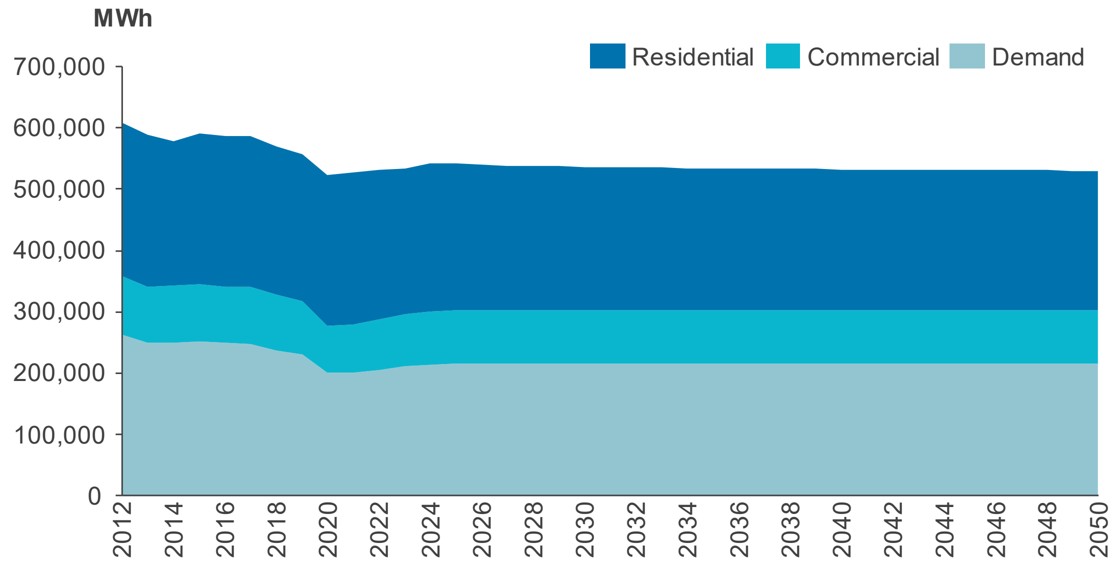
The number of demand metered customers has changed little over the past decade and is expected to remain at the current level throughout the forecast horizon. Excluding BTM solar impacts, electric sales increase slightly in the first few years of the forecast due to a recovering economy and then flatten thereafter.

5.3. Total Energy Sales and Requirements

Total energy sales are the sum of energy sales across the residential, commercial, and demand metered classes. Excluding the impacts of BTM solar, total energy sales declined slightly over the forecast period. The residential energy forecast declines due to ongoing efficiency improvements in home appliances and equipment while the commercial and demand metered class forecasts are driven primarily by GDP and are relatively flat after the first few years of recovery. The share of total energy sales to the residential class decreases from 46 percent in 2022 to 43 percent by 2042, excluding the impacts of BTM solar.

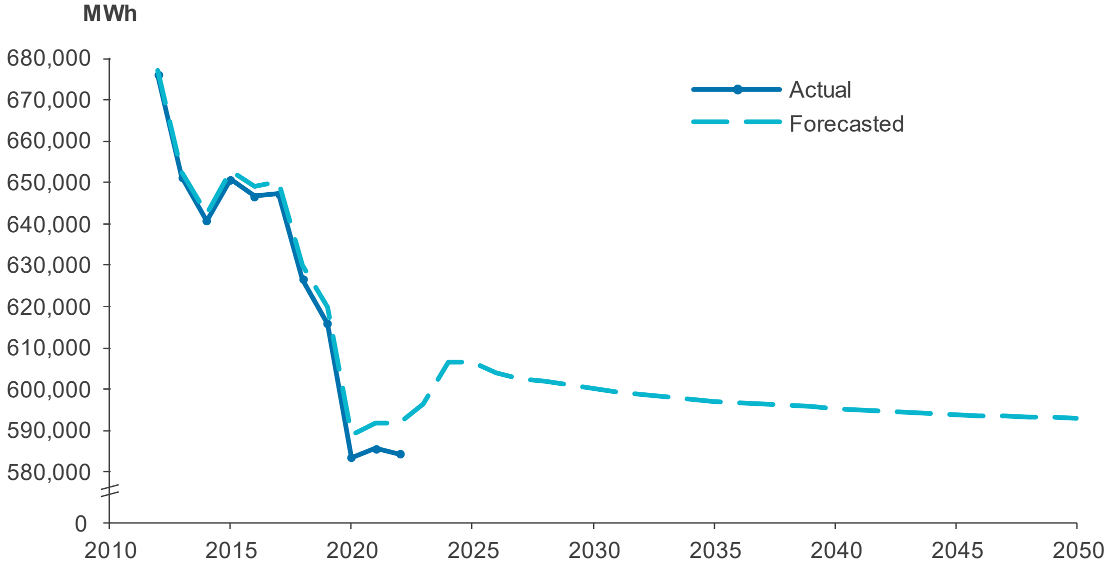
Total net generation requirements without the impact of on-site solar are the sum of retail sales to the three customer classes, distribution, and transmission losses, the TD&R Licensee's use, and any other unaccounted-for energy that may not be metered or otherwise included in retail sales. The combination of losses, own use, and other energy has averaged 10.5 percent of total net generation over the past five years, and the forecast remains at that monthly average. Total net generation declines slightly into the future excluding the impacts of BTM solar. Retail sales without BTM solar and total net generation forecasts are summarised in Figure 5 and Figure 6.

Figure 5. Energy Sales Forecast by Class without BTM Solar[7]



[7] 2012 – 2022 contains actual energy sales; 2023 and on are forecasted

Figure 6. Total Net Generation (TNG)



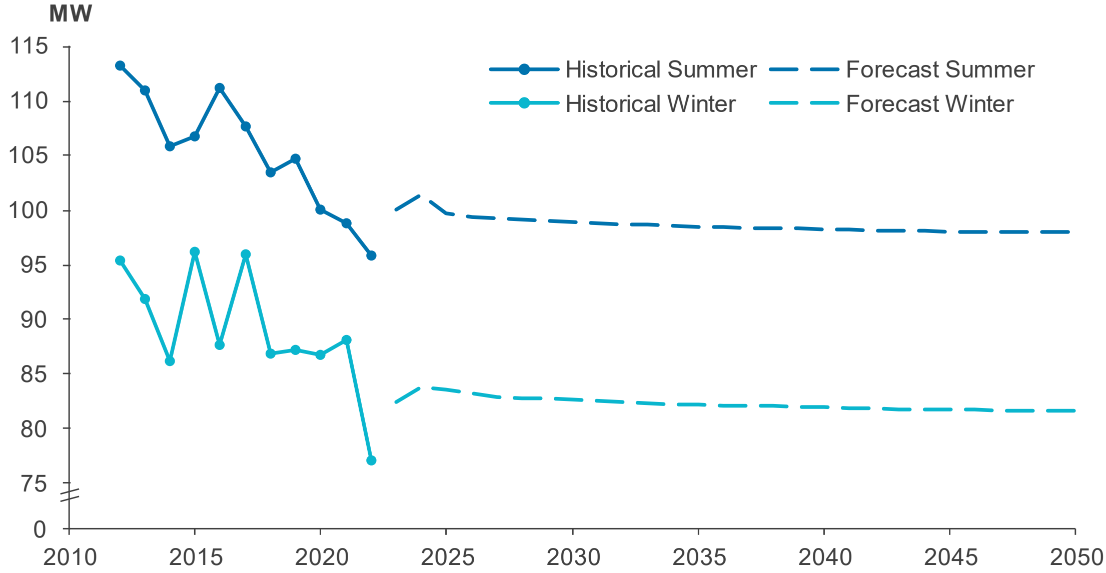
5.4. System Peak Demand

The TD&R Licensee's monthly system peak demand has decreased in recent years, following the trend of energy sales and total net generation. It is significantly impacted by the weather on the monthly peak day along with economic conditions and other underlying influences of load growth.

The monthly system peak demand forecast was developed using an econometric model relating monthly peak demand to monthly total net generation excluding BTM solar impacts, heating degree days on the monthly peak day, cooling degree days on the monthly peak day, and monthly variables as needed to capture the unique system monthly peak demand shape. The total net generation driver excludes the impacts of BTM solar since the system peak typically occurs in the early evening. Daily degree days capture the impacts of weather on the peak day while monthly total net generation captures the underlying drivers of long-term load trends and ties the peak demand forecasts to the system energy forecasts for consistency.

The system's peak demand forecast generally follows the trends of total net generation without BTM solar impacts and has a slight decline expected over time. The system is expected to remain a summer-peaking system throughout the forecast horizon while the annual system load factor remains near 69 percent, in line with recent averages. The seasonal peak demands are illustrated in Figure 7.

Figure 7. Seasonal System Peak Demand Forecasts



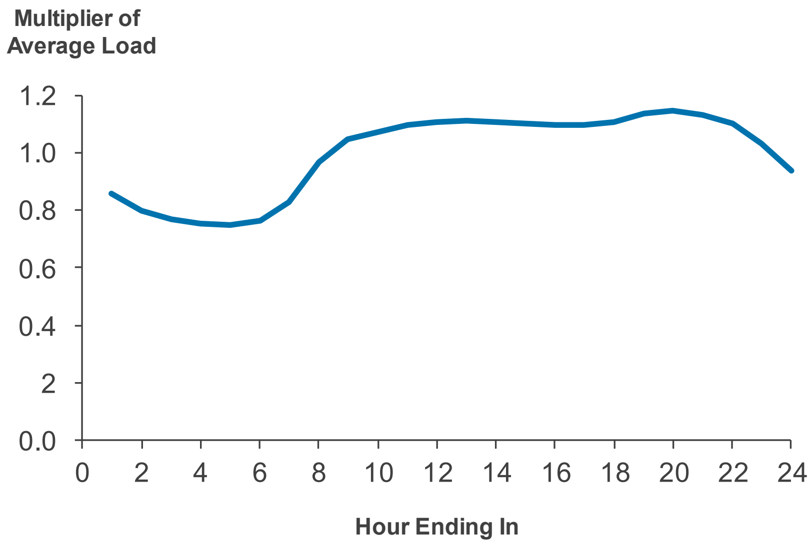
5.5. Load Shape

A load shape based on a typical meteorological year (TMY) of 2017 was used. This provided a more realistic shape excluding extreme weather events that are unpredictable. However, there were some weather disturbances, so the 2017 TMY shape was smoothed over these weather disturbances.

As displayed in Figure 8, the average hourly load shape is relatively flat. There is a long daily peak between the hours of 12:00 to 22:00, but demand goes down in the early mornings, which is expected. Figure 8 displays an average daily shape, which averages out differences by season and weekday or weekend. Bermuda is a summer peaking system, so load is typically higher in the summer which follows greater demand for cooling and HVAC, and lower in the shoulder months as seen in Figure 20 in Section 8.3.

There is also load shape variation between weekdays and weekends. Load shapes are typically more uniformly distributed along the weekends and higher overall. On the weekdays, the load is generally higher in the afternoon to late evening hours and low during the morning.

Figure 8. Daily load shape multiplier to Average Load



5.6. Load Scenarios

The total energy and peak demand forecasts presented above represent one of many possible outcomes. Energy consumption and peak demands can be influenced by factors that are inherently difficult to predict, such as weather and economic growth. Therefore, it is important to develop flexible plans for meeting future power needs based on a range of forecast outcomes.

The IRP Proposal modelled uncertainty in the scenario analysis (Section 10). A low and high load forecast was developed to examine rapid and slow economic growth under normal weather conditions.

The forecast ranges for demographic and economic variables have been developed by flexing the growth rate of the independent variables around the base-case forecast of growth for each variable. For instance, the real GDP forecast has a base forecast that remains flat while the optimistic economic scenario grows real GDP by 0.5 percent per year and the pessimistic economic scenario decreases it by 0.5 percent per year throughout the forecast horizon. The GDP ranges are then applied to the residential, commercial, and demand class forecasts to develop forecast ranges. The resulting economic growth ranges for total energy requirements are expected to diverge by 23 percent to 28 percent around the base projection by 2050. The economic growth scenarios plausibly broaden over time as the long-term economic growth uncertainty increases.

The optimistic and pessimistic economic energy requirements forecast ranges were applied to the peak demand forecast to adjust the corresponding peak demand forecast consistently and plausibly. The forecasts indicate that the annual system peak demand will range from 80 to 120 MW by 2050, given the assumptions mentioned herein.

The load forecast ranges for energy requirements are presented in Figure 9 while the peak demand forecast ranges are presented in Figure 10.

Figure 9. Total Energy Requirements Forecast Ranges (MWh)

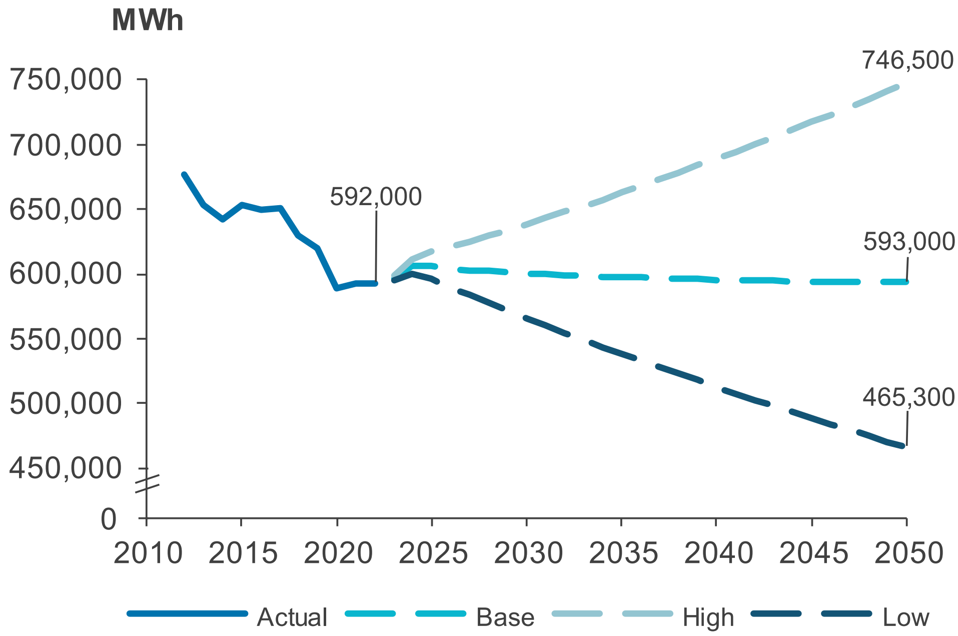
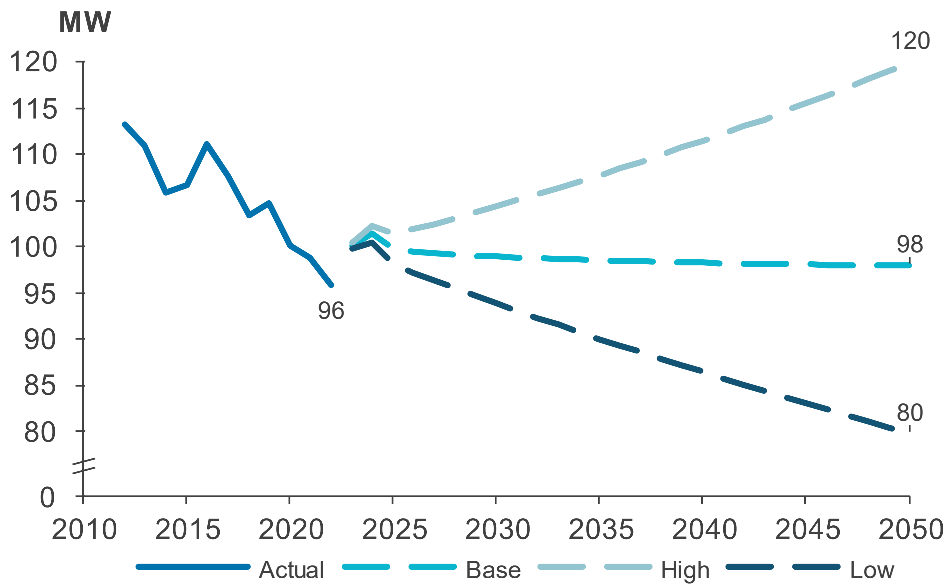


Figure 10. Annual Peak Demand Forecast Ranges (MW)



5.7. Load Forecast Adjustments

The load forecast presented above represents the base load forecast without any additional adjustments. Load-side adjustments are made in the model to account for the variations in load over time. Bermuda must account for the growth of electric vehicles, which increase load over time, in contrast to DERs such as behind-the-meter solar and storage, which decrease net load requirements. Both load changes have different load shapes distinct from the load shapes for the residential, commercial, and demand classes.

5.7.1. Electric Vehicles

To create an accurate electric vehicle (EV) load forecast, long-term EV adoption rates and their associated charging demand impact were assessed. EVs offer many benefits for customers to help reduce greenhouse gas emissions when renewables penetrate the grid more, but the impacts on overall energy requirements and peak load must be considered. Bermuda has some specific considerations when it comes to vehicles on the island.[8]

- **One car per household**: All residents of Bermuda are allowed only one automobile (private car) per household. This is important because although Bermuda is only 21 miles long and less than 2 miles wide, vehicles on the island are driven more miles per day because they are shared within households.
- **Limit on Car Size**: Cars must be at the pre-approved size for the island.
- **Supply Chain**: In Bermuda, cars drive on the left side of the road, and the supply chain for right hand drive cars is more limited. Cars also must be shipped to the island which can cause delays in receiving supply.

All potential constraints were included in developing the assumptions for the EV energy impacts.

Energy Impacts

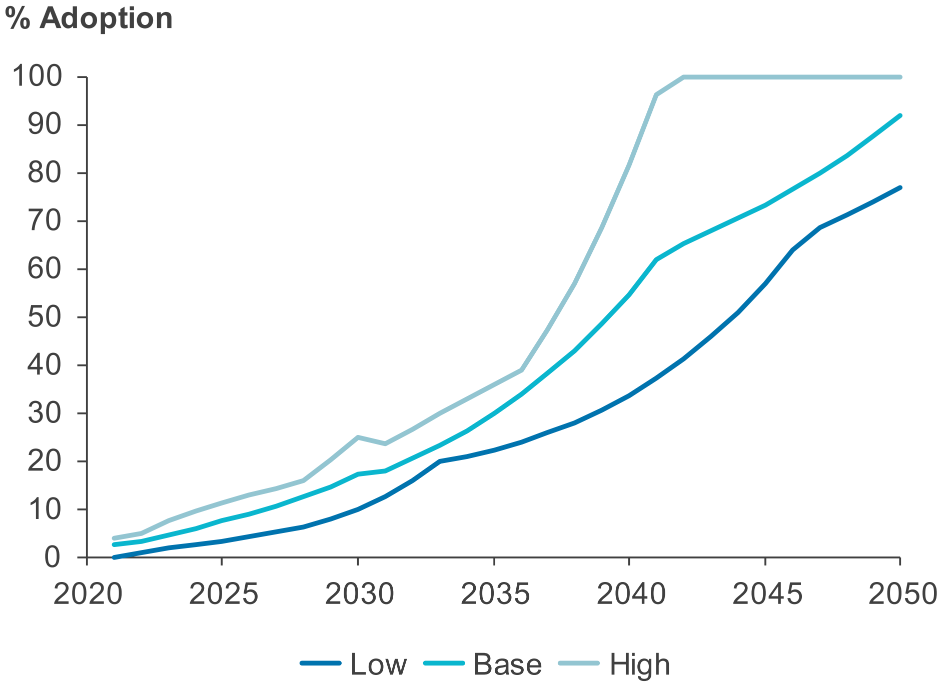
Key inputs to determine the impact on the total energy (MWh) and the total peak demand (MW) included miles driven per day, number of current vehicles, customer adoption rates, and policy considerations. The impacts of EV adoption were evaluated. Key assumptions used as inputs are as follows:

8 Transportation, Bermuda Online: http://www.bermuda-online.org/wheels.htm

- Both battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) were included given their ability to plug in and charge on the grid. The average trip length in Bermuda given its tip-to-tip length of 25 road miles is within most PHEV electric ranges. Therefore, battery power is assumed to be utilised for most of the trip.
- On average, Light-Duty Vehicles are driven 6,500 miles annually.
- Vans, SUVs, pickups, and light trucks use the same proportions.
- The forecast assumes no growth in total vehicles based on Bermuda's one car per household limits – there are approximately 23,000 light-duty vehicles on the road.
- In 2020 there were approximately 430 registered EVs overall in Bermuda.[9]

Figure 11 displays the adoption rates for the low, base, and high scenarios and Table 2 shows a table of the total energy demand from EVs annually.

Figure 11. EV Adoption Rate Scenarios



9 Electrified Islands Report 2020

Table 2. Total Annual Energy Demand from New EVs (MWh)

Year	Low	Base	High
2024	4,569	4,750	4,932
2025	4,784	5,037	5,291
2026	5,063	5,392	5,721
2027	5,405	5,807	6,209
2028	5,840	6,320	6,800
2029	6,316	6,907	7,498
2030	6,915	7,661	8,407
2031	7,543	8,405	9,268
2032	8,289	9,283	10,277
2033	9,110	10,238	11,366
2034	10,070	11,333	12,596
2035	11,163	12,548	13,933
2036	12,402	13,866	15,329
2037	13,733	15,336	16,939
2038	15,244	17,066	18,888
2039	16,944	19,084	21,224
2040	18,882	21,465	24,047
2041	20,952	24,099	27,246
2042	23,171	26,889	30,606
2043	25,431	29,661	33,890
2044	27,797	32,466	37,135
2045	30,003	34,993	39,982
2046	32,335	37,639	42,943
2047	34,712	40,263	45,813
2048	37,202	42,943	48,684
2049	39,521	45,356	51,191
2050	41,969	47,856	53,742

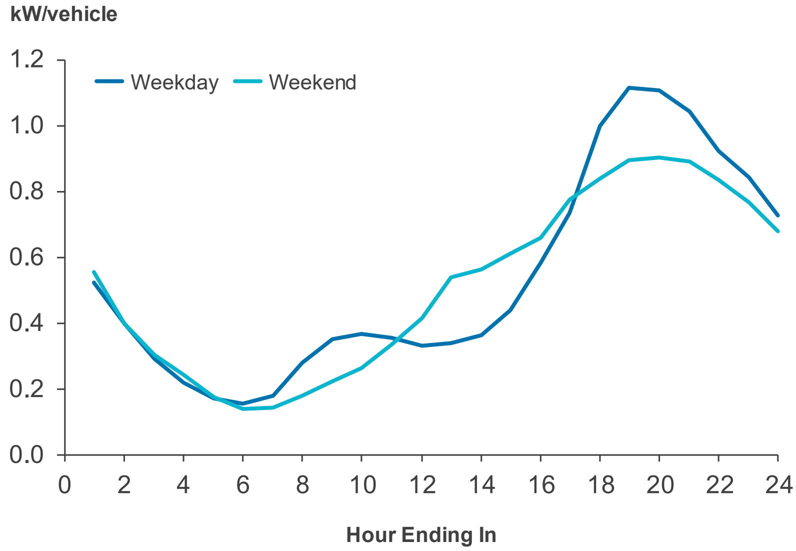
EV Load Shape

The U.S. Department of Energy's Alternative Fuels Data Center (AFDC) offers a tool, EVI-Pro Lite, that provides a way to estimate how much electric vehicle charging may be needed and creates a load profile that can be used in modelling.[10] Load shapes for the weekday and weekend electric load were estimated using Kahului, Hawaii as a proxy. Assumptions such as miles driven per day, temperature, charging type, and number of vehicles that were specified in the model are as follows:

- 10,000 vehicles: the EV load profile shifts as more cars come on the road. In the Base Case the # of cars shifts from approximately 500 in 2023 to 15,000 in 2050.
- Average 35 miles driven per day.
- Average ambient temperature of 20°C
- Mostly Level 2 charging
- Preference for home charging
- Home charging strategy: delayed, start at midnight.
- Workplace charging strategy: delayed, finish by departure.

The developed load shape is used for all vehicle types and scenarios over the entire forecast period. The load shape can be seen below in Figure 12.

Figure 12. EV Load Shapes – 10,000 vehicles



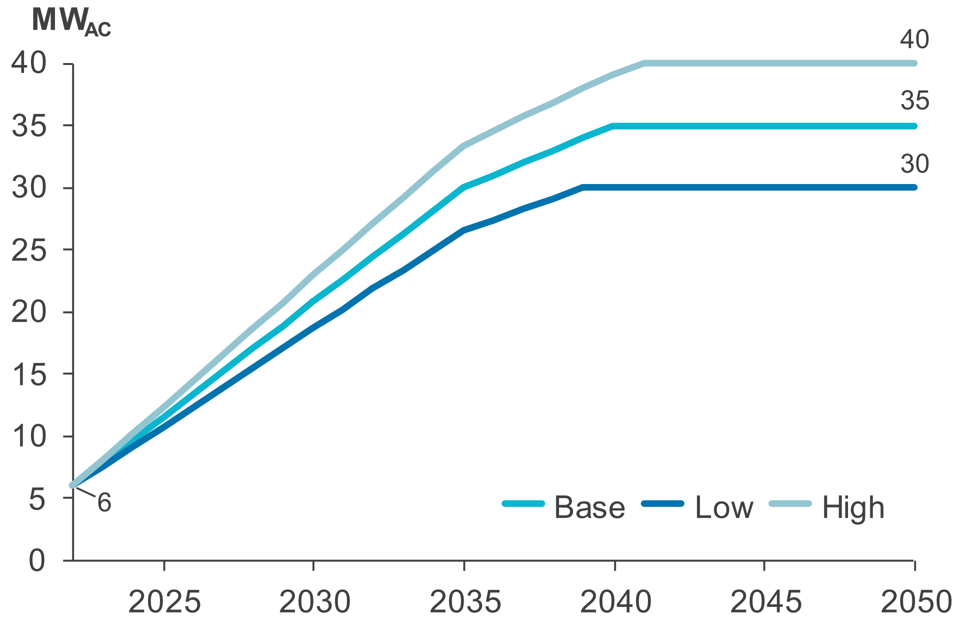
10 EV Infrastructure Projection Tool, DOE https://afdc.energy.gov/evi-pro-lite

5.7.2. Distributed Energy Resources

The DER forecast is mainly made up of BTM solar. Bermuda has seen continued growth in rooftop solar capacity. About 3 percent of the TD&R Licensee's electric customers now have rooftop solar. Although the demand class has the largest adoption rates (circa 11 percent), the residential class has installed the most capacity.

Forecasts for the future deployment of rooftop solar were based on historical growth and customer adoption as well as spatial potential, energy potential, and grid stability limitations. The forecast can be seen in Figure 13. All three of the forecasts are based on a system maximum with annual limits to make sure the transmission and distribution (T&D) system has time for the necessary upgrades. The low, base, and high forecasts have a system maximum of 30, 35, and 40 MW respectively. A separate system impact study is being completed to determine the actual system limits for distributed generation.

Figure 13. BTM Solar Forecast (MW_{AC})



The generation shape used for utility-scale and floating solar was used to determine the capacity factor for BTM solar, which is around 18 percent.

6. Demand-Side Resource Options

The IRP Proposal considers demand-side and supply-side options for meeting future load requirements. This section describes the demand-side options included in Bermuda's portfolio analysis.

A study on EE and demand-side resource options was conducted. The TD&R Licensee does not currently have any demand-side management programmes (EE or DR). This section describes the methodology taken to develop and analyse measures specific to Bermuda and the final assumptions for the programmes selected including impacted classes, costs, and implementation schedules.

6.1. Energy Efficiency

EE is a key demand-side resource that can help lower overall electricity demand and reduce the need to invest in new electricity generation and transmission infrastructure.[11] Other key benefits include risk management, reducing bills and price volatility, and lower carbon emissions. The remaining part of this section details how EE was considered in the modelling of the IRP Proposal and what assumptions were used.

6.1.1. Measure Development and Qualitative Screening

The study on EE and demand-side resource options covered a forecast horizon through 2050 and examined residential and commercial customers. Bermuda's load forecast and inputs, weather data, avoided costs, regional Technical Reference Manual (TRM), and prior studies were all used to analyse EE programmes suitable for Bermuda. The study resulted in a list of EE measures that would be feasible and appropriate to potentially deploy given the climate, building stock, and demographics of Bermuda. A qualitative screening was completed to identify measures most viable for Bermuda. Considerations for the qualitative screening included factors such as applicability to residential and commercial building construction materials and methods, equipment commonly found in Bermuda, typical building operations and maintenance practices, market availability, customer acceptance, equipment and labour costs, and other factors. The qualitative measure screening reduced the total number of measures going forward in the study down to 29 measures placed into a series of programme bundles that were categorised by sales class and end-use. They were also

[11] Local Energy Efficiency Benefits and Opportunities, EPA.

assigned delivery mechanisms (i.e., direct install, midstream, prescriptive, and custom) used to estimate project costs.

Table 3 shows the final end-use bundles along with their measures.

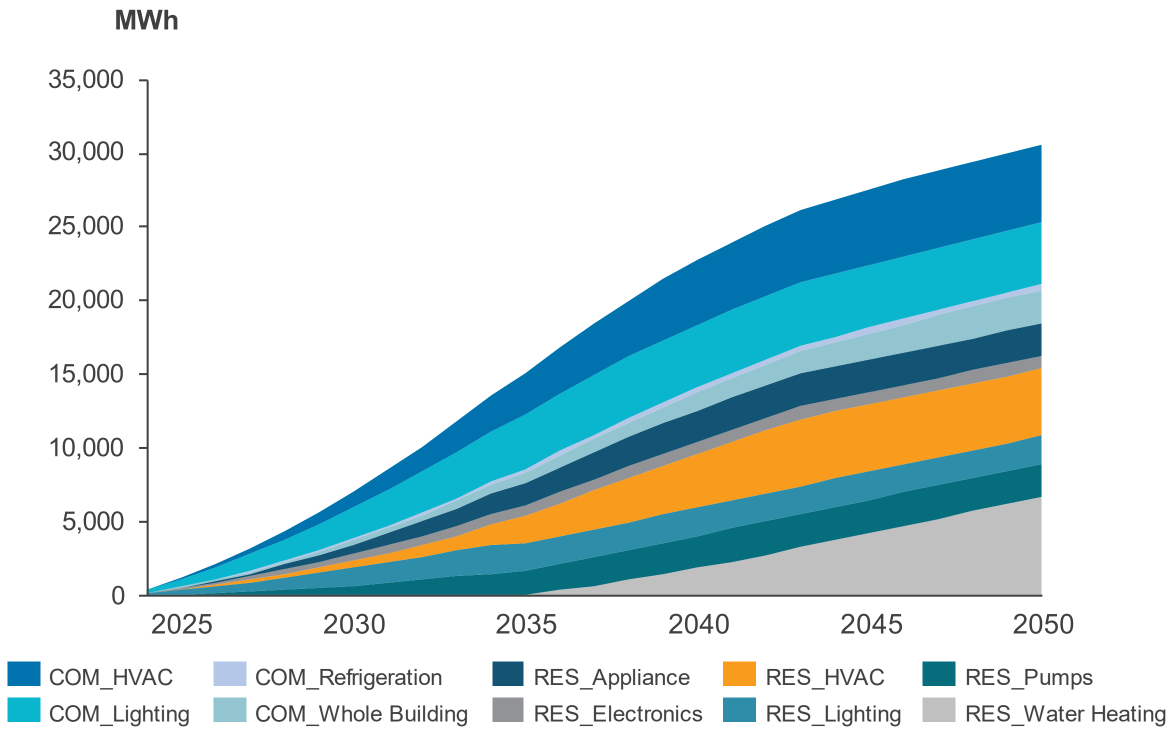
Table 3. Final EE Bundles for IRP Proposal

End-Use Bundle	Measure
Residential Appliances	Dehumidifier Air Purifiers Energy Star Clothes Washer Energy Star Refrigerator Energy Star Clothes Dryer Energy Star Freezer Energy Star Dishwasher
Residential Electronics	Advanced Power Strip Electric Vehicle Charger
Residential Heating, Ventilation, and Air Conditioning (HVAC)	Efficient Room AC Ductless Heat Pump Mini Split
Residential Lighting	Standard LEDs Specialty LEDs
Residential Pumps	Pool Pump
Residential Water Heating	Solar Water Heater Solar Pool Heater
Commercial HVAC	Variable Speed Drives for HVAC Supply and Return Fans Variable Speed Drives for HVAC Pumps and Cooling Tower Fans Electric Chiller Ductless Heat Pump Mini Split Small Commercial Thermostat
Commercial Lighting	Standard LEDs Specialty LEDs Interior High-Bay Fixtures Linear LEDs Exterior Area Lighting
Commercial Refrigeration	Refrigerator – Variable Speed Compressor
Commercial Whole Building	Retro-commissioning Advanced New Construction Designs

6.1.2. Measure Characterisation and Quantitative Screening

A cost-benefit model was developed around the 29 remaining measures. Critical assumptions such as savings, incremental costs, incentives, and measure life were compiled along with economic assumptions such as avoided costs, discount rate, inflation rate, and load forecasts. Each measure was then quantitatively screened for cost-effectiveness using the levelised cost at the measure level. The levelised cost utilised the incremental cost of the measure and its savings. The levelised costs were compared to the associated avoided fuel costs. All measures were found to be less expensive than the fuel costs and moved forward for inclusion in the savings potential analysis and modelling. The cumulative savings forecasted per bundle can be seen in Figure 14.

Figure 14. EE Cumulative Energy Savings



Based on the EE savings forecasted in Figure 14, the savings potential is expected to reach 0.8 percent of baseline demand over 5 years and 2.2 percent of baseline over 10 years. By 2050, cumulative EE savings potential is expected to reach 5.7 percent of baseline consumption. Residential and commercial lighting are the dominant end-uses in the near term through 2030, comprising more than 25 percent of the total potential. Residential solar water heaters and ductless heat pump mini-splits amount to approximately 22 percent of the potential by 2050. Commercial participation is estimated to reach 934 participants over 5 years and residential participation is estimated to reach 10,109 over 5 years.

6.1.3. Modelling Considerations

The Levelised Cost of Energy (LCOE)[12] for each programme was compared against the LCOEs for the other supply-side resources. The LCOEs proved significantly lower than the supply-side resources (in Section 7) so all demand-side programmes were implemented in each portfolio. An implementation schedule was created to stagger the start of the programmes beginning sometime between 2025 and 2030. Staggering was done based on least-cost programmes that were the simplest to implement. Table 4 shows the EE bundle implementation schedule.

Table 4. EE Implementation Schedule

Year	Implementation Measure
2025	• RES Appliance – Dehumidifier • RES Appliance – Energy Star Freezer
2026	• RES Appliance – Energy Star Clothes Washer • RES Electronics – Advanced Power Strip
2027	• COM HVAC – Chiller Aux • COM Lighting – Interior (Interior High-Bay Fixtures,
2028	• RES HVAC – Efficient Room AC • RES Pumps
2029	• COM HVAC – Chiller Full • COM HVAC – Small Com (Ductless Heat Pump
2030	N/A
2031	N/A
2032	N/A
2033	N/A
2034	• RES Appliance – Energy Star Dishwasher • RES Electronics – Electric Vehicle Charger
2035	• RES HVAC – Ductless Heat Pump Mini Split
2036	N/A
2037	• RES Water Heating

[12] LCOE measures the lifetime costs divided by energy production. It allows for comparison of different technologies of unequal life spans, project size, different capital cost, risk, return, and capacities.

6.1.4. EE Scenarios

Figure 15 and Table 5 show a summary of the low, base, and high scenario results and specifications. The implementation schedule and programmes remain the same throughout each scenario.

Figure 15. Cumulative Energy Savings by Scenario

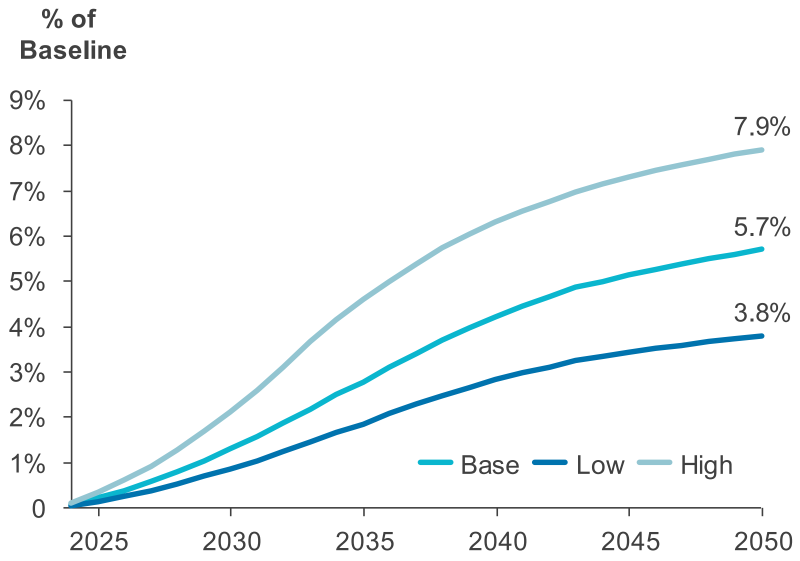


Table 5. EE Scenario Assumptions

Scenario Assumption	Low Savings	Base Savings	High Savings
Achievable Factor	20%	30%	40%
Measure Screening	TRC > 1	TRC > 1	None
Incentive Amount (% of Incremental Cost)	25%	50%	100%
Cumulative EE Savings as % of baseline in 2030	0.9%	1.3%	2.1%
Cumulative EE Savings as % of baseline in 2050	3.8%	5.7%	7.9%

6.2. Demand Response Considerations

As more renewables and distributed energy resources come online, demand response (DR) could be an effective tool for Bermuda to reduce peak demand without having to overbuild the system. A similar analysis to EE was completed for DR programmes. Six programmes were identified as most feasible for future consideration by the TD&R Licensee. These programmes are described below:

1. **Commercial and Industrial (C&I) Third-Party Curtailment:** By voluntarily reducing peak demand periods, companies could benefit from financial incentives and utilities can receive reductions in load during peak and near-peak conditions.
2. **Residential Behavioural Demand Response (DR):** Residential DR programmes incentivise homeowners to actively manage their consumption and engage in EE.
3. **Electric Vehicle Connected Charger Direct Load Control (DLC):** By actively managing and controlling the charging of EVs, the TD&R Licensee can control inherent after-work peaks from customers plugging in their vehicles to charge, balance resources on the grid, promote grid stability, and reduce energy costs.
4. **EV Managed Charging through Vehicle Telematics:** By optimising charging schedules based on real-time data and grid conditions, the TD&R Licensee could reduce the strain on the grid during peak hours.
5. **Storage DLC:** This offers the ability to actively manage and control electricity demand using stored energy from batteries to help balance the grid and mitigate peak demand.
6. **EV Fleets:** The EV fleet can lead to significant cost savings in terms of fuel and maintenance expenses and demonstrate a commitment to sustainability.

The IRP Proposal must consider DR. Based on the cost-benefit analysis, EE programs have a large impact on total energy requirements and peak demand. For this reason, EE programs are modelled, and DR programs are recommended for development and implementation in conjunction with regulatory tariff applications and processes.

7. Supply-Side Resource Options and Assumptions

This section describes the supply-side resource assumptions that were included in the portfolio analysis. This section begins by describing Bermuda's existing supply-side resources and the options available to Bermuda. This includes retiring current BELCO thermal generating units earlier or later than planned and retrofitting units to operate more efficiently or on different fuel types. The IRP Proposal also considered new supply-side resource options available to meet the defined objectives. These include solar, wind, and dispatchable renewable resources such as biomass, wave, and storage. There is also a fuels price forecast for all the fuels considered in the IRP Proposal. This includes a price forecast for fuel oils, natural gas and biomass.

Resource assumptions require locally relevant data input assumptions. To better understand the Bermuda factors for renewable energy, the TD&R Licensee engaged with local solar installers, utility-scale renewable energy project developers and local charities that support the renewable energy transition. The stakeholder meetings focused primarily on the resource assumptions, energy output, capital costs, operational and maintenance (O&M) costs, project timelines and other input assumptions for renewable energy development in Bermuda. CapEx and operational expenditures (OpEx) values were adjusted where necessary and sensitivity ranges incorporated when stakeholder opinions differed. The timelines were adjusted as necessary, and in general, the TD&R Licensee tended towards optimistic timelines promoting faster rates of technology implementation for Bermuda. Targeted stakeholder engagements enabled robust IRP modelling with sound and locally relevant input assumptions. Furthermore, the input assumptions have also undergone additional professional third-party verification.

The IRP modelling assumes all resources are competitively procured.

7.1. Existing Resources

This section provides an overview of Bermuda's existing supply-side portfolio. The current supply-side resource mix comprises reciprocating engines, gas turbines, WTE, storage, and solar photovoltaics. Currently, most of the capacity is thermal and operated on heavy or light fuel oil, as described in Table 6.

Table 6. BELCO BG Owned Generating Thermal Units

Unit Name	Unit	Primary Fuel Type	C.O.D.[13]	Nameplate Capacity (MW)	Heat Rate (Btu/kWh)	Retirement Date
East Power Station	E5	HFO	2000	14.3	7,955	2040
	E6	HFO	2000	14.3	7,955	2040
	E7	HFO	2005	14.3	7,787	2045
	E8	HFO	2005	14.3	7,787	2045
North Power Station	N1	HFO	2020	14.3	7,631	2060
	N2	HFO	2020	14.3	7,631	2060
	N3	HFO	2020	14.3	7,631	2060
	N4	HFO	2020	14.3	7,631	2060
Gas Turbines	GT5	LFO	1995	13.0	13,266	2025
	GT6	LFO	2010	4.5	12,394	2035
	GT7	LFO	2010	4.5	12,394	2035
	GT8	LFO	2010	4.5	12,394	2035

More information on assumptions surrounding existing units can be found in Appendix C.

7.1.1. Life Cycle Extension or Upgrade of E5 to E8

Two options to extend the life of EPS engines for baseload generation are investigated: the LCE and the life cycle upgrade (LCU). The LCE extends the useful life of the plant by 10 years, reducing the annual depreciation expense to customers. The life cycle extension is possible due to the reduced hours of thermal plant operation due to increased renewable generation. As this is simply the extension of engines' useful lives with no direct capital cost, it is applied as the default operational strategy. The capacity expansion modelling still permits early retirement of the engines if they are no longer cost effective or required to meet demand.

The other option is the LCU of the EPS engines to a modern platform and extends the life by 30 years. These engine upgrades provide the same capacity rating at a higher efficiency. These upgraded engines will enable new fuel options such as LNG and, potentially, hydrogen.

[13] C.O.D. refers to the commercial operation date.

7.1.2. Fuel Options

BELCO bulk generation (BELCO BG) currently utilises HFO and LFO as fuel sources in its reciprocating engines and gas turbines. The IRP Proposal investigates retrofitting existing generators to accommodate multiple fuel sources to reduce cost and emissions.

Switch to LFO

To employ this strategy, LFO fuel must be contracted in larger volumes for the NPS and EPS as the GTs already run on LFO. The EPS and NPS can switch to LFO without any additional infrastructure changes. LFO has environmental benefits over HFO such as reduced emissions. However, LFO is more expensive on a commodity cost and delivered fuel cost basis compared to HFO, which is discussed in section 7.3 of the Fuel Forecast. Table 7 shows the retirement and heat rate assumptions for the EPS and NPS engines running on LFO.

Table 7. LFO Switch Assumptions

Replacement Options	Fuel Type	LCE Retirement Date	LCU Retirement Date	Heat Rate (Btu/kWh)
E5	LFO	2040	2056	7,955
E6	LFO	2040	2056	7,955
E7	LFO	2045	2056	7,787
E8	LFO	2045	2056	7,787
N1	LFO	2060	2060	7,631
N2	LFO	2060	2060	7,631
N3	LFO	2060	2060	7,631
N4	LFO	2060	2060	7,631

For details on LFO switch, see Appendix C, Table 33.

Switch to Natural Gas

LNG is another fuel that has been assessed in this IRP Proposal. For this fuel case, LNG would be produced in the United States and shipped to Bermuda. Based on the 2016 LNG Feasibility study completed by Castalia,[14] LNG represents a feasible fuel option, using Ferry Reach Terminal to receive the LNG shipments along with the necessary infrastructure upgrades. The infrastructure upgrades would include

[14] Viability of Liquefied Natural Gas (LNG) in Bermuda : https://www.gov.bm/sites/default/files/Viability-of-Liquefied-Natural-Gas-in-Bermuda.pdf

additional terminal and regasification infrastructure that will need to be developed, along with pipelines and storage units. These capital costs were estimated in 2016 to be $130 MM for LNG infrastructure based on a receiving terminal and pipeline from Ferry Reach.

The LCU is necessary for the EPS engines to burn natural gas. This is referred to as the LNG Retrofit. The capital costs for LNG retrofits on E5 through E8 and N1 through N4 are captured in the modelling and displayed in Table 8. The earliest full conversion or upgrades for the engines would be in 2028.

Table 8. LNG Switch & Retrofit Assumptions (2022 $)

Replacement Options	Fuel Type	Retirement Date	CapEx ($/kW)	Heat Rate (Btu/kWh)
E5_Retrofit	LNG	2056	454.6	8,260
E6_Retrofit	LNG	2056	454.6	8,260
E7_Retrofit	LNG	2056	454.6	8,260
E8_Retrofit	LNG	2056	454.6	8,260
N1	LNG	2060	138.9	8,260
N2	LNG	2060	138.9	8,260
N3	LNG	2060	138.9	8,260
N4	LNG	2060	138.9	8,260
GT5	LNG	2025	0.00	11,700
GT6	LNG	2035	44.4	11,700
GT7	LNG	2035	44.4	11,700
GT8	LNG	2035	44.4	11,700

For details on the LNG retrofit details, see Appendix C, Table 34.

7.1.3. Battery Energy Storage System

BELCO also owns a battery energy storage system (BESS) that helps maintain its operating reserves, as described in Table 9.

Table 9. BELCO Owned Renewable / Storage Resources

	Nameplate Capacity (MW)	Storage Capacity (MWh)	C.O.D.	Annual Degradation Rate
Li-ion 30 min 10 MW	10	5.5	2019	2.2%

7.1.4. Third Party Bulk Generators

The TD&R Licensee purchases energy from an onshore solar facility, known as "The Finger", and a WTE facility, Tynes Bay. Assumptions for these two can be found in Table 10.

Table 10. Third Party Generator Nameplate Capacity

	Fuel Type	Nameplate Capacity (MW)	Capacity Factor
The Finger	Solar	6	21%
Tynes Bay	WTE	7.3	26.5%

7.2. New Resources

In this IRP Proposal, new resource technologies are considered for their effects on cost to customers, reliability, and their ability to lower emissions. The RA Guidance included the following technologies for Bermuda to test in this IRP Proposal: fuel oils including existing fuels and lower sulphur content fuel oils, onshore and floating solar photovoltaic (PV), OSW, LNG, Liquified Propane Gas (LPG), biomass, and wave power generation.

A variety of baseload, peaking, renewable, advanced generation, storage, and alternative supply-side resources were considered. Furthermore, new fuel types, previously unused in Bermuda, were also considered.

The following are discussed in the upcoming section:

- **New Resource Assumptions:** Includes an overview of the assumptions for renewable energy resources and storage. This includes a discussion of capital costs[15] operations and maintenance (O&M) costs, lifespan, capacity factor, earliest build date, and others. For details on new resource assumptions see Appendix D.
- **Excluded Resources:** This includes an explanation for resources that were analysed during the development of the IRP Proposal but not included in the modelling process.

[15] Capital costs are the all-in capital costs inclusive of equipment, EPC (engineering, procurement, and construction) costs, soft costs, interest during construction, and interconnection costs to the grid but exclude any grid upgrades or modifications, and any other balance of plant components.

7.2.1. Solar

Solar PV systems use semiconductor materials surrounded by protective layers to convert sunlight into electricity. The system has a modular structure that allows it to be scaled to meet different levels of energy needs, large or small.

Onshore Solar

Utility-scale onshore solar PV is first made available as a resource option in the capacity expansion model in 2024. Current solar generation is modelled as a must-run resource with a generic hourly production profile representative of the region with a capacity factor of approximately 21 percent for utility-scale solar and 18 percent for BTM solar. The percentage credit is modelled at an average of 2 percent and varies across the month (which aligns with the anticipated solar production curve). The hourly production profile and resultant capacity factor are based on modelling outputs of utility-scale and BTM solar projects from a third-party software using a decade of hourly weather data.

Onshore solar capital costs were derived based on the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2023 capital costs with appropriate Bermuda adders. The fixed O&M costs and capacity factor were derived using estimates from an existing solar bulk generator.

Solar PV is made available in a configuration of 5 MW. The maximum annual capacity addition is 5 MW. In Bermuda, land constraints prevented solar capacity from reaching beyond 20 MW. Based on an estimate of available land space and potential siting of onshore solar, 20 MW reached the acreage limits for total resource capacity.

Table 11. Key Onshore Solar Assumptions

Capital Costs (2022 $/kw-yr)	Fixed O&M (2022 $/kw-yr)	Variable O&M (2022 $/kw-yr)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
2,750	20	0	2025	30	5	20	21%

Floating Solar

Floating solar is a nascent renewable technology where solar panels are placed on the surface of the water. Due to Bermuda's land constraints, offshore renewable resources are needed to reach higher levels of renewable generation. Floating solar resources have previously been mostly in ponds and reservoirs[16] but are more recently being developed for the ocean.[17]Further studies are being conducted on the impact that salt water or wave action may have on the performance and lifetime of these resources.

Capital costs for floating solar were reviewed by stakeholders and corroborated with a U.S. Department of Energy, National Renewable Energy Laboratory (NREL) study between onshore and floating solar. The high fixed O&M cost compared to onshore solar internalises additional maintenance due to wave turbulence affecting system performance. The overall maximum build is also constrained by the siting specifics and is restricted by the environmental restoration efforts of the location. Since this technology is still in the early stages of development, the maximum capacity is 5 MW for the first two years, with assumptions of technological advancement increasing the annual limit to 10 MW thereafter.

Table 12. Key Floating Solar Assumptions

Capital Costs (2022 $/kw-yr)	Fixed O&M (2022 $/kw-yr)	Variable O&M (2022 $/kw-yr)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
4,125	150	0	2027	27	5 or 10	80	21%

7.2.2. Offshore Wind

OSW is a potential option for Bermuda due to its location, climate, and ocean space, however further resource, technical and economic studies are required to verify the viability of OSW in Bermuda. There have been multiple studies completed that look at the feasibility of OSW potential, costs, and locations. Assumptions were developed from Greenrock & BVGAssociates,[18] Ricardo[19] and other reports for Bermuda and cross-referenced with Annual Energy Outlook[20] and operational wind farms.

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[16] In 2016, Japan developed a 13.4 MW farm on a reservoir above a dam using 50,000 solar panels. Another plant in China can produce up to 40 MW which was constructed in 2017. (Smithsonian Magazine)

[17] In 2021, Singapore developed a 60 MW floating solar farm which uses 13,312 panels. 5MW-peak system installation is expected to produce an estimated 6 million kW-hours of energy per year. (The Straits Times)

[18] Bermuda offshore wind: LCOE assessment https://www.greenrock.org/projects/offshore-wind

19 Assessment of the Offshore Wind Potential in Bermuda

20 U.S. Energy Information Administration https://www.eia.gov/outlooks/aeo/

There was variation among the studies regarding capital costs and O&M. The additional cost it may take to deliver and install large offshore turbines to Bermuda was considered. Capital costs were derived using EIA AEO 2023 estimates with a Bermuda adder and compared against United States OSW farms, such as Dominion's 2.5 GW offshore farm in Virginia.

The overall system maximum was 60 MW for OSW. It was predicted that operationally, OSW developers would bid for a project size of around 60 MW. Therefore, OSW was constrained to build the maximum capacity in the first economic year.

Table 13. Key OSW Assumptions

Capital Costs (2022 $/kw-yr)	Fixed O&M (2022 $/kw-yr)	Variable O&M (2022 $/kw-yr)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
6,300	161	0	2028	32	15	60	41%

7.2.3. Wave

Due to Bermuda's limited acreage for new onshore resources and the potential to reach untapped renewable energy, wave power has been of great interest to Bermuda as it approaches commercial maturity. Wave power harnesses the motions of waves, converting mechanical energy into electrical energy.

Wave power is contingent on the wave height and wavelength at any given time. The TD&R Licensee has received data for a 250-kW device that would produce 700 MWh annually with an average power of 82 kW. Wave power is a great resource to offset solar and wind seasonal contingencies. Wave power was limited to a unit build of 5 MW and total max system build of 20 MW.

Table 14. Key Wave Assumptions

Capital Costs (2022 $/kw-yr)	Fixed O&M (2022 $/kw-yr)	Variable O&M (2022 $/kw-yr)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
10,179	529	0	2030	25	5	20	27%

7.2.4. Biomass

This IRP Proposal considered biomass as a placeholder for a clean, dispatchable resource. Without the option of new thermal engines (except in a business-as-usual case), the rapid renewable penetration in the IRP Proposal requires a dispatchable resource when intermittent resources such as solar and wind are not meeting their production demands. Storage will make up for some of the misalignments in renewable energy production and demand, but another resource is still required. Whilst biomass is considered in this IRP Proposal, further research on alternative dispatchable resources should be done as markets evolve and technologies mature.

Biomass is a renewable material that can be processed from wood or wood waste, agricultural crops, biogenic materials in municipal solid waste, or animal manure. Biomass was included in the 2019 Bermuda IRP following the IRP consultation process.

Typically, biomass storage can be a pile in an open-air system, but the heat content of wood pellets is sensitive to moisture. Therefore, the high humidity environment in Bermuda was considered when evaluating the storage constraints.

To develop the delivered cost of biomass, Enviva's 2022 Q3 Investor Presentation report was used to forecast the associated cost of commodity and transport.[21] The overall capacity of the plant is 10 MW units, but the system was able to build two units for a total maximum build of 20 MW due to land constraints.

Table 15. Key Biomass Assumptions

Capital Costs (2022 $/kw-yr)	Fixed O&M (2022 $/kw-yr)	Variable O&M (2022 $/kw-yr)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
6,867	150	5.41	2028	40	20	20	-

7.2.5. Storage

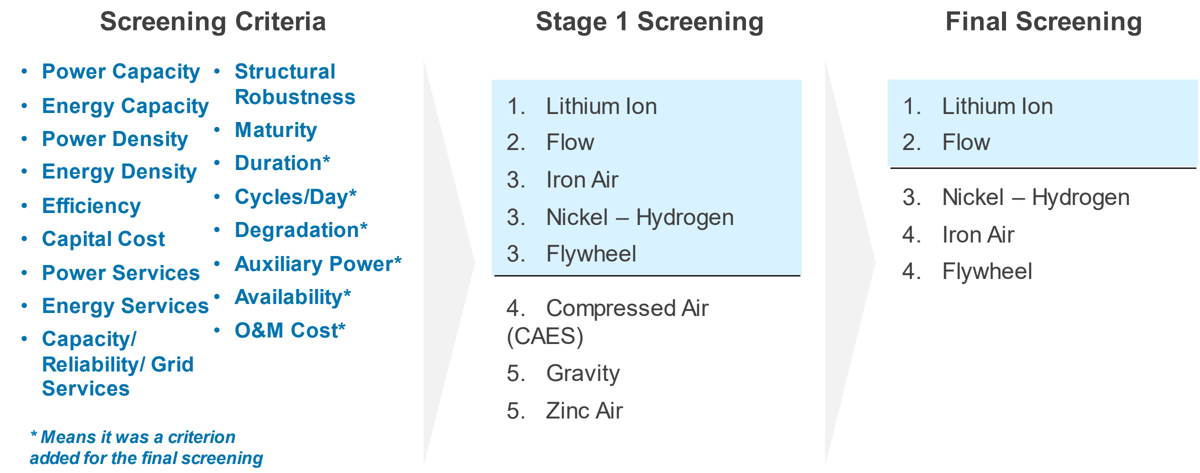
Utility-scale short and longer duration storage technologies were considered as peaking technologies that provide additional capacity during periods of peak energy demand through discharging of energy stored typically during periods of low energy demand. Deployment of these technologies can also help smooth out energy price volatility. The TD&R Licensee commissioned an energy storage study that considered both short- and long-duration storage technologies.

[21] Enviva 2022 Q3 Investor Presentation

Multiple BESS technologies were evaluated that have been commercially deployed or are expected to achieve a technical readiness level sufficient for commercial deployment in the next three to four years. The study was completed specifically in the context of Bermuda. There were eight battery technologies scored in a semi-quantitative process against eleven key metrics. The list was then narrowed down for a final screening with an additional six criteria. Li-ion batteries were identified as the most viable storage technology as Li-ion was the most mature, energy-dense, and cost-effective technology. Flow batteries were second due to their projected future low costs, despite limited commercial deployment. Both technologies were modelled for the IRP Proposal.

A summary of the criteria used to screen the technologies and the resulting technologies modelled can be found in Figure 16.

Figure 16. Summary of the Storage Study Screening of Battery Technologies



Li-Ion Battery

Li-ion batteries store and discharge energy through the movement of lithium ions between a negative and positive electrode, separated by an electrolyte. These batteries are experiencing rapid growth in utility-scale deployments as their costs have fallen significantly and their value as a complement to renewable energy has increased. Li-ion batteries demonstrate advantageous operating characteristics that include high round-trip efficiency, high energy density, and lower self-discharge. The batteries can also respond to demand signals within a second, making them well suited for primary frequency regulation, i.e., providing an initial immediate response to deviations in grid frequency driven by sudden demand spikes or supply losses. However, Li-ion batteries have limited cycle life due to degradation; battery augmentation is required during the project lifetime to maintain performance.

In addition to the currently operational battery, new Li-ion battery builds are first made available in the model starting in 2025 and are modelled as a short-term energy storage option with a duration of two, four, and eight hours. The capacity expansion model optimises charging and discharging and considers a round-trip efficiency of 79 percent for the 2 hour battery, 84 percent for the 4 hour battery, and 86 percent for the 8 hour battery, and a self-discharge rate of 0.10 percent per day. As a duration-limited resource, the ability of Li-ion batteries to meet demand peaks will decline as greater amounts of renewable generation widen the length of demand peaks. All three durations of Li-ion batteries are made available in a configuration of 10 MW with no maximum, minimum, or annual build constraints in the model.

Flow Battery

Flow batteries were determined to be the second viable storage option for Bermuda. Flow batteries are a type of electrochemical battery where chemical energy is provided by two chemical components dissolved in liquids, pumped through the system on separate sides of a membrane. Ion transfer inside the battery occurs through the membrane while both liquids circulate in their own respective space. The energy capacity is a function of the electrolyte volume, and the power is a function of the surface area of the electrodes. Flow batteries have certain technical advantages over batteries with solid electroactive materials like Li-ion batteries, such as independent scaling of power (determined by the size of the stack) and of energy (determined by the size of the tanks), long cycle and calendar life, and potentially lower total cost of ownership. All flow batteries suffer from low cycle energy efficiency and have lower specific energy compared to Li-ion batteries.

Flow batteries are first made available in the capacity expansion model starting in 2025 and are modelled as long-duration storage with a storage energy capacity of twenty-four hours. Flow batteries were assumed to have a round-trip efficiency of 65 percent and a self-discharge rate of 0.02 percent per day. Flow batteries are made available in a configuration of 10 MW with no maximum, minimum, or annual build constrained in the model.

The smaller the storage duration, the greater the decline in capacity credits as more storage is added. Hence, the Li-ion technologies see declining capacity contribution while the 24-hour flow battery can provide full credit.

Table 16. Key Battery Assumptions

Battery Duration	Capital Costs (2022 $/kw-yr)	Fixed O&M (2022 $/kw-yr)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
2 hr.	1,291	33	2025	20	10	-	-
4 hr.	2,300	38	2025	20	10	-	-
8 hr.	4,180	45	2025	20	10	-	-
24 hr.	11,974	79	2025	20	10	-	-

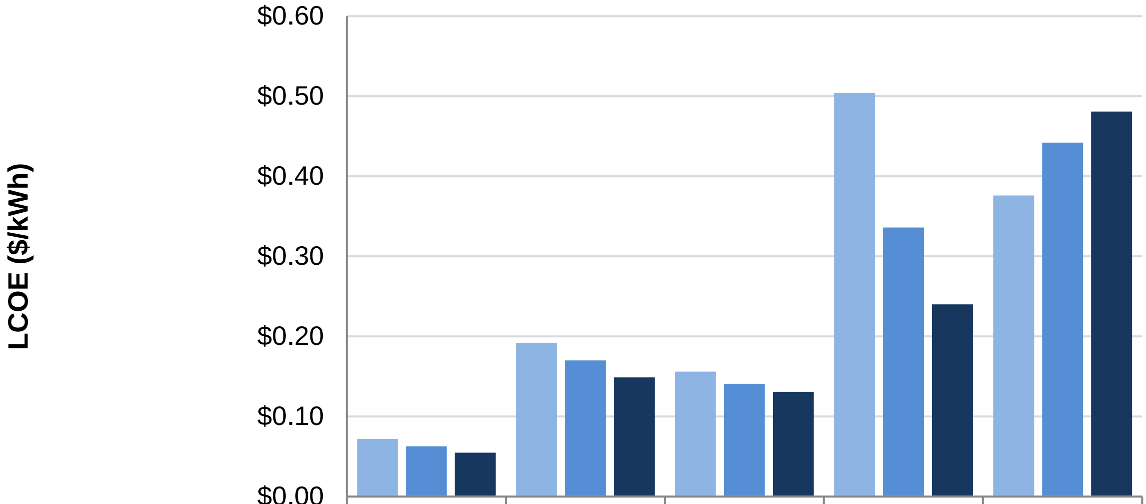
7.2.6. Levelized Cost of Energy of New Resources

The LCOE is useful to understand the potential costs of technology and is an important component in system planning. However, it should not be used in isolation when determining the lowest cost system that is also reliable. The LCOE narrowly looks at energy only, ignoring the contribution of resources to capacity and reserves. One type of technology may be the least expensive on its own but, due to its generation profile, may be more expensive at different levels of capacity. For example, solar energy could be sized to provide 100% of Bermuda's energy needs, however as solar does not generate at night, it requires additional system buildout not considered in the solar LCOE.

Figure 17 below gives the simplified LCOE[22] for each technology over the planning period and provides a helpful visual to indicate the lower cost technologies from an energy only perspective. The LCOE values are based on a set of input assumptions used for the IRP modelling and demonstrate the reduced cost of renewables over time and the increase in cost of biomass with time.

22 Simple Levelized Cost of Energy (LCOE) Calculator Documentation

Figure 17: Levelised Cost of Energy for New Resources in Bermuda



	Solar	Floating Solar	Wind	Wave	Biomass
2030 LCOE in Bermuda	0.072	0.192	0.156	0.504	0.376
2040 LCOE in Bermuda	0.063	0.17	0.141	0.336	0.442
2050 LCOE in Bermuda	0.055	0.149	0.131	0.24	0.481

The LCOE varies with weather, time, dispatch, and curtailment. Due to this variability, LCOE has limited usefulness as a relative cost metric for a system with technologies that have widely different capacity values. The Aurora model has built-in functionality within the capacity expansion model to assess the 'system value' and select resources based on the size and mix of resource options and a more comprehensive set of benefit streams. As a result, the capacity expansion model considers LCOE when determining the final portfolio mix but within the context of other system requirements. This enables the model to account for changing LCOE over the forecast horizon. For thermal resources, LCOE is affected by the dispatch of the unit and annual fuel price trends over time.

7.2.7. Excluded Resources

LPG

Consistent with the RA Guidance, Liquefied Petroleum Gas was considered as an alternate fuel option for the IRP Proposal. LPG is classified as a group of hydrocarbon gases typically including propane, butane, and isobutane derived from refining or natural gas processing that are liquefied via pressurisation[23] and would be delivered to Bermuda in bulk ocean tankers and stored at an existing storage facility.

[23] EIA Glossary

A study was completed to compare LPG to LNG to evaluate if LPG made sense to add as a fuel to the model instead of, or in addition to, LNG. To explore the feasibility of LPG for Bermuda, (1) commodity costs, (2) capital costs, (3) carbon intensity, and (4) relative feasibility were considered. On a pure commodity cost basis, propane near-term prices from 2023 to 2035 are $3/MMBtu higher than Henry Hub prices (about a 100 percent markup from current Henry Hub prices). However, the cost of transportation and storage is lower. This is particularly given that LPG is already on-island delivered via bulk carrier and ISO container. No additional capital costs are required to convert or retrofit existing GTs. Storage costs for LPG are less than LNG, as it can be fired from tanks versus LNG which must be stored cryogenically and regasified.

Despite the benefits, the carbon intensity of LPG (63 gCO_2/MMBtu) is higher than that of LNG (53 gCO_2/MMBtu).[24] Additionally, the EPS and NPS engine manufacturer does not offer an LPG package for these engines at this time. Currently only the GTs, which dispatch infrequently, can burn LPG. Given the operating profile of infrequent dispatch and the complexities and infrastructure associated with adding a fifth fuel to the mix. LPG was considered but not included in the current IRP Proposal for the reasons noted above.

Hydrogen

Hydrogen can play multiple roles within an electricity system. It can provide storage capacity during periods of high renewable generation and, depending on hydrogen prices, cycling capabilities for intermediate loads or generation capacity during periods of high electricity demand.

Hydrogen CTs operate on the same principle as the Natural Gas Combustion Turbine (NGCT) systems but the fuel properties of hydrogen are different from that of natural gas. These properties lead to a difference in fuel handling, nozzle design, combustor design, and the need to control NOx leading to higher capital costs of hydrogen burning CTs relative to natural gas.

Due to the difficulties of transporting gaseous hydrogen, hydrogen storage and transportation are modelled using the Liquid Organic Hydrogen Carrier (LOHC). Although this makes hydrogen less efficient in terms of energy output, the chemical allows hydrogen to attach to a chemical in a liquid state and can be stored in fuel

[24] Carbon Dioxide Emissions Coefficients, EIA

oil tanks. This eliminates any difficulties with transporting compressed or liquified hydrogen and the associated combustion risk.

Hydrogen was assumed to be green and has zero emissions. The commodity cost forecast was derived using electricity prices, water costs, and capital costs from electrolysers. The capital cost for hydrogen that the capacity expansion model uses is based on building a turbine that can combust hydrogen. The hydrogen is modelled as a fuel, which is produced outside of Bermuda but shipped and combusted on the island.

While hydrogen assumptions were developed, ultimately the resource option was not modelled due to the current state of this technology's advancement and the high dependency on a firm dispatchable resource within the first ten years of the forecast period. As a result, the resource has a high development risk that impacts other resources to the same extent. There were also safety considerations and large infrastructure overhauls on the generation, transmission, distribution, and end-use fronts that prevented this resource from being selected.

Ammonia

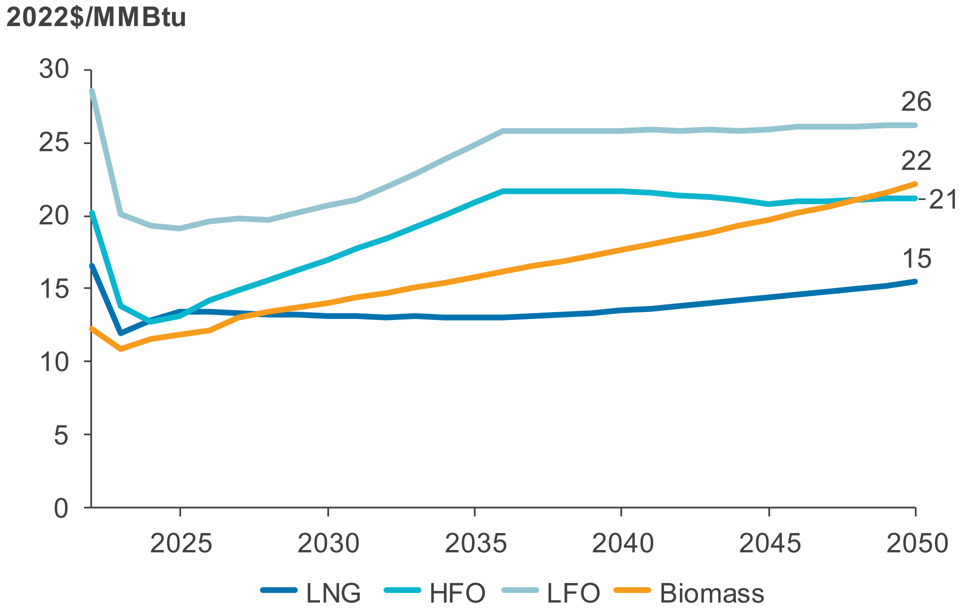
A study was performed to evaluate if the consumption of ammonia was feasible to help Bermuda meet future demand for clean energy. The assessment looked at the import cost of ammonia from the US Gulf Coast, on-island storage of ammonia, and on-island power production via ammonia capital costs, operational costs, and efficiency. It was found that the consumption of ammonia for power generation is not commercially available. The original equipment manufacturers (OEMs) that were contacted implied that the technology would not be available until the late 2020s and, as a result, reliable data could not be provided regarding capital and operation assumptions for an ammonia-fuelled power generator. This technology may be considered in future IRP proposals.

7.3. Fuel Forecast

Fuel price forecasts were developed for fuel oil, LNG, biomass, and hydrogen. Commodity costs were attained from public sources such as the EIA, Henry Hub, and others. Freight and margin were added to get the final delivered costs. Figure 18 shows the delivered price at port fuel forecast.[25] Additional detail for each fuel is described below.

[25] This includes no throughput for any of the fuels.

Figure 18. Delivered Price Fuel Forecast – Base Case



7.3.1. Fuel Oil

HFO and LFO price forecasts were developed using near-term forecasts and a blend of the CME Group Futures until 2026 with the AEO 2023 Low Oil Price Case.[26] These forecasts capture the near-term drop in oil and better calibrate fuel costs to represent current prices.

From 2026 to 2037, a blend of the AEO 2023 Reference Case was used with the AEO 2023 Low Oil Price Case to show a steady increase/return to the AEO Reference Case. 2038 onwards uses the AEO 2023 Reference Case for the long-term forecast.

7.3.2. LNG

To determine the forecasts for LNG, near-term Henry Hub price forecasts were used. These forecasts are determined based on a blend of forward prices and fundamental modelling: from 2023 to 2026, prices are based exclusively on forwards; from 2027 to 2029 prices are based on a blend of forwards and fundamentals; and from 2030 onwards, prices are based on fundamentals.

Infrastructure such as pipelines and regasification plants will be needed if LNG were to be selected as a fuels source on island. The capital investment in LNG infrastructure is included with a fair return on investment as a passthrough cost in the CRA revenue requirement model, and not included as a variable cost in the

26 CME Group Futures

delivered fuel price. This approach ensures that the costs are properly captured if the LNG infrastructure becomes stranded.

7.3.3. Biomass

To develop the delivered cost of biomass, Enviva's 2022 Q3 Investor Presentation report was used to forecast the associated cost of commodity and transport.[27] The cost breakdown was based on Enviva's estimates of material, production, and processing costs (fibre, energy, fixed costs, and variable costs).[28] The biomass forecast was derived using a Handy Whitman index that was applied to Enviva's forecasted commodity cost CAGRs.

Shipping and logistics forecasts were estimated using a blend of the Handy Whitman index and the diesel fuel forecast. Diesel fuel was used as a basis for the delivery costs due to the association of bunker fuel costs associated with shipping.

7.4. Economic Assumptions

7.4.1. Financial Assumptions

The core financial assumptions used in the IRP Proposal are shown in Table 17. Note that the income tax rate for Bermuda is currently zero, and the land tax rate does not apply to this analysis.

Table 17. Financial Module Assumptions

Parameter	Value
Income Tax Rate	0.00%
Return on Equity	9.68%
Cost of Debt	5.50%
Equity % Rate Base	60.0%
Debt % Rate Base	40.0%
AFUDC	5.50%
Social Discount Rate	8.00%

7.4.2. Social Discount Rate

The social discount rate signals what future benefits and costs are worth today. [29] For the IRP Proposal, the social discount rate is used to derive the present value of

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27 Enviva 2022 Q3 Investor Presentation
28 Enviva Investor Day 2023 Report
29 Discounting Future Benefits and Costs, EPA Guidelines https://www.epa.gov/sites/default/files/2017-09/documents/ee-0568-06.pdf

future societal benefits and cost impacts in the assessment of the capital expansion plan. A lower discount rate tends to favour higher capital costs and lower operational costs, whereas a higher discount rate would prefer lower capital costs and higher operational costs. For the capacity expansion, a lower social discount rate favours new renewable builds with low operational costs.

Financial literature indicates a broad range of social discount rate values ranging from Treasury bond rates (5 percent) to as high as 10 percent. As future economic growth is uncertain, a rate closer to the mid-point (8 percent) was used. The sensitivity analysis described in Section 15.1 demonstrates the impact of using a lower and higher social discount rate (6 percent and 10 percent, respectively).

7.4.3. Social Cost of Carbon

The social cost of carbon (SCC) represents the discounted present value of damages from one additional ton of CO_2 equivalent emitted at a certain point in time.[30] The cost represents in dollars the value of damages avoided as a benefit of carbon reduction. The SCC varies based on the discount rate, the domestic or global nature of the scope, and which externalities are included. To determine a SCC forecast, the following distinguished public sources were analysed in addition to what was used previously in Bermuda:

- **Dynamic Integrated Model of Climate and the Economy (DICE) Model:** assesses climate change in the framework of economic growth. This model specifically integrates the Ramsey model to include climate investments. DICE applies a 3 percent discount rate. [31]
- **Environmental Protection Agency (EPA):** the EPA provides a forecast based on a 5 percent, 3 percent, and 2.5 percent average discount rate.[32]
- **RFF Greenhouse Gas Impact Value Estimator (GIVE):** Resources for the Future (RFF) is a group of economists and scientists that estimate the social cost of carbon through their GIVE model. This model tends to have a very

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30 Auffhammer, Maximilian. 2018. "Quantifying Economic Damages from Climate Change." Journal of Economic Perspectives

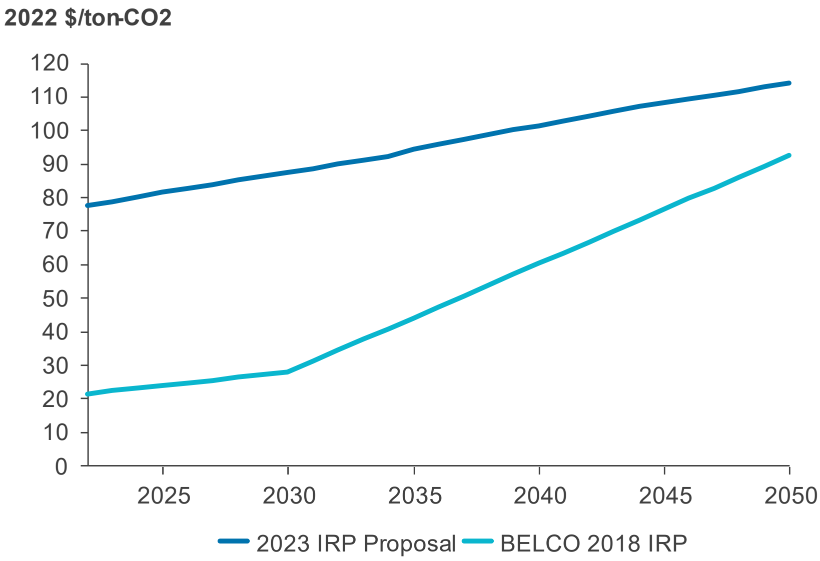
31 Results from the DICE-2023 Model, National Bureau of Economic Research https://www.nber.org/papers/w31112; The Ramsey Model is an economic growth model that explicitly models the consumer side and endogenizes savings.

32 Social Cost of Carbon Snapshot, EPA https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html

aggressive forecast. They publish four forecasts for discount rates of 7 percent, 5 percent, 3 percent, and 2.5 percent.[33]

The EPA 2.5 percent was the decided-upon forecast as it strikes a good balance between being too low and too aggressive. A more aggressive forecast is usually considered if there is a need to achieve large economy-wide reductions. Further, an overly aggressive forecast will also lead to premature retirements of thermal generation and cause significant rate impacts. The IRP Proposal social cost of carbon forecast can be seen compared to what was used in the TD&R Licensee's 2018 IRP Proposal in Figure 19.

Figure 19: IRP Proposal Social Cost of Carbon Forecast



It is important to note that the SCC is different than a market carbon price or cap-and-trade system. The SCC is used in the IRP Proposal to capture the negative externality of generating carbon emissions. The social cost of carbon is a planning concept that influences choice of new generation build and dispatch, but it is not a direct cost to ratepayers, unlike a carbon tax or a cap-and-trade programme. As such, the SCC has been modelled for purposes of capacity expansion, but the implied emission costs do not flow through to the revenue requirement calculation.

[33] Social Cost of Carbon 101, Resources for the Future https://www.rff.org/publications/explainers/social-cost-carbon-101/

8. Reliability Planning

Reliability is built into the model as a constraint. The system is required to meet a reserve to maintain the system loss of load event (LOLEv) target of "1-day-in-10-years." Or the system can experience a loss of firm load of any magnitude or for any duration less than one day every ten years, on average. When capacity expansion for each model was complete, if the system did not meet this target, portfolios were adjusted to maintain this minimum reliability.

8.1. Operating Reserves

Operating reserves are generation that is not currently being used to meet demand but can, in a short amount of time, become available in the case of an unplanned event on the system, such as a loss of generation or when real-time demand is higher or lower than forecast. This generation can be from generators that are synchronised (connected) to the power grid or offline and from certain loads, designated as demand-side response, which can be removed from the grid. The characterisations of different operating reserves terminology and definitions can be found in Table 18.

Table 18. Operating Reserve Service Definitions[34]

Name	Use	Response Speed	Other Names
Operating reserve	Any capacity is available for assistance in active power balance.	Seconds to 10 minutes	
Regulating Reserve	Capacity available during normal conditions for assistance in active power balance to correct any system imbalance that occurs.	Second to 1 minute	Regulation, load frequency control, secondary control
Contingency Reserve	Capacity available for assistance in active contingency power balance during infrequent events that are more severe than balancing needed during normal conditions and are used to correct instantaneous imbalances.	Seconds to 10 minutes	(Spinning and non-spinning reserve)
Spinning Reserve	Online capacity, synchronised to the grid, that can increase output in response to a major generator or transmission outage.	Seconds to 10 minutes	Synchronised Reserve
Non-Spinning Reserve	Offline capacity that can be brought online after a short delay in response to a major generator or transmission outage.	Seconds to 10 minutes	Quick start Reserve

8.1.1. Contingency Reserve: GT5

GT5 currently meets the TD&R Licensee's contingency reserve. The unit carries non-spin reserves to supplement the primary spinning reserves carried by other resources. The existing GT5 will be replaced with a more efficient gas turbine that will be available to provide non-spin reserves to and supplement the primary spinning reserves on the system.

The current GT5 unit will retire at the end of 2025. This upgraded unit is modelled to be operational in January of 2026 and remain in service through the remainder of the forecast period.

[34] Ela, E., Milligan, M., & Kirby, B. (2011). Operating reserves and variable generation (No. NREL/TP-5500-51978). National Renewable Energy Lab. (NREL), Golden, CO (United States).

In the model, GT5 and its replacement is treated as contingency reserve, generating energy to manage instances of capacity shortfall over a significant period, which can result in load shedding.

8.2. Planning reserves

Planning reserves are estimated based on the Planning Reserve Margin (PRM) requirement, which is the amount of capacity required to reliably meet expected demand over the forecast period.[35] While operating reserves are used in the shorter-term to respond to an unplanned event on the system, planning reserves are used in the longer term to ensure adequate power supply given a forecasted load in the years ahead.

The TD&R Licensee is required to carry adequate generating capacity to maintain reliability for Bermuda, in accordance with the EA. This additional capacity is necessary to mitigate against the uncertainty in the peak load. Uncertainty in peak load can be due to weather or forecast error.

In addition, each portfolio must have sufficient capacity to accommodate two or more generators in the system going offline due to unplanned failure or planned maintenance. Given the isolated island nature of its system, the grid must have sufficient capacity to safely operate without the two largest generators. This equates to 28.8 MW currently.

Historically BELCO has taken a more deterministic approach to determining the planning reserve margin, is shown below.

$$\begin{aligned} PRM(MW) = {} & dependable\ capacity\ of\ the\ two\ largest\ traditional\ generating\ resources \\ & + the\ dependable\ capacity\ of\ the\ WTE\ plant \\ & + the\ dependable\ capacity\ of\ the\ utlity\ scale\ solar \\ & + the\ aggregate\ dependable\ capacity\ of\ BTM\ solar \end{aligned}$$

As Bermuda moves towards a renewable and diverse energy mix, traditional planning methods must reflect a more probabilistic approach that considers statistical demand and weather patterns as well as the capacity contribution of variable and dispatchable resources. The TD&R Licensee has targeted a "1-day-in-10-years" reliability target, which is a standard reliability target across many utilities. The capacity needed to meet this target and accommodate planned and unplanned outages represents the total reliability need (TRN). From this total required capacity, the PRM can be determined as the required generation capacity

35 NERC Reliability Indicators.

available above peak system load to meet the reliability target. Often this is represented as a percentage of the peak demand forecast as shown below.

$$PRM(\text{percent}) = \frac{Total\ Reliabilty\ Need - Peak\ Demand}{Peak\ Demand}$$

The annual peak demand is unknown and must be forecasted based on load shape and load growth. Generally, the load shape exhibits seasonal, weekly, and daily periodic behaviour and will change over time due to technological and economic factors. The exact load depends on the weather, time of day, day of the year, and consumer behaviour. All these factors impact the time at which peak load occurs as well as the magnitude of the peak load. These factors must be considered when determining the PRM required to maintain reliability. The resulting PRM needed to meet the desired reliability target and accommodate N-2 security is reported in Table 19.

Table 19: Planning Reserve Margins

Year	PRM (%)	PRM (MW)
2024	39%	38.5
2025	40%	38.3
2026	40%	39.8
2027	40%	40.5
2028	40%	39.8
2029	40%	39.6
2030	40%	39.5
2031	40%	39.5
2032	40%	39.4
2033	40%	39.4
2034	40%	39.3
2035	40%	39.3
2036	40%	39.2
2037	40%	39.2
2038	40%	39.2
2039	40%	39.2
2040	41%	40.1
2041	41%	40.1
2042	41%	40.1
2043	41%	40.0
2044	41%	40.0
2045	41%	40.0
2046	41%	40.0
2047	41%	39.9
2048	41%	39.9
2049	41%	39.9
2050	41%	39.9

8.3. Effective Load Carrying Capacity (ELCC)

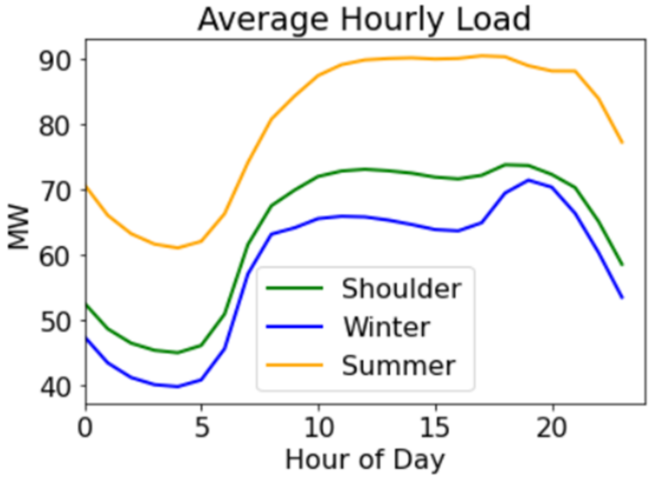
No generating resource is 100 percent reliable. Variable generators depend on the weather and thermal resources may experience forced outages. The ELCC was used to capture each resource's contribution towards meeting the PRM. The ELCC of a resource represents the required amount of "perfect" generating capacity needed to replace the imperfect resource while maintaining the same reliability.

It is important to note that the ELCC is not equivalent to the capacity factor (CF) of a resource. The CF is also on a zero to one scale representing the average power production of a resource, normalised by the installed capacity. In many cases, the ELCC will be lower than the CF since it focuses on a resource's contribution during periods of grid stress. When computing ELCC values, it is important to capture the shifting time of peak net load and the impact of the installed capacity on the ELCC. Interactions between technology types must be considered because they can have antagonistic or synergistic effects.

The ELCC for each technology is computed at varying installed capacities. These are reported for the summer, winter, and shoulder seasons. The ELCC is computed as the amount of "perfect" capacity that could be replaced while maintaining the same reliability. A sample of the seasonal ELCC values, as a function of installed capacity, is shown in Figure 21.

The average hourly seasonal loads are shown in Figure 20. These load shapes are useful in understanding the ELCC trends. The summer load is flat during the daytime hours. Thus, a resource would have to cover all high-load hours to achieve a high ELCC. In contrast, a resource needs only cover the evening peak in the winter to achieve a high ELCC. Wave and wind have the greatest potential for contribution in the winter and shoulder months, with lower contribution in the summer since they have lower summer output. The solar ELCCs have high summer values but do not contribute to winter or shoulder reliability since the peak load occurs after the sun has set during these seasons. There is a sharp decline of the solar ELCC with additional capacity since solar generation quickly shifts the peak net load after the sun has set. There are also significant synergies between all renewables and storage, particularly solar, since storage allows the energy generated by the renewable resource to be shifted to the greatest time of need. Wind, wave, and solar energy complement each other as they each have different resource patterns.

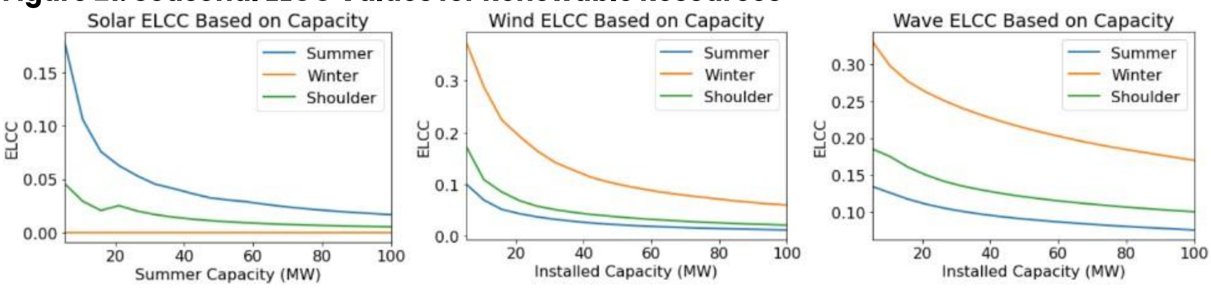
Figure 20. Average Seasonal Hourly Load



The computation of an ELCC value for battery storage is more challenging. The reliability impact of a storage asset is a function of both the technical properties of the battery and the decision on how to charge and discharge the battery. Batteries are used to minimise the peak daily load, using the average daily load profile for each season (Figure 21).

Computing the ELCC value for thermal resources is more straightforward since their output is controllable. The ELCC value for these thermal resources is one minus the forced outage rate.

Figure 21. Seasonal ELCC Values for Renewable Resources



8.4. Ensuring Adequate System Flexibility

The second component of reliability is flexibility. This means having sufficiently flexible dispatchable generating resources to meet any changes in net load (gross load less renewable). If the conventional resources are not sufficiently flexible, the grid could experience load-shedding events due to sharp changes in net load. This will become increasingly important as the portion of renewables increases, since such increases can induce sharp changes in net load. Some utilities have required additional ramping reserves to ensure that there are sufficient fast resources to counter these challenges. These potential flexibility challenges are of interest to Bermuda to achieve high levels of decarbonisation while maintaining reliability.

However, Bermuda is well-positioned to meet these challenges presently and into the future. The existing dispatchable generating resources and the potential future resources considered in this IRP Proposal are highly flexible. Bermuda requires a flexible resource mix to accommodate the variability and uncertainty of intermittent renewables. While these reserves are not explicitly modelled, the ability of future resources to ramp up or serve as commitment units from an offline state should adequately cover this requirement.

9. Model Set Up and Process

Aurora is a commercially available third-party software used to evaluate alternative supply- and demand-side portfolios. Aurora is a reputable tool that is used by utilities internationally to assess the trade-offs between resource options. At Aurora's core is a chronological production cost dispatch engine that evaluates hourly least cost dispatch for a portfolio of resources against a stated demand. Aurora can also identify the least cost optimal schedule of plant retirements and additions to meet a required reserve margin target or renewable targets, subject to a set of operating constraints.

The portfolios were set up within Aurora with all owned and contracted resources. Aurora simulates the hourly chronological dispatch of energy assets and calculates all variable costs associated with the dispatch of owned resources (e.g., fuel, variable operating and maintenance, startup, and emission costs). The Aurora model was run hourly from 2023 to 2050 to evaluate all portfolios against all scenarios. A discussion of the portfolios and scenarios is found in Section 10.1. The full range of planning scenario assumptions defined in Section 10.2 applies to this Aurora portfolio modelling exercise.

9.1.1. Supply Resources

In addition to the owned and contracted resources in the energy system, several other load-varying resources were included in the model. BTM solar was modelled as a distributed generation resource.[36] As BTM solar adoption continues to grow, an assessment was conducted on the distribution level to forecast the ultimate capacity and energy generation capability. Scenarios also altered the state of resource penetration, as discussed further in Section 10. BTM solar follows the same

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[36] As BTM solar is not under the control of the utility, the projections were modelled as given and not included as part of the capacity expansion.

production shape as the other solar resources that are included in Section 7.2.1. By modelling as a supply-side resource, adjustments to the forecast could be easily integrated into the model.

9.1.2. Demand Resources

Electric vehicle penetration in Bermuda is expected to grow over time. Electric vehicles were modelled as part of the demand. EVs are modelled to include the actual vehicle demand and the charging shape to properly simulate the energy demand on the system. EVs are given a negative capacity value, which simulates a resource drawing load from the grid.

The model was set up to include EE programmes and BTM solar was always considered. The resources were set to "must run" so every dispatch result includes generation from these resources. These programmes include residential lighting, appliances, and commercial HVAC systems, among others. Like BTM solar, it is expected that these resources will change over time so modelling them as a supply-side resource allows for easier adjustments.

10. Planning Scenarios

10.1. Overview and Development of Planning Scenarios

As part of the IRP Proposal analysis, the latest market, technology, and policy assumptions were accounted for. The first is the reference scenario (REF) that represents the view of the future where Bermuda continues to evolve based on current expectations for load growth, commodity price trajectories, and technology development. The Bermuda Government pushes to address the social and economic impacts of carbon emissions in electric sector planning. Two additional market scenarios were evaluated, in addition to the REF scenario, that describe plausible futures that may develop over time and result in a materially different set of market conditions under which, regardless of how the future plays out, supply will need to meet demand. Each scenario is driven by a set of thematically oriented fundamental market assumptions. These scenarios are used to test the robustness of portfolio choices to future market conditions. Table 20 summarises the key drivers of each scenario in a matrix.

High Commodity Price Environment Case

As Bermuda is currently fuel oil-dependent, the high commodity price (HCP) environment case scenario tests an environment where commodity costs for fuel oil and LNG are high. This is caused by geopolitical tensions and production challenges that keep oil and natural gas prices high in the long run. A high commodity price environment pushes retail electric rates and gasoline prices higher, accelerating distributed generation and electric vehicle penetration. Sustained, high electric and fuel prices affect tourism and the cost of doing business on the island and negatively impact demand growth while promoting investments in demand-side management programmes. Technology costs remain stable and decline at the same rate as the REF scenario, with gradual relief of supply chain pressure over time.

Technology Driven Decarbonisation Case

The technology driven decarbonisation (TDD) case scenario evaluates an aggressive global shift to decarbonise the electricity sector. Global technology development and the resolution of supply chain issues push towards a decarbonised economy supporting renewables and other non-emitting technologies with large-scale electrification in the transportation sector. As technology costs reduce, there is a significant shift away from fossil fuels in all sectors of the economy, putting downward pressure on global oil and natural gas prices. Low fuel prices in the long run disincentivise DSM programmes but keep distributed generation investments at a base level due to lower technology costs. Demand growth on the island is unaffected as fundamental macro drivers for the Bermuda economy remain unchanged.

Table 20. Scenario Assumption Matrix

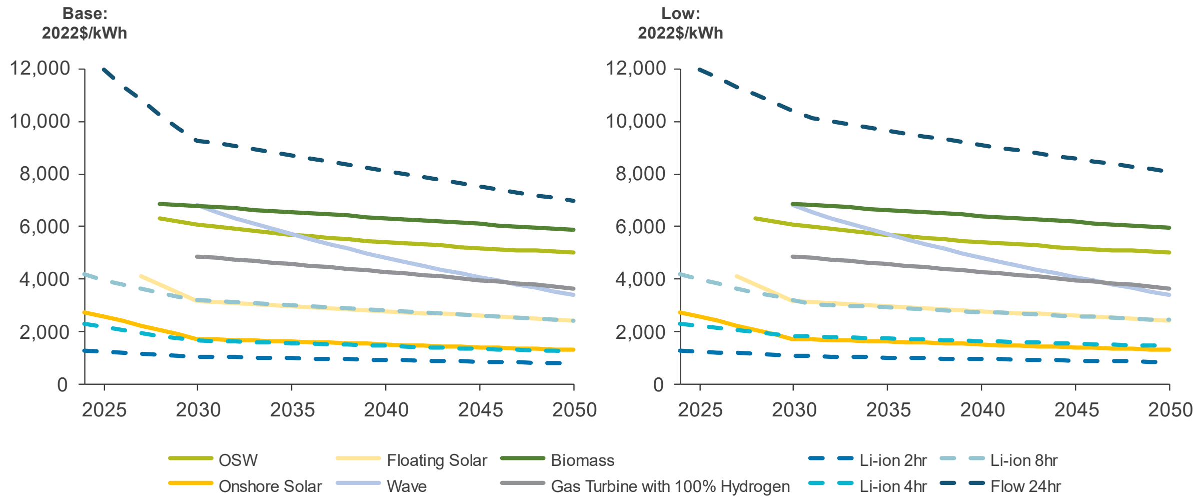
Scenario Concept	REF	HCP	TDD
Technology Costs	Base	Base	Low
Fuel Prices	Base	High	Low
Macro Load Growth	Base	Low	Base
Demand-Side Management	Base	High	Low
EV Penetration	Low	Base	High
Distributed Solar Penetration	Base	High	Base

10.2. Scenario Inputs

10.2.1. Scenario Technology Cost Assumptions

To calculate scenario technology costs, the same starting CapEx for each technology was used and the technology learning rates were altered over the forecast period. The "Moderate" and "Advanced" learning rate curves from NREL's Annual Technology Baseline (ATB) were used and applied them to the REF and TDD scenarios respectively. The advanced learning rates have an accelerated cost decline curve giving lower technology costs over the forecast period. CapEx for the various technologies over the forecast period can be seen in Figure 22.[37]

Figure 22. Scenario Technology Assumptions - Base and Low



10.2.2. Scenario Fuel Cost Assumptions

Fuel cost ranges were compiled based on various predictive scenarios within the EIA AEO 2023 and can be seen in Figure 23.[38] A combination of CRA's internal fuel forecasts and EIA scenarios were used to arrive at the final fuel forecast scenarios.

The purpose of altering commodity costs is to present the impact of high and low fuel prices on resource selection and cost to customer. As a result, the EIA forecast scenarios used for the Low forecast were "Low LNG Price" and "High Oil and Gas Supply" and the High forecasts were based on the "Low Oil and Gas Supply" scenario, which was the most downside forecast. Final delivered costs included the same adders as the REF scenario.

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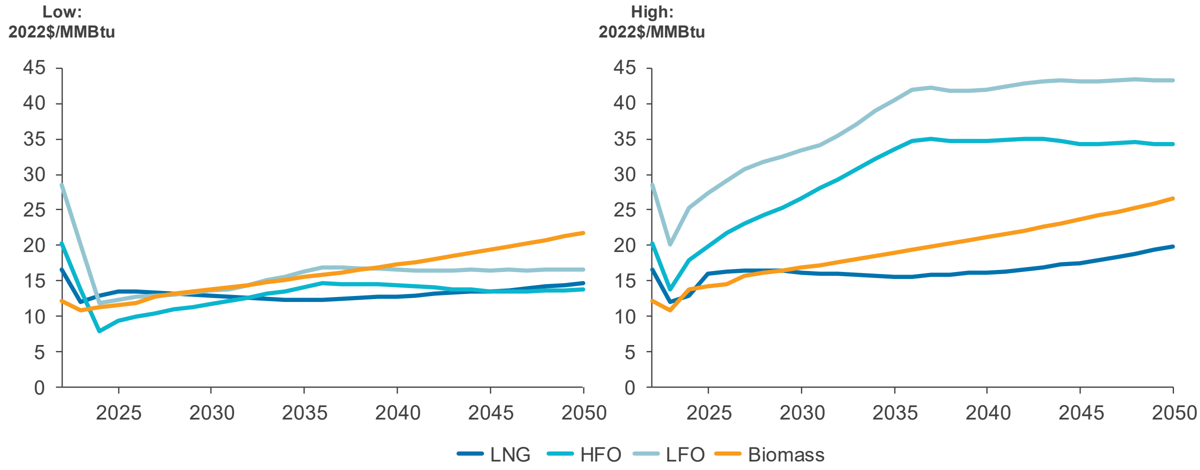
37 Note that CapEx over the forecast period is displayed in nominal terms and does not reflect inflation, only learning rates.

38 Table 12. Petroleum and Other Liquids Prices, AEO 2023

Biomass fuel cost assumptions for the various scenarios were generated by altering the delivery cost of biomass. This in turn was based on the range of HFO used for the various scenarios. In lieu of a dispatchable renewable energy, biomass is used as a placeholder. The biomass fuel cost is comprised of commodity price, ocean shipping and delivery to port. In the scenarios, only the biomass ocean shipping costs were altered.

Figure 23. Fuel Forecast High and Low Forecasts



10.2.3. Scenario Load Assumptions

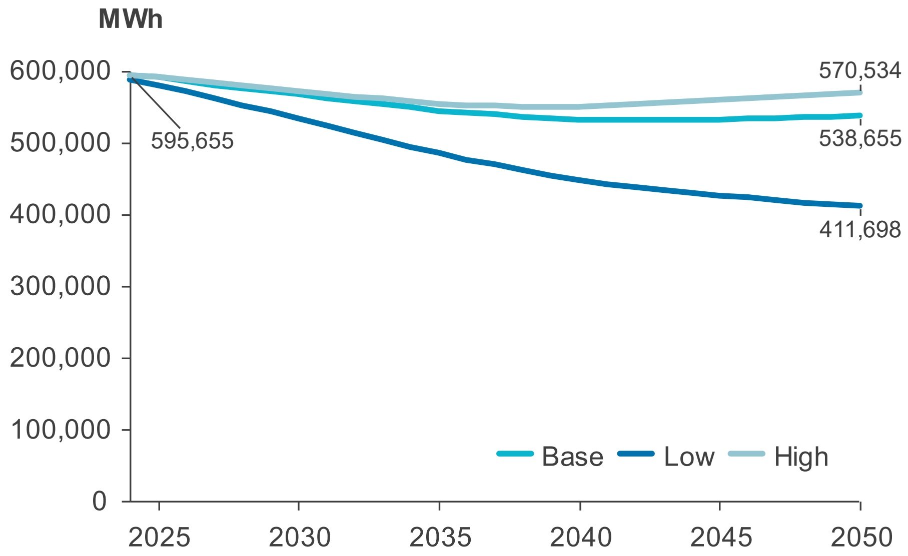
Load ranges revolved around varying gross system demand and load-varying resources such as EV, EE, and BTM Solar. The underlying system load is based on historical load and customer data. Changes to these resource levels can represent plausible future load conditions on the energy system.

Load-varying resources impact net load, which is the ultimate demand that supply side resources will need to meet. As described further in Sections 5.7 and 6, these resources are added as either a demand side or supply side resource. A higher EV penetration adds more demand to the system due to greater demand for EV charging, while a higher penetration of DSM and BTM Solar lowers the overall system load. These load-varying resources will complement the underlying system load, which is described in Section 5.

The TDD case flexes the EV, EE, and BTM projections with the gross demand being the same as the reference case. The system base load in the TDD case was not changed because historical data has not shown any significant load growth. Increasing EV load and lowering DSM and BTM penetration results in a higher overall net load case.

The HCP case uses the low system load in addition to decreases in EV and increases in DSM and BTM resources. These effects will simulate an overall net load case with less generation needed from baseload generation and renewables.

Figure 24. Net Load (Energy) Scenario Comparison



11. Portfolio Development

As described in section 9, the Aurora software was used to analyse how supply-and-demand-side resource portfolios can evolve under future market conditions. This section describes how alternative portfolios were selected and analysed.

The Aurora software can run a portfolio optimisation programme that finds the least cost resource solution given a set of resource options, market assumptions, and any modelling constraints or requirements. For this IRP Proposal, 11 optimising simulations were run with varying resource options and modelling constraints. Market assumptions were tested separately in the scenario analysis.

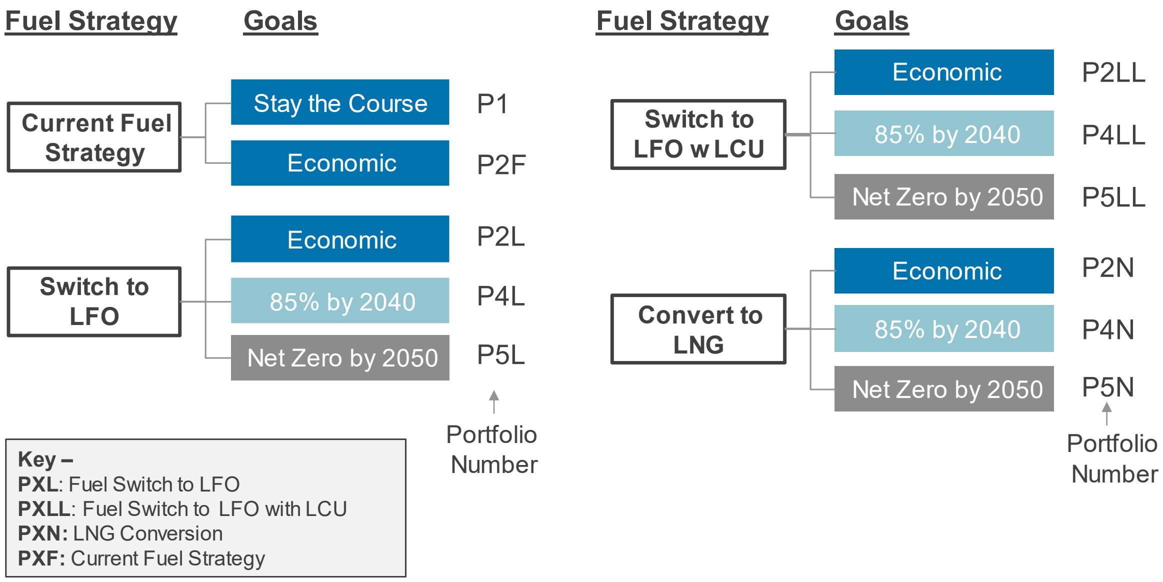
The 11 optimising simulations varied the fuel strategy and the clean energy target. The fuel strategy included the option of shifting to burn exclusively LFO or LNG in the NPS, EPS, and GT units. Currently, HFO is burned in the NPS and EPS while LFO is burned in the GT units. Converting the engines to run on LNG would require capital investment.

Each fuel strategy was then run under different conditions, economic or carbon constrained. The economic portfolios have no clean energy target and optimise for the lowest cost. For the carbon-constrained portfolios, two targets were tested, 85 percent renewable generation by 2040 and Net Zero by 2050. The 2019 Bermuda

IRP set an 85 percent renewable generation goal for 2035. As the IRP is meant to be a living document that is updated periodically, the 2035 timeline was found to be too aggressive for the technology options and too expensive. Thus, the target was pushed out to 2040.

Figure 25 illustrates the portfolio input permutations.

Figure 25. IRP Proposal Portfolio Buildout Combinations



12. Modelling Results

Across all the portfolios, there is a significant build out of wind, storage, and solar. Section 12.1 shows the results of the optimisation modelling for the procurement window (2030), the 20-year forecast period (2043), and the long-term (2050) on an installed capacity (ICAP) and unforced capacity (UCAP) basis. ICAP represents the total installed capacity, also known as nameplate capacity, that is required. UCAP is the amount of reliable capacity that can be attributed to each resource and delivered during peak demand, which is derated based on their ELCCs.[39] By 2050, the EPS units will be retired, and the resource gap must be filled with alternatives. Biomass, or another clean dispatchable resource, is built over the long-term to provide additional dispatchability and reliability.

12.1. Portfolio Expansion and Dispatch Results

The capacity expansion modelling resulted in the buildout shown in the following sections presented in UCAP MW and ICAP MW. The buildout was optimised for the

[39] Terminology for ICAP, UCAP, CIRs, and ELCC; PJM.

least cost, subject to annual (and horizon) resource constraints, reserve margin, renewable energy generation targets, operating reserve requirements, and land constraints.

There are significant amounts of storage added to shore up the capacity position, time shift renewables, and provide reserves, which becomes increasingly necessary as renewable penetration increases and thermal generation retires. These storage units are needed as renewables do not provide significant capacity credit and their contribution to the reserve margin declines as more renewables are added. Outside of biomass, storage is the only new resource that provides material capacity values to meet reserve margin targets as engines and existing gas turbines retire over time.

12.1.1. Procurement Window Buildout (Through 2030)

The buildout during the procurement window is shown in Figure 25 and Figure 26. Throughout the procurement window, all portfolios build an additional 15 MW to 20 MW ICAP of Onshore Solar, most build 60 MW of OSW, and a few builds 5 MW to 10 MW of Floating Solar. In most of the carbon-constrained portfolios (P4 and P5), biomass gets built during the procurement window to achieve the 85 percent or 95 percent renewable generation targets.

Onshore solar and offshore wind get built the earliest. These technologies have the lowest LCOE, and the model finds it economical to build these technologies relative to dispatching the engines with expensive fuel. Therefore, during the procurement window, as renewables get built, the dispatch of the engines is reduced significantly.

Figure 26. Capacity in ICAP for all Portfolios in 2030

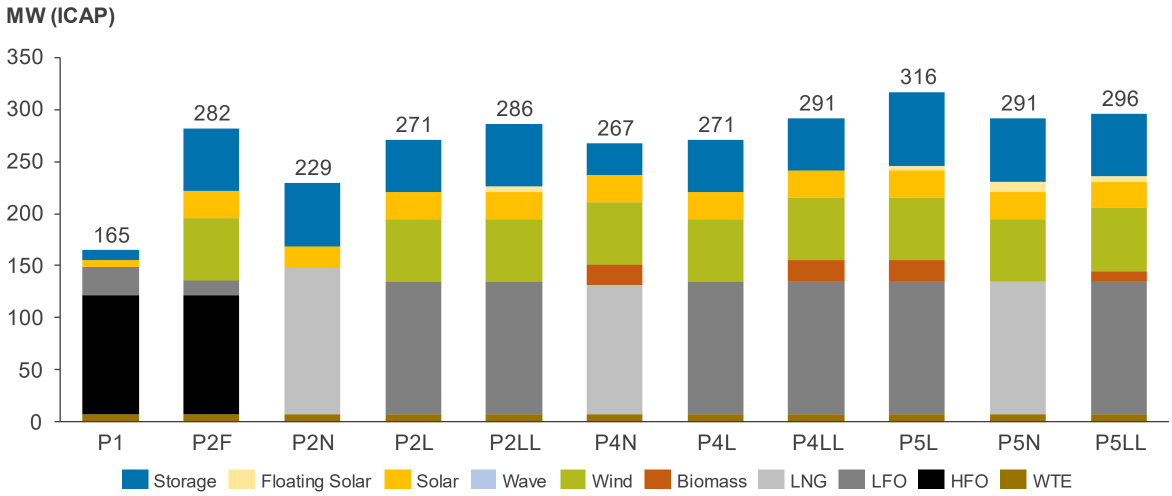
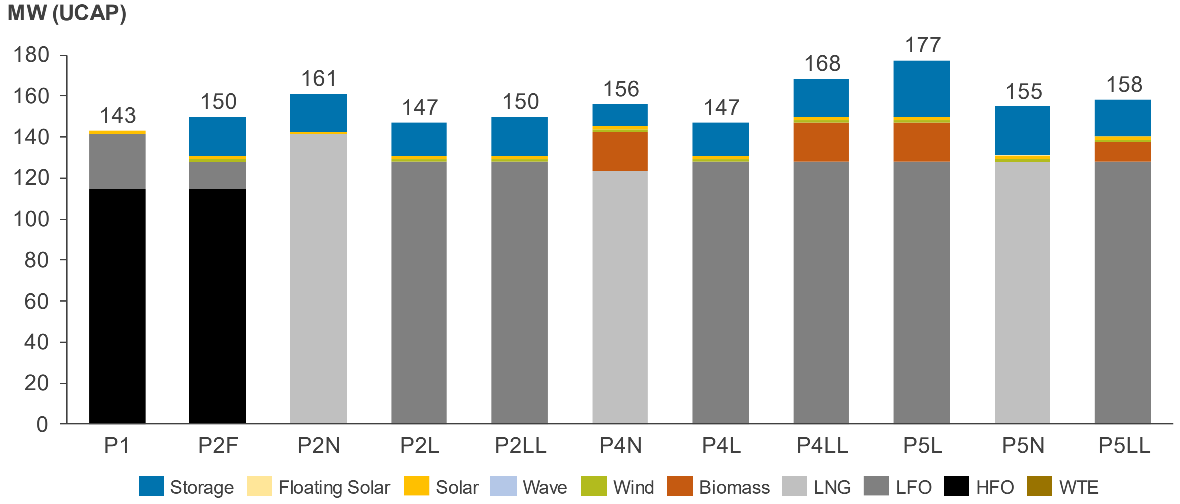


Figure 27. Capacity in UCAP for all Portfolios in 2030



For all portfolios except one, there is at least 50 MW of storage built during the procurement window. The storage buildout is primarily 4-hour Lithium-Ion batteries, with support from 2- and 8-hour durations. Batteries complement renewables, provide energy time shifting, spinning reserves, capacity value, and ancillary services. Due to the renewable buildout similarities between portfolios by 2030, overall battery buildout is similar across all economic and carbon-constrained portfolios.

12.1.2. 20-Year Buildout (2024 to 2043)

The buildout during the forecast window is shown in Figure 28 and Figure 29. Some resources like solar and OSW have already reached the maximum buildout in the procurement window. From 2030 to 2043, Bermuda's system will likely add approximately 50 MW of floating solar and 100 MW to 150 MW of storage. There is also about 10 MW to 20 MW of a clean dispatchable resource, such as biomass, built in most portfolios by 2043. For the carbon-constrained portfolios, they all build a clean dispatchable resource option and almost all will have at least 50 MW of floating solar and an average of 170 MW of storage. After 2043, there are additional floating solar buildouts and approximately another 50 MW of storage build.

Figure 28. Capacity in ICAP for all Portfolios in 2043 (20-year forecast)

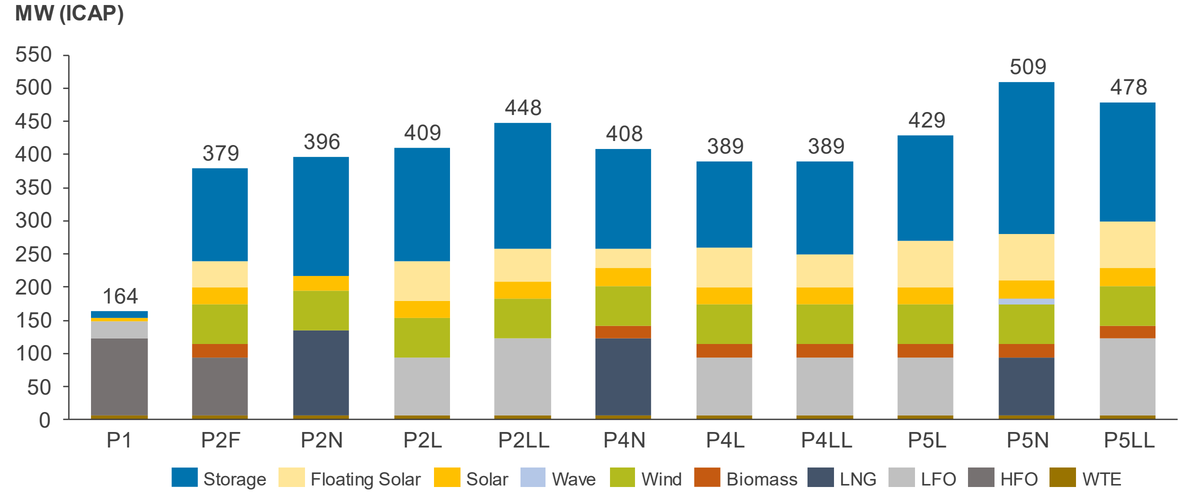
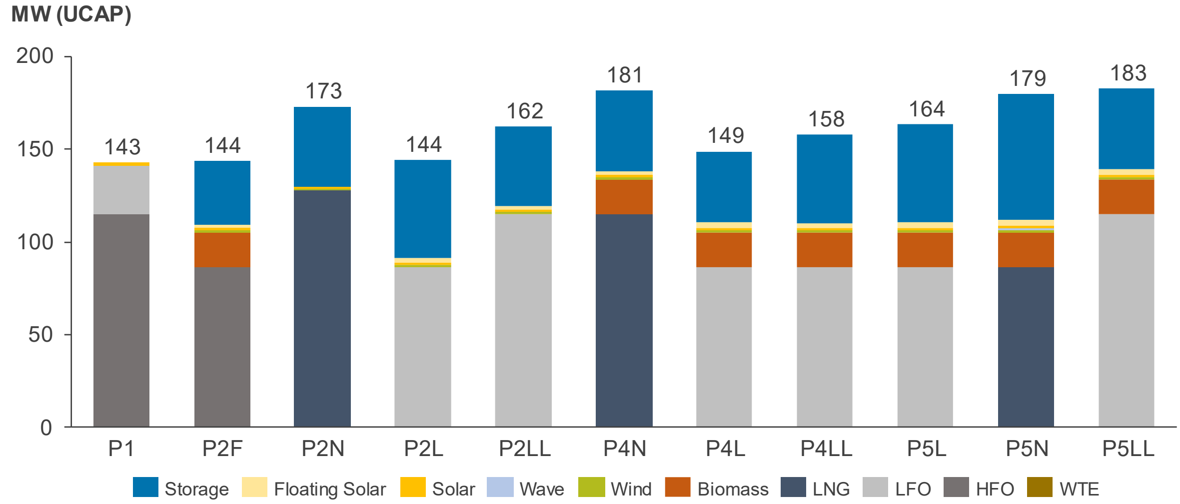


Figure 29. Capacity in UCAP for all Portfolios in 2043



12.1.3. Long-Term Buildout (2024 to 2050)

By 2050, the buildout will increase significantly, and most portfolios have at least 200 MW of storage, 170 MW of renewables, and 20 MW of biomass or another alternative dispatchable resource. At the end of the forecast horizon, only the NPS units remain operational. Between 2030 and 2050, additional renewables in the form of floating solar and clean dispatchable resources will be added. Figure 30 shows the post procurement period buildout in ICAP and Figure 31 shows the buildout in UCAP (MW).

Figure 30. 2050 Capacity in ICAP for all Portfolios

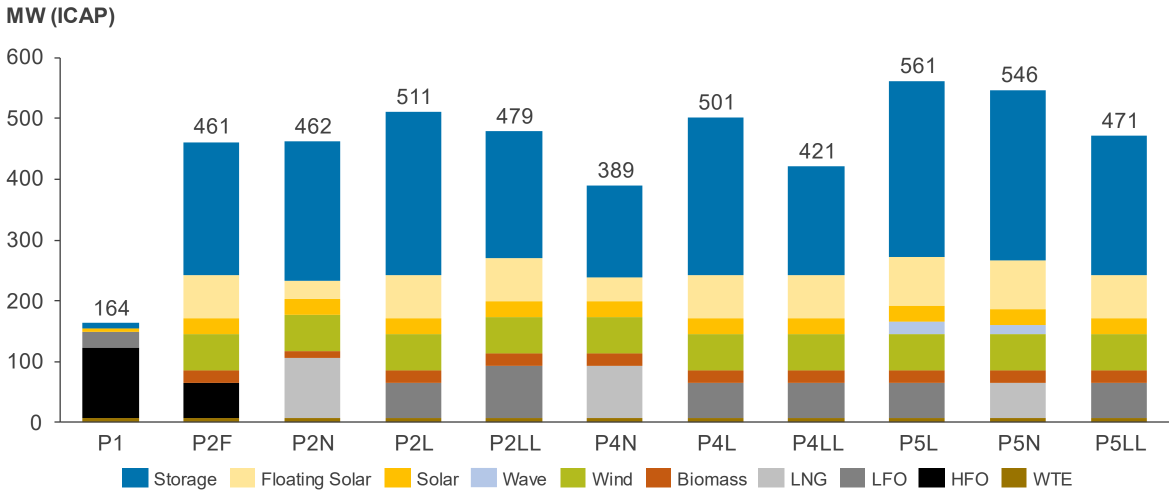
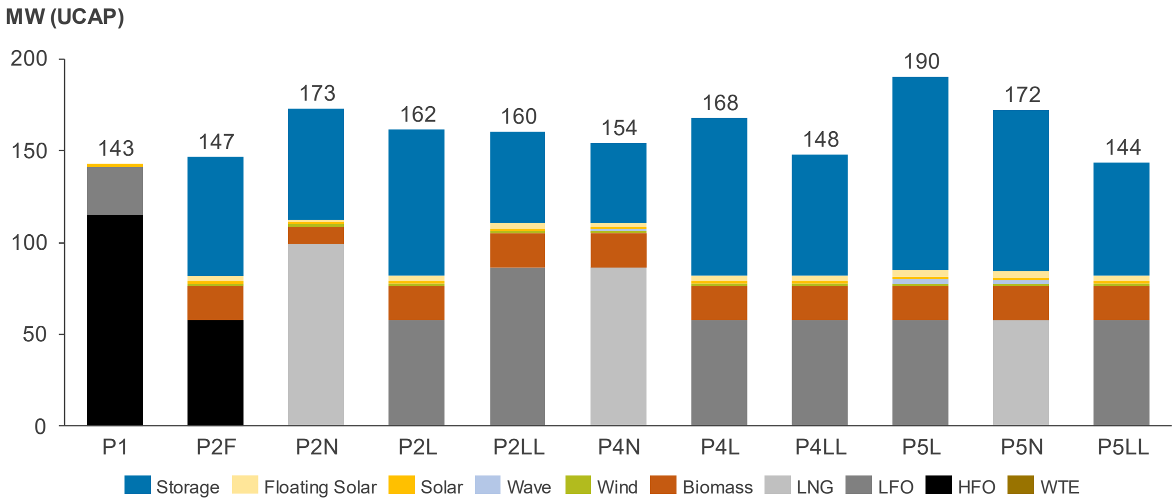


Figure 31. 2050 Capacity in UCAP for all Portfolios.



12.1.4. Battery Dispatch

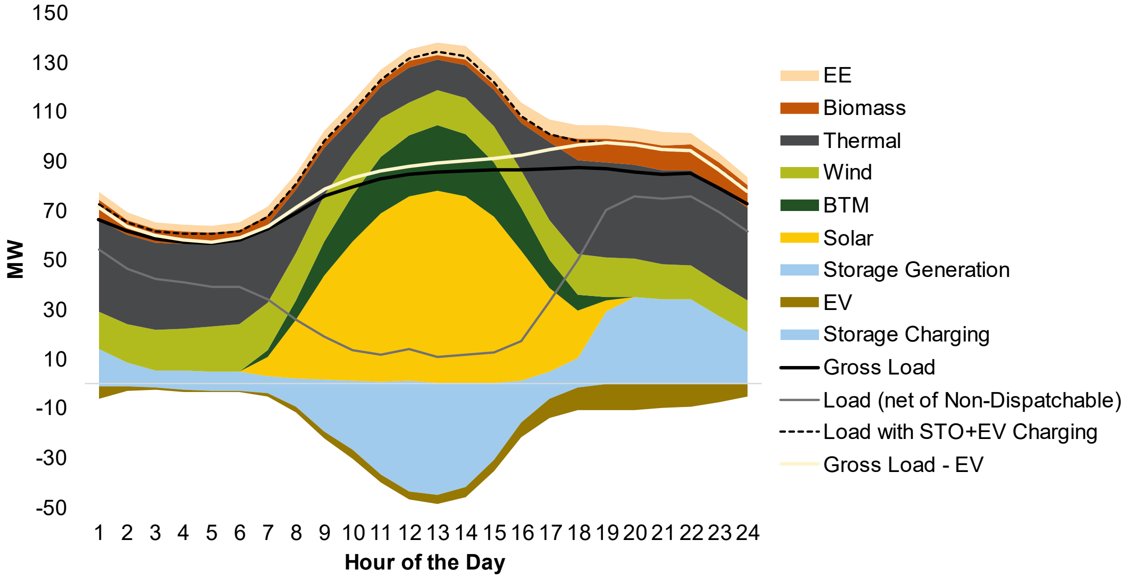
Renewable builds such as wind and solar need storage as the generation output is not always aligned with demand. As discussed previously, batteries are used to perform energy time shifting by charging during high renewable penetration hours and discharging when renewables are unavailable. Battery charge and discharge cycle follow load and available renewable generation and changes depending on the hour of the day as well as the season.[40]

Sometimes the renewables and storage are not enough to meet demand and charging demand at all hours, thereby requiring dispatchable resources. This is also partly because storage units may at times be held for reserves and are not

[40] The batteries were allowed to have one charge and discharge cycle per day, which offers a conservative view of overall battery performance.

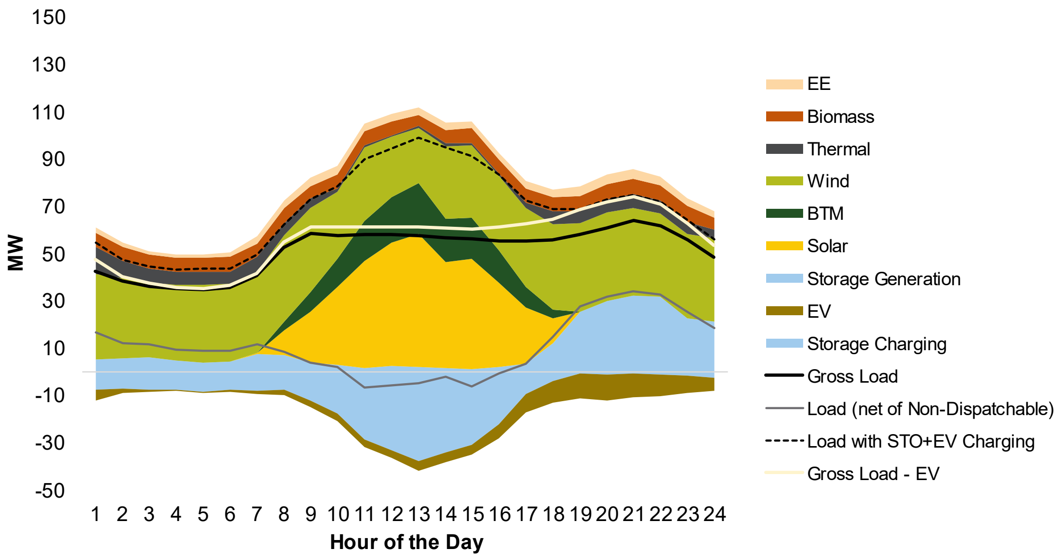
available to provide energy. Resources such as HFO, LFO, LNG, or biomass are needed to supplement the storage during the late evening and early morning hours when solar is unavailable. Figure 32 demonstrates this phenomenon.

Figure 32. High Load Month – August 2050



During a low load month such as March (Figure 33), solar generation is lower, but wind generation is higher. Batteries are still primarily charging in the early hours of the day with wind generation and discharging during the night. However, since wind generation is more stable throughout the day compared to solar and the load is overall lower, dispatchable resources are not relied upon nearly as much during shoulder months.

Figure 33. Low Load Month – March 2050



12.1.5. Early Retirements

Early retirements were allowed in the capacity expansion model. Overall, most portfolios economically retired the EPS engines a few years before their listed retirement date. The model elects to economically retire a unit if the energy margins earned by the unit are not enough to recover the unit's fixed O&M. The earliest EPS engine retirement occurred in 2036 in P4LL.

Table 21. Early Retirements by Portfolio

Portfolio	Early Retirements
P1	–
P2F	–
P2N	E7 / E8: 2043
P2L	–
P2LL	E5 / E6: 2048
P4L	E5 / E6: 2039
P4LL	E5 / E6: 2036 E7 / E8: 2049
P4N	E5 / E6: 2039
P5L	–
P5LL	E5 / E6: 2043 E7 / E8: 2049
P5N	E5 / E6: 2043 E7 / E8: 2040

12.1.6. Projected Generation Mix

Figure 35 shows the generation mix for all portfolios in 2043 and Figure 35 shows the generation mix in 2050. Renewable builds significantly reduce dispatch from engines in all portfolios, with wind accounting for nearly a third of the total energy demand. There is also a significant contribution from solar. The P2 portfolios show a higher level of generation contribution from engines as fewer renewables are built economically compared to portfolios with 85 percent renewable (P4) and Net Zero (P5) portfolios.

Due to the lowered overall fuel cost of LNG compared to HFO and LFO, LNG generation is higher in P2N compared to the other economic cases. Decarbonisation pressures from P4N and P5N lead to similar thermal and renewable generation between the LFO and LNG portfolios. Biomass is also favoured in carbon-constrained portfolios because it offers flexibility as a dispatchable resource while also allowing the system to reach its renewable goals.

Figure 34. Generation Mix in 2043 by Portfolio

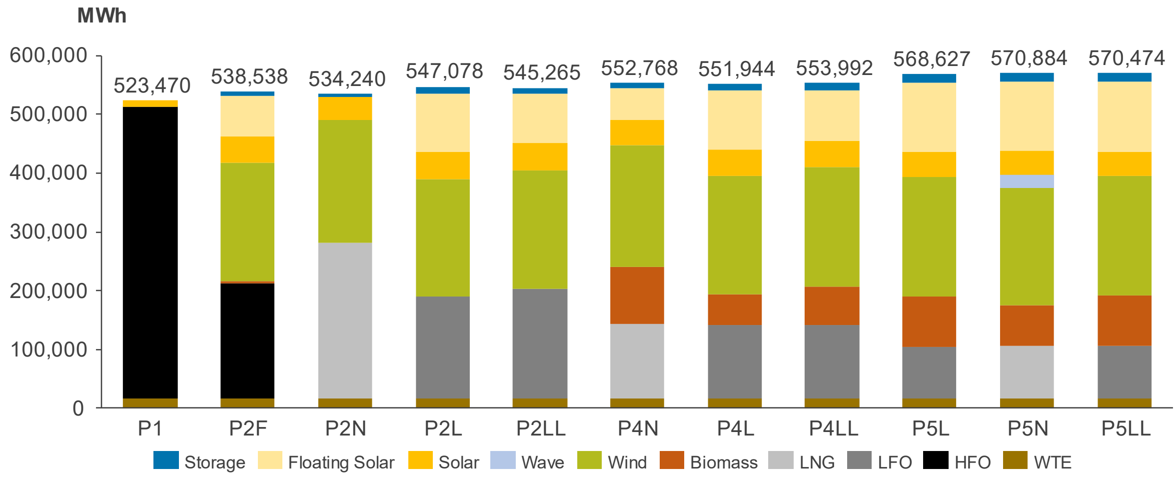
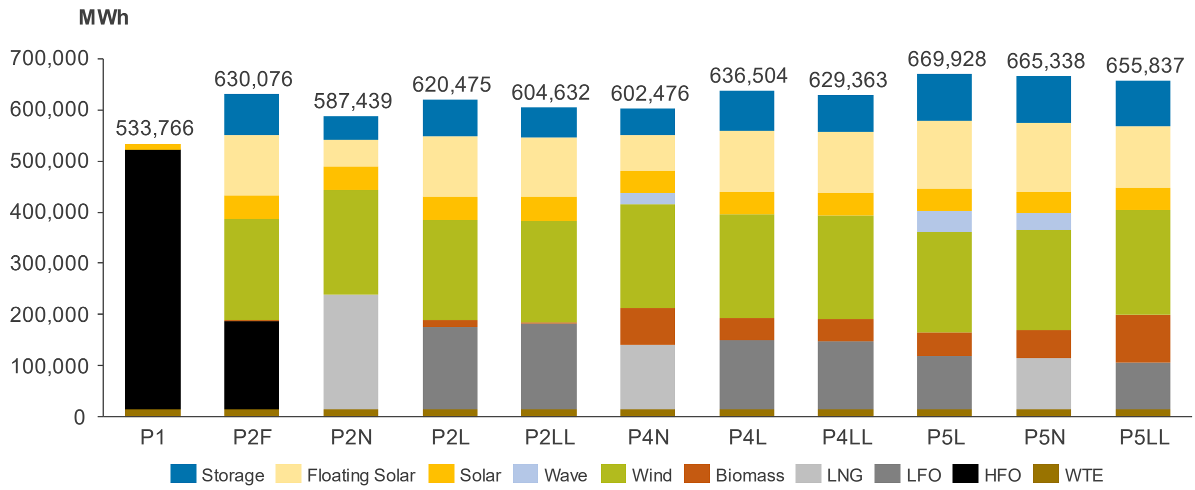


Figure 35. Generation Mix in 2050 by Portfolio



12.1.7. Projected Carbon Emissions

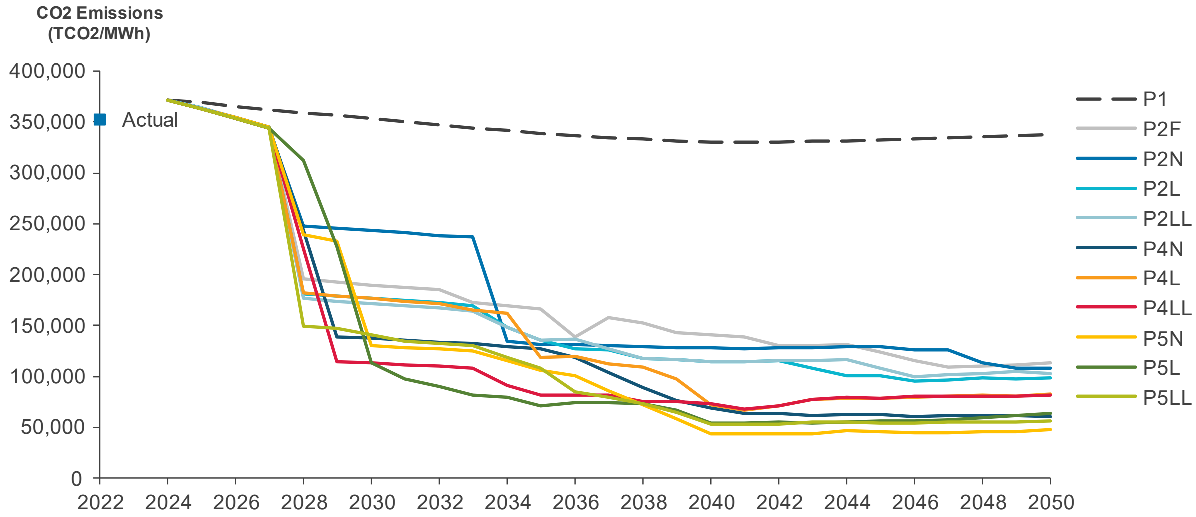
The emission reductions associated with each portfolio were compared to Bermuda's electricity generation 2022 scope 1 emission levels which were 352,715 tCO_{2e}. Figure 36 shows the carbon emissions for the forecast period. Emissions increase from 2022 levels before they start to decline in 2027. The Net Zero targeted portfolios, P5L, P5LL, and P5N, experience the largest declines in emissions by 2043 at 87 percent, 87 percent, and 90 percent, respectively. The 85 percent renewable targeted portfolios have emission reductions of 82 percent for P4L and P4LL and 85 percent for P4N. The economic targeted portfolios (P2s) experience the least emission reductions ranging from 67 percent to 73 percent by 2050.

Large declines in emissions can be seen in all of the portfolios as renewables come online (especially wind). As noted previously, wind generation meets approximately one third of the energy demand, resulting in large reductions in average emissions. After this drop, emissions slowly decline through 2040 and remain steady until 2050. By 2040, all 85 percent renewable targeted portfolios (P4s) have reached 85 percent renewable energy and all Net Zero targeted P5 portfolios (P5s) have reached 95 percent renewable energy, as expected.

After 2040, emissions generally remain stable because there are no significant renewable buildouts in the 85 percent renewable targeted and Net Zero targeted portfolios or a significant shift in generation dynamics. In the economic portfolios, the continued buildout of floating solar allows further reductions in emissions, and, in some carbon-constrained portfolios, wave power comes online after 2045 further reducing emissions.

Achieving Net Zero or 100 percent scope 1 emission reductions was investigated. It was demonstrated that without emerging technologies and rapid learning curves, Net Zero would be a challenge for Bermuda at a reasonable cost. Results indicated that hydrogen fuelled generators could provide a balance of affordability and sustainability, if commodities such as green hydrogen are produced at lower cost.

Figure 36. Carbon Emission Projections



13. Stochastic Risk Analysis

13.1. Assessing the reliability of a proposed portfolio

A stochastic risk analysis was performed to assess the reliability of the proposed portfolios. The analysis simulates random events to quantify the likelihood, magnitude, and duration of a potential load shed. The reliability was found to be maintained in all potential portfolios. It is important to note that these are predictions based on the probability of grid behaviour. It cannot predict when load shedding or stressed conditions occur but can identify periods when they are more likely to occur. The analysis can be used to identify possible causes and mitigations of load shedding conditions.

A Monte Carlo-based stochastic risk analysis was performed for each portfolio from the years 2025 to 2050. To achieve this, 100 possible wind generation, solar generation, and load demand annual time series were simulated. The unavailability of each resource was also simulated by randomly generating failure events and accounting for planned maintenance events. To accurately capture the impact of the bulk storage resources, the stored energy and charging/discharging behaviour of the battery for each hour of the day was tracked. It was assumed that any unused renewable capacity was used to charge the batteries. It was also assumed that the battery resources would only be discharged after all other resources had been utilised. It is recognised that this may not be the typical operating strategy as the batteries' utilisation will be based on load forecasts and weather predictions whilst balancing along with available capacity and dispatch cost minimisations.

The reliability and risk associated with each portfolio was evaluated using the Loss of Load Expectation (LOLE), which computes the expected number of days per year where at least one shortfall or load shedding event occurs. The "1-day-in-10-years" reliability target is equivalent to meeting a 0.1 LOLE target. All portfolios achieved the desired reliability target in the planning window and all load shedding events modelled occurred during the summer months.

The results demonstrate that the summer months are more likely to experience stressed conditions than the other seasons. For all outage events, the expected magnitude and duration of the outage was recorded. All load shedding event durations were 1 hour or less. The low magnitude of the load shedding indicates that these potentially tight operating conditions could be countered using demand-side response. The demand side response was not simulated in the stochastic risk assessment. The portfolios were assessed for load shedding due to a lack of flexible resources, but none of these instances were found. This is due to the high flexibility afforded by these potential portfolios.

Further examination of the stochastic risk assessment results revealed that all load shedding events were caused by a generator failure during or slightly before a high net load event. Generator failures before the actual event impacted the system's performance because they limited the ability to charge storage resources. This indicates that preventing forced outages, particularly during the summer months, is important to maintaining reliability. Lastly, the importance of storage and proactively charging the storage resources before peak net load events in maintaining system reliability in high-renewable portfolios is recognised.

14. Financial Revenue Requirement Analysis and Results

14.1. Overview of CRA's Financial Model

CRA's financial model projects utility revenue requirements by using inputs from Aurora (which include total variable power supply costs), capital expenditures associated with the new or existing fleet, fixed operating and maintenance (FOM) costs, and financial accounting of depreciation, taxes, and utility return on investment. For the IRP Proposal, an annual revenue requirement was projected for the 2023 through 2050 period. The following sections describe in greater detail the key financial assumptions, financial accounting of the existing assets and future replacement resources, and the overall approach for projecting impact on customer rates.

14.2. Financial Model Calculation of Customer Rates

The financial model provides a projection of annual bundled customer rates on a cents per kilowatt-hour basis by dividing the total annual revenue requirement by the energy demand for that year. First-year rates generated from the financial model are baselined against actual electricity rates (less RA fees, governmental fuel taxes, etc.) to validate the model. The annual revenue requirement is estimated from the bottom up by summing five key categories: book depreciation, O&M expense, return on equity and cost of debt.

The book depreciation component includes depreciation expenses of existing resources, depreciation expenses of new resources, depreciation expenses of ongoing maintenance, and amortisation. Assets will continue to depreciate in this model, even if they're retired early.

The O&M expense component can be broadly broken down into variable O&M (VOM) expenses, fixed O&M (FOM) expenses, and DSM costs. VOM expenses include those incurred during the normal operation of resources, including fuel costs, startup costs, and emissions costs. FOM expenses include those incurred regularly to maintain the operation of resources, including regular maintenance and labour. DSM costs represent those incurred by the TD&R Licensee to deploy system-wide DSM programmes to customers.

The return on equity and cost of debt components represents the financing costs required to operate the utility, including the financing of new resource construction and transmission upgrade projects. The financial model does not treat future assets as if they are owned by any specific entity and applies the same input assumptions for future project costs, irrespective of ownership in accordance with the EA and RA Guidance.

At present, the TD&R Licensee does not incur any tax on profits.

14.3. Financial Module Treatment of Existing Assets

Costs associated with existing resources are handled largely endogenously within the financial model. The model inputs the starting rate base, inclusive of BELCO BG; TD&R; and other/shared rate base components. The BELCO BG component of the rate base is largely comprised of BELCO BG's existing generating assets, including the EPS, NPS and existing battery storage.

Forecasts of sustaining capital expenditures, routine maintenance costs, and depreciation expenses for BELCO BG, TD&R, and other/shared assets are generated based on historical values and used as inputs to the financial model. As each candidate portfolio is run through the model, BELCO BG forecasts for sustaining capital expenditures and routine maintenance costs are adjusted to account for any early retirements, extensions, or upgrades of the EPS engines, and the TD&R forecasts are adjusted to account for any necessary pipeline costs associated with switching to LNG as the primary fuel. Any sustaining capital expenditures are added to the rate base, and any routine maintenance costs are added to the O&M section of the revenue requirement build-up. Intermittent major repairs for BELCO BG's existing generating assets are amortised over three years and added to the book depreciation section of the revenue requirement build-up.

Other O&M costs associated with existing generating resources, including fuel costs and VOM expenses, depend on the dispatch schedule of each resource and are received as outputs from Aurora's standard zonal modelling. These costs are added to the O&M section of the revenue requirement build-up.

14.4. Financial Module Treatment of New Resources

As with existing resources, costs associated with new resources are handled largely endogenously within the financial model. Using the outputs from Aurora's capacity expansion modelling, the financial model incorporates the deployment schedule of new resources with the capital cost and FOM forecasts discussed in Section 7.2 to calculate annual capital expenditures and FOM expenses for new generating resources. For each new resource, an allowance for funds used during construction (AFUDC) adder is included in the annual capital expenditure total to arrive at the all-in capital cost, inclusive of funds used during construction. In the year that these resources enter service, their book values are added to the rate base and depreciated according to the serviceable lifetimes discussed in Section 7.2, and their FOM expenses are added to the O&M section of the revenue requirement build-up.

Other O&M costs associated with new generating resources, including fuel costs and VOM expenses, depend on the dispatch schedule of each resource and are received as outputs from Aurora. These costs are added to the O&M section of the revenue requirement build-up.

14.5. Financial Findings

At a high level, the results of the financial model indicate a trade-off between capital expenditures and operational expenditures. The current fleet of generating resources relies heavily on thermal resources, i.e., engines burning fuel oil. Procuring and importing fuel oil to Bermuda is expensive. As a result, the portfolio representing the "Stay the Course" trajectory, P1, sees high annual operational expenditures (OpEx) totals, to which fuel costs are the largest contributor. Each of the other portfolios modelled here calls for new, non-thermal generating capacity in the form of OSW, solar, and battery storage. These resources have low variable O&M costs compared to the existing fleet, with most of the cost locked up in capital and fixed O&M costs. The result is a set of portfolios with much higher CapEx totals, but much lower OpEx totals compared to P1.

The non-thermal resource options can be highly capital-intensive due to financing, procurement, and deployment costs. These costs are passed on to customers through rates. Customer CAGRs are highest in the short term (2024 to 2030) and decrease over the longer time horizon. This can be seen in

Table 22. In the short-term, expected customer rates are the highest in the Net Zero targeted portfolios (P5L, P5LL, and P5N). After this initial procurement window, the rate CAGRs and ranges between portfolios shrink, though P5N, P5L, P5LL, and P4L portfolios still exhibit the highest rate CAGRs. In general, customer rate increases are positively correlated to the emission reductions achieved.

Table 22. Rate CAGRs in different time periods (REF-scenario specific)

Portfolio	2024 – 2030 (Short Term)	2030 – 2043 (Medium Term)	2024 – 2043 (Full Term)	2024 – 2050 (Long Term)
P1	4.6%	3.6%	3.9%	3.6%
P2F	6.7%	2.9%	4.1%	3.4%
P2N	5.1%	3.5%	4.0%	3.4%
P2L	7.0%	3.0%	4.2%	3.6%
P2LL	7.4%	2.9%	4.3%	3.6%
P4L	7.0%	3.2%	4.4%	3.7%
P4LL	8.7%	2.6%	4.5%	3.6%
P4N	7.8%	3.2%	4.6%	3.6%
P5L	9.1%	2.6%	4.6%	3.8%
P5LL	8.1%	3.4%	4.9%	3.7%
P5N	7.6%	3.9%	5.0%	3.8%

Rate CAGR differences between the status quo, represented by P1, and the portfolios are presented for the short term (2024 to 2030), full 20-year term (2024 to 2043), and long-term (2024 – 2050) in Table 23. In the short term, the rate of growth relative to P1 ranges from 0.5 percent to 4.5 percent. In general, the economically targeted portfolios (e.g., P2F, P2N, P2L, and P2LL) experience the lowest rate of growth relative to P1 with a range of 0.5 percent to 2.8 percent. Portfolios with more stringent clean energy targets fare worse: portfolios with an 85 percent renewables target fare slightly worse with a range of 2.4 percent to 4.1 percent, and portfolios with a Net Zero target have a range of 3.0 percent to 4.5 percent. In the 20-year forecast period and through 2050, all portfolios experience rate growth commensurate with P1. P1 is the "stay the course" portfolio that builds new thermal units and only experiences 9 percent emission reductions compared to 2022. The portfolios with carbon constraints that build a significant number of renewable resources see similar rate CAGRs to P1 over the long term as seen below in Table 23. Through 2043 these portfolios are still higher than the other portfolios but align with P1 the closer to 2050 they get. This is because P1 has significant fuel costs and costs for new GTs over the full term which are comparable to the increase in the CapEx from the renewable builds in the other portfolios.

Table 23. Rate CAGRs relative to P1 (REF-scenario specific)

Portfolio	2024 – 2030 (Short Term)	2024 – 2043 (Full Term)	2024 – 2050 (Long Term)
P1	0.0%	0.0%	0.0%
P2F	2.1%	0.2%	(0.2%)
P2N	0.5%	0.1%	(0.2%)
P2L	2.4%	0.3%	0.0%
P2LL	2.8%	0.4%	0.0%
P4L	2.4%	0.5%	0.1%
P4LL	4.1%	0.6%	0.0%
P4N	3.2%	0.7%	0.0%
P5L	4.5%	0.7%	0.2%
P5LL	3.5%	1.0%	0.1%
P5N	3.0%	1.1%	0.2%

15. Scenario Results

The scenario analysis used the portfolios from the REF scenario but altered dispatch against different future uncertainties. The main variables that were modified were net load, commodity prices, and technology costs. Overall, emissions do not vary across scenarios. Curtailment from overbuilding and exposure to fuel prices are risks that were identified through this scenario analysis.

In the HCP scenario, a lower net load outlook was paired with a higher outlook for commodity prices. Lower load leads to less need for engines to dispatch and thus lower emissions. As the buildouts are the same, the HCP scenario experiences higher curtailment as demand is lower and renewables are not dispatchable. The increase in curtailment is also seen as an increase in cost to customers since customers must still pay for resources that are not dispatching as much. The costs in this scenario have the highest rate exposure as fuel prices are higher and portfolio capital costs and fixed costs are recovered over smaller volumes.

In the TDD scenario, a slightly higher net load outlook is combined with a lower outlook for technology costs and commodity prices. Higher load in the TDD scenario results in greater emissions as engines dispatch more over the forecast period. Curtailment, and therefore costs, only vary slightly below the REF scenario.

Further information about the resulting CO_2 emissions and associated rates can be found in Section 0.

15.1. Sensitivities

In addition to the scenario analysis, several one-off sensitivities were run to test the sensitivity of the result to changes in a single input variable. The full list of sensitivities evaluated is depicted in Figure 24.

Table 24. List of Sensitivities

Sensitivity	Test Purpose	High Level Results	Portfolio to Model
Higher CapEx for Advanced Techs	How do increases in capital cost for advanced technologies (OSW and Floating Solar) change the timing and buildout of all resources?	Increases in capital cost do not change the timing of the buildout in P4L as these resources are necessary to decarbonise.	P2L and P4L
No Wind	What will Bermuda's system look like if OSW does not materialise?	Without wind, the system will rely heavily on LFO generation, preventing progress in emission reductions.	P2LL
Varying Social Discount Rate (6% and 10%)	How does a higher discount rate impact the buildouts and present value of revenue requirements?	The discount rate does not change the overall buildout within the procurement window or through 2050, despite some changes in additional dates. Since the buildout is the same, the revenue requirement and rates are unaffected.	P2L

Sensitivity	Test Purpose	High Level Results	Portfolio to Model
Unconstrained Wind	How will no limit on the capacity of wind change the system? Will Net Zero be met sooner or at a lower cost?	Despite 180 MW of OSW, Net Zero is not achieved due to seasonal mismatches between load and generation.	P5L

More details on the sensitivity results can be found in Appendix E.

16. Summary of Findings and Conclusions

16.1. Scorecard

In resource planning, a scorecard can be an effective tool in decision-making. "Scorecard" for resource planning purposes refers to a device that illustrates the performance of alternative resource plans across a set of defined objectives, performance indicators, and metrics. A scorecard enables a utility to develop and defend resource decisions based on how different plans score against core planning objectives. It provides a simple and structured means of explaining how sometimes objectives align, or where the trade-offs are, to ensure a reasonable decision is made in the best interest of customers.

The scorecard used in this IRP Proposal is illustrated in Table 25 and described here:

- **Objectives** are overarching goals that align with the RA Guidance, the purposes of the EA, the objectives in NESP, and the goals of the NFP. The objectives included on the IRP Proposal scorecard[41] are:
  - Customer Affordability
  - Rate Stability
  - Environmental Stewardship
  - Resource Adequacy
  - Resource Diversity
- **Performance indicators** measure progress towards goals and serve as measurable categories across which portfolios can be compared. There are eleven performance indicators on the scorecard; these align with the objectives and are detailed below.
- **Metrics** are the units in which the performance indicators are measured. Often they include a time element (e.g., net present value, cumulative period, future test year) in addition to numerical value or calculation.

[41] Note, that three additional supplemental performance indicators do not fall under these objectives.

Table 25. Elements of the IRP Proposal Scorecard

Objective	Performance Indicator
Customer Affordability	Economic Cost to Customer
	Financial Cost to Customer
	Rate Growth
Rate Stability	Cost Certainty
	Cost Risk
Environmental Stewardship	Renewable Energy Targets
	Carbon Reduction
Resource Adequacy	Dispatchable Capacity
Resource Diversity	Technology Concentration
Supplemental	Minimise Renewable Curtailment
	Minimise Land Use
	Execution Risk

16.1.1. Customer Affordability

Cost to Customer

The financial cost to customer metric is defined as the 20-year Net Present Value Revenue Requirement (NPVRR) averaged across all scenarios. The financial cost to customers does not include the social cost of carbon in the revenue requirement calculations as the social cost of carbon is a planning concept and not a carbon tax.

The economic cost to customers considers the social cost of carbon in the revenue requirement calculation. The economic cost to customer metric is defined as the 20-year NPVRR inclusive of the social cost of carbon averaged across all scenarios.

The net present value (NPV) is calculated as:

$$NPV = \sum_{t=0}^{n} \frac{RR_t}{(1+r)^t},$$

where t is the current period, n is the number of periods, r is the discount rate, and RR_t is the revenue requirement in period$t$. This metric represents, in aggregate, the costs incurred over the next 20 years, considering the time value of money. Here, a lower number is preferred as it indicates a lower overall cost to customers over the planning period.

Table 26. Portfolios Economic and Financial Cost to Customer ($MM)

Portfolio	Economic Cost to Customer ($MM)	Financial Cost to Customer ($MM)
P1	$3,275	$2,882
P2F	$3,304	$3,063
P2N	$3,271	$3,015
P2L	$3,344	$3,117
P2LL	$3,410	$3,184
P4L	$3,342	$3,131
P4LL	$3,500	$3,290
P4N	$3,420	$3,212
P5L	$3,489	$3,289
P5LL	$3,460	$3,257
P5N	$3,438	$3,235

In general, portfolios with no carbon constraints see lower 20-year NPVRRs as fewer new resources are deployed in these portfolios. P1 is the lowest financial cost across all portfolios at $2.88 billion, and P2N has the lowest economic cost $3.27 billion across all portfolios. Relative to the other economic targeted portfolios (P2F, P2L, and P2LL), P2N has the lowest financial cost but faces development risk and exposure to fuel price volatility with the switch to LNG. Overall, these portfolios exhibit similar economic and financial costs regardless of the fuel strategy.

Portfolios with an 85 percent renewables target (P4N, P4L, and P4LL) are, in general, more expensive than portfolios without a renewables target. Of these portfolios, P4L has the lowest economic cost to customers at $3.34 billion, and P4LL has the highest economic cost to customers at $3.5 billion. Portfolios with a Net Zero target (P5L, P5LL, and P5N) have the highest costs across all portfolios due to the amount of new capacity required to reach renewable targets. As with P2N, P5N has the lowest economic cost across Net Zero portfolios but faces development risk and exposure to fuel price volatility with the switch to LNG. P5L has the highest economic cost across all portfolios at $3.49 billion. In the long term, all the portfolios in 2050 increase at the same rate, approximately $528 million.

Rate Growth

The Rate Growth metric is defined as the 20-year CAGR of expected customer rates, averaged across all scenarios, calculated as

$$\text{Rate Growth} = \left(\frac{\text{Rate}_{2043}}{\text{Rate}_{2024}}\right)^{\frac{1}{2043-2024}} - 1.$$

This metric represents the rate at which customer rates are expected to change over the next 20 years. Here, a lower number is preferred as it indicates a slower increase in customer rates over the simulation horizon.

Table 27. Portfolio Rate Growth (%)

Portfolio	Rate Growth (%)
P1	4.20%
P2F	4.37%
P2N	4.45%
P2L	4.45%
P2LL	4.54%
P4L	4.66%
P4LL	4.77%
P4N	5.03%
P5L	4.89%
P5LL	5.13%
P5N	5.37%

In the short term (2024 to 2030), customer rates are highly affected by near-term resource additions. In portfolios with stringent RET targets, the short-term rate CAGRs range from 7.0 percent to 8.7 percent for 85 percent renewable targeted portfolios and range from 7.6 percent to 9.1 percent in the Net Zero target portfolios. These ranges are significantly higher than the portfolios without renewable targets, which range from 4.6 percent to 7.4 percent. Over the full simulation horizon (2024 – 2043), however, the differences between portfolios shrink, as near-term resource additions are balanced by relatively low fuel costs in subsequent years. P2N has the lowest rate CAGR across all portfolios at 3.99 percent. The other economic portfolios have slightly higher rate CAGRs ranging from 4.10 percent to 4.33 percent. In general, portfolios with renewable targets have the highest rate CAGRs: 85 percent renewable targeted portfolios grow at a rate of 4.38 percent to 4.64 percent, and Net Zero targeted portfolios grow at a rate of 4.61 percent to 5.03 percent. Over the long term the rate CAGRs decrease at similar rates. Rate CAGRs in 2050 range from 3.41 percent to 4.00 percent.

16.1.2. Rate Stability

Cost Certainty and Cost Risk

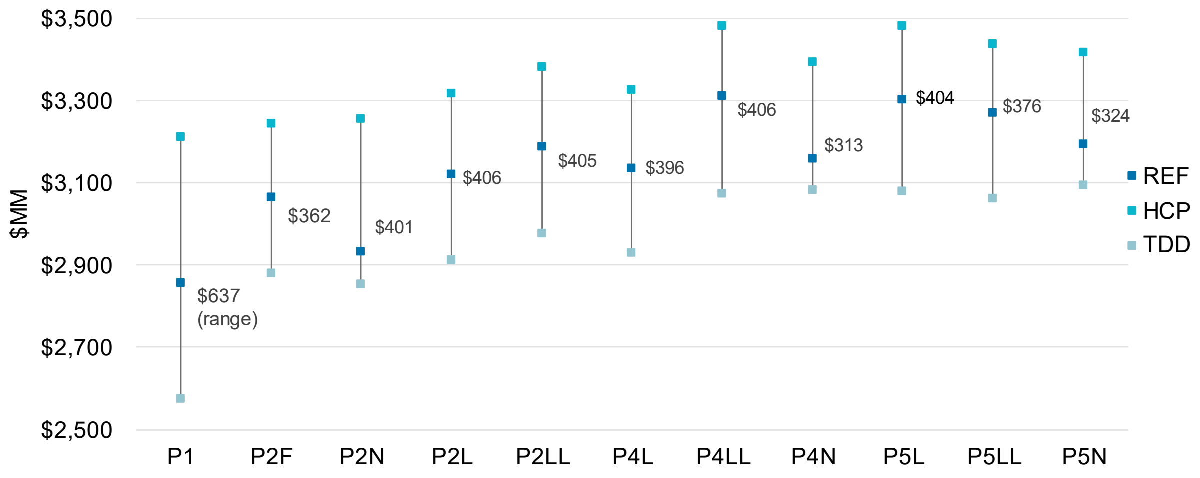
The Cost Certainty metric is defined as the range of the 20-year NPVRR across all scenarios and represents the potential swing in costs across several future scenarios. Here, a lower value is preferred as it represents a more stable portfolio across scenarios.

The Cost Risk metric is defined as the greatest 20-year NPVRR across all scenarios and represents the most extreme case in costs across several future scenarios. Here, a lower value is preferred as it represents a less severe worst-case scenario given different potential future states of the world.

Table 28. Portfolio Cost Certainty ($MM) and Cost Risk ($MM)

Portfolio	Market Scenarios			
	REF	HCP	TDD	High/Low Difference ($M)
P1	$2,858	$3,212	$2,575	$637
P2F	$3,065	$3,243	$2,881	$362
P2N	$2,934	$3,256	$2,854	$401
P2L	$3,121	$3,318	$2,912	$406
P2LL	$3,189	$3,383	$2,979	$405
P4L	$3,135	$3,327	$2,931	$396
P4LL	$3,313	$3,481	$3,075	$406
P4N	$3,159	$3,395	$3,082	$313
P5L	$3,304	$3,484	$3,080	$404
P5LL	$3,270	$3,439	$3,063	$376
P5N	$3,194	$3,418	$3,094	$324

Figure 37. 20-Year NPVRR Range ($MM) 2024 to 2043



The current fleet of generating resources is highly reliant on imported fuel oils, the price of which can prove volatile given market instability due to socioeconomic and geopolitical tensions. As a result, portfolios that rely heavily on HFO and LFO generally exhibit large NPVRR ranges across scenarios as fuel prices experience short-term or long-term price jumps. Without renewables and storage, costs and customer rates are highly sensitive to changes in fuel costs. By 2043, P1 builds the smallest capacity of renewables and storage and has the greatest fuel price risk as evidenced by the NPVRR range of $637 million across all scenarios. Comparatively, with renewables and storage, customer rates become less sensitive to fuel prices over time as reliance on fuel prices reduces. All other portfolios that rely on HFO and LFO but build significant amounts of renewables and storage have Cost Certainty metrics that range from $313 million to $406 million.

Regardless of renewable targets, P4N and P5N, which represent the switch to LNG, see some of the lowest Cost Certainty metrics ranging of $313 million and $324 million respectively. Much like imported fuel oils, LNG faces significant cost risk depending on the geopolitical state of LNG-producing countries. Furthermore, LNG transport prices are typically tied to long-term "take or pay" contracts that grow increasingly expensive as the desired volume of fuel decreases. Unlike portfolios that rely on HFO and LFO, however, portfolios that switch to LNG use the fuel as more of a short-term bridge between current thermal generating assets and future renewable assets, with biomass, or an alternative dispatchable resource, playing a major role in the generation mix by 2043 instead of expensive LNG consumption. As a result, these portfolios see a lower overall NPVRR range across scenarios despite greater historical volatility of LNG prices. Beyond the quantitative risks, a switch to LNG faces execution risk in the form of lack of public support, and infrastructure logistics and investments needed to bring fuel to the island.

16.1.3. Environmental Stewardship

Carbon Reduction

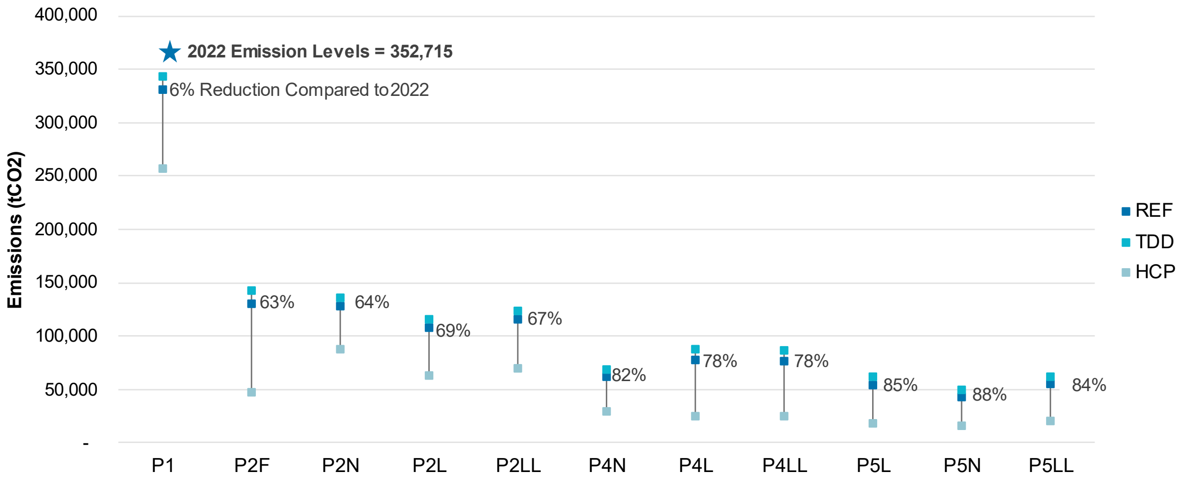
Carbon reductions are represented as an average across all three scenarios calculated with the following formula:

$$\frac{(\text{Emissions in Year X } - \text{Emissions in 2022 (tons } CO_2)}{\text{Emissions in 2022 (tons } CO_2)}$$

where emissions in 2022 are equal to 352,714 tons of CO_2.

All portfolios except for the P1 status quo portfolio hit at least 67 percent reductions in 2043 compared to 2022. The economic portfolios range from 67 percent to 73 percent and the constrained emissions portfolios range from 82 percent to 90 percent. Carbon emission reductions for all the portfolios with the ranges for the HCP and TDD scenarios can be found in Figure 38.

Figure 38. Portfolio Emissions Levels in 2043



In the HCP scenario, emission reductions were less than the REF scenario but only by a few percentage points. The TDD scenario, on the other hand, experienced emissions reductions of a minimum of 80 percent. The Net Zero portfolios (P5L, P5LL, and P5N) all saw reductions of at least 87 percent compared to 2022.

Renewable Energy Targets

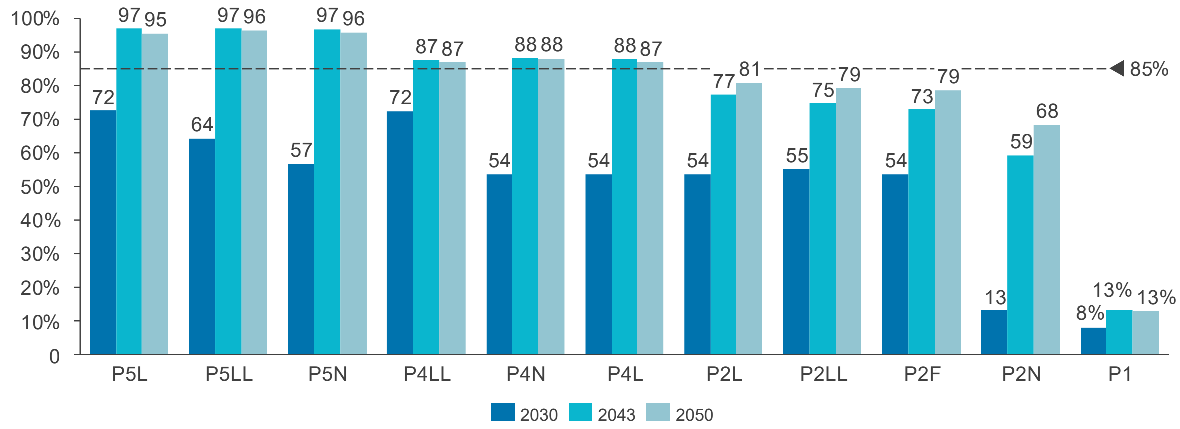
In addition to overall carbon emission reductions compared to historical levels, there was another target set in the previous 2019 IRP for Bermuda. This target looked at hitting a target of renewable energy generation. This is calculated by the following formula:

$$Renewable\ Energy\ Target = \frac{Energy\ Output\ from\ Renewables}{Energy\ Required + EV - EE - DG}$$

The numerator represents the actual generation from renewables over the year in question. The denominator represents the energy requirement. This represents the actual load that generation needs to meet. Load adders could be subtracted from the numerator but, in this case, they are being kept in load. So, to adjust for demand-side resources, demand from EVs is added and any load met with EE and BTM solar are subtracted.

Figure 39 shows the portfolio's RET in 2030, 2043, and 2050. All the 85 percent RET and Net Zero portfolios hit the 85 percent target by 2040. After this, they experience a slight jump in emissions due to higher LFO dispatch. None of the economic portfolios ever hit this target in the forecast period. P2L, P2LL, and P2F are the closest to reaching this in 2050 at 81 percent, 79 percent, and 79 percent respectively. The largest jump in hitting the goal is when OSW comes online and makes up a large part of the generation.

Figure 39. RET Targets



16.1.4. Resource Adequacy

Dispatchable Capacity

Dispatchable capacity includes any resource type that can be dispatched or generated when load is needed. Since Bermuda cannot import power, dispatchable capacity ensures the island can always meet the load, especially if intermittent resources such as renewables are unable to produce energy. Even in the carbon-constrained portfolios, dispatchable capacity is still needed to maintain a stable grid, so biomass was needed to substitute as a "clean" fuel. In this IRP Proposal, only scope 1 emissions were considered. The emission rate for biomass was assumed to be zero tons CO_2/MMBtu.[42]

Dispatchable capacity is measured by the following formula:

$$Dispatchable\ Capacity\ = \frac{Battery + Biomass + LFO + HFO + LNG\ (ICAP\ MW)}{Total\ Installed\ Capacity\ (ICAP\ MW)}$$

All the portfolios without LNG have at least 58 MW to 86 MW of baseload generation from either NPS or EPS by 2043. The LNG portfolios have 99 MW of baseload generation. All portfolios except for P2N have 20 MW of biomass, which is considered dispatchable. The storage buildout varies between 150 MW and 290 MW, but the portfolios with greatest battery buildout may not have as much baseload generation capacity. As a result, the LNG portfolios have the highest baseload remaining and the LFO portfolios (P4L and P5L) with the greatest storage buildout have the highest dispatchable capacity amongst the carbon-constrained portfolios.

16.1.5. Resource Diversity

Technology Concentration

Technology concentration ensures the system does not rely too heavily on a resource to hedge against global pressures such as volatility on commodity pricing, technology costs, or supply chain issues.

Technology concentration uses the HHI which is a widely used metric to measure concentration in markets.[43] The HHI is calculated with the following formula, where s = share of a given resource in installed capacity in percent:

$$HHI = \frac{\sum s^2}{100^2}$$

A higher HHI value implies the system has technologies concentrated in fewer types of resources, and a lower HHI implies higher system diversity. Portfolios with high HHI are more at risk of not meeting load if a technology does not materialise on the island. On the other hand, portfolios with greater diversity can rely on a wider range of resource types if there are construction delays, inability to procure a resource by a certain date, or other execution risks.

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[42] The debate on the true carbon intensity of biomass was not studied as it applies to Bermuda and for modelling.

[43] Concentrating on Technology, S&P

Technology concentration is especially important to hedge against any global pressures or supply chain disturbances that cannot be predicted. Diversifying the fleet allows the island to meet demand even when fuel shortages prevent units from running or supply chain issues affect OSW. Adding more types of generation resources may also reduce the dependence on emissions-intense generation to hedge against renewable intermittency.

The economic portfolios have less diverse buildouts compared to the carbon-constrained cases because there are not stringent renewable targets that require additional renewable resources. Some portfolios such as P2LL and P4N have lower overall system capacity despite the same types of resources, which leads to a slightly lower HHI compared to P2L or P2N, respectively.

16.1.6. Supplemental

Minimise Renewable Curtailment

Curtailment is calculated with the following formula:

$$Curtailment = 100 - Capacity\ Factor = 1 - \frac{Actual\ Output}{Expected\ Output}$$

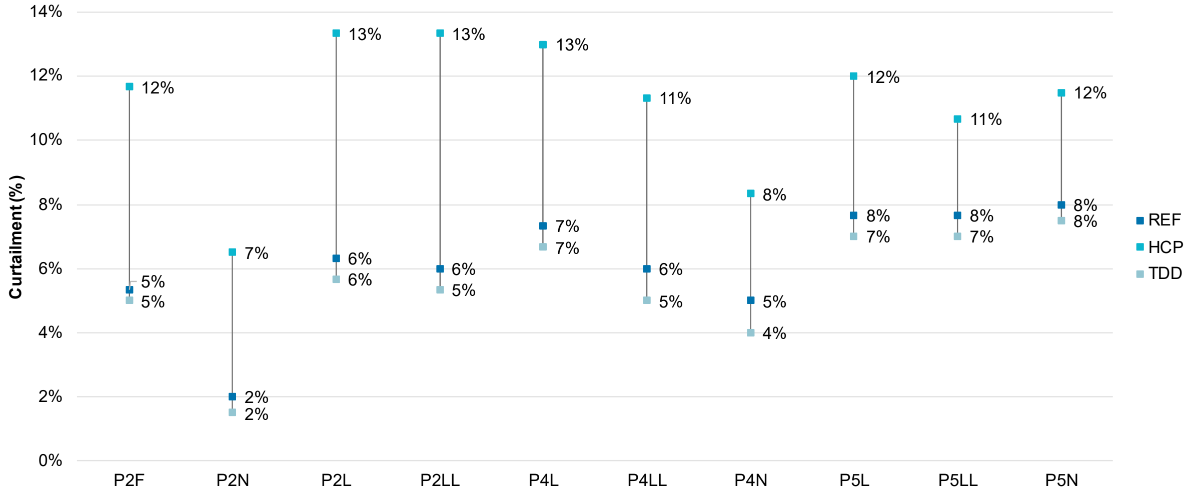
Curtailment occurs when there is too much renewable generation and not enough demand. Storage is capable of mitigating some of this mismatch through load shifting, but current technologies are insufficient to mitigate seasonal mismatches.

Larger buildouts of renewable resources will lead to greater curtailment due to mismatches between load and generation capability. As shown in Figure 40, P5L, P5N, and P4L have the highest curtailment levels (9 percent) percent) among the carbon-constrained portfolios. The system builds renewables and storage to meet carbon constraints, yet these resources are not always called upon. However, because solar availability is highest during lower load periods, curtailment tends to be high and will be even greater with more solar resources. P2N had the lowest renewable buildout so the curtailment for this portfolio is the lowest. In 2050, average curtailment increases the most in the carbon constrained portfolios. P5L and P5N increase the most to 11.3 percent and 10.5 percent respectively.

Curtailment tends to also vary seasonally. The seasonality of higher load during winter and summer months compared to shoulder months cannot be bridged using the current storage systems. This is because all batteries were modelled to only serve one charge/discharge cycle per day and long-duration flow batteries were not chosen. The seasonality of higher load during winter and summer months compared to shoulder months cannot be bridged using the current storage systems.

Overall, the portfolios have similar curtailment between the reference, HCP (high load), and TDD (base load) due to similar buildouts of renewables and storage. P5LL has the lowest curtailment in the high load case due to engine retirements leading to greater reliance on renewable resources. Lower load months would generate more energy from renewables than would be needed to serve load, resulting in higher curtailment during shoulder months. The lower load scenarios (TDD) therefore have the greatest curtailments.

Figure 40. Average Percent Curtailment for Portfolios in 2043



Land Use

Land use was a constraint in the model. Current acreage available was estimated to be in the range of 60 to 70 acres, though future land availability may increase this availability. Portfolios were examined to ensure their land usage did not materially exceed the expected land availability expectation. All the portfolios vary between 70 to 73 acres in 2043.

Execution Risk

Execution risk is an important qualitative scorecard metric that examines the ability to execute its preferred plan. Execution risk is measured on a scale of zero to four. A score of four represents a portfolio with the highest execution risk and a score of one represents a portfolio with the lowest execution risk. P1 is ranked a zero as it represents minimum risk with continuing to run on a predominantly thermal fleet. There are four qualitative metrics used to determine execution risk:

1. **Infrastructure –** Historically Bermuda has relied on thermal plants with a mix of baseload engines and turbine-based plants for peaking purposes. Over time, Bermuda will bring on significant amounts of renewables and change its fuel mix. To execute on any of the identified portfolios in this IRP Proposal, a wide range of infrastructure must be contracted. The risk associated with infrastructure includes supply chain delays, permitting, and land constraints among many others. Supply chain delays have been seen globally for OSW turbines in particular. Portfolios with a larger diversity of resources experience a higher exposure to risk from an execution standpoint. Permitting for biomass, an LNG facility, and other offshore resources will take time and could hinder the ability to build new resources. Lastly, the overall size of projects leads to higher execution risk due to land constraints. LNG is the best example of this. To execute on any of the LNG portfolios, miles of pipeline, a regasification facility, and storage must be built.
2. **Contracting –** Bermuda faces unique LNG contracting issues, as the traditional take-or-pay contracts with fixed volumes may not be workable in an environment where volumes are expected to reduce over time. There are also risks that Bermuda may not be attractive to LNG carriers who may be incentivised to direct their cargo to international buyers with larger volumes. More information on LNG risk for Bermuda can be found in the Appendix E.
3. **Stranded Assets –** Stranded costs are accrued if the asset ceases to be 'used and useful' before it is fully depreciated. There is stranded cost risk associated with the early retirement of engines (especially with the LCU upgrade) or with significant reductions of LNG volumes (PXLL and P2N). The PXL portfolios have less stranded cost risk.
4. **Public Sentiment –**Although there is some sentiment that the public is in favour of decarbonizing Bermuda's electricity system, with significant interest in renewables, for certain technologies, there are also "Not In My Backyard" (NIMBY) concerns.

Based on these factors, portfolios P4N and P5N have the highest execution risk. Bringing LNG to the island will be a significant investment. Since these portfolios must also meet renewable targets, there will be a large buildout of renewables reducing the value of bringing LNG. There is also a risk that the EPS LCU upgrades will become stranded due to declining capacity factors. Contracting LNG may also be difficult with lower volumes over time. Finally, siting of LNG infrastructure such as receiving terminals, storage facilities, regasification facilities, and pipelines may lead to NIMBY concerns by the public.

Portfolios P2N and P5LL score a three for execution risk, which is slightly less risky than P4N and P5N. For P2N, while LNG needs to be transported to the island, its reliance on new technology is less due to a lower renewable buildout. P5LL includes a significant amount of renewable resources leading to a higher infrastructure risk. P5LL requires EPS engine upgrades which add 30 years to their expected lifetime, but decarbonisation will decrease the engines' capacity factor and the units will retire early. Therefore, retirement may not justify the CapEx to increase the engines' lifetime. However, since the engines will primarily be operating on LFO, the supply chain and infrastructure development risks are alleviated compared to LNG, given BELCO's familiarity with LFO.

Portfolios P2LL, P4LL, and P5L all score a two for execution risk. For P2LL and P4LL, a decrease in renewable buildout lowers the infrastructure risks in comparison to P5LL. In P5L, the EPS engines have a life extension but do not undergo a full engine upgrade like in P5LL so there is less execution risk. For P5L, there is less execution risk compared to P5LL because the EPS does not need to be upgraded.

Portfolios P2F, P2L, and P4L all score a one for execution risk. These profiles are the lowest risk in comparison to the other portfolios given lower renewable buildouts and familiarity with fuel infrastructure requirements. These portfolios also consider 10-year life extensions rather than complete unit overhauls, limiting the risk of stranded assets if Bermuda moves to decarbonise in the future. Finally, given the minimal land requirement for new resources in this portfolio, there is significantly less risk surrounding the permitting and building of new assets. The final scorecard can be found in Figure 41.

Figure 41. Final Scorecard

The preferred portfolio, that best achieves the scorecard objectives, is P4L shown below in bold.

	Low Rates			***Rate Stability***			***Sustainability***		***Resource Adequacy***	***Supplemental***		
	Economic Cost to Customer ($MM)	Financial Cost to Customer ($MM)	Rate Growth (% Avg.)	Cost Certainty ($MM)	Cost Risk ($MM)	Technology Concentration	Carbon Intensity (Ton Co2/MWh)	Carbon Reduction Compared to 2022 (%)	Dispatchable Capacity	Minimize Land Use (Acres in 2050)	Minimize Renewable Curtailment (in 2050)	Execution Risk (0 = None, 3 = High)
P1	$3,275	$2,882	4.20%	$637	$3,212	0.52	0.57	12%	92%	--		0
P2F	$3,304	$3,063	4.37%	$362	$3,243	0.23	0.19	70%	65%	71	7.3%	1
P2N	$3,271	$3,015	4.45%	$401	$3,256	0.34	0.21	67%	78%	70	3.3%	3
P2L	$3,344	$3,117	4.45%	$406	$3,318	0.26	0.17	73%	63%	72	8.4%	1
P2LL	$3,410	$3,184	4.54%	$405	$3,383	0.28	0.19	71%	68%	71	8.2%	2
P4L	**$3,342**	**$3,131**	**4.66%**	**$396**	**$3,327**	**0.22**	**0.10**	**82%**	**61%**	**72**	**9.0%**	**1**
P4LL	$3,500	$3,290	4.77%	$406	$3,481	0.23	0.11	82%	63%	71	7.4%	2
P4N	$3,420	$3,212	5.03%	$313	$3,395	0.25	0.10	85%	70%	70	5.8%	3
P5L	$3,489	$3,289	4.89%	$404	$3,484	0.23	0.08	87%	62%	73	8.9%	2
P5LL	$3,460	$3,257	5.13%	$376	$3,439	0.24	0.08	87%	66%	72	8.4%	3
P5N	$3,438	$3,235	5.37%	$324	$3,418	0.27	0.06	90%	66%	73	9.0%	3

16.2. Preferred Portfolio Analysis

16.2.1. Screening Analysis

After a review of the initial modelling results and scorecard, it was determined that 6 of the 11 portfolios were inferior to one or more of the remaining 5 options. Portfolios excluded from consideration as the preferred plan are as follows:

P1 and P2F: Any portfolio that allowed the continuation of HFO was ruled out because it will continue to emit sulphur oxides and particulate matter, thereby preventing Bermuda from achieving decarbonisation goals. Furthermore, it is possible that HFO fuel costs become more volatile as demand decreases and other nations shift towards more sustainable fuel. Greater cost uncertainty puts these portfolios at risk.

P2LL, P4LL, and P5LL: These portfolios were ruled out because the analysis favoured an early retirement despite the engines' 30-year life extension. As a result, the capital expenditure needed to increase the lifetime is not justified if the portfolio would have retired the engine early anyway. These portfolios resulted in achieving similar levels of carbon emission reductions at higher costs.

P5N: This portfolio was ruled out because it has the most stringent renewable goals while investing in LNG infrastructure and engines that will be retired early. This will result in under-utilised assets, as there are no current plans for maximising economic co-benefits such as using natural gas for combined heat and power applications.

16.2.2. Short-listed Portfolios

Five portfolios were short-listed from the original 11 and were considered for preferred portfolio selection. Table 29 provides summary of the short-listed portfolios specifically for the REF scenario.

Table 29. Summary of Narrowed Preferred Portfolios (REF-scenario specific)

	P2N	P2L	P4N	P4L	P5L
Fuel Switch	LNG	LFO	LNG	LFO	LFO
Clean Target	Economic	Economic	85% Renewable	85% Renewable	Net Zero
RET in 2030	13%	54%	54%	54%	72%
RET in 2043	59%	77%	88%	88%	97%
Emission Reductions in 2030	31%	50%	61%	50%	68%
Emission Reductions in 2043	64%	69%	82%	78%	85%
Rate CAGR in 2030	5.1%	7.0%	7.8%	7.0%	9.1%
Rate CAGR in 2043	4.0%	4.2%	4.6%	4.4%	4.6%
NPVRR ($M) in 2043	2,930	3,120	3,160	3,140	3,300
Early Retirements	E7/8: 2043	–	E7/8: 2043	E5/6: 2039	–
Procurement Window Builds	15 MW Onshore Solar 50 MW Storage (200 MWh)	20 MW Onshore Solar 40 MW Storage (160 MWh) 60 MW OSW	20 MW Biomass 20 MW Onshore Solar 20 MW Storage (120 MWh) 60 MW OSW	20 MW Onshore Solar 40 MW Storage (180 MWh) 60 MW OSW	20 MW Biomass 20 MW Onshore Solar 5 MW Floating Solar 60 MW Storage (280 MWh) 60 MW OSW

16.2.3. Preferred Portfolio Analysis

While the economic targeted portfolios (P2s) were less costly than the clean energy targeted portfolios (P4s and P5s) they were only marginally less costly than the 85 percent renewable targeted portfolios (P4s). Given the significantly higher emissions profile of the economic targeted portfolios, none of these were selected as the preferred portfolio.

On the other hand, while P5L (LFO with Net Zero target) allows Bermuda to achieve 95 percent renewable penetration, it comes at an incremental cost of $200 million on NPVRR basis over the 85 percent renewable targeted portfolio, P4L. An additional $200 million to achieve greater than 85 percent renewables was deemed unnecessary and P5L was consequently eliminated from consideration.

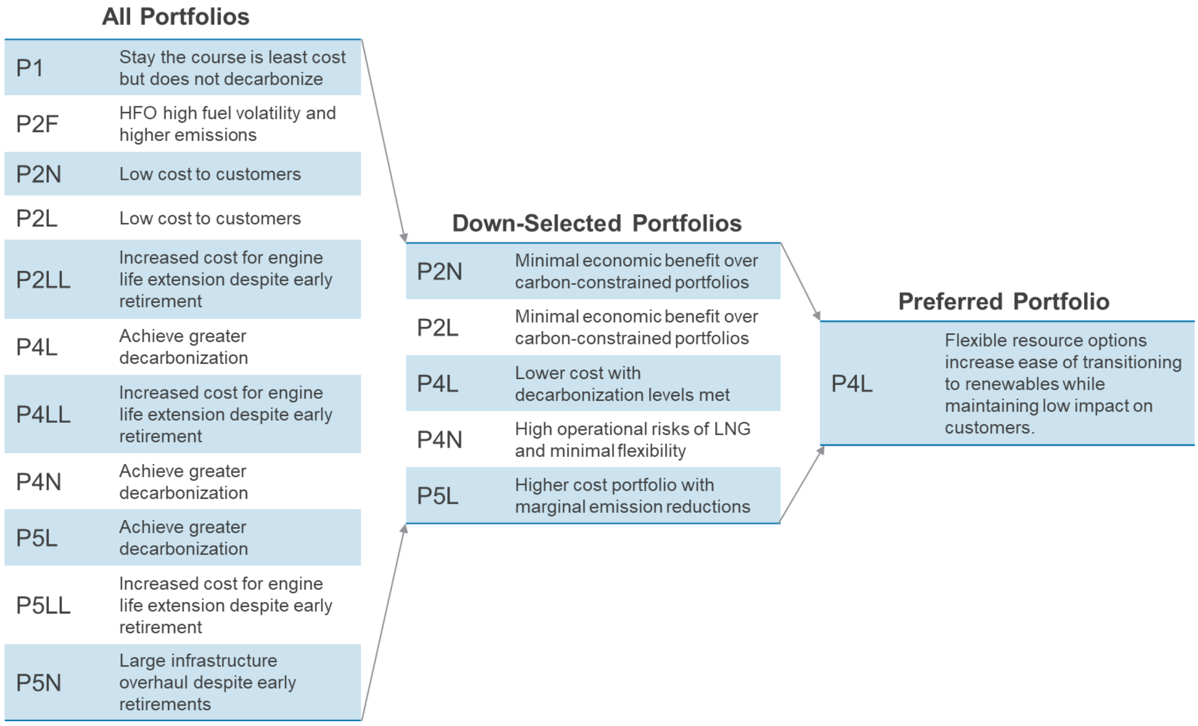
Investing in LNG raises significant risks for Bermuda. P2N would require large LNG infrastructure and LCU investments in the near term to transition the fleet to burning natural gas. Further, there are some challenges with contracting for LNG given the push for renewables and expected lower volumes of LNG deliveries over time. Pricing would need to be negotiated and long-term contracts established to provide for flexibility in accepting lower volumes in the future with greater renewable penetration. This flexibility is expected to come at a premium. Further, Bermuda will face competition from other countries that may demand a larger volume of cargo. The massive infrastructure projects may not justify the amount of fuel the island may need or the stranded assets it may have. Finally, the public sentiment around LNG may create practical challenges to implementation (siting, lack of public support).

Bermuda may benefit from preserving optionality in how it will achieve full decarbonisation. All the selected portfolios build onshore solar, OSW, and storage within the 2030 procurement window. These technologies are adequate to reach significant levels of decarbonisation through 2030. For any decisions after 2030, it may be prudent for Bermuda to wait and see how clean energy technologies evolve. For example, the analysis showed that clean and dispatchable technologies such as biomass are needed to achieve high levels of decarbonisation. However, there may be other technologies such as biofuels or hydrogen that may also become economic in the future.

P4L achieves the best outcome in terms of cost, emission reductions, and ease of transition. It also avoids stranded cost risk from LCU investments and helps achieve large reductions in soot.

A summary of the rationales for the down-selected and preferred portfolios can be found in Figure 42.

Figure 42. Preferred Portfolio Decision Rationale



16.2.4. Preferred Portfolio: P4L

P4L was chosen as the preferred portfolio. P4L offers an operationally simpler conversion to LFO on all engines with a 10-year extension of EPS (LCE). In this portfolio, there is no required life cycle upgrade of the engines at EPS. These upgrades would have been unnecessary as the engines see an early retirement. Operating on LFO is less susceptible to fuel price volatility or contract negotiation outcomes for LNG. P2L and P4L are the same buildouts up until the end of the forecast period. This allows near-term flexibility as it does not lock Bermuda into a single decarbonisation pathway immediately, should advances in decarbonisation technologies occur over the IRP Proposal forecast period that were not considered in this study. However, in the long run, P4L does hit renewable portfolio goals of 85 percent renewable energy by 2040 and achieves an 82 percent reduction in carbon emissions in 2043 compared to 2022 levels. This all comes while not increasing rates significantly (4.7 percent over the forecast period). The timeline for added and subtracted installed capacity is shown in Figure 43. Figure 44 presents the same additions and subtractions in terms of the unforced capacity. An illustration of the builds and retirement of the different technologies over the long-term period are shown in Figure 44.

Figure 43. Capacity Mix for P4L (ICAP)

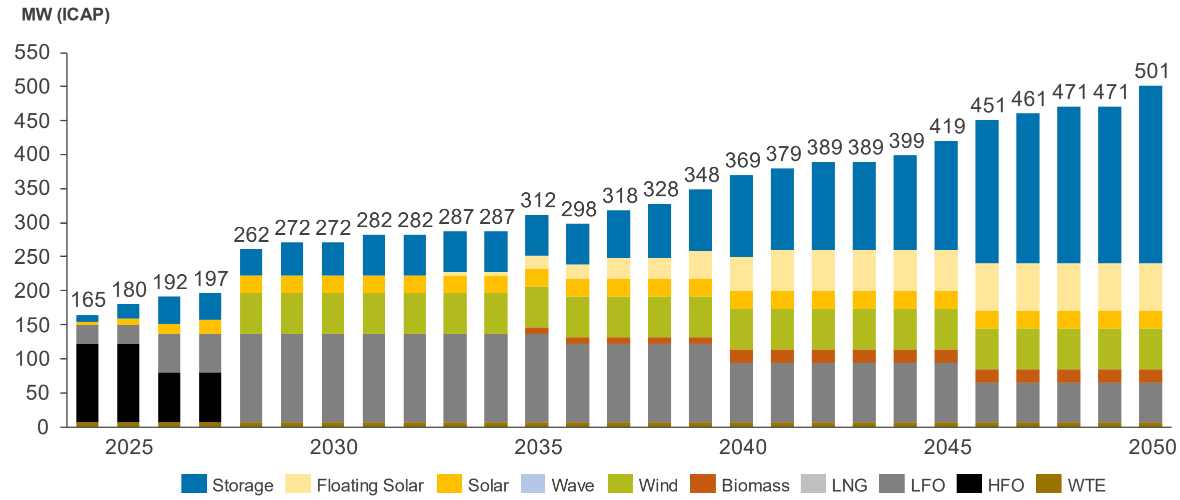


Figure 44. Capacity Mix for P4L (UCAP)

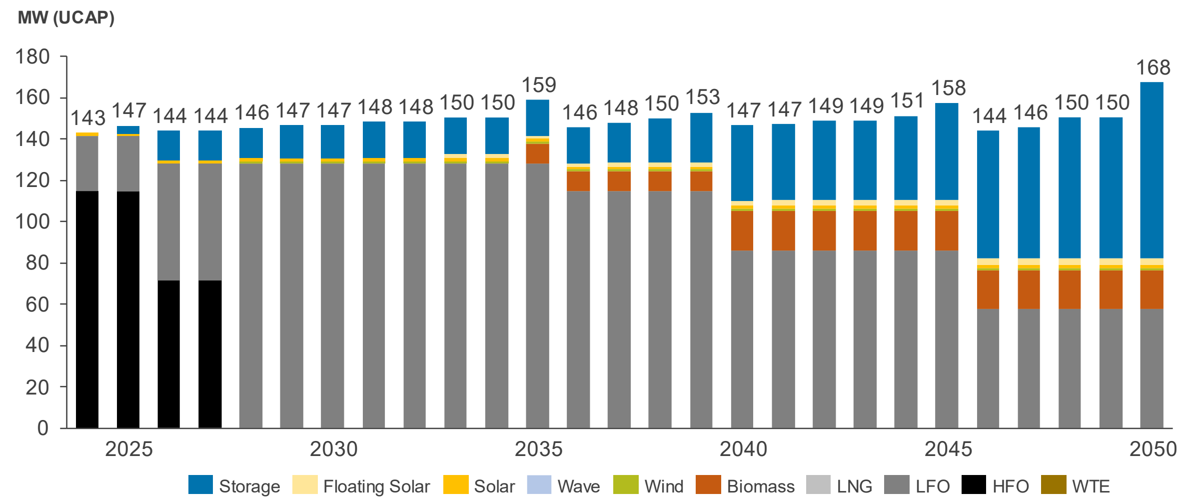
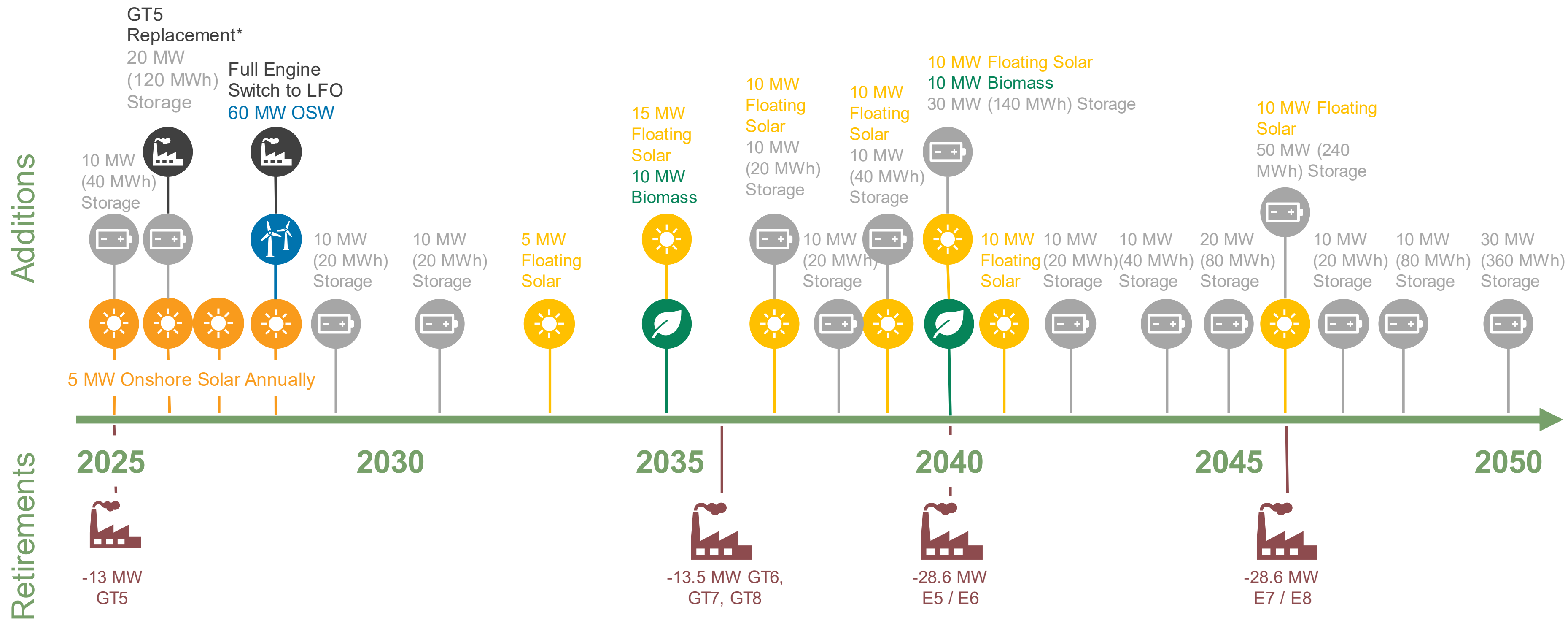


Figure 45. P4L Additions and Retirement Timeline Over Forecast Period



16.2.5. Procurement Plan

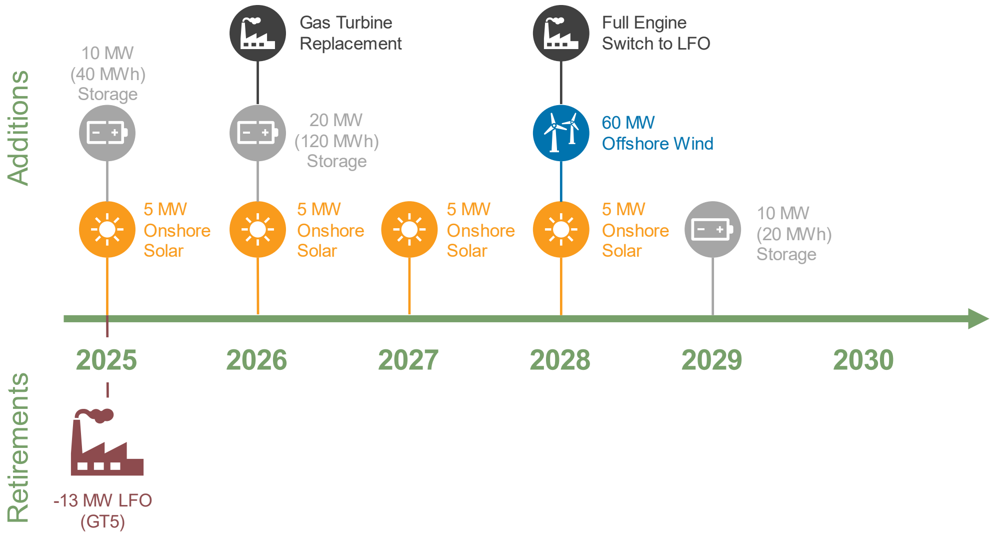
In the procurement window (2024 to 2030), the preferred portfolio will have baseload generation that features EPS engines, NPS engines, and GTs 6 through 8. GT5 retires at the end of 2025 and its replacement will come online and serve as part of the contingency reserve, as described in Section 8.1. EPS and NPS will convert to running on LFO, but no engine upgrades or switches will be needed.

The new resources built in the procurement window include 60 MW OSW, 40 MW (180MWh) of storage (10 MW 2-hr Li-ion, 20 MW 4-hr Li-ion, and 10 MW 8-hr Li-ion), and 20 MW of utility scale onshore solar. No biomass, floating solar, or wave were to be built in this period. The build schedule in the procurement window can be seen in Figure 46.

To achieve the timing of these buildouts, permitting, contracting, operations, and planning must begin soon after the IRP Proposal is approved. Within the first five years, it is also important to plan for the next five years (2030 – 2035) where there is planned build for biomass (10 MW), floating solar (20 MW), and storage (10 MW, 20MWh). Although planning for biomass begins in the procurement window, not building it until later is an attractive option.

In addition to builds and retirements of resources, the TD&R Licensee must also consider the implementation of demand-side resources. A third-party completed a system stability study on P4, and initial results found that P4L will experience frequency instability without mitigation solutions. More information can be found in Appendix F. BTM resources are likely to reach 21 MW_{AC} by 2030. Additionally, almost all EE programmes will be implemented by 2030 as described. These programmes will reduce gross load and be critical to Bermuda's decarbonisation efforts, so any delays in implementation may prolong decarbonisation efforts.

Figure 46. Additions and Retirements for Procurement Window



16.2.6. Signposts

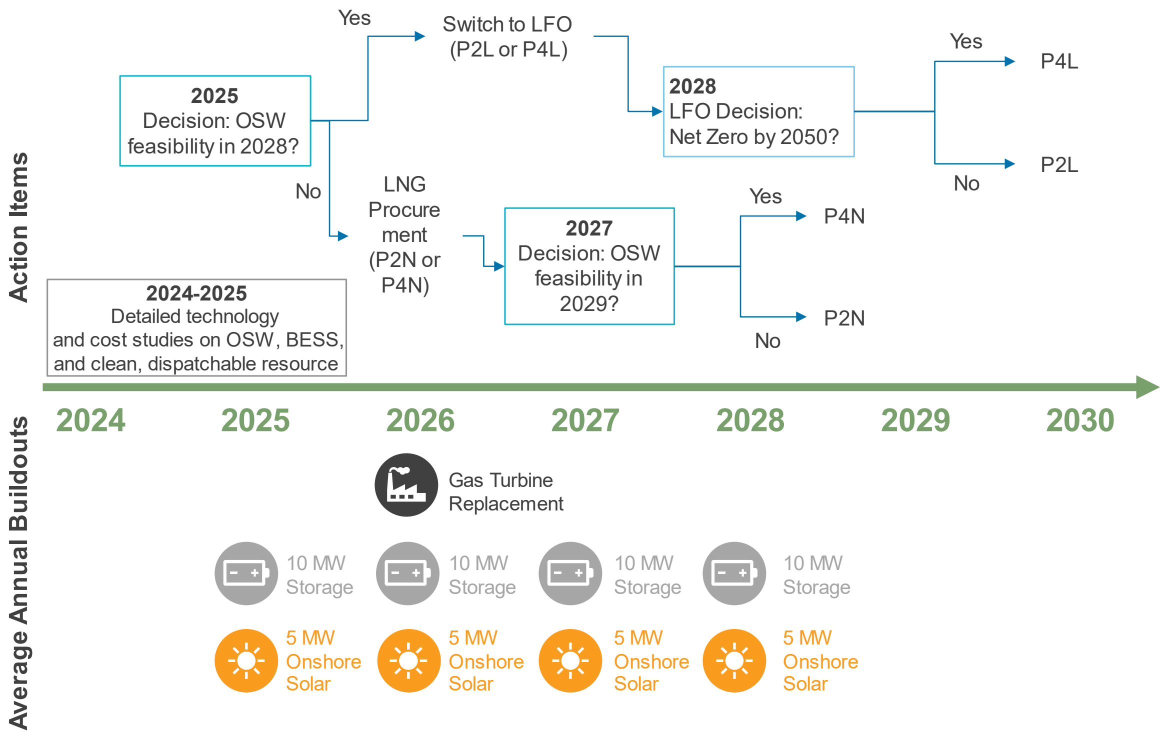
The uncertainties shown in Table 30 have pivot strategies that are to be considered such that Bermuda can rapidly switch to another portfolio strategy if market or economic conditions change. For example, if OSW is not able to be permitted or does not receive sufficient public support, pivoting to LNG can help Bermuda with a cleaner fuel strategy to continue to meet carbon targets.

Table 30. Signposts for Pivot Strategies

Signpost	Strategy
Headwinds against the development of OSW projects	Pivot to P4N: Consider an LNG strategy to get closer to carbon targets
LFO Fuel commodity costs increase materially	Explore fuel price hedging mechanisms
Headwinds against the development of onshore solar projects	Pivot to floating solar when technically feasible
Floating solar technology matures more rapidly than expected	Reevaluate the earliest commissioning date of floating solar
Floating solar decreases in CapEx and/or OpEx	Reevaluate the capacity expansion offering solar at lower costs
Inverter based technology is challenged to provide adequate virtual inertia	Limit buildout of battery energy storage and invest in flexible gas turbines with the option to burn hydrogen or biofuels in the future
Hydrogen technologies mature in cost, technology, and availability	Consider building new gas turbines running on green hydrogen and scale back on battery energy storage
Biomass cannot be permitted	Explore the use of an alternative clean dispatchable resource or cleaner fuels in the EPS, NPS or new GTs

The first significant short-term decision that Bermuda should make is around the building of OSW. All the down-selected portfolios have similar buildouts through 2028. Therefore, regardless of the preferred portfolio (P4L) there is room to pivot portfolios in the short-term. In 2028 P4L and P2L build offshore wind and switch to LFO. However, P2N holds off on building OSW until 2034 but switches to LNG in 2028 which leads to a decrease in emissions. Ultimately, the differences in portfolio come about in 2028 regarding OSW and fuel switch. This is where the customer rates start to increase at varied rates. Thus, the decision for whether OSW will come to fruition in 2028 must be made in 2025. This decision could be based on project finances, availability of turbines, permitting, and other factors. If OSW does not pan out, then in 2028 a pivot to LNG (P2N) would be the best strategy to decarbonise. This decision tree is illustrated in Figure 47 below.

Figure 47. Decision Tree for Procurement Window



17. Appendices

APPENDIX A: CRA OVERVIEW

CRA is a consulting services firm engaged in management consulting and expert support to clients worldwide. The company was founded in 1965 and has expanded to approximately 1000 consultants focused across numerous industries.

The CRA Energy Practice was formed in the early 1980s and comprises energy experts and economists who perform rigorous, high-quality analyses for our varied clients. Its consultants have expertise in resource strategy and planning, market analysis and design, transaction support, corporate strategy, stakeholder management, and regulatory and litigation support. As a firm founded on principles of applied economics and whose work product is frequently reviewed and critiqued in regulatory or other public settings, CRA places a premium on quality control and sound project management to produce the highest quality work. The figure below depicts CRA's practice offerings and specialties.

About CRA's Energy Practice

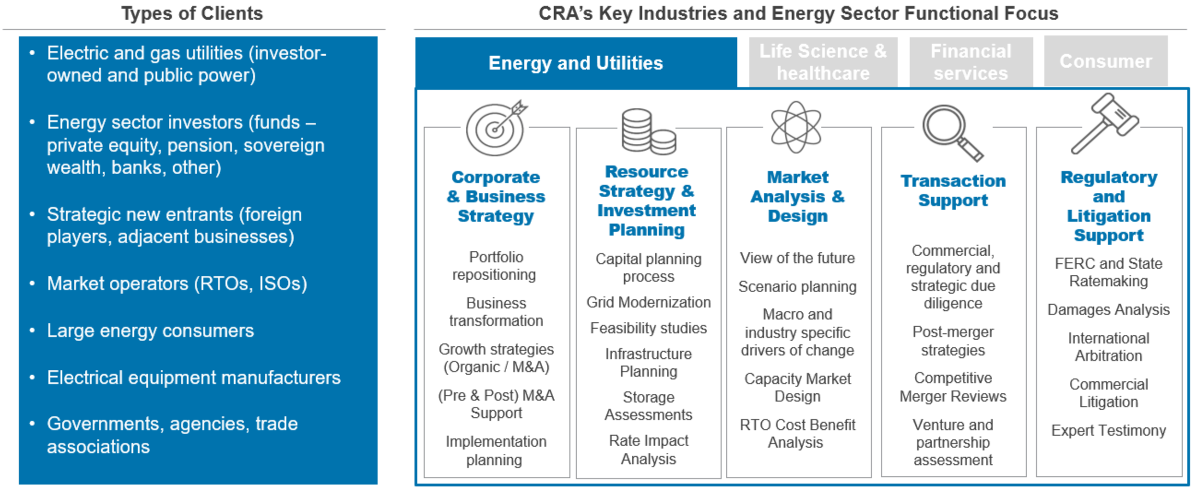
The CRA Energy Practice comprises energy experts and economists who apply rigorous economic and management consulting to every engagement. CRA has offices located in Boston, Washington, New York, Toronto, and London. CRA advises clients on almost every aspect of the energy industry. CRA consults with a wide range of clients, including governments, industry organizations, investor-owned utilities, generators, power pools, transmission companies, distribution companies, competitive retailers, companies from other industries, and regulators.

CRA Experience in Integrated Resource Planning

In the electric utility space, CRA supports clients with strategy, planning, and execution. On behalf of electric utilities, CRA provides market outlooks and forecasts, conducts resource strategy and retail rate analyses, supports large capital investment decisions, assists in resource procurement activities, and provides regulatory briefings and testimony before Federal Energy Regulatory Commission (FERC) or state regulators. CRA has significant experience over the last five years in completing or assisting in the development of integrated resource plans, advising on resource investment as part of company strategy, conducting RFPs for generation resources, and supporting market due diligence in M&A

transactions. As part of such activities, CRA is often communicating results to internal management and external stakeholders.

Figure 48: Overview of CRA's clients and key industries.



APPENDIX B: LOAD FORECAST DETAIL

Residential Customer Class Forecasts

The residential customer class includes nearly 33,000 customers. Total sales to the residential class were approximately 239 GWh in 2022, slightly less than the 250 GWh of sales in 2012. The number of residential customers over the past decade has remained stable, however energy demand been offset by lower electric use per customer, driven by more efficient appliances and lighting along with solar installations by over 1000 residential customers as of late October 2023.

The residential customer forecast is correlated to Bermuda's population. Bermuda's population growth has now slowed to near zero, as is reflected in the residential customer trends. Bermuda's population is projected to remain flat into the foreseeable future. For this reason, the residential customer forecast remains flat after 2023.

Average electricity use per residential customer has declined at an average annual rate of 0.7 percent over the past decade, driven by more efficient appliances and homes, the LED lighting transformation, and the installation of BTM solar at over 1000 homes. Excluding the estimated impacts of BTM solar, the annual decline would have averaged 0.5 percent. The residential kWh per customer forecast is developed using an econometric model that relates the historical monthly series excluding the impacts of BTM solar to the real (inflation-adjusted) price of electricity (a 12-month moving average to smooth volatility), monthly heating degree days, monthly cooling degree days, and an appliance efficiency index. Shift variables are included for selected months, as needed. The resulting forecast of electricity use per customer decreases at an average annual rate of 0.2 percent over the 2023 to 2042 period excluding the impacts of BTM solar, which are incorporated separately in the IRP Proposal analysis. This decline is primarily driven by continued improvements in home appliances and lighting efficiencies.

Commercial Class Forecasts

The TD&R Licensee serves over 3,000 commercial customers, including a wide variety of small to medium-sized businesses and other non-residential accounts. Energy sales to the commercial class have declined over the past decade due to economic, EE, and BTM solar impacts. The influence of the Pandemic on commercial electricity sales is evident in 2020 and 2021, with some rebound in 2022 that is expected to carry into 2023 and 2024 before stabilizing.

The number of commercial customers has remained stable over the past decade, mirroring the residential customer trends. The commercial customer forecast is developed using an econometric model relating the number of customers to real (inflation-adjusted) GDP with a 24-month lag and a tourism output value available from Bermuda statistics. Bermuda's real GDP has shown periods of increases and decreases over the past decade, including the Pandemic, but has not consistently increased nor decreased and is therefore left flat in the future. The tourism value index follows the real GDP forecast. The resulting commercial customer forecast provides a flat trajectory over the long term.

Average electric use per commercial customer has declined over the past decade due to slow economic growth, efficiency improvements in commercial lighting and other equipment, coupled with a modest amount of BTM solar installed. The commercial energy use-per-customer forecast uses an econometric model relating average energy use without BTM solar impacts to real GDP (a 12-month moving average) and cooling degree days. A shift is incorporated from March to October 2020 during the Pandemic and selected monthly variables are included, as needed, to fit the unique monthly pattern of commercial electric sales. The resulting forecast projects that average energy use excluding BTM solar will continue to recover in the early years of the forecasts before stabilising in the long run, following the flat trajectory of real GDP. The impacts of future BTM solar are incorporated separately in the IRP Proposal analysis.

The commercial electric sales forecast is the product of the customer and average use per customer forecast. Excluding BTM solar impacts, commercial sales rebound slightly in 2023 and 2024 due to the continued recovery from the Pandemic impacts before remaining flat through the remainder of the forecast horizon, as driven by the flat real GDP forecast.

Demand Metered Class Forecasts

The TD&R Licensee serves 210 customers that are metered and billed on both energy and demand and have a minimum billable demand of 50 kW. These demand customers are generally larger than the businesses and other non-residential accounts that are included in the commercial class. This class comprised nearly 40 percent of retail electric sales in 2022 with the average annual electric use per customer near one million kWh.

The number of demand-metered customers has changed little over the past decade and is expected to remain at the current level throughout the forecast horizon. It is possible that some existing commercial customers may choose to move onto the demand metered rate within the forecast horizon and it is also possible that some may move in the opposite direction or discontinue operations. With a relatively flat real GDP, a flat trajectory for demand metered customers is considered plausible and used for the forecast.

Average electricity uses per demand metered customer has declined over the past decade, driven by economic conditions, efficiency improvements in lighting, heating, ventilation, air conditioning and other equipment, and some installation of on-site solar. These trends and drivers are similar to those impacting the commercial class. The forecast of average electric use per customer is developed using an econometric model relating use per customer (without BTM solar impacts) to real GDP (a 12-month moving average) and cooling degree days. A shift is incorporated from March to October 2020 during the Pandemic and selected monthly variables are included, as needed. It is noteworthy that these variables are the same as were used in the commercial energy use model, reflecting the similarities in the growth drivers between the two classes. The resulting forecast increases modestly in the early years of the forecast due to continued recovery from the Pandemic lows and then flattens following the flat long-term real GDP forecast trajectory.

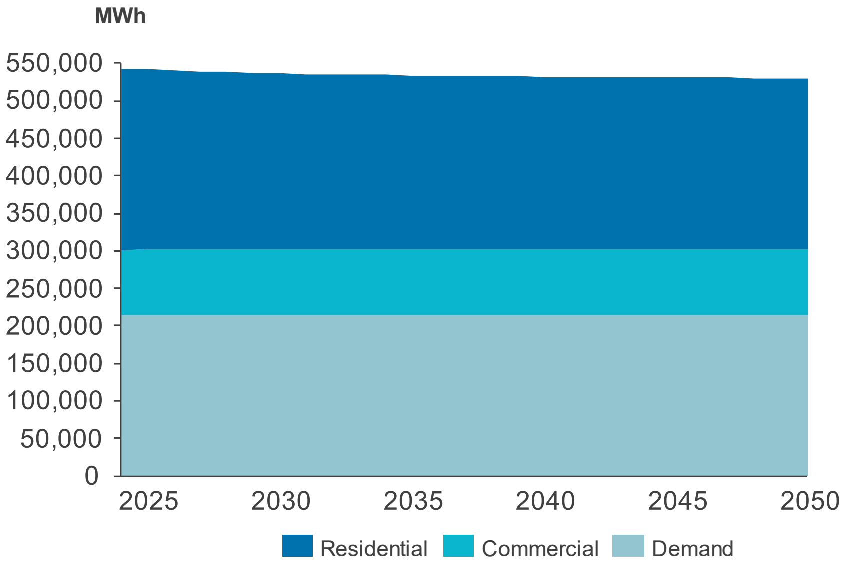
Total electricity sales to the demand metered class are the product of the customer and energy use per customer forecasts. Excluding BTM solar impacts, electric sales increase slightly in the first few years of the forecast due to a recovering economy and then flatten thereafter.

The historical data includes both actual (metered) and an estimate excluding the impacts of BTM solar generation and self-consumption.

Class Summary

The total energy sales by class can be seen in Figure 1 showing a stable forecast over the planning period.

Figure 49. Energy Sales by Class (MWh)



APPENDIX C: EXISTING RESOURCE ASSUMPTIONS

Table 31. Existing Resource Assumptions – Detailed

Plant Name	East Power Station				North Power Station				Gas Turbines			
Unit Number	**E5**	**E6**	**E7**	**E8**	**N1**	**N2**	**N3**	**N4**	**GT5**	**GT6**	**GT7**	**GT8**
Heat Rate	7,955	7,955	7,787	7,787	7,631	7,631	7,631	7,631	13,266	12,394	12,394	12,394
Capacity (MW)	14.3	14.3	14.3	14.3	14.4	14.4	14.4	14.4	13	4.5	4.5	4.5
Primary Fuel Type	HFO	HFO	HFO	HFO	HFO	HFO	HFO	HFO	LFO	LFO	LFO	LFO
Variable O&M ($/MWh)	10.95	10.95	10.95	10.95	13.02	13.02	13.02	13.02	62.66	53.16	44.89	74.90
Fixed O&M ($/kW-year)	20.36	20.36	20.36	20.36	21.31	21.31	21.31	21.31	23.07	10.86	10.86	10.86
Forced Outage (percent)	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Maintenance Rate (%)	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	1.64	1.64	1.64	1.64
Minimum Capacity	7	7	7	7	7	7	7	7	1	1	1	1
Resource COB	2000	2000	2005	2005	2020	2020	2020	2020	1995	2010	2010	2010
Resource Retirement	2040	2040	2045	2045	2060	2060	2060	2060	2025	2035	2035	2035
Min Up Time (hrs.)	3	3	3	3	3	3	3	3	—	—	—	—
Min Down Time (hrs.)	2	2	2	2	2	2	2	2	2	2	2	2
Emission Rate CO_2 (lbs./MMBtu)	173.32	173.32	173.32	173.32	173.32	173.32	173.32	173.32	161.27	161.27	161.27	161.27
Emission Rate NO_x (lbs./MMBtu)	10.35	10.35	10	10	10	10	10	10	0.12	0.11	0.11	0.11
Emission Rate Sox (lbs./MMBtu)	5.7	5.7	5.51	5.51	5.51	5.51	5.51	5.51	0.91	0.87	0.87	0.87

Table 32. EPS Engine LCU Retrofit Assumptions (2022 $)

Plant Name	East Power Station			
Unit Number	**E5_LFO**	**E6_LFO**	**E7_LFO**	**E8_LFO**
Capital Costs LCU ($/kW)	384.62	384.62	384.62	384.62
Resource COB	2000	2000	2005	2005
Resource Retirement (LCU)	2056	2056	2056	2056

Table 33. LFO Fuel Switch Assumptions (2022 $)

Plant Name	East Power Station				North Power Station			
Unit Number	**E5_LFO**	**E6_LFO**	**E7_LFO**	**E8_LFO**	**N1_LFO**	**N2_LFO**	**N3_LFO**	**N4_LFO**
Heat Rate (LHV)	7,955	7,955	7,787	7,787	7,631	7,631	7,631	7,631
Capacity (MW)	14.3	14.3	14.3	14.3	14.4	14.4	14.4	14.4
Fuel Type	LFO	LFO	LFO	LFO	LFO	LFO	LFO	LFO
Variable O&M ($/MWh)	10.95	10.95	10.95	10.95	13.02	13.02	13.02	13.02
Fixed O&M ($/kW-year)	20.36	20.36	20.36	20.36	21.31	21.31	21.31	21.31
Forced Outage (%)	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Maintenance Rate (%)	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Minimum Capacity	7	7	7	7	7	7	7	7
Resource COB	2000	2000	2005	2005	2020	2020	2020	2020
Resource Retirement	2040	2040	2045	2045	2060	2060	2060	2060
Resource Retirement (LCU)	2056	2056	2056	2056	—	—	—	—
Min Up Time (hrs.)	3	3	3	3	3	3	3	3
Min Down Time (hrs.)	2	2	2	2	2	2	2	2
Emission Rate CO_2 (lbs./MMBtu)	161.27	161.27	161.27	161.27	161.27	161.27	161.27	161.27
Emission Rate NO_x (lbs./MMBtu)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Emission Rate SO_x (lbs./MMBtu)	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91

Table 34. LCU – LNG Resource Assumptions (2022 $)

Plant Name	East Power Station				North Power Station				Gas Turbines			
Unit Number	E5 Retrofit LNG	E6 Retrofit LNG	E7 Retrofit LNG	E8 Retrofit LNG	N1 LNG	N2 LNG	N3 LNG	N4 LNG	GT5 LNG	GT6 LNG	GT7 LNG	GT8 LNG
Heat Rate (LHV)	8260	8260	8260	8260	8260	8260	8260	8260	11,700	11,700	11,700	11,700
Capacity (MW)	14.3	14.3	14.3	14.3	14.4	14.4	14.4	14.4	13	4.5	4.5	4.5
Capital Costs LCU ($/kW)	454.55	454.55	454.55	454.55	138.89	138.89	138.89	138.89	0	44.44	44.44	44.44
Fuel Type	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG
Variable O&M ($/MWh)	13.02	13.02	13.02	13.02	13.02	13.02	13.02	13.02	62.66	53.16	44.89	74.90
Fixed O&M ($/kW-year)	21.31	21.31	21.31	21.31	21.31	21.31	21.31	21.31	23.07	10.86	10.86	10.86
Forced Outage (%)	4	4	4	4	4	4	4	4	2	2	2	2
Maintenance Rate (%)	6	6	6	6	6	6	6	6	3	3	3	3
Minimum Capacity	7	7	7	7	7	7	7	7	1	1	1	1
Resource COB	2000	2000	2005	2005	2020	2020	2020	2020	1995	2010	2010	2010
Resource Retirement	—	—	—	—	2060	2060	2060	2060	2025	2035	2035	2035
Resource Retirement (LCU)	2056	2056	2056	2056	—	—	—	—	—	—	—	—
Min Up Time (hrs.)	3	3	3	3	3	3	3	3	—	—	—	—
Min Down Time (hrs.)	2	2	2	2	2	2	2	2	2	2	2	2
Emission Rate CO_2 (lbs./MMBtu)	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98
Emission Rate NO_x (lbs./MMBtu)	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.01	0.01	0.01	0.01
Emission Rate SO_x (lbs./MMBtu)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	4.57	4.57	4.57	4.57

APPENDIX D: NEW RESOURCE ASSUMPTIONS

Table 35. New Resource Build Assumptions (2022 $)

Replacement Options	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)	Capital Costs (2022 $/kw)	Fixed O&M (2022 $/kw)	Variable O&M (2022 $/kw-yr)
OSW	2028	32	15	60	41%	6,300	161	–
Onshore Solar	2025	30	5	20	21%	2,750	20	–
Floating Solar	2027	27	5	80	21%	4,125	150	–
Wave	2030	25	0.2	20	27%	10,179	529	–
Gas Turbine (GT5 Replacement)	2025	25	13	13	–	1,346	23	62.66
Gas Turbine Future Addition 13 MW unit	2025	25	13	13	–	1,346	11	53.16
Gas Turbine Future Addition 4.5 MW unit	2025	25	4.5	2.5	–	1,346	11	53.16
Biomass	2028	40	10	20	–	6,867	140	5.41
Gas Turbine w/100% Hydrogen	2030	20	10	–	–	2,121	–	19.20
Li-ion 2hr 10 MW	2024	20	10	Not constrained	8%	1,291	33	–
Li-ion 4hr 10 MW	2024	20	10	Not constrained	17%	2,300	38	–
Li-ion 8hr 10 MW	2024	20	10	Not constrained	33%	4,180	45	–
Flow 24hr 10 MW	2025	25	10	Not constrained	28%	11,974	79	–

APPENDIX E: SENSITIVITY RESULTS

Higher CapEx for Advanced Technology

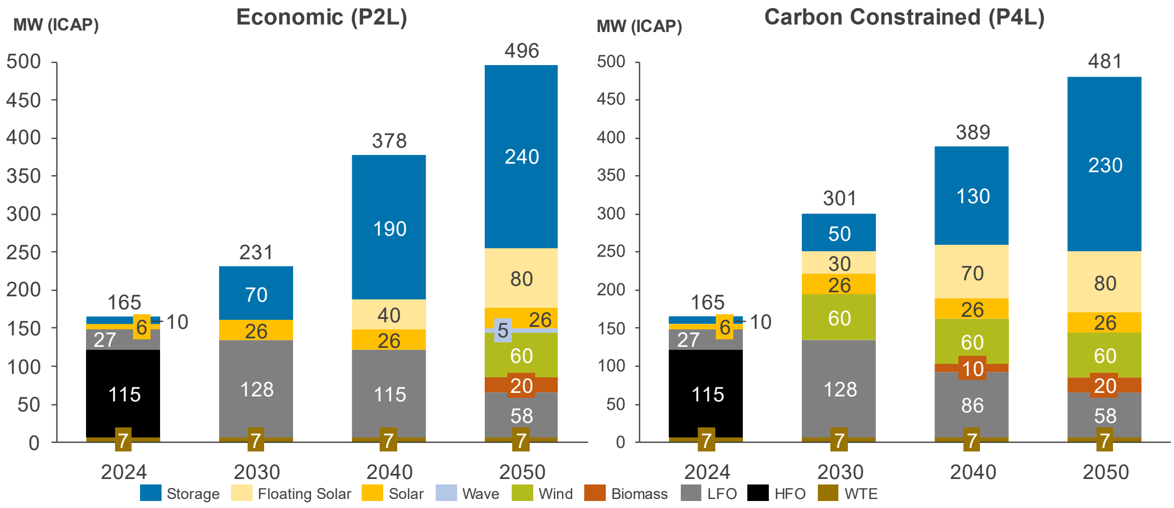
Sensitivity Purpose

The sensitivity evaluates a higher CapEx sensitivity for nascent technologies that have only recently become commercially viable or are still at the demonstration stage. The ability to decarbonise Bermuda's electricity mix despite the higher capital costs of renewable technologies was tested through applying 25 percent higher capital costs to OSW, floating solar, and wave power in P2L and P4L. A conservative learning rate was applied rather than cost declines over time to the final forecast.

Key Insights

Despite higher capital costs, the overall buildout in the renewable portfolio case (P4L) did not change (Figure 50). Wind and floating solar buildouts do not get delayed because of constraints to meeting renewable generation targets. On the other hand, the economic case shows a scenario of buildouts entirely dependent on costs. In P2L, there is both a delay in building floating solar and a significant delay to 2045 for building wind.

Figure 50. Higher CapEx – Buildouts (ICAP) in MW



Wind and floating solar prove to be necessary for energy purposes to meet decarbonisation targets. Higher capital costs delay OSW buildout timelines.

The P2L HCE portfolio sees higher rates in the mid-2040s through the rest of the forecast period. The P4L HCE portfolio is higher than the P4L rates from 2029 to 2047 by 4 to 6 ₵/MWh. Rates even out post 2047. (Figure 52).

Figure 51. Higher CapEx – Emissions

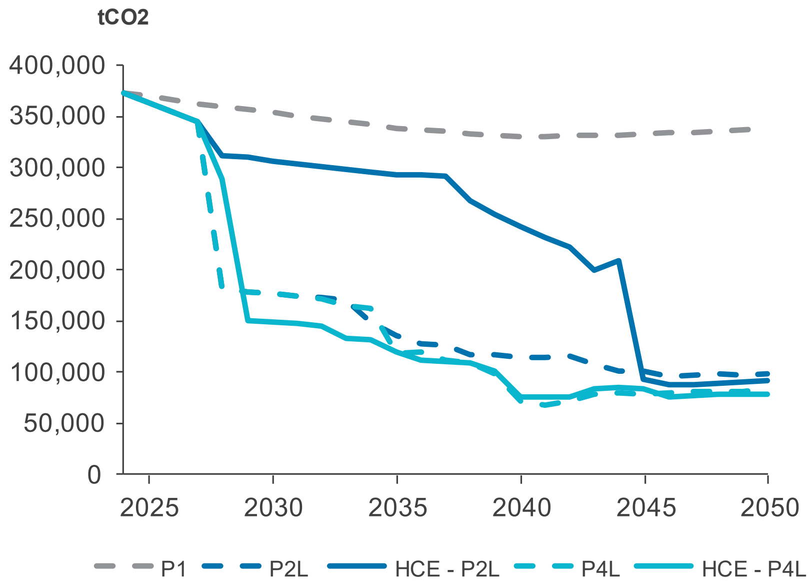
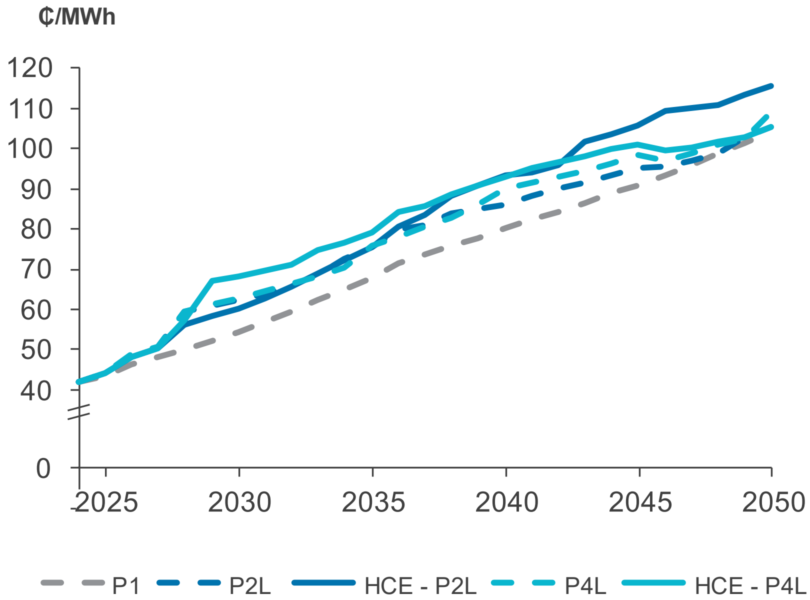


Figure 52. Higher CapEx – Rate Requirement



No Wind

Sensitivity Purpose

The OSW industry has recently experienced shortages and supply chain issues regarding turbines and components. The No Wind sensitivity is designed to assess the impacts of OSW not deploying in Bermuda due to risks such as the lack of willing developers, turbine supply chain issues, and logistical hurdles. This sensitivity tests the buildout without the significant OSW generation resource, evaluates the ability of Bermuda to decarbonise, and determines the costs to customers. This test was performed on P2LL, in which the fuel switches to LFO, with a 30-year life extension to the EPS engines.

Key Insights

The No Wind sensitivity exhibits higher emissions compared to the same portfolio in the REF scenario. As the floating solar and wave power capacities are fully utilised, thermal generation and less storage is required to meet the generation capacity met by OSW. Only 160 MW of storage is built in the no wind sensitivity, compared to the REF scenario building 210 MW by 2050 (Figure 53). The EPS engines (with LCU) and the NPS engines continue to burn LFO to meet demand. The greater LFO consumption leads to greater emissions relative to the REF case and prevents Bermuda from decarbonisation (Figure 54). The consumption of LFO leads to relatively higher marginal costs of generation (Figure 55), and as a result, the no wind sensitivity is more expensive than the REF scenario. This is despite the lower requirement for storage to smooth variable generation.

Figure 53. No Wind – Buildout (ICAP) in MW

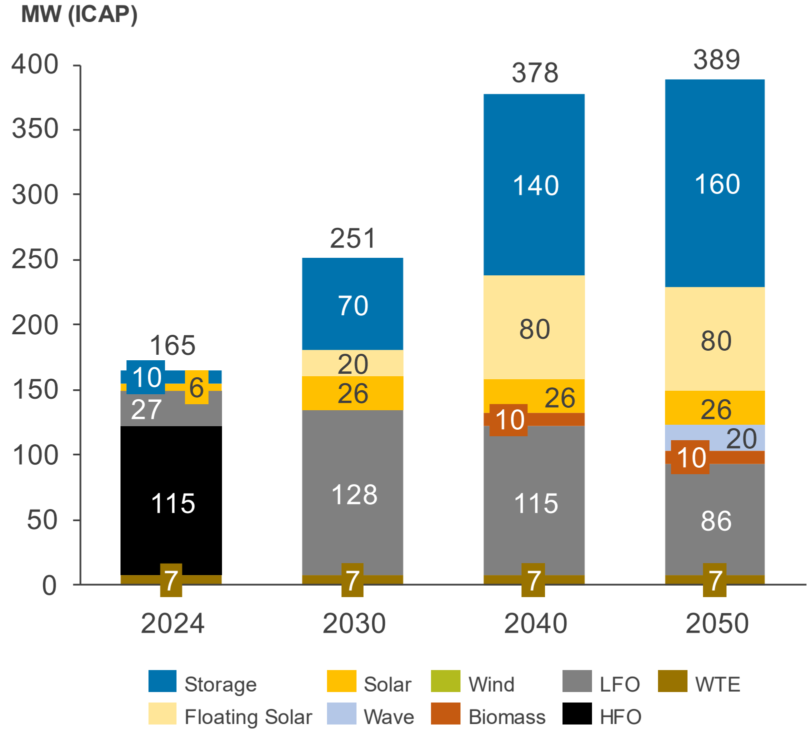


Figure 54. No Wind – Emissions

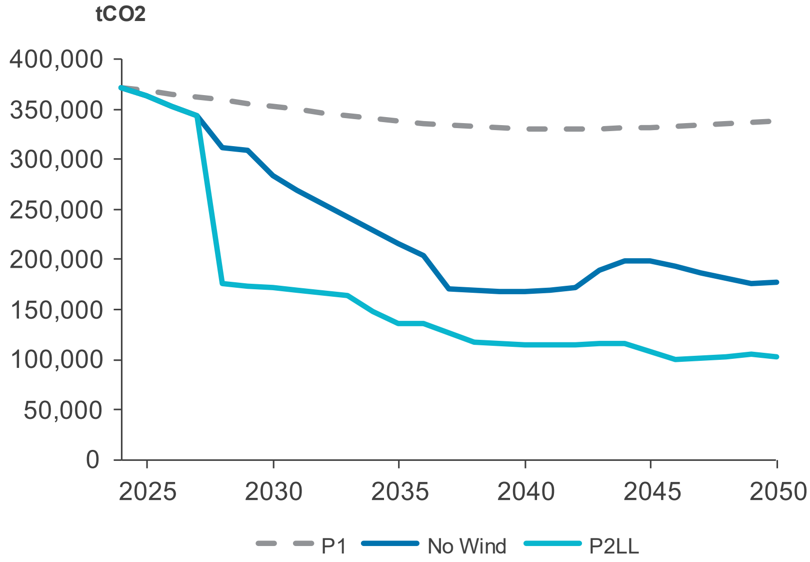
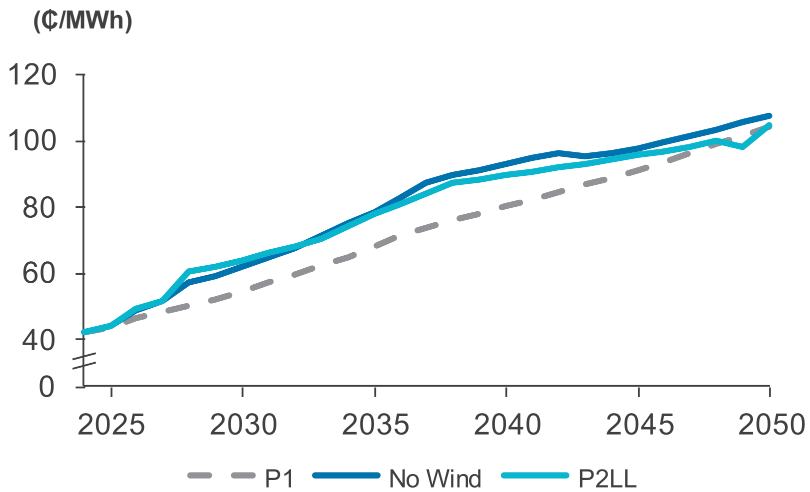


Figure 55. No Wind – Rate Requirement



Unconstrained Wind

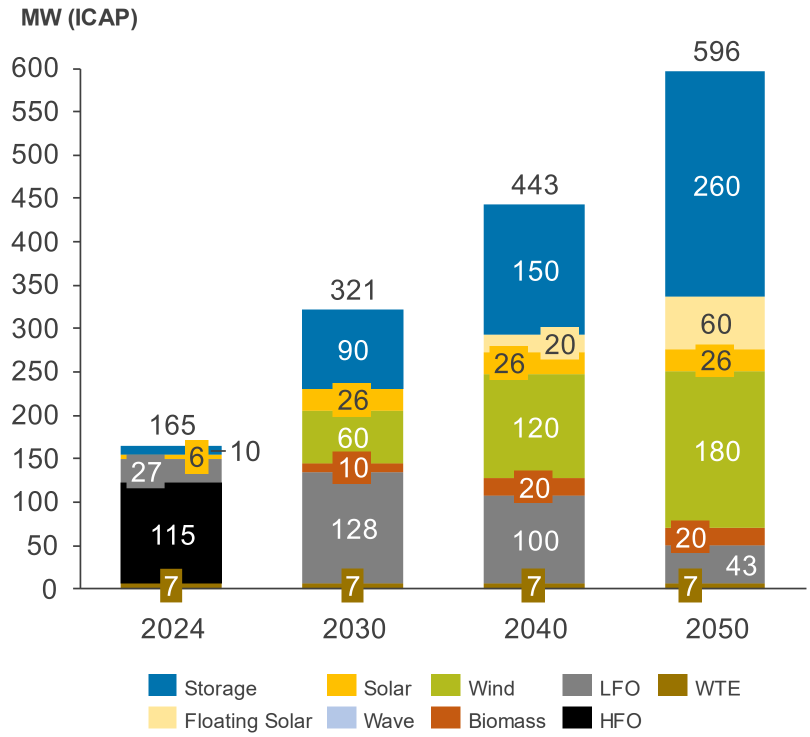
Sensitivity Purpose

The unconstrained wind sensitivity explores if deploying more OSW is capable of fully decarbonising Bermuda's electricity mix. This sensitivity tests whether the REF scenario assumptions of 60 MW severely limited this resource option. In this sensitivity, OSW siting was assumed to be unconstrained, with no seabed limitations. This sensitivity was tested on P5L, and no additional carbon constraints were modelled.

Key Insights

The maximum unconstrained buildout of OSW is 180 MW by 2050. The initial 60MW is built in 2030 with the next 60 MW being built only 4 years later in 2034. The last 60 MW is not deployed until 2050 as seen in Figure 56.

Figure 56. Unconstrained Wind – Buildout (ICAP) in MW



With a greater buildout of wind, the earliest engine retired in 2030 to accommodate for the future increase in lower cost marginal resource generation. The storage requirements also increase the quantity of 24-hour duration storage built to compensate for the increased variability of wind generation.

There were some trade-offs between OSW and other renewable resources. There is less floating solar build overall due to the lower costs of OSW capacity. If offshore solar becomes more mainstream and sees costs reductions in the coastal environment.

Full decarbonisation is not achieved (Figure 57), which is likely due to the lack of suitable storage technologies for long term energy shifting. The probability of curtailment is also increased as seasonal and daily mismatches between load and generation continue to limit the 24-hour batteries' performance to increase system flexibility.

The unconstrained wind case is more costly to customers than the reference case, and there are steep rate increases that follow OSW buildout in 2030 and 2034. P5L and the unconstrained wind portfolio have similar rate requirements in 2049 but the unconstrained wind sees one last increase in 2050 when the last 60 MW is built (Figure 58).

Figure 57. Unconstrained Wind – Emissions

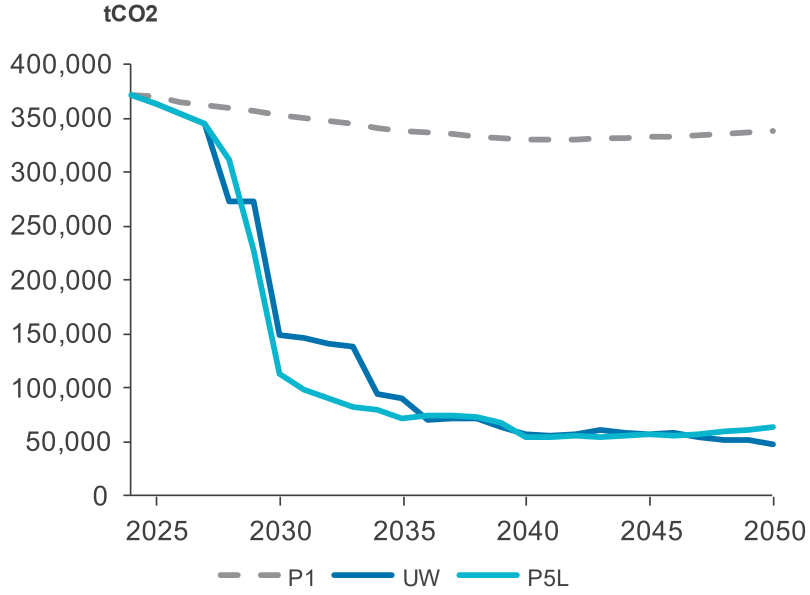
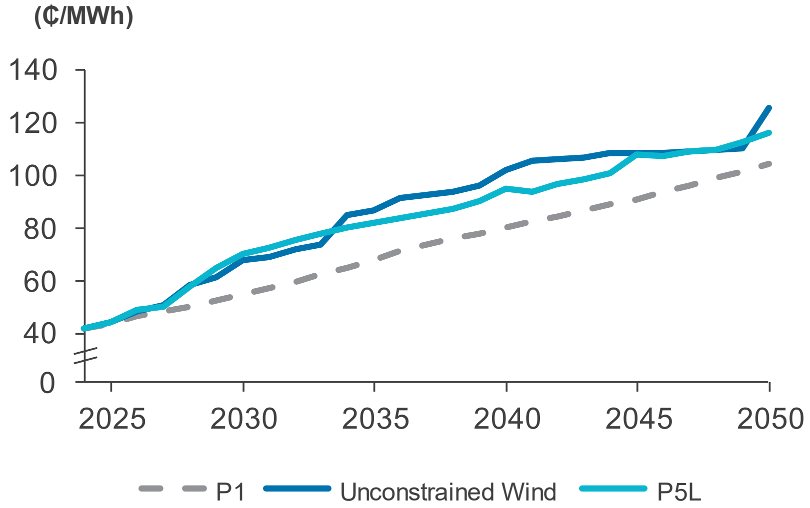


Figure 58. Unconstrained Wind – Rate Requirement



Social Discount Rate Sensitivity

Sensitivity Purpose

Social discount rate is a measure of valuing the future in terms of present values from a societal perspective. Higher social discount rates value present benefits more than future benefits. The purpose of this test is to see if varying social discount rates by either increasing or decreasing from the 8 percent REF scenario alters the buildouts and the subsequent cost to customers. The sensitivity does not address the social cost of carbon or the societal costs of different generation types. This sensitivity was tested on P2L and P4L.

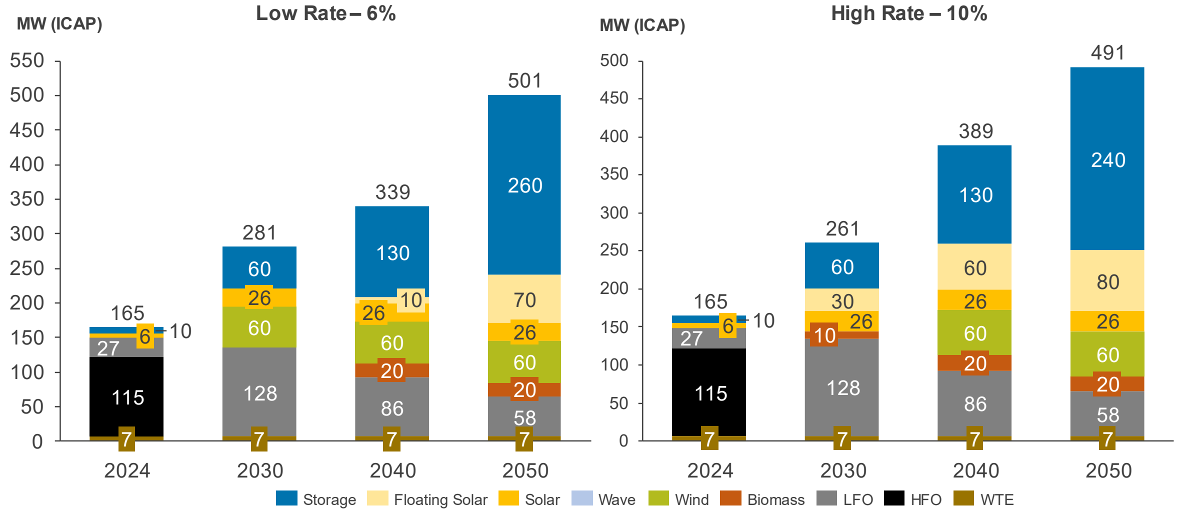
Key Insights

In general, the flexing of the social discount rate had minimal impact on the final build selection chosen in the capacity expansion model, therefore small changes are seen in the cost to customers and emission reductions.

In the economic case (P2L), the buildouts within the five-year procurement window do not change with varying discount rates. The final overall build and retirements in 2050 also do not change in the economic case as seen in Figure 59. Thus, emission levels in 2050 stay the same (Figure 60).

The timing of buildouts and resource preferences do change with the social discount rate. The 10 percent social discount rate is seen to delay OSW but accelerate floating solar and biomass deployment. In the lower social discount rate sensitivity, floating solar deployment and the deployment of biomass is delayed and 60MW of OSW is called for by 2030.

Figure 59. Varying Social Discount Rate – Buildouts (ICAP) in MW



The final revenue requirement changes even if the buildouts are the same (Figure 61). In the high social discount rate sensitivity, the portfolio has a lower NVPRR. The higher discount rate allows a higher cost of borrowing and therefore leads to a lower NVPRR with similar buildouts. The low social discount rate similarly leads to higher NVPRR.

Figure 60. Varying Social Discount Rate – Emissions

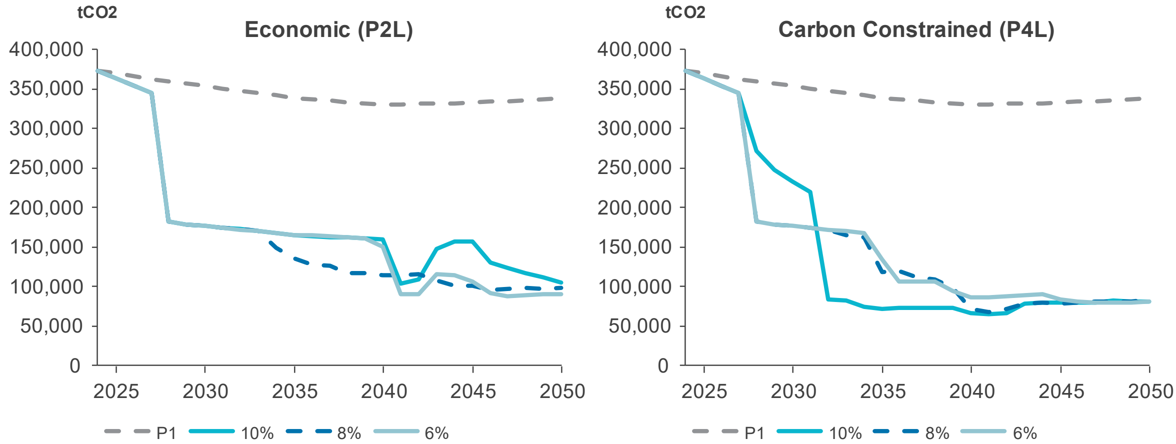
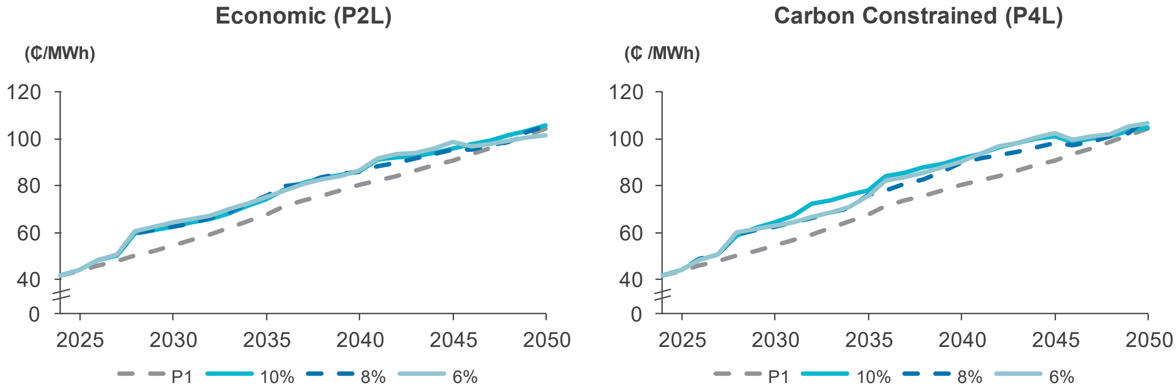


Figure 61. Varying Social Discount Rate – Rate Requirement



APPENDIX F: SYSTEM STABILITY STUDY

Initial studies performed by a third-party for the preferred portfolio indicates that in 2030 under minimum (night) and light (day) load conditions, the grid will experience frequency instability. Mitigation solutions will be further explored through more detailed studies.

The TD&R Licensee retained a third-party to perform grid stability studies for the preferred (portfolio) P4L under three system conditions – peak, day (light), and minimum (night) loading conditions for study years 2030 and 2043. Stability studies were performed to ensure that the system remained stable under conditions of high renewable generation and low load which are likely to manifest themselves as early as 2030 after the 60 MW wind plant becomes operational. Stability is a general concern in all systems with loss of system inertia as inverter-based resources replace synchronous generation resources but particularly so in island systems with no external transmission support.

The system was projected to be stable under peak load conditions in the 2030 period. However, frequency instability was observed for the other two cases. In the minimum thermal load case where wind generation is the highest and synchronous generation capacity is not online, the system experiences a frequency collapse. In the light(day) load conditions, the system is also unstable for certain faults. Instability is observed in the form of large rate of change of frequency events and/or frequency settling down to a value lower than nominal.

Additional analysis was performed to mitigate frequency instability events by backing off or curtailing wind generation and dispatching thermal generation. This leads to an improvement in frequency response. Further studies will be undertaken to analyse the ability of battery energy storage devices to provide the inertial response. Additional solutions might be to convert some of the retiring thermal generation into synchronous condensers. Such studies will require more sophisticated modelling tools that can simulate the very fast response of inverter controls.

It is recommended that the TD&R Licensee undertake detailed studies as soon as possible so that cost effective mitigation solutions can be identified. If battery energy storage devices are effective, procurement activity will need to specify the technical requirements for storage setting including potential need for grid forming inverters.

APPENDIX G: PEER REVIEW OF ASSUMPTIONS

The peer review of the assumptions generally found that the inputs assumptions in the IRP Proposal were appropriate for future energy planning and generally appear to be reasonable. The IRP Proposal assumptions aligned with mature technologies with appropriate Bermuda adders applied. Developing technologies such as floating solar deployed in coastal waters were difficult to verify without existing data sets. As the TD&R Licensee team consulted with local project developers and obtained local estimates, these are accepted despite being higher than that expected by the peer review.

APPENDIX H: PEER REVIEW OF OUTPUTS

The peer review of the IRP Proposal modelling process, sensitivities and outputs performed by Professor Aristides E. Kiprakis SMIEEE MIET, Chair of Agile Energy Systems at the School of Engineering, University of Edinburgh. Overall, the review found the modelling to be fit for purpose and meets the typical needs of energy planning.

APPENDIX B: RA’S ASSESSMENT OF THE IRP PROPOSAL

31. The document linked below contains the RA’s assessment of the IRP Proposal:

    a. Assessment of IRP Proposal

IRP ASSESSMENT REPORT

Review and Analysis of BELCO's IRP Proposal

Report for: Regulatory Authority of Bermuda

Ref. ED15619101

Ricardo ref. ED15619101 | Issue: 1 | 14/06/2024

Customer:
Regulatory Authority of Bermuda

Customer reference:
ED15619101

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Date:
14/06/2024

Ricardo is certified to ISO9001, ISO14001, ISO27001 and ISO45001.

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1. INTRODUCTION

This report presents our independent analysis and assessment of BELCO's Integrated Resource Plan (**IRP**) Proposal submitted to the Regulatory Authority of Bermuda (**RA**) in November 2023 and thereafter, in March 2024 and May 2024. The report accompanies the Public Consultation Document published by the RA that aims to collate public comments and alternative proposals for bulk generation or demand side resources, and therefore, should be read and treated together. The rest of the report is structured as follows:

- Section 2 summarises BELCO's IRP Proposal
- Section 3 presents our independent analysis
- Section 4 provides a conclusion

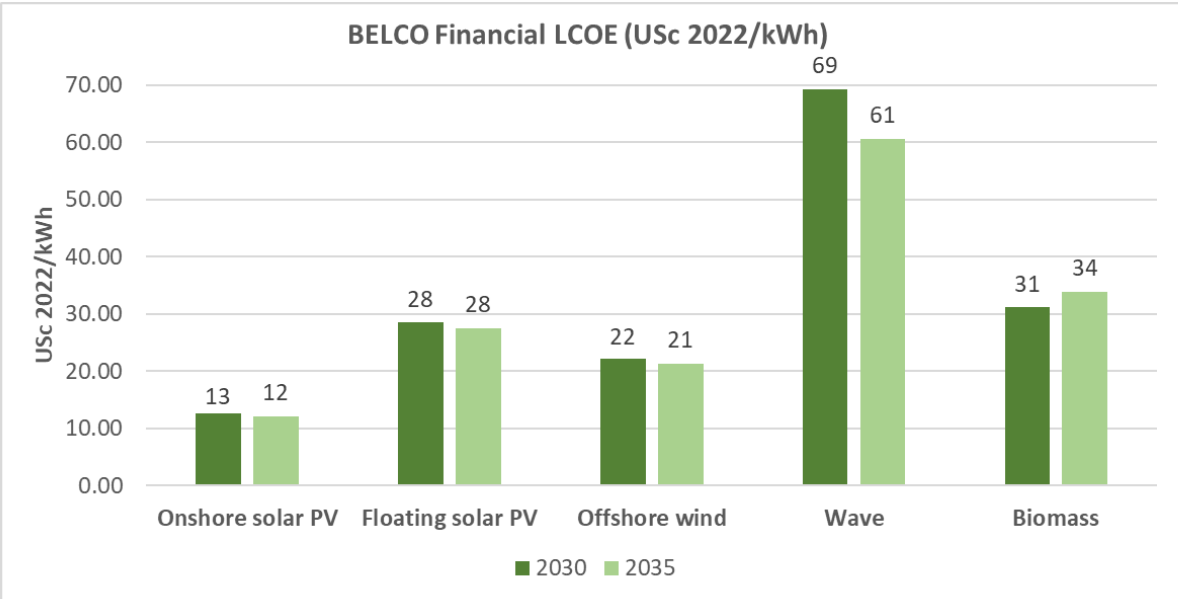
2. SUMMARY OF BELCO'S IRP PROPOSAL

The following subsections briefly summarise BELCO's IRP Proposal (the **Proposal**) including a summary of some of the inputs, the scenarios modelled, and key results.

2.1 INPUTS

In order to understand the relative lifetime cost of different technologies considered in the Proposal, BELCO provided their levelised cost of electricity (**LCOE**) analysis. In the Proposal, they only presented the LCOE for the renewable energy technologies considered including solar, floating solar, offshore wind, wave, and biomass.

Figure 1. LCOE for technologies considered in BELCO's IRP[1]



As observed from the figure, onshore solar has the lowest LCOE, signalling that it could be developed before the other technologies, followed by offshore wind, floating solar, biomass, and lastly wave.

For details on the other inputs and assumptions used by BELCO in their analysis, please refer to the following sections and pages in BELCO's IRP Proposal document:

- Demand: section 5 of the IRP Proposal, starting on page 23
- Fuel prices: section 7.3 of the IRP Proposal, starting on page 56

[1] In order to compare these values more fairly with our analysis and calculations, discussed in section 3, Figure 1 presents BELCO's LCOE analysis adjusted to reflect our calculation method including a discount rate of 10%. From our understanding, BELCO used a discount rate of 8% in their analysis.

Some of the notable differences between BELCO's inputs and our independent analysis are discussed further in this report, in section 3.

2.2 SCENARIOS

To consider different pathways for the electricity sector in Bermuda, BELCO modelled 11 different scenarios. The scenarios were created through a series of differentiating factors including decarbonisation constraints and fuel strategies. A summary of these scenarios is provided in Table 1 below.

Table 1. Summary of BELCO's modelled scenarios

Scenario name in BELCO's Proposal	Fuel strategy	Decarbonisation targets
P1	Current fuel strategy (Heavy Fuel Oil (**HFO**) and Light Fuel Oil (**LFO**))	Stay the course
P2F	Current fuel strategy (HFO and LFO)	No targets[2]
P2L	East Power Station (**EPS**) and North Power Station (**NPS)** switch to run on LFO with a 10-year life extension	No targets[2]
P2LL	EPS and NPS switch to run on LFO with a 30-year life cycle upgrade	No targets[2]
P2N	EPS, NPS, and Gas Turbines (**GTs**) switch to run on Liquefied Natural Gas (**LNG**) with a 30-year life cycle upgrade	No targets[2]
P4L	EPS and NPS switch to run on LFO with a 10-year life extension	85% renewable generation by 2040
P4LL	EPS and NPS switch to run on LFO with a 30-year life cycle upgrade	85% renewable generation by 2040
P4N	EPS, NPS, and GTs switch to run on LNG with a 30-year life cycle upgrade	85% renewable generation by 2040
P5L	EPS and NPS switch to run on LFO with a 10-year life extension	Net Zero by 2050
P5LL	EPS and NPS switch to run on LFO with a 30-year life cycle upgrade	Net Zero by 2050
P5N	EPS, NPS, and GTs switch to run on LNG with a 30-year life cycle upgrade	Net Zero by 2050

2.3 RESULTS

Once BELCO modelled the 11 scenarios, they compared them using key performance indicators (**KPIs**). Some of these metrics included the economic costs to customers[3], financial costs to customers, annual electricity rate growth, cost certainty and risk, carbon emission reduction, technology diversity, etc.

After presenting the different KPIs and results, BELCO notes that their preferred scenario for Bermuda is one that **converts NPS and EPS engines to run on LFO with 10-year life extension** and targets **85% of renewable energy generation by 2040** (i.e. P4L).

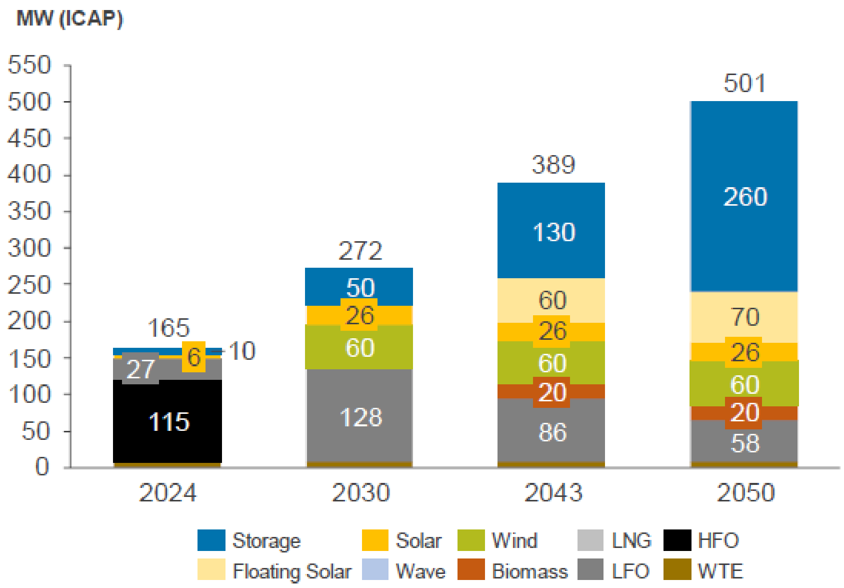
Figure 2 below shows the installed capacity timeline for BELCO's preferred scenario. Some additional notes on this scenario include:

[2] Whereby no targets we interpret to mean that the model optimises capacity expansion to minimise economic costs.

[3] Economic costs try to quantify the net benefits to society in monetary terms, for example, the carbon emissions avoided. Therefore, the economic costs are equivalent to the financial costs of the scenario in addition to the net benefits to society.

- Average annual electricity rate growth is estimated at 4.66% for the next 20 years
- Carbon emissions are expected to reduce by 77% in 2050 relative to 2025
- Renewable energy generation of total energy requirements (including self-consumption) is estimated to be around 80% in 2050[4]

Figure 2. Installed capacity in BELCO's preferred scenario (i.e. P4L)



Key features of other scenarios modelled by BELCO are highlighted in Table 2 below.

Table 2. Key observations on alternative scenarios

Metric	Scenario
Carbon Emission Reduction in 2050, relative to 2025 (%)	
Highest reduction	P5N (i.e. NPS, EPS, and GTs switch to run on LNG and target Net Zero by 2050)
Lowest reduction	P2F (i.e. Current fuel strategy, with NPS and EPS running on HFO and GTs on LFO + no decarbonisation targets)
Average Annual Electricity Rate Growth (%) for the next 20 years	
Lowest	P2F (i.e. Current fuel strategy, with NPS and EPS running on HFO and GTs on LFO + no decarbonisation targets)
Highest	P5N (i.e. NPS, EPS, and GTs switch to run on LNG and target Net Zero by 2050)
Renewable Energy Generation of Total Energy Requirements (including self-consumption) in 2050 (%)	
Highest	All the Net Zero by 2050 scenarios (i.e. P5L, P5LL, P5N)
Lowest	P2N (i.e. NPS, EPS, and GTs switch to run on LNG with no decarbonisation targets)

BELCO selected their preferred scenario (P4L) on the basis of a qualitative assessment.

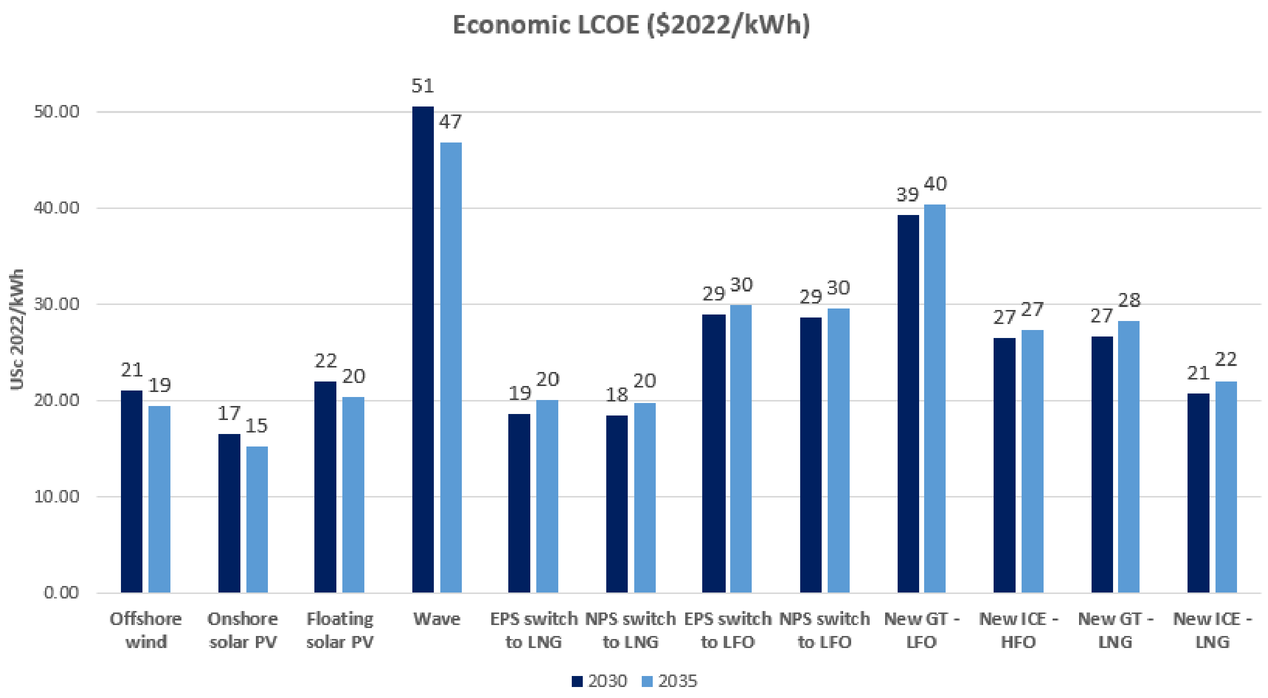
[4] We have recalculated the proportion using our approach to compare against our analysis more fairly in sections 3 and 4.

3. OUR INDEPENDENT ANALYSIS

3.1 INPUTS

Similar to BELCO, in order to understand the relative lifetime cost of different technologies, we have conducted an LCOE analysis. Figure 3 below includes the LCOE of both thermal and renewable energy technologies.

Figure 3. Our LCOE analysis (10% discount rate)



As observed in Figure 3, in terms of renewables, onshore solar looks like the most attractive option (similar to BELCO's analysis), followed by offshore wind and floating solar. In addition, we can observe that new internal combustion engines (**ICE**)**,** such as EPS and NPS, and new GTs are not as attractive as onshore solar and offshore wind even though they could be necessary for reliability and other technical constraints.

Some other highlights from the assumptions that we used in our analysis, and how they compare to BELCO's are noted below:

- Demand:
  - Total energy requirements (including self-consumption) are estimated to continuously increase and rise above 650GWh by 2050, which is about 10% higher than levels forecasted by BELCO. This difference predominantly comes down to electricity consumption in the transport sector, which we derived to try and align with the Draft Transport Policy.
  - In our analysis, demand from electric vehicles (**EVs**) is forecasted to reach 100GWh in 2050, about 30 times larger than the demand estimated for 2025, and almost 2.5 times higher than BELCO's assumption in 2050.
- Fuel prices:
  - Our HFO prices are projected to increase by ~9% in 2050 relative to 2025, and on average, are 7% higher than BELCO's estimates for 2025-2050.
  - LFO prices are forecasted to increase by 10% in 2050 relative to 2025, and on average, are around 16% higher than BELCO's projections for 2025-2050.

  - LNG base prices[5] are estimated to increase by 3% in 2050 relative to 2025 and are similar to BELCO's forecasts.
- Technology costs:
  - We have assumed lower offshore wind, floating solar, and biomass capital costs than BELCO: on average, 15%, 11%, and 26% lower, respectively, in the period between 2025-2035
  - We have assumed higher onshore solar and wave capital costs than BELCO: on average, 12%, 19%, respectively, in the period between 2025-2035. We have also assumed higher battery storage costs
- In order to account for land scarcity and feasibility of deploying projects, it is important to place a cap on the capacity that each technology can deploy. We have used different caps to BELCO's for the following technologies:
  - Offshore wind: BELCO caps the technology at 60MW. However, we believe that there is potential for up to 120MW of offshore wind.
  - Floating solar PV: BELCO caps the technology at 80MW. However, we believe that 25MW is more realistic considering international experience to date with this technology at sea.
  - Battery storage: BELCO does not set a cap for battery storage. However, we have set a cap of 200MW to reflect land restrictions for building such infrastructure.
- In BELCO's IRP Proposal, BELCO assumes that LNG can be introduced on island as early as 2028. We believe that it is more realistic to assume that LNG could not be introduced until 2030, considering new infrastructure needs this involves.

3.2 SCENARIOS

Similar to BELCO, we modelled a series of five different scenarios, and aimed to cover the different constraints considered by BELCO. Therefore, we created our scenarios by differentiating the fuel strategy and the renewable energy generation of total energy requirements (including self-consumption). These scenarios are summarised in Table 3.

Table 3. Summary of our modelled scenarios

Scenario name	Fuel strategy	Renewable energy generation of total energy requirements (including self-consumption) in 2050
LNG_Switch	EPS and NPS switch to run on LNG	24%[6]
No Fuel_Switch	EPS, NPS, and GTs keep running on the same fuel (EPS and NPS on HFO and GTs on LFO)	45%[6]
LFO_Switch	EPS and NPS switch to run on LFO	61%[6]
Max RES_LNG	EPS and NPS switch to run on LNG	93%
Max RES_No LNG	EPS, NPS, and GTs keep running on the same fuel (EPS and NPS on HFO and GTs on LFO)	93%

[5] Our LNG base prices include the commodity price of natural gas in addition to other costs such as liquefaction and regasification. Additionally, we have included a cost component to represent diseconomies of scale in scenarios with relatively low LNG requirements. However, that is not represented in this figure.

[6] Whereby the model is optimising capacity expansion to minimise economic costs.

3.3 RESULTS

Once we finished the modelling, we compared the scenarios across a range of different KPIs, similar to the process followed by BELCO. We compared the scenarios using six KPIs, including:

- Compound annual electricity rate growth for the next 20 years (%)
- Carbon emission reduction in 2050, relative to 2025 (%)
- Renewable energy generation of total energy requirements (including self-consumption) in 2050 (%)
- Dispatchable capacity of total installed capacity in 2050 (%)
- Resource diversity in 2050
- Operational risks[7]

Then, we have ranked each scenario from most attractive to least attractive for all the KPIs. The weights we have used to establish scenario "attractivity" scores are presented in Table 4. We are seeking the public's inputs on these assumptions.

Table 4. Weights applied to KPIs in our analysis

KPI	Weight (%)
Compound annual electricity rate growth for the next 20 years (%)	70%
Carbon emission reduction in 2050, relative to 2025 (%)	10%
Renewable energy generation of total energy requirements (including self-consumption) in 2050 (%)	20%
Dispatchable capacity of total installed capacity in 2050 (%)	0%
Resource diversity in 2050	0%
Operational risks[8]	0%
Total	**100%**

Once applying the weights from Table 4 to the rankings of scenarios across the KPIs, our analysis showed that the **highest-scoring scenario was the scenario that switches NPS and EPS engines to run on LNG with 24% renewable energy generation of total energy requirements (including self-consumption) in 2050**. Alternatively, the lowest-scoring scenario from our analysis is the scenario that continues running EPS, NPS, and GTs on the same fuel (EPS and NPS on HFO and GTs on LFO) and reaches 93% of renewable energy generation of total energy requirements (including self-consumption) in 2050.

Figure 4 below shows the installed capacity timeline for the highest-scoring scenario, and Figure 5 depicts the respective procurement timeline. Some additional notes on this scenario include:

- Compound annual electricity rate growth is estimated at 2.6%[9] for the next 20 years.
- Carbon emissions are expected to reduce by 31% in 2050 relative to 2025.
- Renewable energy generation of total energy requirements (including self-consumption) is estimated to increase from less than 10% in 2025 to 24% in 2050.

[7] Operation risk is meant to reflect the risks associated with potentially running engines at less optimal conditions, in particular due to higher renewable generation (e.g. more frequent start-ups and shut downs, etc). This could potentially lead to higher operating and maintenance costs, higher emissions, etc.

[8] Operation risk is meant to reflect the risks associated with potentially running engines at less optimal conditions, in particular due to higher renewable generation (e.g. more frequent start-ups and shut downs, etc). This could potentially lead to higher operating and maintenance costs, higher emissions, etc.

[9] Including assumed inflation over the period.

Figure 4. Installed capacity of highest-scoring scenario from our independent analysis

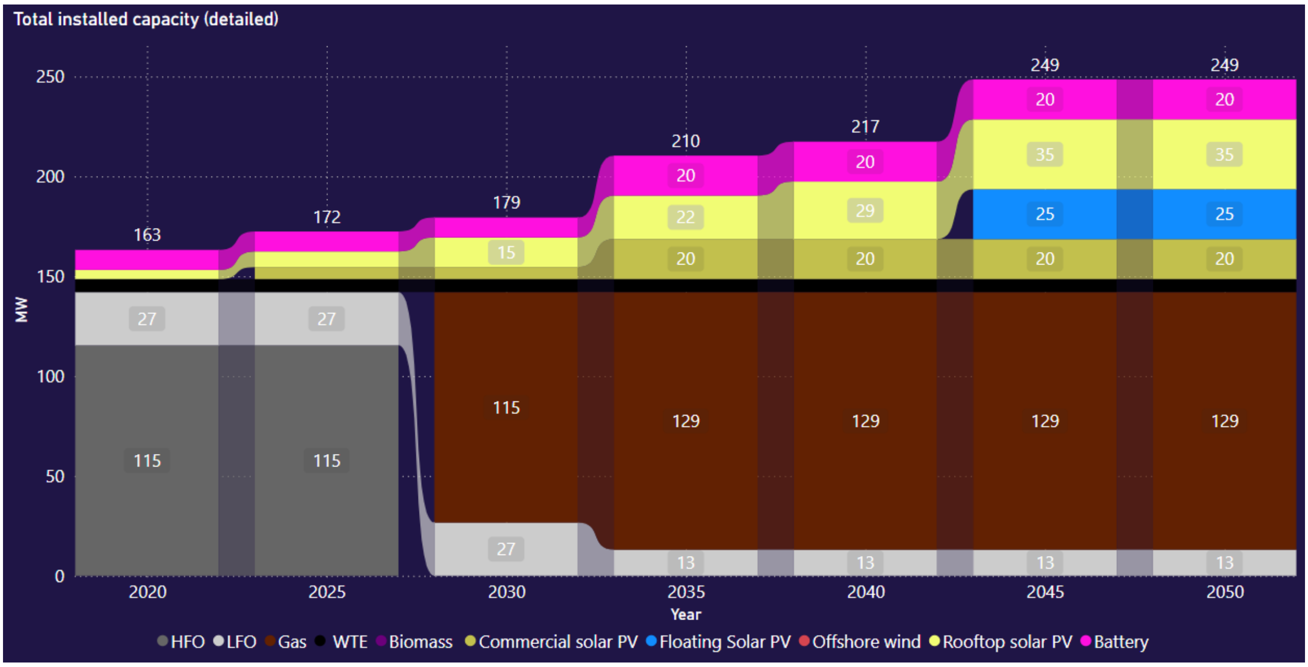
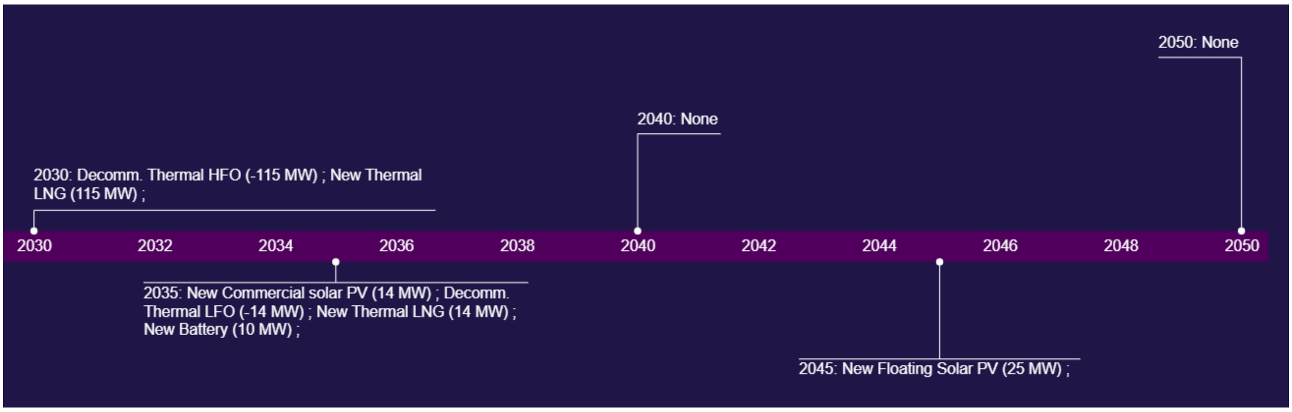


Figure 5. Procurement Timeline for the highest-scoring scenario from our independent analysis



Even though this scenario is the highest-scoring pathway, some interesting notes on some alternative scenarios are highlighted in Table 5.

Table 5. Key notes on alternative scenarios from our independent analysis

Metric	Scenario
Carbon Emission Reduction in 2050, relative to 2025 (%)	
Highest reduction	EPS, NPS, GTs switch to run on LNG and renewable energy generation of total energy requirements (including self-consumption) reaches 93% in 2050
Lowest reduction	EPS and NPS switch to run on LNG with 24% renewable energy generation of total energy requirements (including self-consumption) in 2050
Compound Annual Electricity Rate Growth (%) for the next 20 years	

Metric	Scenario
Lowest	EPS and NPS switch to run on LNG with 24% renewable energy generation of total energy requirements (including self-consumption) in 2050
Highest	EPS, NPS, and GTs keep running on the same fuel (EPS and NPS on HFO and GTs on LFO) and renewable energy generation of total energy requirements (including self-consumption) reaches 93% in 2050
Renewable Energy Generation of Total Energy Requirements (including self-consumption) in 2050 (%)	
Highest	Both scenarios that reach 93% renewable energy generation of total energy requirements (including self-consumption) in 2050
Lowest	EPS and NPS switch to run on LNG with 24% renewable energy generation of total energy requirements (including self-consumption) in 2050

As previously discussed in section 2.3, and as we can observe from Table 5, the weights that are applied to each of the studied metrics can largely change the highest-scoring scenario. Therefore, the weights require careful consideration and public input.

As observed in this chapter, our approach and outputs are similar to BELCO's, except for the following:

- Our analysis features lower deployment of battery storage capacity than that deemed be required by BELCO, in particular in scenarios with higher thermal contributions to the energy mix.
- Our scenario ranking is quantitative: an overall KPI score is calculated for each scenario, based on which scenarios are ranked from most to least attractive.

4. CONCLUSIONS

As discussed, to thoroughly investigate and analyse BELCO's IRP Proposal, we conducted our own independent analysis.

Figure 6 below shows the five scenarios that we have modelled with their estimated compound annual electricity rate growth for the next 20 years and the renewable energy generation of total energy requirements (including self-consumption) in 2050. Additionally, Figure 7 shows the same metrics for the five scenarios from BELCO's IRP Proposal which are most comparable to our scenarios.

Figure 7 points out BELCO's preferred scenario, P4L. Additionally, the figure highlights the highest-scoring scenario resulting from applying the same weights that we have used in our analysis (as shown in Table 4), which would actually be P2F (i.e. Current fuel strategy (HFO and LFO) and no decarbonisation targets).

Figure 6. Renewable energy generation and compound annual electricity growth rate for our five scenarios[10]

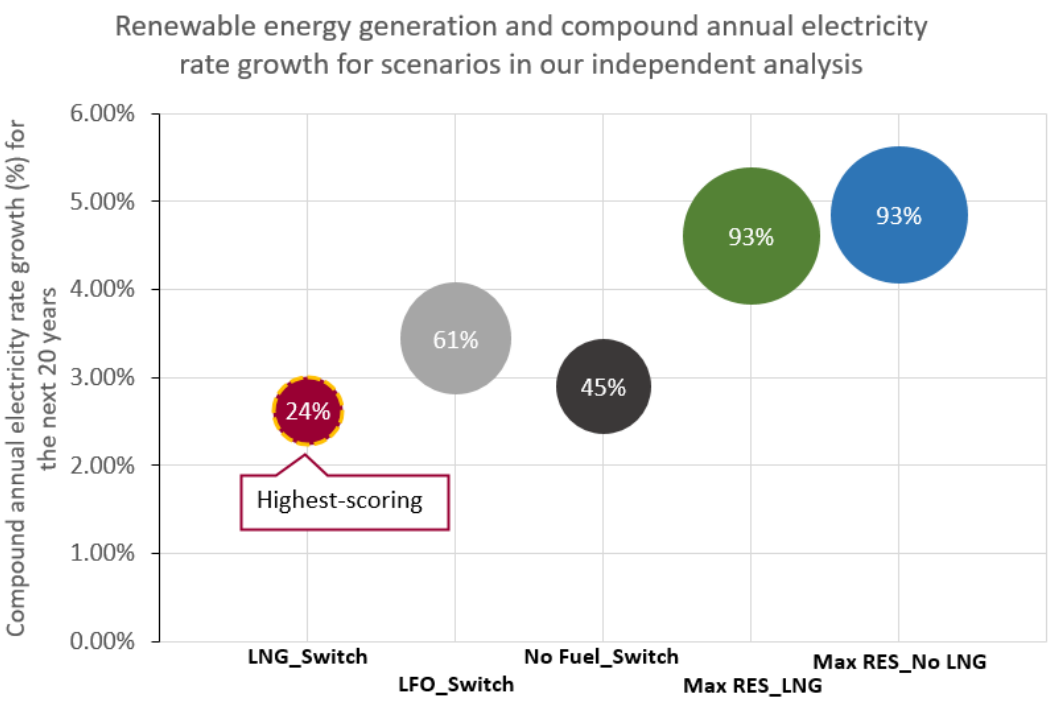
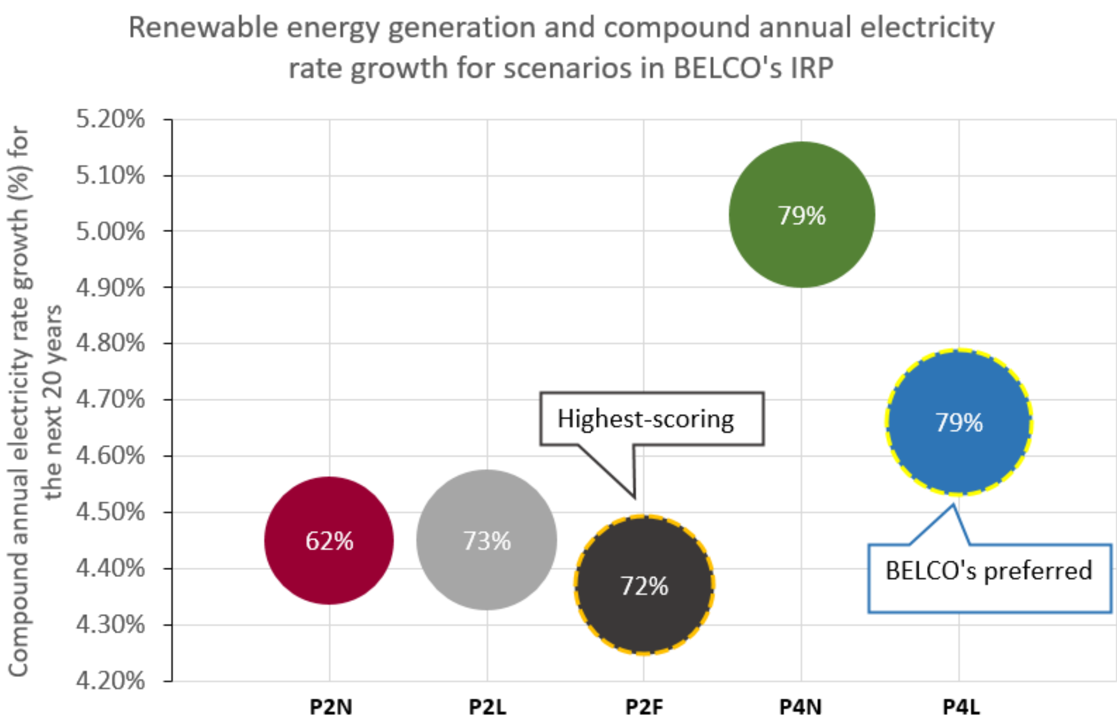


Figure 7. Renewable energy generation and compound annual electricity growth rate for five of BELCO's scenarios[11]



[10] Renewable energy generation shown is the proportion of renewable energy generation of total energy requirements (including self-consumption) in 2050 and is reflected by the size of the bubbles in the figure. The compound annual electricity rate growth is estimated for the next 20 years including inflation.

[11] Only five scenarios from BELCO's 11 scenarios are shown, which are the pathways that are most comparable to ours. Renewable energy generation shown is the proportion of renewable energy generation of total energy requirements (including self-consumption) in 2050 and is recalculated, using our approach, to compare with our values more fairly. This proportion of renewable energy is reflected by the size of the bubbles in the figure. The compound annual electricity rate growth is estimated for the next 20 years.

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APPENDIX C: IRP PROPOSAL NOTICE AND GUIDANCE

32. The document linked below contains the guidelines that should be considered for the submission of alternative generation proposals.

    a. IRP Proposal Notice and Guidance Document

REGULATORY AUTHORITY
OF BERMUDA

Integrated Resource Plan (IRP) Proposal Request

Matter: 20221117

Date: 17 November 2022

1st Floor, Craig Appin House, 8 Wesley Street, Hamilton HM 11, Bermuda
T: (441) 405-6000 • E: info@ra.bm

Notice of Request for Integrated Resource Plan Proposal

In the matter of the Electricity Act 2016, as amended (**EA**), and in accordance with section 40 of the EA, NOTICE IS GIVEN that the Regulatory Authority (**RA**) requests an Integrated Resource Plan (**IRP**) proposal (**IRP Proposal**) from the Transmission, Distribution and Retail (**TD&R**) Licensee that complies with the requirements of this Notice, the EA, and any relevant administrative determinations.

The IRP Proposal must cover no less than a 5-year period from the date that the RA approves the IRP (**Period**). The IRP Proposal must contain:

(a) a resource plan that includes the Period's projected demand and account for the existing generation resources available to the TD&R Licensee; and
(b) a procurement plan detailing how the TD&R Licensee proposes to meet projected demand.

In preparing the IRP Proposal, the TD&R Licensee must:

(a) consider all reasonable resources, including new generation capacity, demand side resources and generation capacity retirements;
(b) consider various renewable energy and efficient generation options, and prudent generation portfolio diversification;
(c) prioritise actions that most meet the EA's purposes, conform to Ministerial directions, and be reasonably likely to supply electricity at the least cost, subject to trade-offs contained in any Ministerial directions or instructions from the RA;
(d) indicate recommendations regarding whether any resources will be procured through competitive bidding in accordance with section 48(7) of the Regulatory Authority Act 2011; and
(e) include proposed limits, if any, for total distributed generation capacity over the planning period.

The IRP Proposal's form and content must be in accordance with Annex A of this Notice. The TD&R Licensee must submit the IRP Proposal to the RA no later than 17 November 2023.

REGULATORY AUTHORITY
OF BERMUDA

ANNEX A:
Integrated Resource Plan (IRP) Proposal Guidance

Matter: 20221117

Date: 17 November 2022

1st Floor, Craig Appin House, 8 Wesley Street, Hamilton HM 11, Bermuda
T: (441) 405-6000 • E: info@ra.bm
www.ra.bm

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Integrated Resource Plan Guidelines

1. Introduction

1.1 These guidelines establish the Regulatory Authority of Bermuda's (**RA**) expectations of the Transmission, Distribution and Retail (**TD&R**) Licensee for updating the Integrated Resource Plan (**IRP**) (**Guidelines**). The Guidelines seek to ensure that the RA and BELCO meet their statutory obligations under the Electricity Act 2016 (**EA**) in a manner that is consistent with the National Electricity Policy; and to implement the regulatory regime established by the electricity sector licences. The Guidelines reflect established practice and precedents for the development of IRPs and similar capacity planning exercises seen in relevant regulatory jurisdictions.

2. IRP Aims

2.1 The EA under section 40 requires the RA to direct the TD&R Licensee to prepare an IRP Proposal at least every five years. The IRP Proposal should contain:

(a) "a resource plan that includes the expected demand for the period and the state of the TD&R Licensee's existing resources; and

(b) a procurement plan to details how the licensee proposes to meet this demand."

2.2 The TD&R Licensee must consider all resources required to meet demand, including but not limited to:

(a) New conventional generation capacity;

(b) Expected lifetime and date of retirement of conventional generation capacity;

(c) Various renewable energy and efficient generation options;

(d) Prudent generation portfolio diversification; and

(e) Demand side resources (including demand response and energy efficiency).

2.3 As under section 40(2)(b) of the EA the TD&R Licensee must "prioritise actions that most meet the purposes of this Act, conform to Ministerial directions, and be reasonably likely to supply electricity at the least cost, subject to trade-offs contained in the Ministerial directions or instructions from the Authority"; Trade-offs include, but are not limited to, meeting demand with acceptable reliability and implementation risk.

2.4 Following the TD&R Licensee's proposal, the RA will engage in "at least one public consultation, whether alone or together with a consultation in respect of other proposals". [1]

2.5 The IRP Proposal must be credible, comprehensive in its treatment of available resources, auditable, and robust to identifiable sources of uncertainty in order to enable the RA to:

(a) Assess alternative capacity environmental, and social implications and determine optimal trade-offs;

(b) Identify the lowest cost, or otherwise most suitable plan aligned with the EA and this guidance document.

[1] Section 43(a) of the EA

3. IRP Requirements

3.1 Approach and Methodology

The TD&R Licensee should undertake its IRP Proposal from an objective perspective, focusing on the country, its economic, environmental and populace's needs. Specifically:

(a) Methodologies must remain neutral to any (current or future) specific business's commercial interest. They must be squarely focussed on the country's overall economic benefit.

(b) Capital, operational and fuel costs modelled must be evaluated on economic rather than financial terms, meaning that:

- The analysis must be conducted in real terms, using levelized electricity costs, rather than nominal terms;
- Taxes, subsidies, PPA considerations, duties, import tariffs, demand side conservation program incentives, and distributed generation incentives must be excluded;
- Social discount rates (i.e.,10% or less), irrespective of potential developers, must be used rather than business returns (Cost of Capital);
- Wherever reasonable and practical, account for supply chain environmental impacts, rather than just local impacts (e.g., fuel commodity extraction, delivery chain and local use impacts plus, and remediation rather than just costs plus local impacts). If reasonable, associated externalities should be monetised and internalised in the calculation of levelized costs underpinning the analysis;
- Account for estimated social costs e.g., negative community health implications, costs to the environment of carbon and other relevant emittants such as nitrogen oxides ("NOx") and sulphur oxides ("SOx") (social damage costs) – associated externalities should be monetised and internalised in the calculation of levelized costs underpinning the analysis;
- Country & overall economy benefits must be evaluated rather than any particular business entity's financial prospects.

(c) Under the constraints listed above, use quantitative modelling methodologies and mathematical programming approaches to project demand across the simulation period (10-20 years), including sensitivities that account for:

- Projected local conditions affecting demand;
- Existing and projected asset condition;
- Historical system data;
- Current and projected site-specific resource availability;
- Planned asset retirements;
- Planned capacity additions;
- Battery storage; and
- Specified potential fuel options.

(d) Determine Levelized Electricity Costs, seeking lowest cost (Present Value) and

Maximal Net Present Value within policy, social, and geographic constraints;

(e) Use the technical & economic inputs provided in the specifying section below to constrain modelling; Inputs must be reported in the assumptions register template provided by the RA at a date the RA specifies separately;

(f) Use Scenario Analysis as specified below;

(g) Provide the RA with models underpinning their IRP Proposal in native format(s) – including from Microsoft Excel©, PLEXOS© and any other software used for the purpose of the analysis;

(h) The IRP Proposal must include detailed references and other supporting documentation where necessary;

(i) Screen evaluated technologies primarily using LCOE analysis;

(j) Carry out transmission power flow and dynamic stability studies to quantify additional investments (e.g., battery storage, transmission and distribution network reinforcements) needed to ensure the resilience and reliability of the power system under each scenario considered – and ensure they are monetised and included in the scenario benchmarking analysis;

(k) Determine the optimal timeline to commission supply and demand side resources, whilst considering practical tendering and implementation constraints;

(l) Ensure outputs are:
- Diligent;
- Peer reviewed independently;
- Account for expert input as required;
- Technically, financially, and economically sensible;
- Comprehensive; and
- Easy to read and understand by the general public.

(m) Propose a plan consolidating all the above, meeting projected demand while satisfying technical, economic, environmental, and policy objectives.

4. Policy Objectives

4.1 The EA requires that the IRP Proposal reflects the RA and/or Ministerial policy guidance. Overarching policy objectives include system reliability, affordability, and environmental sustainability.

4.2 The IRP must comply with established bulk generation licensing requirements including meeting applicable codes and standards.

4.3 The IRP Proposal must establish and target a specified Loss of Load Expectation (LOLE) suited to Bermuda.

4.4 Where possible, the IRP must specify and account for shadow factors and social costs (such as carbon costs).

4.5 The IRP must consider Bermuda's National Electricity Sector and National Fuels Policy.

5. Input Assumptions

All participating parties are to use the IRP inputs listed below. Where applicable, all parties will also use the approach and methodology specified above.

5.1 Input Assumptions

IRP developments must use the following input assumptions:

(a) Simulation horizon 10-20 years;

(b) Sales Forecast, accounting for

- Assumptions on future macroeconomic performance (e.g., GDP growth);
- Residential consumer activity;
- Commercial consumer activity and future connections;
- Distributed Generation impacts;
- Energy efficiency programs should be considered as demand side resources.
- Conservation programmes (e.g., Water heater and pool pump timer installations) warrant consideration; and
- Consider potential electric vehicle adoption rates, likely demand impacts and including smart charging capabilities.

(c) Supply Side

- Proposed CAPEX and OPEX assumptions must be justified using (decreasing order of preference): RA-provided studies, other feasibility studies, pre-feasibility studies, recent experience in other small islands, or reputable sources (e.g., IEA, IRENA, World Bank).
- Must consider technologies including but not necessarily limited to:
  1. Fuel oils including existing fuels and lower sulphur content fuel oils;
  2. Onshore & offshore solar PV;
  3. Offshore wind;
  4. Liquified Natural Gas (LNG);
  5. Liquified Propane Gas (LPG);
  6. Biomass; and
  7. Wave Power Generation.

(d) Technical and operating characteristics of the generation technologies and their availability;

(e) Prices for input fuels, any other related commodities, as well import infrastructure availability or developmental requirements, accounting for any diseconomies of scale;

(f) Battery Energy Storage Systems can be considered to the extent that system stability and IRP economic analysis supports (or warrants exclusion);

(g) IRP Resources

- The IRP shall make use of the RA's August 2021 RA desktop wind (and any future) studies, existing PV studies and any other relevant, readily available resources as IRP base materials, in addition to studies conducted by BELCO.

(h) Scenario Analysis

- The IRP Proposal should consider a minimum of three scenarios corresponding to the various combination of supply side and demand side resources.

(i) Sensitivity Analysis

- IRP development must include base case, plus plausible high and low sensitivity analysis. In particular the sensitivity analysis should consider:
  1. Demand uncertainty;
  2. Fuel price uncertainty;
  3. Alternative carbon price assumptions;
  4. Alternative capital and operating cost assumptions for future generation resources;
  5. Extended existing generation resources operation beyond planned retirement dates; and
  6. Retirement of existing generation resources before their planned retirement date.

6. Outputs

6.1 IRP Outputs must include:

(a) 10 to 20-year demand projections;

(b) 10 to 20-year generation projection including reserve capacity and connection costs, if any;

(c) Proposed procurement plan including timelines for at least a 5-year period;

(d) Rate impact analysis; and

(e) Any other relevant information and supporting analysis to meet expectations this document lays out.

APPENDIX D: PROCEDURE, LEGISLATIVE CONTEXT AND BACKGROUND

D.I. PROCEDURE

33. The procedure and accompanying timelines, under which this invitation to comment is taking place are set out in the paragraphs below.

34. Written comments should be submitted before 5:00 pm (Bermuda time) on 30 September 2024.

35. The RA invites comments from members of the public, electricity sectoral participants and providers, and other interested parties. the RA requests that commenting parties, in their responses, reference the number of the relevant question, as set forth in this invitation to comment document, to which they are responding. a complete list of questions presented by this invitation to comment document appears in chapter vii of this document.

36. Responses to this invitation to comment document should be filed electronically in MS word or adobe acrobat format. parties wishing to file comments should go to the RA's website https://www.ra.bm/consultations/consultations-directory and click on the "open consultation form" button on the respective public consultation page:

37. All comments should be clearly marked "response to Invitation to Comment: comments on Integrated Resource Plan Proposal Invitation to Comment Document".

38. The RA intends to make responses to this Invitation to Comment Document available on its website. If a commenting party's response contains any information that is confidential in nature, a clearly marked "non-confidential version", redacted to delete the confidential information, should be provided together with a complete version that is clearly marked as the "confidential version." Redactions should be strictly limited to "confidential information," meaning a trade secret, information whose commercial value would be diminished or destroyed by public disclosure, information whose disclosure would have an adverse effect on the commercial interests of the commenting party, or information that is legally subject to confidential treatment. The "confidential version" should highlight the information that has been redacted. Any person claiming confidentiality in respect of the information submitted must provide a full justification for the claim.

39. The principal point of contact at the RA for this Invitation to Comment document is Shonette Harrison, who may be contacted by email, referencing "comments on Integrated Resource Plan Proposal Invitation to Comment" at consultation@ra.bm or by mail at:

Shonette Harrison
Regulatory Authority
1st floor, Craig Appin House
8 Wesley street,
Hamilton, Bermuda

40. In this Invitation to Comment Document, except insofar as the context otherwise requires, words or expressions shall have the meaning assigned to them by the EA, the RAA and the Interpretation Act 1951.

41. This Invitation to Comment Document is not a binding legal document and does not contain legal, commercial, financial, technical or other advice. The RA is not bound by this Invitation to Comment Document, nor does it necessarily set out the RA's final or definitive position on particular matters. To the extent that there might be any inconsistency between the contents of this Invitation to Comment Document and the due exercise by the RA of its functions and powers, and the carrying out of its duties and the achievement of relevant objectives under law, such contents are without prejudice to the legal position of the RA.

D.II. LEGISLATIVE CONTEXT

42. The RAA established a cross-sectoral, independent and accountable regulatory body "to protect the rights of consumers, encourage the deployment of innovative and affordable services, promote sustainable competition, foster investment, promote Bermudian ownership and employment and enhance Bermuda's position in the global market".

43. In June 2015, the ministry of economic development of Bermuda published the national electricity sector policy (the policy document). The policy document set out the groundwork for the institution of the subsequent EA and the desired structure of the electricity sector of Bermuda.

44. The EA established an electricity sector regulatory framework within the meaning of the raa. the EA received royal assent on 27 February 2016 and came into operation on 28 October 2016 pursuant to the electricity act 2016 commencement day notice 2016 (BR 101/2016). The EA repealed the energy act 2009.

45. The Minister responsible for electricity is currently the Minister of Home Affairs (the Minister). The Minister can issue ministerial declarations that establish policies for the electricity sector and can also issue ministerial directions to the RA regarding any matter within his authority with regard to the electricity sector. In formulating ministerial directions, the minister shall set priorities and resolve trade-offs or conflicts that arise from the purposes of the EA in a way that he thinks best serves the public interest.

46. The RA has the powers to supervise, monitor and regulate the electricity sector in Bermuda in accordance with the purposes of the EA. Such purposes, as set forth in section 6 of the EA, and include:

    a) "to ensure the adequacy, safety, sustainability and reliability of electricity supply in bermuda so that bermuda continues to be well positioned to compete in the international business and global tourism markets;

b) to encourage electricity conservation and the efficient use of electricity;

c) to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources;

d) to provide sectoral participants and end-users with non-discriminatory interconnection to transmission and distribution systems;

e) to protect the interests of end-users with respect to prices and affordability, and the adequacy, reliability and quality of electricity service;

f) to promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity."

47. The principal functions of the RA, in relation to any regulated industry sector, are described in section 12 of the RAA as follows:

a) "to promote and preserve competition;

b) to promote the interests of the residents and consumers of Bermuda;

c) to promote the development of the Bermudian economy, Bermudian employment and Bermudian ownership;

d) to promote innovation; and

e) to fulfil any additional functions specified by sectoral legislation."

48. Section 14 of the EA gives the RA the function "generally to monitor and regulate the electricity sector" together with the detailed functions described in the RAA and elsewhere in the ea. hence, the RA regulates the electricity sector in Bermuda.

49. In accordance with the policy document, the reformed electricity sector in Bermuda will introduce competition between existing generation facilities, prospective third-party bulk generators (i.e. independent power producers), distributed generators, and other demand-side resources. In order to achieve greater efficiency while maintaining an appropriate level of overall system reliability, the costs and benefits of all competing resources and sectoral developments will need to be considered when developing future investments plans, to ensure that these plans are efficient. The TD&R licensee is required to produce an IRP proposal that contains a resource plan and a procurement plan specifically designed to address future sectoral demand.

50. Section 40 of the EA (i) requires the RA to issue a notice requesting the IRP proposal from the TD&R licensee within two years of the commencement date of the EA and every five years or less; and (ii) sets forth the requirements for the notice, including requirements for the IRP proposal.

51. Section 41 of the EA requires the IRP proposal to (i) comply with the EA, any administrative determinations and the notice requesting the IRP proposal; and (ii) contain the requirements set forth in section 40 of the EA.

52. The RA shall also request the submission of proposals for bulk generation or demand side resources (alternative proposals) pursuant to sections 42(2) and 42(3) of the EA.

53. Section 43 of the EA requires the RA to hold at least one public consultation for each alternative proposal received before the stipulated deadline and to hold meetings, if necessary with the proponent of each alternative proposal, the TD&R licensee and any other persons that the RA considers relevant in order to assess the alternative proposals.

54. Section 44 of the EA requires the TD&R licensee to prepare a final draft IRP for the RA's review and approval that takes the public comments and alternative proposals into consideration and implements the RA's comments. section 44 also sets forth the process for the RA's approval of the IRP.

55. Section 45 of the EA requires the RA to publish the approved IRP on its official website.

56. The remainder of the invitation to comment document explains the IRP process, seeks views on the IRP proposal from the TD&R licensee, and seeks alternative proposals for bulk generation or demand side resources.

D.III. BACKGROUND

57. An IRP is a plan that seeks to balance the future demand and supply of electricity. Broadly, the IRP's purpose is to set out the strategy for the procurement and retirement of generation assets as well as demand side resources that meets the needs of consumers in a cost-efficient manner.

58. Accordingly, this plan should incorporate the latest evidence on the costs and technical characteristics of different generation and load management technologies to evaluate the least-cost capacity expansion plan for the electricity market of Bermuda. The plan should include both a resource plan—including a forecast of expected demand and the state of the existing generation resources—and a procurement plan, which details how the TD&R licensee proposes to meet the expected demand.

59. The RA issued the notice to the TD&R licensee on 17 November 2022, which required the TD&R licensee to submit an IRP proposal by 17 November 2023. The notice required the IRP proposal to detail a proposed procurement plan including timelines for at least a five-year period.

60. The TD&R licensee submitted its IRP proposal to the RA on the 17 November 2023.

61. Thereafter, the RA reviewed the IRP proposal and provided feedback to the TD&R licensee to improve the alignment between the IRP proposal and the notice and guidelines provided by the

RA. The TD&R licensee considered the feedback and resubmitted their IRP proposal on 19 March 2024, and thereafter on 9 May 2024.

62. The RA has reviewed the IRP proposal to assess its compliance with the EA and the notice and guidelines (collectively, the proposal requirements), as required under section 41 of the EA.

63. The RA has accepted the IRP proposal for the purposes of public consultation, although the RA's assessment (set forth in appendix b) highlights differences with an independent analysis. While the RA has accepted the IRP proposal for public consultation, it will, concurrent with this consultation, undertake a further detailed analysis of the IRP proposal to determine whether the proposal represents the capacity expansion plan that best balances the different priorities for the electricity market of Bermuda.

64. In the consultative process, which this invitation to comment document initiates, the RA seeks comments from the public on the IRP proposal submitted by the TD&R licensee, and on the alternative proposals for generation resources.

APPENDIX E: DEFINITIONS

Accounting Standards: generally accepted accounting principles as promulgated by the International Accounting Standards Board (“IASB”), Financial Accounting Standards Board (“FASB”) and such other accounting bodies as accepted and approved by the RA

Activity-based costing: costing methodology that identifies activities in an organization and assigns the cost of each activity with resources to business units according to the actual consumption by each.

AFUDC: means Allowance for Funds Used During Construction.

Allowed revenue: means the amount of money an entity is allowed to earn in undertaking its regulated business activities, typically on an annual basis.

Asset life assumption: an accounting estimate of the number of years it is likely to remain in service for the purpose of cost-effective revenue generation

Authority: means the Regulatory Authority of Bermuda established under the Regulatory Authority Act 2011 (as defined by the Electricity Act 2016).

BELCO: means Bermuda Electric Light Company Limited

Bulk generation: means generation using a system with an installed capacity at or above the licence threshold (as defined by the Electricity Act 2016).

Bulk generation licence: means a licence granted under section 25 of the Electricity Act 2016.

Bulk generation licensee: a party that has been granted a bulk generation licence under section 25 of the Electricity Act 2016.

Bulk Supply Tariff: means the electricity price of bulk supply when the cost of generation and transmission is recovered.

CAPEX: means capital expenditure, i.e. expenditure related to the acquisition or upgrade of fixed assets.

Capital structure: means the proportion of debt and equity that an entity uses to finance its activities.

CAPM: means capital asset pricing model, a methodology commonly used to estimate the cost of equity for an entity.

CEO: means Chief Executive Officer.

Competitive market: means an idealised market in which a large number of firms compete to provide goods and services for a large number of customers.

Cost of capital: means the return on investment required by investors providing funding for an entity's activities.

Cost of debt: means the return on investment required by an entity's debt holders.

Cost of equity: means the return on investment required by an entity's equity holders.

Cost pass-through allowance: means a cost allowance within regulated tariff setting, such that there is no deviation between allowed costs and costs actually borne by an entity.

Country Risk Premium: means investors demand an additional return for investing in foreign countries compare with domestic market as higher risk is associated with their investment.

CWIP: means Construction Work in Progress, an asset account in which the value of assets under construction is recorded.

Demand side response: means the reduced demand for electricity resulting from demand side management by allocating incentives for consumers by changing their consumption pattern to help keep the grid balanced at peak time.

Depreciation: means the gradual decrease in the value of an asset through time due to use, wear and tear or obsolescence; within regulatory tariff setting, depreciation also refers to a cost allowance (as a component of allowed revenue) that is determined to allow an entity to recover its capital expenditure.

Discounted Cash Flow: means using a valuation methodology to estimate the value of an asset based on its forecast cash flow.

Distributed generation: means generation using a system with an installed capacity below the licence threshold (as defined by the Electricity Act 2016).

Distributed generator: means a person that has a Standard Contract (as defined by the Electricity Act 2016).

Distribution: means conveying electric power below 22 kilovolts (kV) (as defined by the Electricity Act 2016).

DMS: stands for Dimson, Marsh, and Staunton

EA: means the Electricity Act 2016.

Economic lifetime: means the estimated lifespan over which an asset is expected to be able to serve its intended purpose.

Efficiency: means achieving maximum benefits with minimum resources.

Electricity sector: means the regulated industry sector involving the supply, transmission, distribution and consumption of electricity (as defined by the Electricity Act 2016).

End user: means a person or entity that uses electric power provided by the TD&R licensee on a retail basis (as defined by the Electricity Act 2016).

Equi-proportionate mark-up: a cost allocation share plan based on the direct cost of a business unit.

ERRA: stands for Energy Regulators Regional Association

EV: stands for Electric Vehicle

Ex ante: means before the event, i.e. this refers to items that are defined before actual results are known.

Ex post: means after the event, i.e. this refers to items that are based on actual rather than forecast data.

Facility: means a site where electrical equipment is located to provide some form of electrical service (as defined by the Electricity Act 2016).

FAR mechanism: means the fuel adjustment rate mechanism designed to recover the cost of fuel used to produce electricity.

Feed-in tariff: means the pre-determined rate at which renewable energy is purchased by the TD&R licensee from a distributed generator, for a pre-determined period, and under pre-determined conditions in accordance with Part 6 of the Electricity Act 2016

Fixed Assets: means tangible assets that are not readily convertible to cash (as opposed to liquid assets); this typically refers to plant, property and equipment, which is in service.

Fixed Assets Register: an accounting method used for major resources of a business. Fixed assets are those such as land, machines, office equipment, buildings, patents, trademarks, copyrights, etc. held for the purpose of production of goods or rendering of services and are not held for the purpose of sale in the ordinary course of business.

GD: stands for general determination.

Gearing: is a measure of the extent of debt that an entity has raised; within this report, gearing refers to the ratio of an entity's net debt to the rate base.

Generation: means the process of producing electric power. This includes generation of renewable energy (as defined by the Electricity Act 2016).

Generation capacity: means the maximum electrical output that an electricity plant can produce (typically measured in megawatts).

GWh: means gigawatt hours, a standard unit of electrical power equal to 1 billion watt hours.

International Financial Reporting Standards: an international accounting standard that provides a common global language for business affairs so that company accounts are understandable and comparable across international boundaries.

IPP: means an independent power producer. This is an entity that provides energy, capacity, and ancillary services for commercial purposes at a bulk scale to the electric utility under long-term contracts.

IRP: means integrated resource plan, an energy plan for the supply of electricity in Bermuda approved by the RA in accordance with, and set out in the matters required by, Part 8 of the Electricity Act 2016.

kW: means kilowatt, a standard unit of electrical power equal to 1,000 watts.

kWh: means kilowatt-hour, a unit of electrical energy equal to one kilowatt of power expended for one hour; the standard unit of measure used for electrical billing.

Licence: means a valid licence granted by the RA under the Electricity Act 2016.

Licensee: means a person that holds a valid licence in accordance with the Electricity Act 2016.

Liquified Natural Gas: is a natural gas changed into liquid by making it very cold for ease of shipping and storage.

Marginal Cost: means and increase or decrease in the total cost of production or producing one more unit.

Market Risk Premium: means an additional return on investment by holding a risky portfolio instead of risk-free assets.

MWh: means megawatt hour, a standard unit of electrical power equal to one million watts, or one thousand kilowatts hour.

OPEX: means operating expenditure. This is expenditure incurred in the day to day running of a business.

PPA: means power purchase agreement. This is an agreement entered into under section 48 of the Electricity Act 2016 between the TD&R licensee and a bulk generation licensee, approved by the RA, whereby the TD&R licensee contracts to purchase or acquire electricity generated by the bulk generation licensee as specified in the agreement (as defined by the Electricity Act 2016).

Price-cap regime: is a type of incentives-based regime where no adjustments to prices due to deviations from volume forecasts are allowed, i.e. volume risk is borne by the regulated entity.

RAA: means the Regulatory Authority Act (2011).

Rate base: means the total value of assets on which a utility is permitted to earn a return.

Rate-of-return: means a net loss or profit on an investment over specific time period.

Regulated Transactions: any transactions that falls under the licensed business units and any associated related parties.

Regulatory Accounts: means accounts that must be prepared in line with the Regulatory Accounting Instructions.

Regulatory Asset Base: means assets of service provider or utility company which are used and useful in the provision of regulated service to the customers.

Re-opener: means a mechanism which facilitates a change in allowed revenues before the next review period.

Return on capital or return on rate base means: a cost allowance determined to allow a company to recover its cost of capital, as a component of regulatory allowed revenue.

Review period: means a period for which retail tariffs are determined by the RA.

Risk-free rate: is a return required by an investor for an investment in a risk-free asset.

SSEG: stands for small scale embedded generation

TD&R: means transmission, distribution and retail.

TD&R licence: means a licence granted under section 25 of the Electricity Act 2016.

ToU: means time of use pricing or billing, whereby charges are based on how much energy is used and when the usage occurs.

Transfer pricing arrangements: refers to arrangements pursuant to which the TD&R business unit of a vertically integrated utility procures power from the generation business units of a vertically integrated utility.

True-up mechanism: means a mechanism which adjusts the cost allowances such that they align with the actual costs borne by a company.

Vanilla WACC: means the weighted average cost of capital using a pre-tax cost of debt and a post-tax cost of equity, as set forth in paragraph 55 of the Retail Tariff Methodology.

Vertically integrated utility: means a company that engages in bulk generation and transmission, distribution, and sale (retailing) of electricity.

Volume risk: means the risk that sold units of electricity deviate from the forecast.

WACC: means weighted average cost of capital.

Watt: means the unit of electrical power equal to one ampere under a pressure of one volt. A Watt is equal to 1/746 horse power.[6]

[6] U.S. Energy Information Administration Glossary