REGULATORY AUTHORITY

Bermuda

Integrated Resource Plan (IRP) Proposal Consultation

Consultation Document

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Responses Due: 2nd July 2018

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I. INTRODUCTION

1. The Electricity Act 2016 (“EA”) received Royal Assent on 27th February 2016. The EA came into operation on 28th October 2016 pursuant to the Electricity Act 2016 Commencement Day Notice 2016 (BR 101/2016). The EA repealed the Energy Act 2009.

2. The Regulatory Authority of Bermuda (the “Authority”) is responsible for regulation of the electricity sector 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 is transparent, fair, reasonable, and non-discriminatory; and
- Investigate and respond to complaints from end users as regards the provision of electricity.

3. Section 40(1) of the EA requires the Authority to request that the Transmission, Distribution and Retail Licensee (the “TD&R Licensee”) prepares an Integrated Resource Plan Proposal (“IRP Proposal”) within two years of the commencement of the EA.

4. On 17th November 2017, the Authority issued the Notice of Request for Integrated Resource Plan Proposal (the “Notice”), which required the TD&R Licensee to submit an IRP Proposal by 17th February 2018.

5. The TD&R Licensee submitted its IRP Proposal to the Authority on 15th February 2018.

6. Section 42 of the EA requires the Authority to publish the IRP Proposal prepared by the TD&R Licensee. Therefore, in line with the requirements of the EA, this Consultation Document aims 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 Authority’s official website in accordance with the EA. The publication of the IRP Proposal, prepared by the TD&R Licensee, does not constitute an endorsement by the Authority of the IRP Proposal.

II. CONSULTATION PROCEDURE

7. This consultation is being undertaken in accordance with sections 69-73 of the Regulatory Authority Act 2011 ("RAA"). The procedure and accompanying timelines (as set out in Section 70 of the RAA), under which this consultation is taking place, have been set out in this Section 2.

8. Written comments should be submitted before 5:00 PM (Bermuda time) on 2nd July 2018.

9. The Authority invites comments from members of the public, electricity sectoral participants and sectoral providers, and other interested parties. The Authority requests that commenting parties, in their responses, reference the numbers of the relevant questions, as set forth in this Consultation Document, to which they are responding. A complete list of questions presented by this Consultation Document appears in Section 7.

10. The Authority also requests submissions of proposals for bulk generation or demand side resources, in accordance with section 42(2) of the EA, as set forth in Section 5.2 below.

11. Responses to this Consultation Document should be filed electronically in MS Word or Adobe Acrobat format. From the Authority's website, www.rab.bm, parties wishing to file comments should click on the 'Consultations' tab in the top menu, and select the fourth option in the drop-down list: "Submit a response". All comments should be clearly marked "Response to Consultation Document: Comments on Integrated Resource Plan Proposal Consultation" and should otherwise comply with Rules 18 and 30 of the Authority's Interim Administrative Rules, which are posted on the Authority's website.

12. The Authority intends to make responses to this Consultation 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. Requests for confidentiality will be treated in the manner provided for in Rule 30 of the Authority's Interim Administrative Rules.

13. In accordance with section 73 of the RAA, any interested person may make an *ex parte* communication during this consultation process, subject to the requirements set

forth in this paragraph 13. An *ex parte* communication is defined as any communication to a Commissioner or member of staff of the Authority regarding the matter being consulted on in this Consultation Document, other than a written submission made pursuant to this Section 2. Within 2 business days after making an *ex parte* communication, the person who made the *ex parte* communication shall submit the following to the Authority: (i) a written description of the issues discussed and positions espoused; and (ii) a copy of any written materials provided. This will be posted on the Authority's website, along with a notice of the *ex parte* communication.

14. The principal point of contact at the Authority for interested persons for this Consultation Document is Monique Lister. She may be contacted by email, referencing "Comments on Integrated Resource Plan Proposal Consultation", at electricity@RAB.bm, or by mail at:

Monique Lister
Regulatory Authority
1st Floor, Craig Appin House
8 Wesley Street
Hamilton, Bermuda

15. In this Consultation 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.

16. This Consultation Document is not a binding legal document and does not contain legal, commercial, financial, technical or other advice. The Authority is not bound by this Consultation Document, nor does it necessarily set out the Authority's final or definitive position on particular matters. To the extent that there might be any inconsistency between the contents of this Consultation Document and the due exercise by the Authority 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 Authority.

III. LEGISLATIVE CONTEXT

17. The Regulatory Authority Act 2011 ("RAA") established a cross-sectoral independent and accountable regulatory authority "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".[1]

18. 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 Electricity Act 2016 ("EA") and the desired structure of the Bermudian electricity sector.

19. The EA received Royal Assent on 27th February 2016. The EA came into operation on 28th October 2016 (the "Commencement Date") pursuant to the Electricity Act 2016 Commencement Day Notice 2016 (BR 101/2016). The EA repealed the Energy Act 2009.

20. The Minister responsible for electricity is the Minister of Transport and Regulatory Affairs (the "Minister"). The Minister can issue Ministerial declarations to the Authority that establish policies for the electricity sector,[2] or regarding any matter within his or her authority as regards the electricity sector.[3] In formulating Ministerial directions, the Minister shall set priorities and resolve tradeoffs or conflicts that arise from the purpose of the EA in a way that he or she thinks best serves the public interest.[4]

21. Section 14(1) of the EA provides that the function of the Authority is generally to monitor and regulate the electricity sector. The Authority has the powers to supervise, monitor and regulate the electricity sector in Bermuda in order to achieve the purposes of the EA.[5] Such purposes, as set forth in section 6 of the EA, include:

(a) to promote 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;

[1] Regulatory Authority Act 2011, p. 5.
[2] Electricity Act 2016, Section 7(2).
[3] Electricity Act 2016, Section 8(3).
[4] Electricity Act 2016, Section 9.
[5] Electricity Act 2016, Section 14(2)(a).

(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."

22. The principal functions of the Authority set forth in section 12 of the RAA include:

(a) "to promote and preserve competition", section 12(a);

(b) "to promote the interests of the residents and consumers of Bermuda", Section 12(b);

(c) "to promote the development of the Bermudian economy, Bermudian employment and Bermudian ownership", section 12 (c); and

(d) "to promote innovation", section 12(d).

23. 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.

24. Section 40 of the EA (i) requires the Authority to issue a notice requesting the IRP Proposal from the TD&R Licensee within 2 years of the Commencement Date of the EA; and (ii) sets forth the requirements for the notice, including requirements for the IRP Proposal.

25. 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.

26. After the Authority has received and accepted the IRP Proposal, section 42(1) of the EA requires the Authority to publish the IRP Proposal on its official website for review and comments by the public. The publication of the IRP Proposal, prepared by the TD&R Licensee, does not constitute an endorsement by the Authority of the IRP Proposal.

27. The Authority 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.

28. Section 43 of the EA requires the Authority to hold at least one public consultation for each Alternative Proposal received before the stipulated deadline and to hold meetings with the proponent of each Alternative Proposal, the TD&R Licensee and any other persons that the Authority considers relevant in order to assess the Alternative Proposals.

29. Section 44 of the EA requires the TD&R Licensee to prepare a final draft Integrated Resource Plan ("IRP") for the Authority's review and approval that takes the public comments and Alternative Proposals into consideration and implements the Authority's comments. Section 44 also sets forth the process for the Authority's approval of the IRP.

30. Section 45 of the EA requires the Authority to publish the approved IRP on its official website.

31. The remainder of the Consultation 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.

IV. BACKGROUND

32. 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 that is also consistent with Bermuda's energy policy objectives.

33. Accordingly, this plan should incorporate the latest evidence on the costs and technical characteristics of different generation and load management technologies in order 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.

34. The Authority issued the Notice on 17th November 2017, which required the TD&R Licensee to submit an IRP Proposal by 17th February 2018. The Notice required the IRP Proposal to cover a period of three years from the date of the approved IRP (the "IRP Period").

35. On 6th December 2017, the Authority issued an Order setting out Integrated Resource Plan Guidelines (the "Guidelines Order") to provide guidance on the development of the IRP Proposal to the TD&R Licensee.

36. The TD&R Licensee submitted its IRP Proposal to the Authority on 15th February 2018.

37. The Authority has reviewed the IRP Proposal to assess its compliance with the EA, the Guidelines Order and the Notice (collectively, the "Proposal Requirements"), as required under section 41 of the EA.

38. The Authority has accepted the IRP Proposal for the purposes of public consultation, although the Authority's assessment (set forth in in Appendix B) is that the IRP Proposal has broadly, but not uniformly, met the Proposal Requirements. While the Authority has accepted the IRP Proposal for public consultation, it will, concurrent with this consultation, undertake a further detailed analysis of the IRP Proposal in order to determine whether the proposal represents the least-cost capacity expansion plan for the electricity market of Bermuda.

39. In the consultative process, which this Consultation Document initiates, the Authority seeks comments from the public on the IRP Proposal submitted by the TD&R Licensee, and on the Alternative Proposals for generation resources.

V. IRP PROPOSAL AND ALTERNATIVE PROPOSALS

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

a) IRP PROPOSAL

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

42. 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.[6] 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.

43. 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.[7] 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 Authority; (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.[8]

44. The Proposal Requirements provided the guidelines on what is expected to be included in the IRP Proposal in order to ensure that the Authority is able to meet its obligations under the EA in a manner that is consistent with the Policy Document and to implement the regulatory regime established by the electricity sector licences.

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

46. The Authority's assessment, set forth in Appendix B, is that the IRP Proposal has broadly, but not uniformly, met the Proposal Requirements. The Authority has, therefore, accepted the IRP Proposal for public consultation.

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[6] Electricity Act 2016, Section 40(1).
[7] Electricity Act 2016, Section 40(2)(a).
[8] Electricity Act 2016, Section 40(2)(b)–(d).

47. While the Authority has accepted the IRP Proposal for public consultation, it will, concurrent with this consultation, undertake a further detailed analysis of the IRP Proposal in order to determine whether the proposal represents the least-cost capacity expansion plan for the electricity market of Bermuda.

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

Consultation questions

1. Are there any provisions in the IRP Proposal that should be modified? Please include any reasoning and evidence in your answers.
2. Do you consider that the procurement strategy outlined in the IRP Proposal is appropriate?
3. Which generation resources should the TD&R Licensee procure using competitive bidding, if any?

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b) ALTERNATIVE PROPOSALS

49. The Authority invites interested parties to provide their views on any alternative scenarios that should be included 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).

50. In particular, this Consultation Document requests submissions of detailed proposals for bulk generation or demand side resources for potential inclusion in the IRP. Any Alternative Proposal should cover a period of three years, the period until the next IRP Proposal will be requested. 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.

Consultation questions

4. Are there alternative scenarios not included in the IRP Proposal, which 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)?
5. Do you have any additional views on the assumptions, assessment methodology, and conclusions set out in the IRP Proposal?
6. Do you have any Alternative Proposals for bulk generation or demand side resources that should be considered in the IRP?

VI. NEXT STEPS

51. The Authority will hold at least one public consultation for every Alternative Proposal received before the deadline set forth in this Consultation Document, whether alone or together with other Alternative Proposals. The Authority 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 Authority considers relevant in order to assess the Alternative Proposals.

52. The Authority will, concurrent with this consultation, undertake a further detailed analysis of the IRP Proposal in order to determine whether the proposal represents the least-cost capacity expansion plan for the electricity market of Bermuda.

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

54. The Authority will review the Draft IRP and may approve it if, acting in accordance with regulatory principles and any administrative determinations, the Authority 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 Authority may require the TD&R Licensee to modify the Draft IRP until it is in a form that can meet the Authority's approval.

55. The Authority will then publish the approved IRP on its official website.

VII. CONSULTATION QUESTIONS

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

Consultation questions

1. Are there any provisions in the IRP Proposal that should be modified? Please include any reasoning and evidence in your answers.
2. Do you consider that the procurement strategy outlined in the IRP Proposal is appropriate?
3. Which generation resources should the TD&R Licensee procure using competitive bidding, if any?
4. Are there alternative scenarios not included in the IRP Proposal, which 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)?
5. Do you have any additional views on the assumptions, assessment methodology, and conclusions set out in the IRP Proposal?
6. Do you have any Alternative Proposals for bulk generation or demand side resources that should be considered in the IRP?

APPENDIX A

APPENDIX A: IRP PROPOSAL

The documents linked below contains the TD&R Licensee's IRP Proposal and the Appendices to the IRP Proposal.

IRP Proposal (**click to open**)

Appendices to IRP Proposal (**click to open**)

APPENDIX B

APPENDIX B: ASSESSMENT OF THE IRP PROPOSAL

The document linked below contains the Authority's assessment of the IRP Proposal's compliance with the Proposal Requirements.

Assessment of IRP Proposal (**click to open**)

Review of the IRP Proposal's compliance with guidelines

Note prepared for the Regulatory Authority of Bermuda

1 May 2018

1 Introduction

1.1 The Regulatory Authority of Bermuda ('the Authority') commissioned Oxera to review the extent to which the Integrated Resource Plan Proposal (the 'IRP Proposal'), dated 15 February 2018 prepared and submitted by the Bermuda Electric Light Company Limited ('BELCO') in its capacity as the Transmission, Distribution and Retail ('TD&R') Licensee, is compliant with the Authority's IRP guidelines.

1.2 This note explains the role of the IRP in the development of the electricity market in Bermuda, and presents a review of the IRP Proposal in terms of its compliance with the Authority's guidelines.

1.3 On 17 November 2017, the Authority issued a Notice, which required the TD&R Licensee to submit an IRP Proposal by 17 February 2018. On 6 December 2017, the Authority issued an Order setting Integrated Resource Plan Guidelines (the 'Guidelines Order') to provide guidance on the development of the IRP Proposal to the TD&R Licensee. As a result, the IRP Proposal has to be compliant with the Electricity Act 2016 ('EA 2016'), the Guidelines Order and the Notice.

1.4 This document is structured as follows:

- section 2 provides the legislative background for developing the IRP;
- section 3 explains the role of the IRP in the development of the electricity market in Bermuda;
- section 4 provides a discussion on the replacement generation proposal submitted by the TD&R Licensee;
- section 5 provides our review of the IRP Proposal's compliance with the Authority's guidelines.

2 Legislative background

2.1 The EA 2016 requires that the TD&R Licensee prepares an IRP at least every five years as determined by the Authority or as directed by the Minister. This should contain:[1]

> (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 that details how the licensee proposes to meet this demand.

2.2 In preparing the IRP Proposal, the TD&R Licensee was required to 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.

2.3 The IRP Proposal is also required to: (i) prioritise actions that most meet the purposes of the EA 2016, 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; (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.

2.4 The Authority may, subsequent to a process of consultation and review, approve the final draft of the IRP as issued by the TD&R Licensee, provided that it is the most appropriate approach to meeting the purposes of the EA 2016 and complies with Ministerial directions.[2]

3 The role of the IRP

3.1 An IRP is a plan that seeks to balance the future demand and supply of electricity. The IRP's purpose is therefore to set out the strategy for the procurement and retirement of generation assets as well as demand-side resources that meet the needs of consumers in a cost-efficient manner that is also consistent with Bermuda's energy policy objectives.

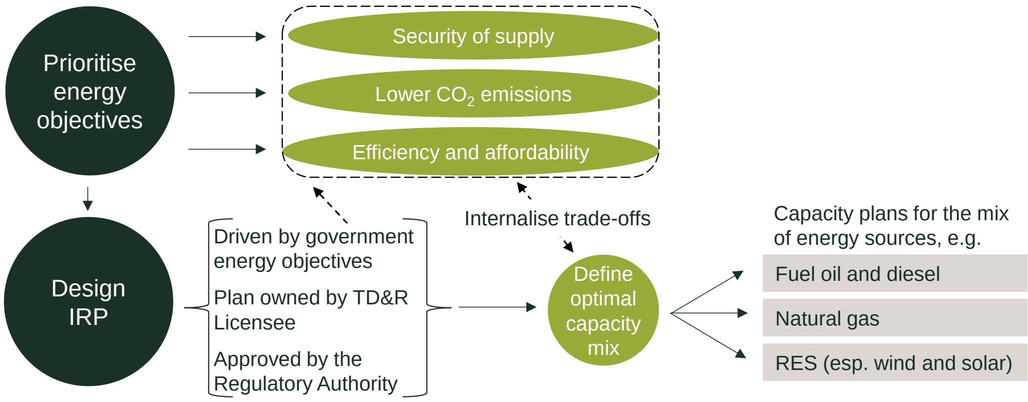
3.2 Accordingly, this plan should incorporate the latest evidence on the costs and technical characteristics of different generation and load management technologies in order to evaluate the least-cost capacity expansion plan for the

[1] Bermuda Electricity Act (2016),Section 40.
[2] Ibid., Section. 44 (2).

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.

3.3 The IRP should balance competing considerations of affordability, sustainability and security of supply in order to create a system that is consistent with Bermuda's energy policy objectives. This process is summarised in the figure below.

Figure 3.1 Illustration of the role of the IRP within policy and regulation



Note: RES—renewable energy sources.

Source: Oxera

3.4 The IRP must therefore be credible, comprehensive in its treatment of available resources (whether currently available or anticipated to be available in future), auditable, and robust to identifiable sources of uncertainty in order to enable the Authority to:

- approve the least-cost, or otherwise most appropriate, electricity capacity expansion plan that meets demand at lowest overall cost and with acceptable levels of system reliability and implementation risk to consumers;
- assess the economic, environmental, and social implications of adopting alternative capacity expansion plans so as to be able to determine the optimal trade-offs contained in Ministerial directions; and
- evaluate the merits of applications by prospective IPPs or other licensees as well as other proposals that entail deviations from the IRP, in particular by calculating their benefits, costs, and risks to the electricity system.

3.5 The IRP is particularly important in the current context. In particular, any substantial investment in new capacity may ‘crowd out’ alternative generation projects until some existing assets need to be replaced or electricity demand increases. The IRP is the crucial instrument to ensure the most efficient development of the electricity market in Bermuda.

4 Condition 20 request

4.1 BELCO submitted a proposal for replacement generation (‘the replacement generation proposal’) to the Authority on 22 December 2017. The replacement proposal included the following.

- Battery energy storage system (BESS)—a utility-scale battery energy storage system with an output capacity of 10MW and storage of 5MW/h to be installed on BELCO’s Pembroke campus (budget price of $8.8m). BESS is expected to provide a portion of the spinning reserve margin;
- North Power Station (NPS)—four new dual-fuel engines totalling 56 MW to be constructed on a site adjacent to existing generating assets on BELCO’s Pembroke campus (budget price of $110m).[3]

4.2 We understand that the supplier of BESS was selected on the basis of a competitive tendering exercise with the assistance of a third-party engineering consultancy in 2017.

4.3 A competitive tendering exercise for NPS was completed by BELCO in 2011 with the assistance of a third-party engineering, management and development consultancy firm. In 2017, BELCO again approached the successful tender and asked for a revised price estimate. The revised price estimate was then analysed by their third-party engineering, management and development consultancy firm, concluding that the price offered by the successful tender is in line with similar projects in other countries and represents acceptable value for money.

4.4 However, given an elapsed period of around six years between the original competitive tender and the recent price revision and the fact that no competitive tender has been undertaken since, it has not been possible for the Authority to test if the price offered by successful tender currently represents good value for money.

[3] BELCO (2017), ‘Proposal for the replacement of the Generation Facilities’, 22 December.

4.5 Two options were considered in relation to the replacement generation proposal:

- accept the replacement generation proposal; or
- delay the decommissioning of the existing plant (thereby requiring the procurement of temporary generation) in order to undertake a new competitive tender.

4.6 Discussions and correspondence between the Authority and its technical advisers, Ricardo Energy & Environment, since July 2017 made it apparent that the critical state of the TD&R Licensee's generation assets would not allow for further delay of decommissioning the existing generation assets.

4.7 It was also clear from the advice of the Authority's technical advisers that the cost of delaying the installation of replacement generation by using temporary generation would have been prohibitive. The final report from the advisers on this matter confirmed that:

> [I]f the new generation plant was to be installed in 2021 rather than when it is needed in 2020, then the net additional cost of leasing temporary power to meet electricity demand in 2020 is estimated to be $44.0 million. To put this in perspective, the capital cost of the Project would need to be less than 63% of the current estimate to make this course of action more cost effective than having the Project operational in 2020. Similarly, if the new generation plant was to be installed in 2022 rather than when it is needed in 2020, then the net additional cost of leasing temporary power to meet electricity demand in 2020 and 2021 is estimated to be $87.8 million. Thus, the capital cost of the Project would need to be less than 26% of the current estimate to make this course of action more cost effective than having the Project operational in 2020.[4]

4.8 Under the EA 2016 and the Regulatory Authority Act 2011, the Authority has a duty to ensure security, adequacy, and reliability of electricity in Bermuda while also seeking least-cost electricity supply. In this instance, the Authority considered that any delays to the commissioning of the NPS was unduly risky as well as uneconomic. Put differently, the Authority deemed that the importance of ensuring security of supply considerations outweighed potential concerns over value for money, leading to the Authority's approval of BELCO's replacement generation.[5]

4.9 Given that the Authority only recently accepted BELCO's replacement generation programme, there may be opportunities to revise the parameters of

[4] Ricardo (2018), 'Temporary Generation Study Update Report', 8 March, p. 4.
[5] Regulatory Authority of Bermuda (2018), 'Order approving the request from the Bermuda Electric Light Company Limited ('BELCO') to the Authority dated 22 December 2017', 6 March.

this programme in response to the outcomes of the IRP consultation process and any other changes to system requirements. It would be important to confirm the extent of such flexibility at an early stage of the IRP consultation process.

5 IRP Proposal's compliance with the Authority's guidelines

5.1 Overall, Oxera considers that BELCO's IRP Proposal is broadly in line with the IRP guidelines. The IRP Proposal weighs up in appropriate detail feasible planning scenarios for Bermuda's energy system, with the selected scenarios representative of the main options that Bermuda now has in terms of electricity generation in the future.

5.2 Notwithstanding the conclusion that the IRP Proposal is broadly compliant with the guidelines, there are some concerns about the documentation provided by BELCO. These include the following.

- **Methodological concerns**. The use of Levelised Cost of Energy (LCOE) screening in developing the four feasible planning scenarios may only approximately gauge the efficacy of alternative generation options.

- **Replacement generation**. The IRP Proposal does not evaluate BELCO's replacement generation proposal—that is, the IRP Proposal assumes that the replacement generation proposal will be built under all scenarios. Therefore, the IRP Proposal provides limited information on whether the replacement generation proposal represented the best option for the development of the energy market in Bermuda.

- **Qualitative assessment**. The IRP Proposal includes a qualitative assessment of the four feasible planning scenarios. The *qualitative* assessment is inherently subjective, whereas the *quantitative* assessment presented in the IRP Proposal shows that the modelled scenarios are tightly grouped in terms of their overall cost. Therefore, the qualitative assessment (focused on attributes other than cost) has a large influence in selecting the preferred scenario.

5.3 In detail, the first concern is that the methodology pursued by Leidos—selecting a number of scenarios and modelling their implied system costs—may not facilitate the identification of the true least-cost options for electricity generation in Bermuda. The scenarios were identified on the basis of the

LCOE screening[6] and discussions with BELCO,[7] and, as such, the scenarios considered in the IRP Proposal represent an input to the modelling process rather than outputs as identified on the basis of the quantitative analysis.

5.4 While LCOE screening is one method to eliminate generation expansion alternatives that are significantly 'less economic', it is commonly recognised that this method does not account for all the costs and benefits of a particular generation technology. For example, the International Energy Agency has stated that 'whenever technologies differ according to the when, where and how of their generation, a comparison based on LCOE is no longer valid and may be misleading'.[8] LCOE screening is therefore likely to be less efficient than alternative methods based on mathematical optimisation approaches from the start.

5.5 Since the generation technologies for each of BELCO's scenarios were pre-selected during their specification, the possibility of using a mathematical modelling approach to determine which generation technologies feature in each scenario is precluded. The PROMOD optimisation took as given predefined scenarios to perform dispatch to load modelling, but was not used in the selection of the optimum generation technologies for each scenario.[9]

5.6 Therefore, utilising a mathematical modelling approach from the outset (rather than an LCOE analysis) may lead to improvements in the system cost efficiency of the options presented. The IRP Proposal does not identify if there are any other feasible scenarios that should have been considered (or the selection of the generation technologies within each scenario).

5.7 The second concern is that the IRP Proposal proceeds under the assumption that the replacement generation Assets are not to be subject to the IRP process.[10] By effectively treating replacement generation as outside of the IRP process, the extent to which the policy objectives of the Government and the Authority, as well as the extent to which the replacement generation facilitates the least-cost provision of electricity, is not considered. By taking the replacement generation as an *input* rather than an *output* of the IRP process, it

[6] Leidos (2018), '2018 Integrated Resource Plan Proposal', p. ES-1.
[7] Leidos (2018), '2018 Integrated Resource Plan Proposal', p. 1–13.
[8] International Energy Agency (2014), 'The Power of Transformation: Wind, Sun and the Economics of Flexible Power Systems', Paris, p. 67. See also International Atomic Energy Agency, (1984). 'Expansion Planning for Electrical Generating Systems – A guidebook', Vienna, section 6.6.
[9] Leidos (2018), '2018 Integrated Resource Plan Proposal', p. 1–12.
[10] Leidos (2018), '2018 Integrated Resource Plan Proposal'. p. 1–8.

is not possible to observe the cost-efficiency of the replacement generation relative to the other options for new generation capacity that are available.

5.8 The third concern is that the qualitative assessment used in the IRP Proposal is inherently subject to judgement. The qualitative assessment assigns a score to different resource options against five qualitative criteria (i.e. supply quality, environmental sustainability, security and cost resilience, logistics, economic development). The scores assigned to each resource option are inherently subjective judgments and so remain open to debate. For example, the economic development criteria is focused on job creation in Bermuda. Under this criterion, a higher score would be assigned to a more expensive technology, as it is likely to generate more employment. We consider that inclusion of the qualitative factors, such as the economic development, distorts the results of the IRP Proposal.

5.9 The qualitative analysis is combined with the quantitative analysis in order to select the best option from the four feasible planning scenarios. These four feasible planning scenarios are as follows.

- **Scenario 1**. A reference scenario that reflects expansion with the continued use of fuel oil as the primary fuel.
- **Scenario 2**. A revised version of Scenario 1 with the addition of (i) cost-effective utility-scale renewables, (ii) EE, and (iii) EVs.
- **Scenario 3**. A full conversion of the NPS engines that are planned for installation in 2020, as well as other existing assets where suitable, to natural gas operation as soon as natural gas can be made available, and future expansion with (i) all thermal resources operating on natural gas, (ii) cost-effective utility-scale renewables, (iii) EE, and (iv) EVs.
- **Scenario 4**. Future expansion with thermal resources operating on liquefied petroleum gas, beginning when the next installation of thermal resources is required, and conversion of suitable existing thermal resources to operate on liquefied petroleum gas plus (i) cost-effective utility-scale renewables, (ii) EE, and (iii) EVs.

5.10 The importance of the qualitative analysis is magnified by the little dispersion in the results of the quantitative analysis. In particular, the IRP Proposal concludes that the conversion to natural gas (Scenario 3) is the preferred option for Bermuda's energy system. However, had only the quantitative analysis been considered, then the continued use of fuel oil (Scenario 2) would have been the preferred option. This narrow range may suggest that the highest ranked scenario is not significantly better than the lowest ranked scenario. This is expected to be a significant consideration for the decision of whether to invest in a liquefied natural gas ('LNG') terminal in Bermuda.

5.11 Notwithstanding these concerns, on balance Oxera considers that the IRP Proposal could be accepted for public consultation. We recommend that the Authority undertakes further detailed analysis of the IRP Proposal in order to determine whether the proposal represents the least-cost capacity expansion plan for the electricity market of Bermuda.

2018 Integrated Resource Plan Proposal

Bermuda Electric Light Company Limited

February 15, 2018

2018 Integrated Resource Plan Proposal

Bermuda Electric Light Company Limited

February 15, 2018

leidos

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EXECUTIVE SUMMARY

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

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

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

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

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

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

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

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

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

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

GLOSSARY OF TERMS

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

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

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

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

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

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

Section 1
IRP PROPOSAL METHODOLOGY

1.1 Project Overview

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

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

The main elements of the IRP process are as follows:

I. Develop the system load forecast

II. Develop a list of candidate fuels and associated price forecast

III. Develop a list of candidate supply-side and demand-side resources along with the technical and economic parameters required for analysis

IV. Conduct a Bermuda electric system capacity gap analysis using the load forecast and existing resource retirement schedule

V. Conduct a Levelized Cost of Energy ("LCOE") screening of the candidate resources to create a shortlist for use in a dispatch analysis

VI. Develop a number of feasible expansion plan scenarios using an optimal blend of supply-side and demand-side resources

VII. Conduct detailed economic analyses of the expansion plan scenarios based on an hourly energy dispatch model

VIII. Conduct a qualitative assessment of the resource planning scenarios

IX. Determine the planning scenario that best meets the objectives of the Policy

1.2 Description of IRP Goals

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

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

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

1.3 Load Forecast

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

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

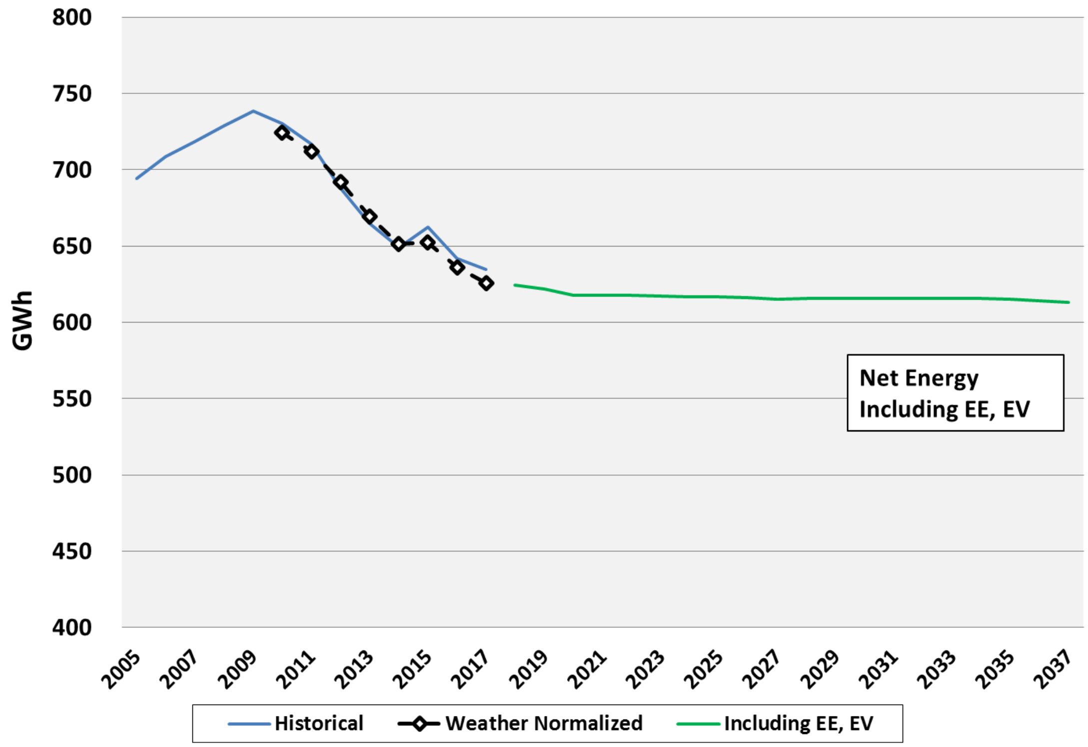

Figure 1.1 – Base Case Energy Forecast (Net of EE and EV) (GWh)

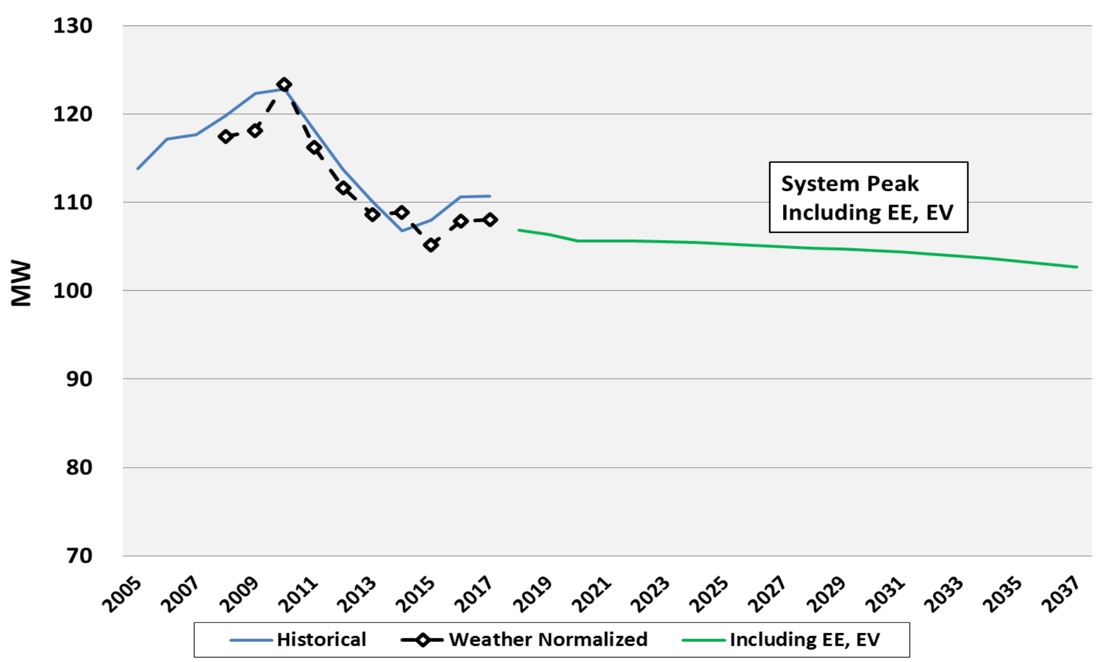

Figure 1.2 – Base Case Peak Demand Forecast (Net of EE and EV) (MW)

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

1.4 Reserve Margin Planning Criteria

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

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

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

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

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

1.5 Fuel Forecast

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

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

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

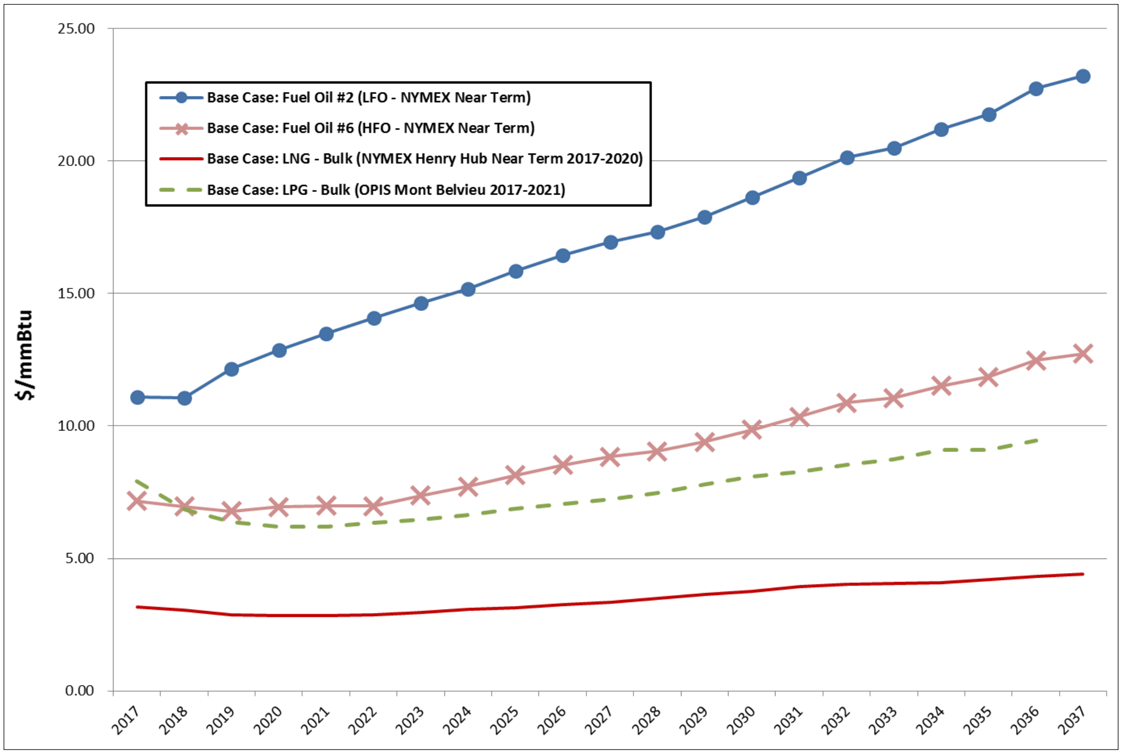

Figure 1.3 – Base Case Commodity Price Forecast

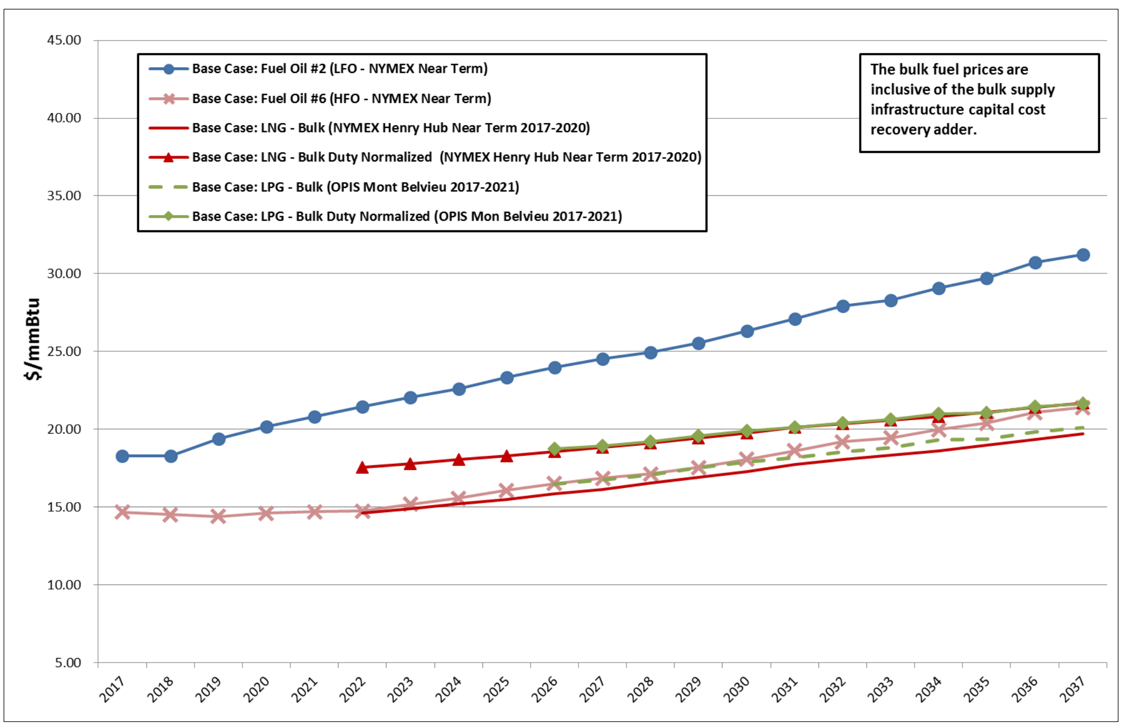

Figure 1.4 – Base Case Delivered Cost Forecast

1.6 Financial and Other Planning Criteria

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

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

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

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

1.7 Existing Resources

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

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

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

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

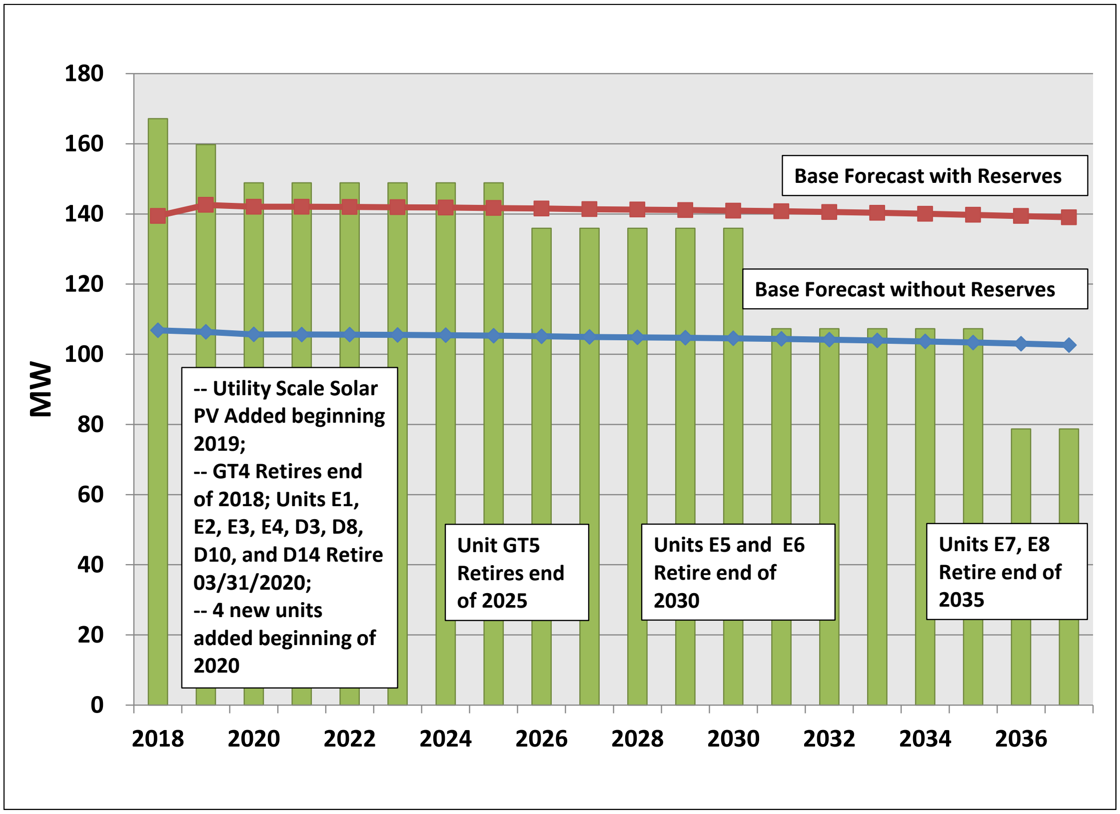

Figure 1.5 – Capacity vs. Load

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

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

1.8 Demand-Side Resource Options

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

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

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

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

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

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

1.9 Supply-Side Resource Options

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

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

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

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

1.10 Levelized Cost of Energy Screening

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

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

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

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

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

1.11 Production Cost Modeling

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

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

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

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

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

1.11.1 Production Cost Modeling Scenarios

Scenario Definitions

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

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

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

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

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

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

1.12 Qualitative Analysis of Candidate Resources

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

Table 1-3
Qualitative Assessment Criteria

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

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

2.1 LCOE Results

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

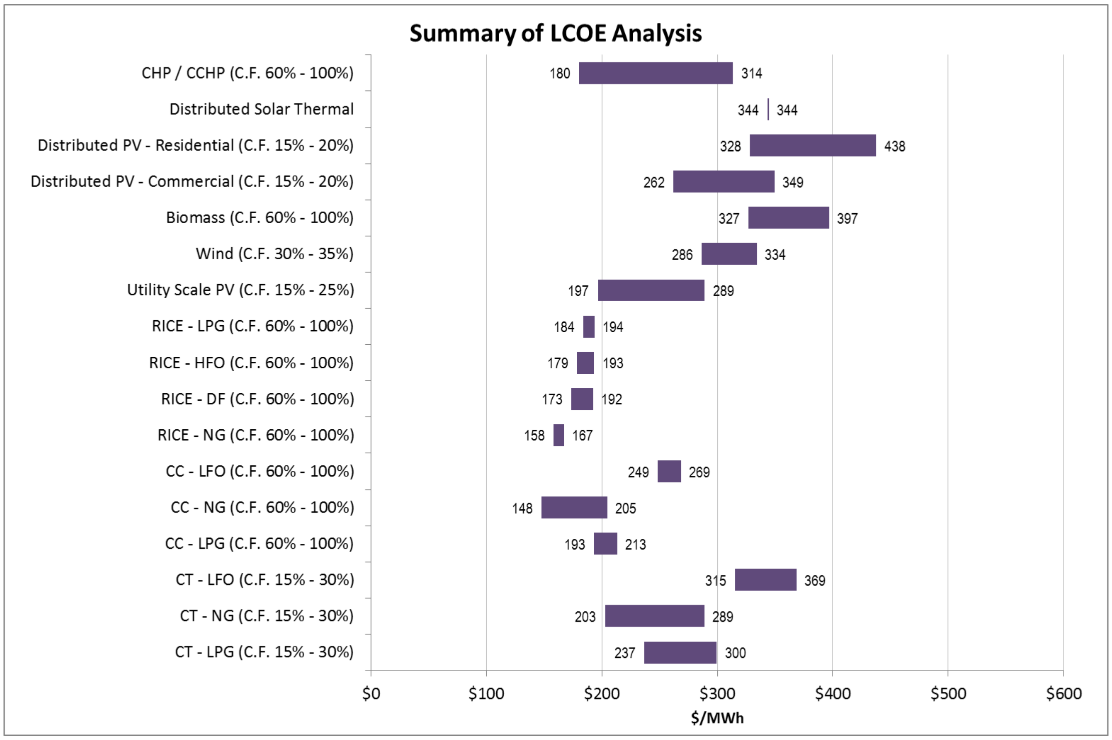

Figure 2.1 – NPV Summary of LCOE Analysis Results

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

2.2 Production Cost Modeling Results

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

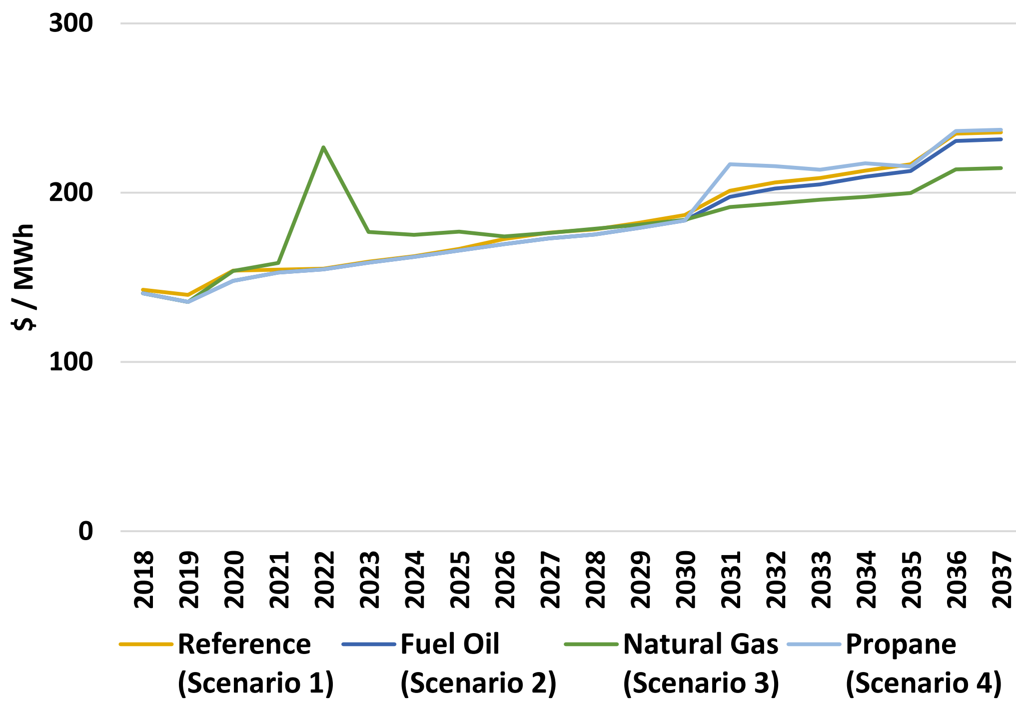

Figure 2.2 – Summary of Annual $/MWh Costs by Scenario

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

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

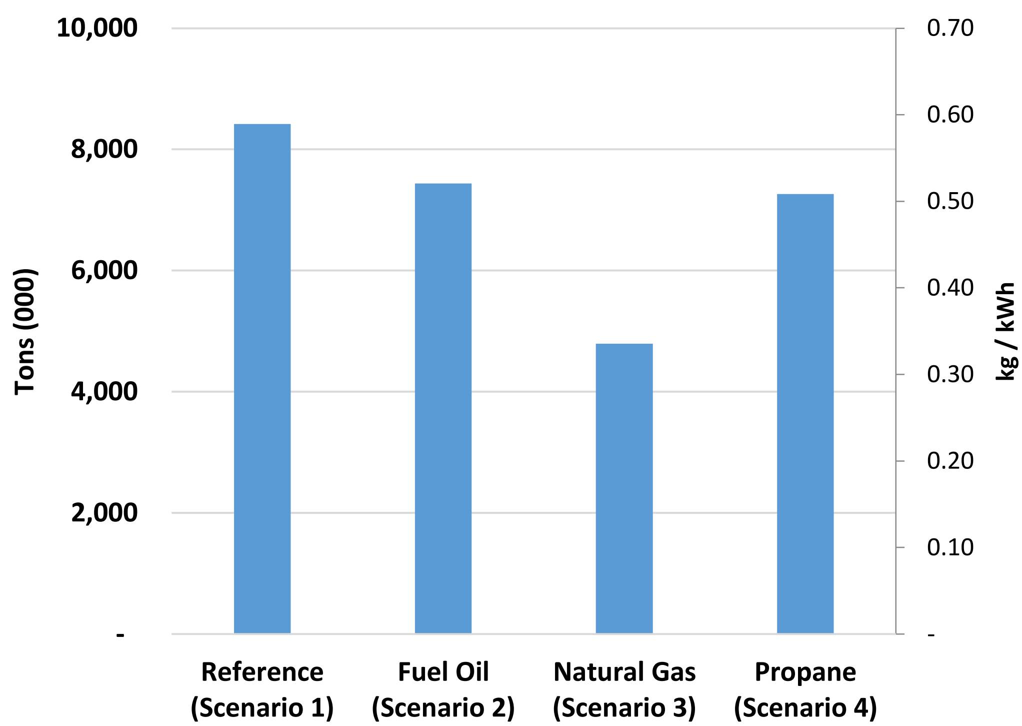

Figure 2.3 – Summary of Carbon Emissions by Scenario During Study Period

As evidenced by the Base Case results above:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Notes:
* Converted to natural gas in 2022
Assumes PV - Dependable capacity is 60% of installed nameplate capacity and degrades at 0.8% annually
Battery for spinning reserve backup and battery for renewable support are not counted toward dependable capacity

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

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

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

2.3 Reliability Analysis

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

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

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

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

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

2.4 Sensitivity Analysis Results

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

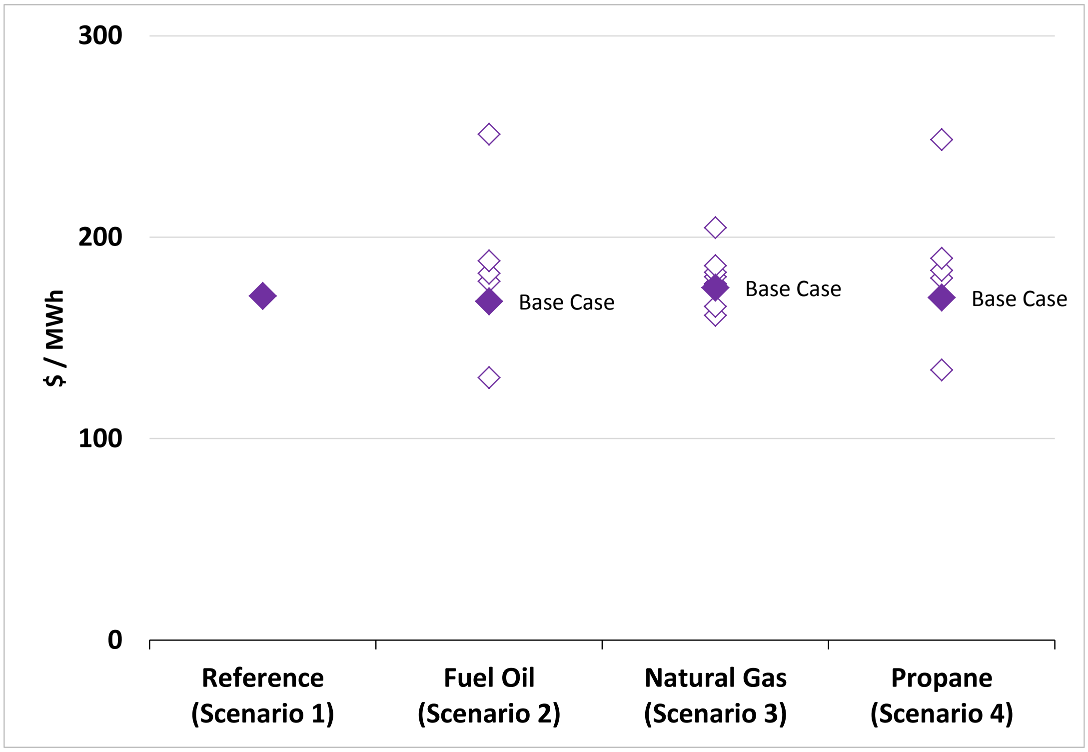

Figure 2-4 – Summary of Levelized Costs by Scenario and Sensitivity

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

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

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

2.5 Qualitative Evaluation Results

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

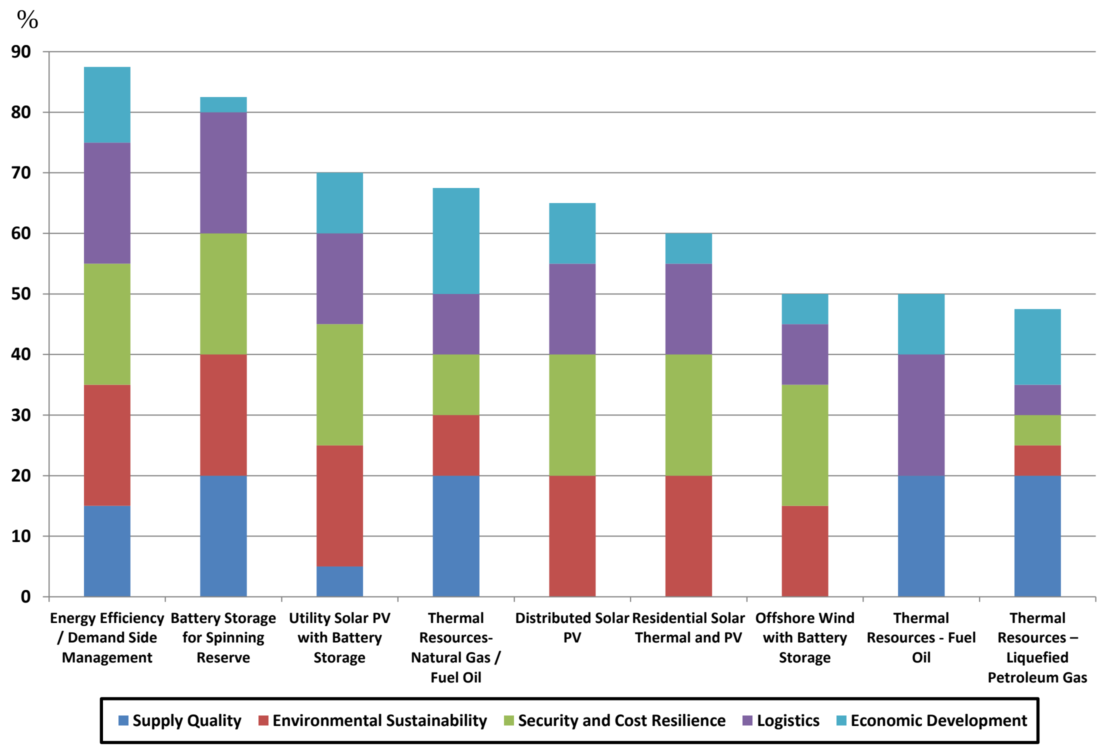

Figure 2-5 – Qualitative Scoring Results

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

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

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

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

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

2.6 Scoring and Findings

2.6.1 Evaluation Methodology

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

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

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

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

Table 2-12
Summary of Scenario Overall Ranking

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

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

Table 2-13
Sensitivity of Overall Ranking to Weighting Factors

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

2.6.2 Findings

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

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

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

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

2.7 Procurement Plan

2.7.1 Procurement Plan Overview

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

2.7.2 Natural Gas Supply

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

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

2.7.3 Liquefied Petroleum Gas Supply

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

2.7.4 Thermal Resources

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

2.7.5 Battery Energy Storage

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

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

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

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

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

2.7.7 Energy Efficiency and Energy Conservation/Demand Side Management

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

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

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

2.7.8 Distributed Solar PV

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

2.7.9 Utility Scale Solar PV

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

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

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

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

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

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

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

APPENDICES TO 2018 INTEGRATED RESOURCE PLAN PROPOSAL

Bermuda Electric Light Company Limited

February 15, 2018

leidos

Appendix I
IRP PROPOSAL TECHNICAL ASSUMPTIONS

I.A Introduction

This Appendix I to the BELCO 2018 IRP presents a summary of the key assumptions, in the form of a technical assumptions document (the "Assumptions Document"), that are used in developing the IRP. The purpose of the Assumptions Document is to provide sufficient detail on the data sources and analytical approach to each aspect of the IRP that must be completed prior to the onset of detailed dispatch modeling. The Bermuda Electricity Act 2016 ("EA 2016") requires that an IRP be prepared by BELCO TD&R at least every five years as determined by the Authority or as determined by the Minister. The Assumptions Document serves as a living document that can be updated and refined in future planning cycles.

Other sections of the appendices to the IRP are referenced throughout this Appendix I as appropriate relative to the specific topics covered. These appendices should be reviewed carefully to ensure full understanding of the technical, economic and load related assumptions underpinning the IRP.

I.B IRP Study Period

The IRP analysis covers the 20-year study period beginning January 1, 2018 and ending December 31, 2037 (the "Study Period").

I.C Financial Factors

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

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

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

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

I.D Load Forecast

Leidos reviewed the Bermuda electric system's historical generation data for the period 2005 through 2016, comprising net energy for load ("NEL") which reflects total generation inclusive of losses, and system peak demand. We also reviewed the 2015 Bermuda Ministry of Finance National Economic Report dated February 2016 (the "National Economic Report 2015"), and the Bermuda Government's 2018 Pre-Budget Report ("Pre-Budget Report 2018") as well as supplemental data regarding the trajectory of key industries within Bermuda and their estimated impact on the economic contraction thru 2014 in real gross domestic product ("GDP"). Our review comprised two parallel efforts, namely: (i) review of economic evidence and intelligence to develop a perspective regarding the load forecast for the Study Period ("Load Forecast"), including the determination of assumptions related to uncertainty in the early portion of the Study Period, and (ii) development of an econometric model of the electric system's historical energy using the GDP data provided in the 2015 National Economic Report, data obtained from IHS Global Insight, weather data, and other available data that was examined for its ability to explain historical variation in electric load (as described further below).

Our review resulted in conclusions within each realm of analysis, which are discussed below, as well as the Load Forecast. The Load Forecast delivers a monthly NEL with load factor and an uncertainty band. The five sub-sections below summarize: (i) the results of a weather normalization analysis, (ii) the results of a review of economic data and intelligence, (iii) the development of and results associated with the econometric model of the electric system's NEL that determines the GDP elasticity upon which the Load Forecast is based, (iv) the methodology used in developing the Load Forecast, which reflects a combination of the electric system's budget load forecast for 2018 and assumptions regarding longer-term growth rates based on Bermuda's future economic outlook from multiple sources, (v) the Load Forecast results exclusive of certain demand-side adjustments, including electric vehicle ("EV") adoption and energy efficiency ("EE") adoption and (vi) the Load Forecast results inclusive of the impacts of anticipated EE and EV adoption programs. Appendix II.A of this IRP provides a tabularized summary of the Load Forecast.

I.D.1 Weather Normalization Results

Weather normalization is a forecast variance decomposition technique that leverages statistical estimates of the incremental impact of weather on electric energy consumption and electric system peak demand to estimate what the levels would have been had normal weather prevailed. Normal weather is typically estimated as a function of long-term average conditions or homogenized "normal" data from weather banks or third-party providers. Separate energy and load factor econometric models were developed for the Bermuda system as part of the IRP process that contained weather normalization coefficients that were deployed to weather normalize Bermuda's electric system load. Weather data was compiled for the available period at the time of analysis, which was then used to define normal conditions as follows:

- For heating degree day ("HDD") and cooling degree day ("CDD") determinants, the normal values were based on long term averages of the hottest and coldest days in each month from the available period of Weather Underground data. Supplemental research was conducted by Leidos on the potential to use National Climatic Data Center (the "NCDC") daily airport data, but such data was subject to significant amounts of missing days, or data points, that rendered the data unusable for normalization purposes.
- For peak demand, the econometric load factor model combined two additional weather terms intended to capture the parabolic response to extreme temperatures on the day during which each monthly system peak demand occurred; peak demand timing information (predicated on historical hourly system loads) was combined with temperature data from Weather Underground to determine the temperatures during peak demand days required to leverage the load factor model for weather normalization purposes.

Appendix I Figure 1 below illustrates the parabolic relationship between extreme temperatures and the electric system peak demand data for a sampling of the historical data.

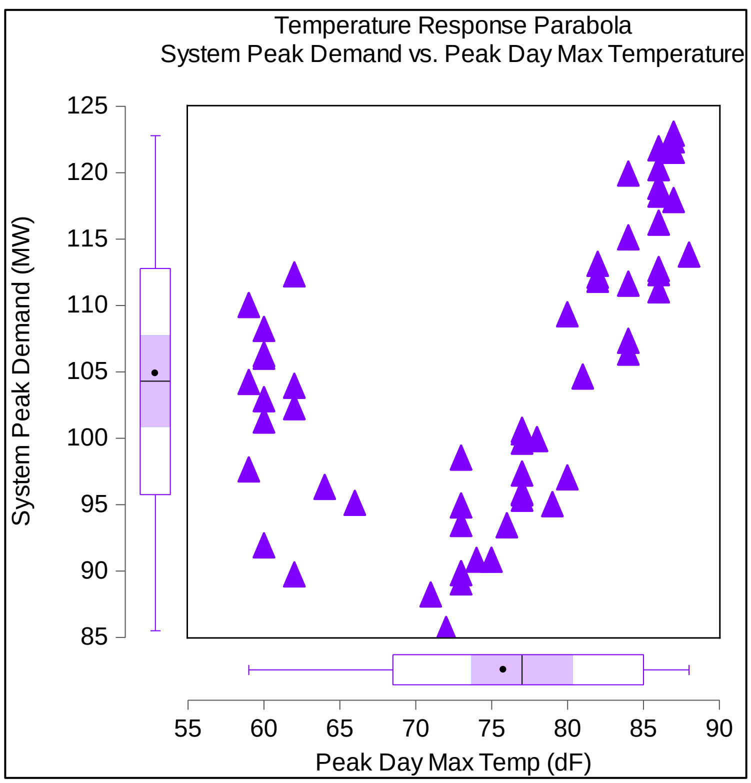

Figure 1 – Parabolic Temperature Response for Bermuda's Peak Demand

As evidenced by Appendix I Figure 1 above, there are "bands" of temperature responses wherein cool or warm temperatures relative to a particular base (above which temperatures may be perceived as extreme by end users) can drive incremental increases in peak demand within each season. The cooling demand response and heating demand response thresholds were 80 degrees Fahrenheit ("°F") for peak day maximum temperature and 58°F for peak day minimum temperature, respectively. In order to estimate normal conditions for such variables, the average of the 1981-2010 monthly maximum and minimum temperatures (for the hottest/coldest days in each month) reported by Weather Underground were used to develop threshold variables across that period, and were combined with threshold variables for those same determinants during the periods representing the electric system peak demand, and then averaged. These normal conditions were then compared to historical values to derive a weather-normalized load factor, which when combined with weather normalized energy, was used to derive weather normalized peak demand.

Appendix I Figure 2 below summarizes historical HDDs and CDDs from the Weather Underground data as compared to long term averages.

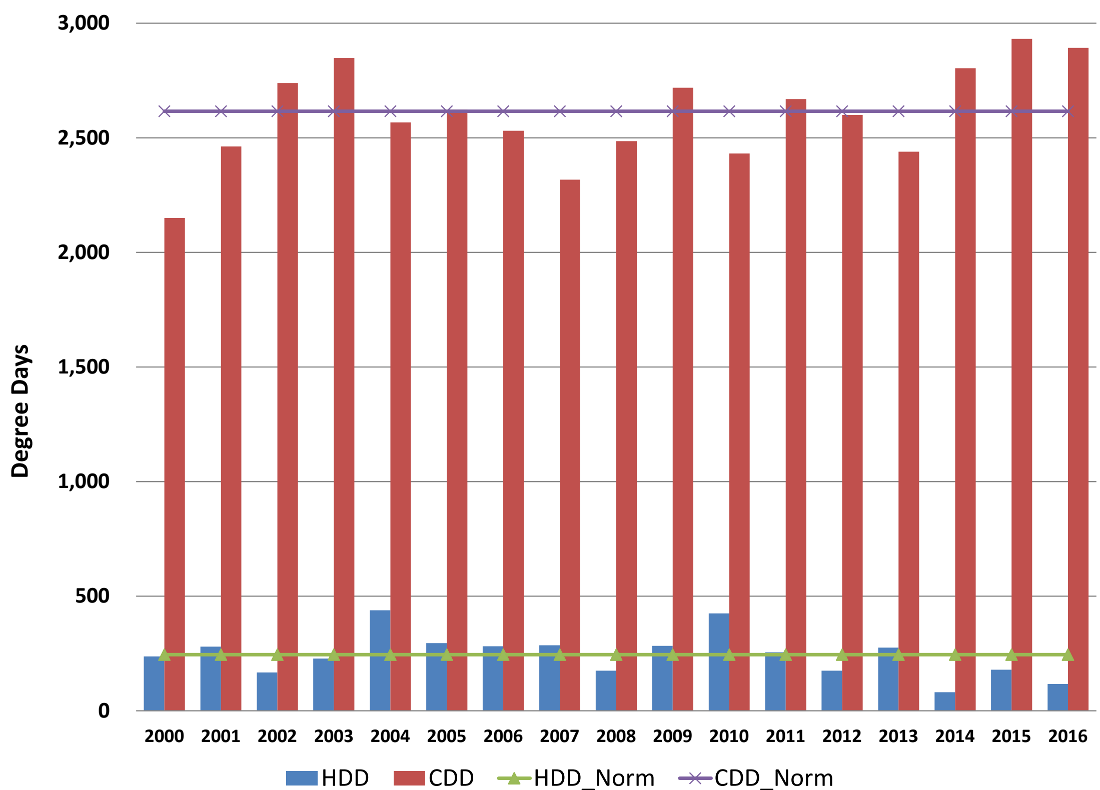

Figure 2 – Actual v. Normal Annual HDDs and CDDs for Bermuda

Graphical review of weather as compared to normal conditions can generally provide an indication of the direction and extent of weather impacts in a given year. As evidenced by the figure above, it was anticipated that the net impact of weather deviations from normal would be significant enough to warrant analysis, but not the primary driver of load declines for either energy or peak demand given the magnitude of actual changes in system load. Figures 3 and 4 below present historical and weather normalized historical Bermuda NEL and electric system peak demand, respectively.

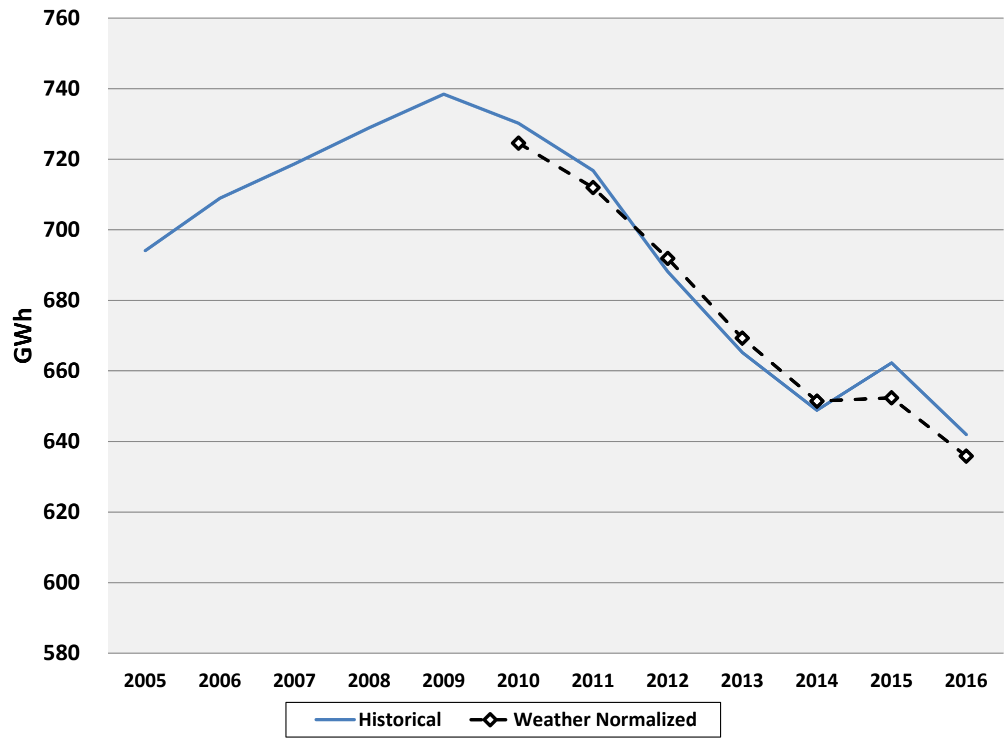

Figure 3 – Historical and Weather Normalized System Energy (GWh)

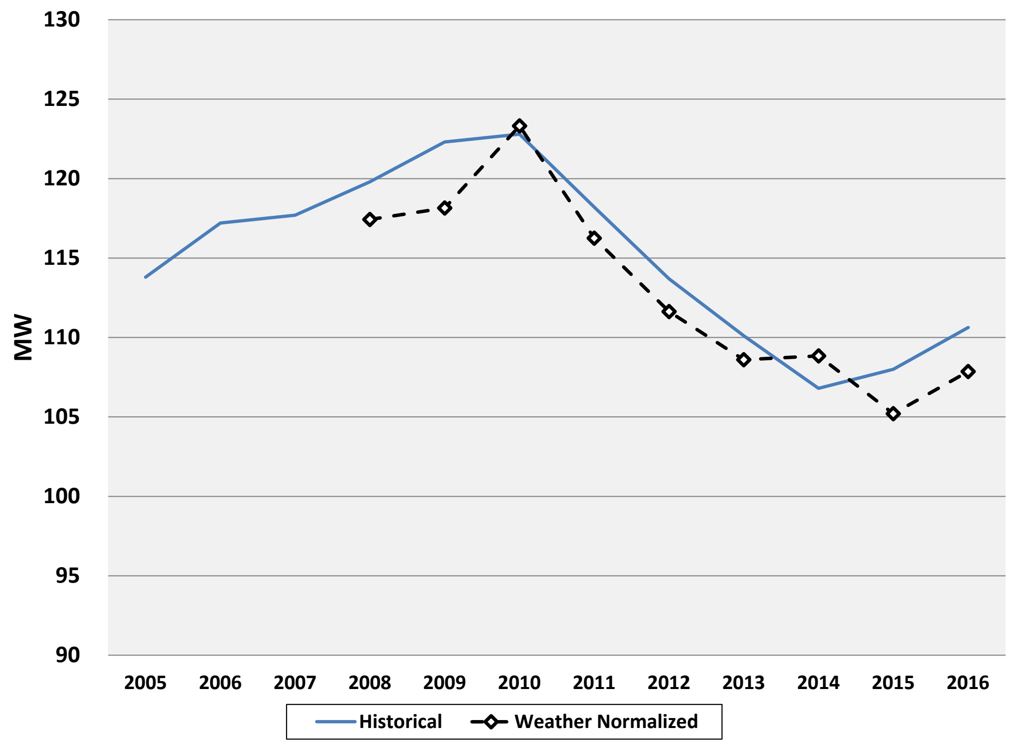

Figure 4 – Historical and Weather Normalized System Peak Demand (MW)

As evidenced by Figures 3 and 4, the net impact of energy normalization on an annual basis (which can fluctuate from month to month in either direction) ranges from -1.5 percent to 0.6 percent over the historical period, and -1.0 percent for 2016. Likewise, the system peak demand normalization impact ranges from -2.6 percent to 1.9 percent over the historical period, and -2.5 percent for 2016.

The weather normalization analysis shows that while weather does have an impact on the electric system load, the relative stability of temperatures within the territory results in fairly bounded impacts that do not explain the magnitude of load contractions in and of themselves entirely.

I.D.2 Economic Data Review

Leidos reviewed the 2015 National Economic Report and the 2018 Pre-Budget Report as well as other available references regarding the real GDP outlook for Bermuda, which is the core econometric variable deployed for load forecasting in the TD&R forecasting architecture. We also reviewed information related to the most recent outlook accompanying the country credit ratings by Standard and Poor's ("S&P") and Fitch rating agencies. The economy in Bermuda was estimated to have suffered another year of contraction in real GDP in the year 2016, with a decline of 0.5 percent.

Appendix I Figure 5 below summarizes the annual percent change in real GDP per year for the period 2009 through 2017.

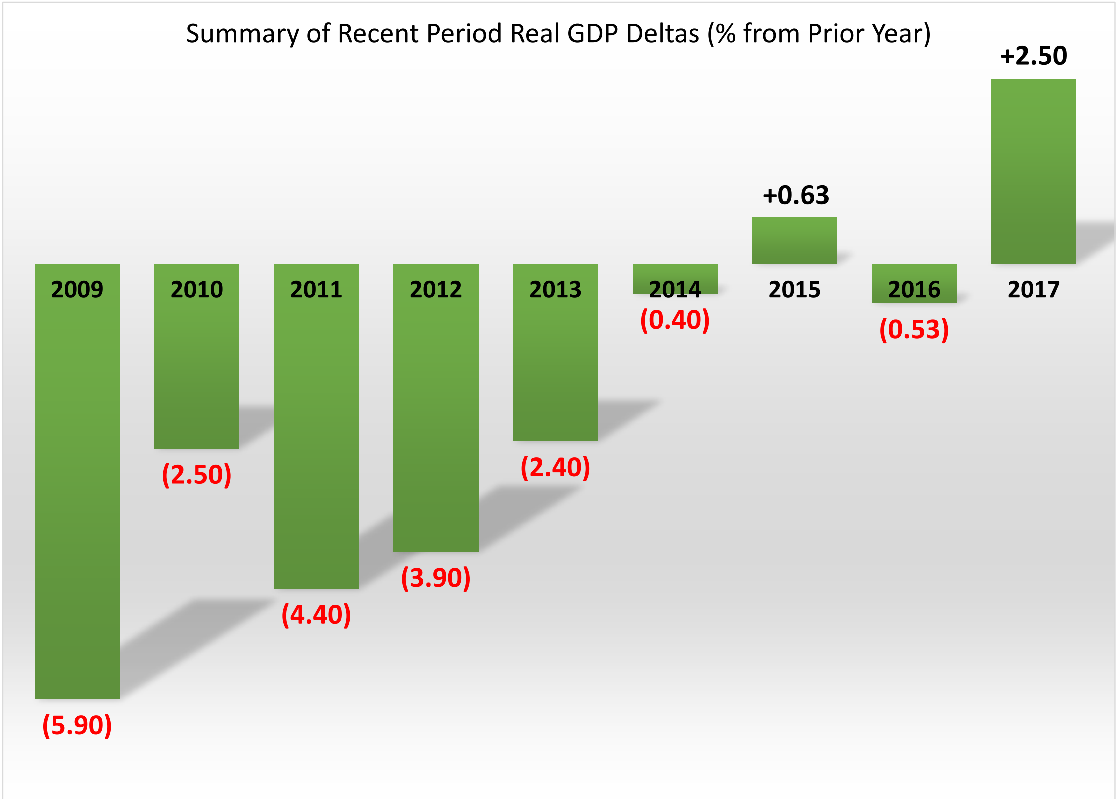

Figure 5 – Summary of Year-over-Year Changes in Real GDP[1]

The 2015 National Economic Report contains a discussion regarding the then current state of the Bermuda economy that provides a mixture of positive metrics and expresses softness in certain components of the economy. Notwithstanding this commentary, the report projected a real GDP growth of 2.0 – 3.0 percent for 2016. As shown in Figure 5, the real GDP actually experienced a contraction of 0.5 percent in 2016 after showing a growth of 0.6 percent in 2015. According to the 2018 Pre-Budget Report, the GDP in 2017 expanded by 2.5 percent as a result of the one time boost experienced by most economic sectors in Bermuda from the hosting of the America's Cup match races. The 2018 Pre-Budget Report points out that "for growth to continue, investment is needed to ensure that economic momentum is not lost". The Bermuda Ministry of Finance has not issued a National Economic Report or published a GDP forecast since the 2015 report.

IHS Global Insight has forecasted year over year real GDP growth rates for Bermuda for the years 2018 through 2022 that range between 1.7 percent and 2.0 percent. BELCO TD&R requested opinions on the GDP outlook for Bermuda from a variety of local stakeholders in the Bermudan Economy including the Government, Chamber of Commerce and Financial Institutions. Unfortunately the responses were limited and those received were classified as "for internal references only". In the absence of an economic forecast by the Ministry of Finance, supported by specified national policies

[1] Source: 2015 Ministry of Finance Report and IHS Global Insight.

to promote economic growth, we have assumed an average annual real GDP growth rate of zero percent for the Study Period. Generally, the feedback received in response to BELCO TD&R's inquiry correlated with our real GDP growth assumption of zero percent.

As evidenced by our review above, the main challenges related to load forecasting for Bermuda utilizing economic data are that: (i) little or no long-term projected economic data currently exists that bears out a relationship between mainland U.S. recovery and recovery in Bermuda, (ii) uncertainty in the short-term may underestimate the range of potential future loads, and (iii) it is important to predicate the forecast on an econometric approach that recognizes the limitations of such models into the future. Refer to the subsection below for a description of Leidos' approach to addressing these challenges when developing the Load Forecast.

I.D.3 Econometric Model of Bermuda's NEL

Pursuant to the receipt of historical data for Bermuda's NEL and key weather determinants, most notably heating degree days and cooling degree days[2], as well as additional data pertaining to the recent fuel cost adjustments, Leidos prepared an econometric model of the NEL. The purpose of the model was to (i) refresh an existing econometric framework previously prepared for Bermuda to determine the stability of historical relationships, most notably relative to real GDP, and (ii) leverage the elasticity resulting from the model to support the growth rate based on the process described further below.

The key variables included in the Bermuda NEL model are as follows:

- Bermuda's real GDP data– this series was "backcast" based on data obtained from IHS Global Insight, coupled with the 2009 – 2015 data from the 2015 Ministry of Finance Report
- Heating and cooling degree days (using a base of 65°F)
- The number of days in the month
- Seasonal, autoregressive, and binary variables (which address isolated anomalies in the monthly data)

The model's findings regarding GDP elasticity were very similar to prior iterations of the same model. The NEL model's findings point to an adjusted R-squared of approximately 97 percent, which implies that 97 percent of the variation in historical NEL can be explained with the variables included in the equation.

It should be noted that the time series data in relation to the fuel cost adjustment was not found to be of sufficient length to be significant as a variable in the model. To the extent the reduction in the recent fuel cost adjustment persists for some extended period

[2] Heating and cooling degree days are calculated based on the difference between daily temperatures and a reference temperature, typically 65°F, and are utilized to capture month-to-month variability in energy due to weather conditions driven from heating and cooling related load response.

of time, future modeling efforts may uncover a material relationship. This relationship would be evidenced by a recovery of load, above what would be expected to result from the economic recovery, associated with end-user response to reduced electricity costs. Refer to the subsection below for further details regarding how the GDP elasticity resulting from the updated model was deployed to develop the final Load Forecast, which is also summarized in Appendix II.A.

I.D.4 Load Forecast Methodology

Recognizing the limitations associated with the lack of long-term perspectives and data regarding the trajectory of real GDP, Leidos devised a load forecast methodology that balances what is currently known with a more expansive treatment of uncertainty over the forecast horizon. This heuristic approach remains underpinned by econometrically estimated parameters that relate economic variations to load levels. Furthermore, an effort was made to retain consistency in the long-term growth rates of the forecast, while developing a band of uncertainty over the forecast period.

The approach to developing the Load Forecast was as follows:

1. The energy forecast has been “anchored” to the 2018 value, based on the electric system’s budget load forecast for that year, with adjustments in succeeding years based on the methods discussed below. In all years and all cases, the peak demand forecast is derived from the energy forecast based on an assumed load factor of 66.7 percent as derived from recent historical load factor values.
2. The energy forecast in future years is based on the econometric model developed to forecast energy as a function of real GDP, cooling degree days, heating degree days and number of days in the month. The resulting energy and demand forecast curves are based on the average annual growth rates during the first ten years and second ten years of the Study Period.
3. Real GDP growth was assumed to be at a rate of zero percent per year for the Study Period.
4. The load values resulting above are further adjusted, beginning in 2018, by assumed reductions resulting from the implementation of the Bermuda Government’s light emitting diode (“LED”) street-lighting program, consistent with a gradual and prolonged economic recovery and the long-term forecast methodology described further below.

Development of Load Forecast Sensitivity Cases

The Load Forecast developed as described above (Base Case Load Forecast) reflects econometric analysis of the NEL. Econometric analysis is a superior approach to trend-based forecasts, as it results in an explanation of history using multivariate statistical analysis, as opposed to an extrapolation of trends. However, it is recognized that the underlying projection of economic activity is subject to considerable uncertainty.

Accordingly, in addition to the Base Case, High Case and Low Case Load Forecasts were developed based on Leidos’ review and application of historical economic forecast errors published by Woods and Poole Economics, Inc. These statistics describe the errors in Woods and Poole forecasts load published over the period 1984-2014 and have been interpreted to capture an 80 percent confidence interval of the potential range of future economic activity on Bermuda as applied to the Base Case economic forecast.

I.D.5 Load Forecast Results

The finalized forecast reflects a combination of leveraging the results of the econometric process and feedback from TD&R.

Figures 6 and 7 depict historical and projected NEL (without the impact of demand side management ("DSM") such as energy efficiency and electric vehicles), with the latter chart reflecting a narrow Y-axis so that year-over-year variations are more visible. Note that the projection assumes an impact associated with the Bermuda Government's ongoing LED street-lighting[3] replacement starting in the year 2018, based on energy differential estimates relative to baseline street lights.

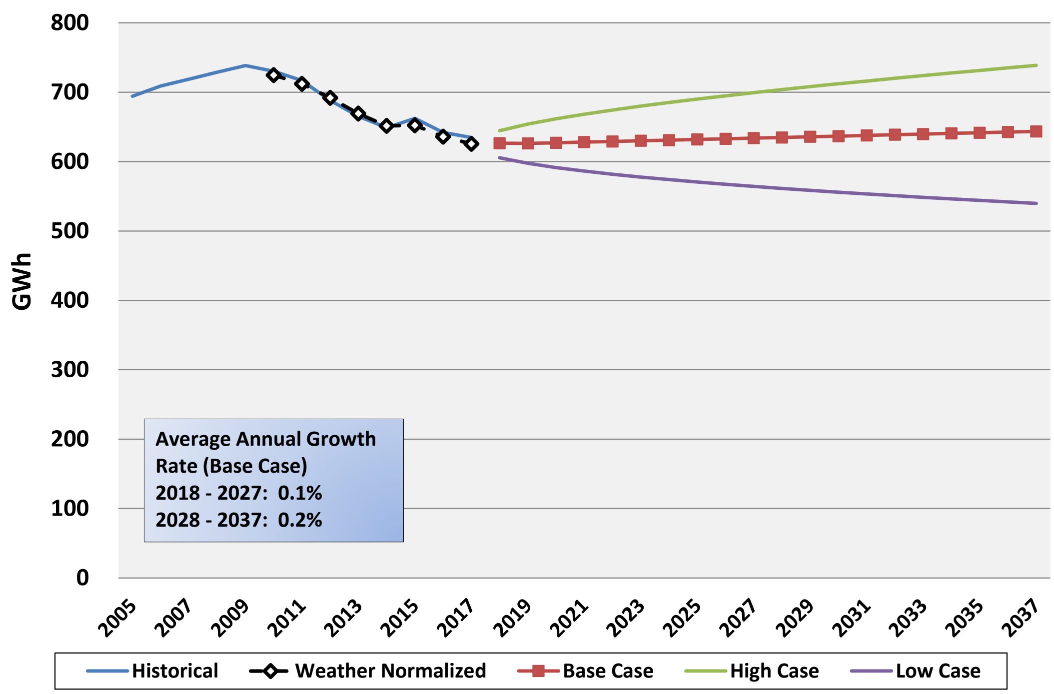

Figure 6 – Energy Forecast

[3] Street lights have been assumed to have zero coincidence with BELCO system peak, and consequently, there is no peak demand reduction associated with the LED street-lighting program.

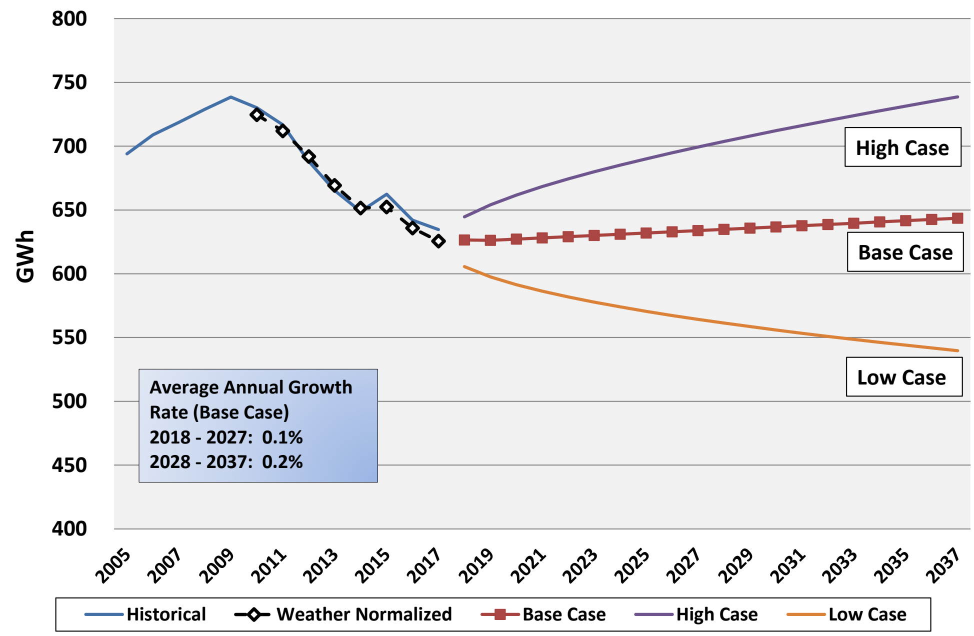

Figure 7 – Energy Forecast (Narrow Y-axis)

Figures 8 and 9 summarize the updated historical and projected electric system peak demand (note the narrow Y-axis, similar to Appendix I Figure 7 above).

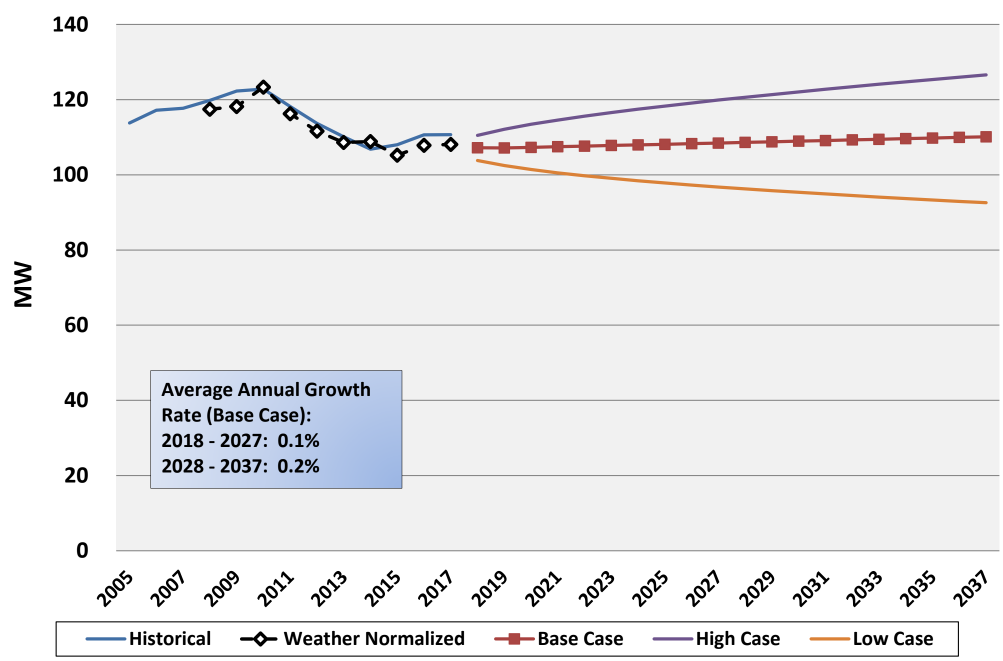

Figure 8 – Peak Demand Forecast (MW)

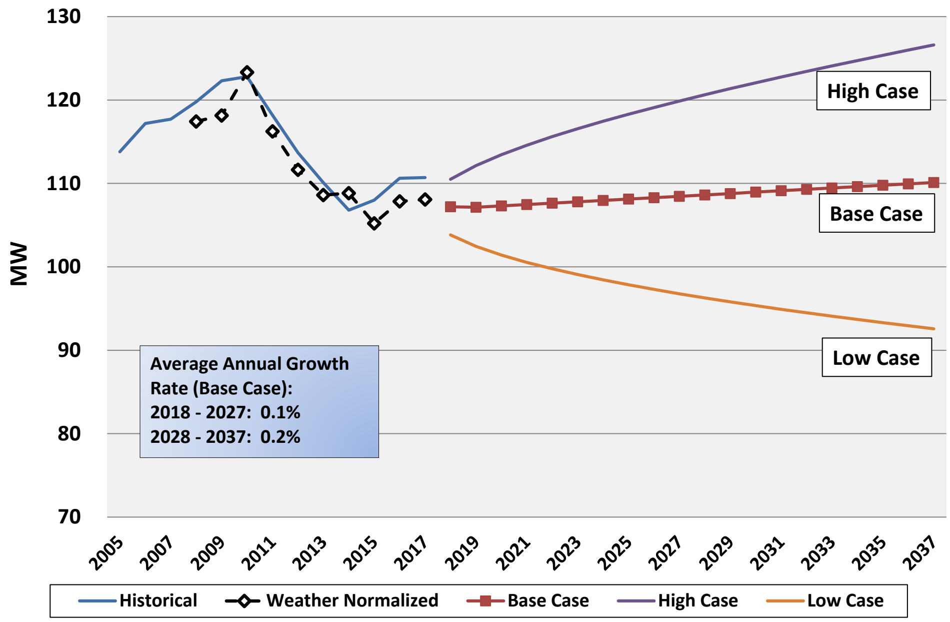

Figure 9 – Peak Demand Forecast (MW) (Narrow Y-Axis)

The forecast results shown above can be thought of as the "organic" forecast prior to the incorporation of estimated impacts of any DSM options deployed in a given resource expansion case. Figures 10 and 11 illustrate the potential impact of a defined energy efficiency program and an electric vehicle deployment program on the electric system's forecast energy and peak demand. Note that Figure 11 reflects an assumption that energy efficiency programs will directly impact system peak demand however electric vehicle demand is presumed to not be coincident with the system peak.

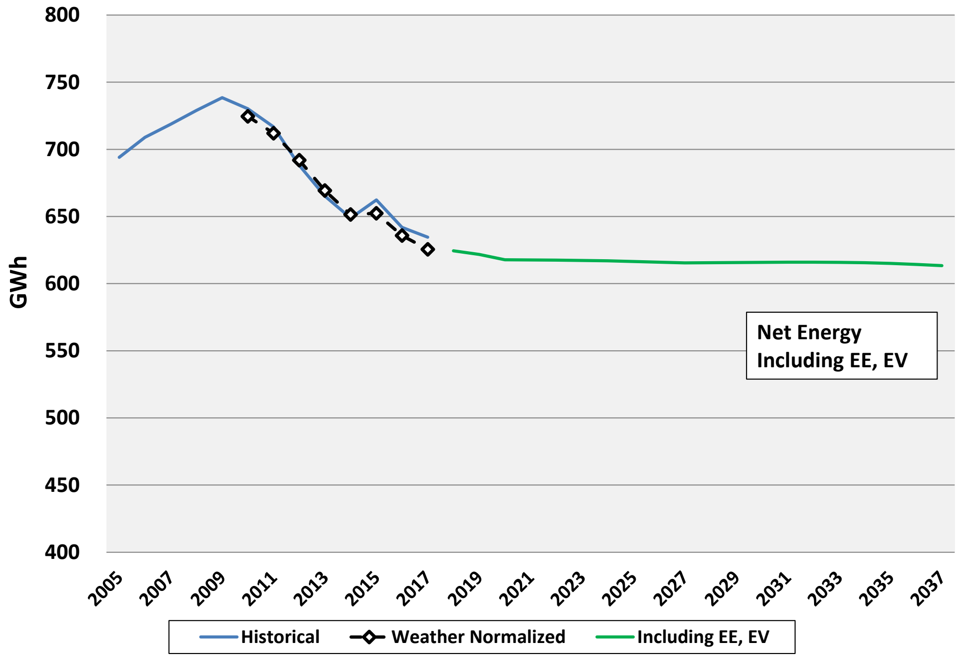

Figure 10 – Net Energy of Base Forecast Including EE and EV

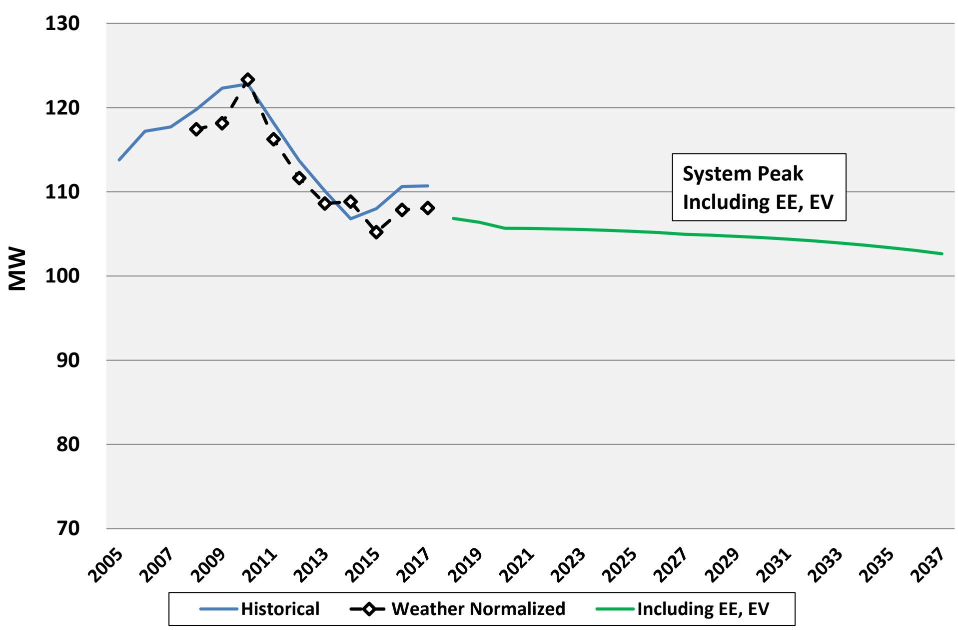

Figure 11 – System Peak Demand Including EE and EV

Appendix II.A contains tabularized results for the Base Case Load Forecast.

I.E Reserve Margin Planning Criteria

In the context of an operating electric utility, PRM or reserve capacity is a measure of the available generating capacity in excess of the capacity required to meet the projected annual system peak demand. It is one of the most important resource planning parameters for a utility as it impacts the level of installed capacity and the level of power supply reliability. For large interconnected grid systems, reserve margin is generally established as a percent of the system installed capacity, while for relatively small stand-alone systems like the one on Bermuda, the reserve margin is established based on the potential unavailability of discrete generating resources due to forced outages. Typically, small systems that employ all dispatchable generating resources establish their resource margins based on the loss of dependable capacity of the two or three largest generating units. In other words, they plan for sufficient total installed capacity to enable the annual system peak demand to be achieved with the two or three largest units out of service. Such outages would normally be of the forced outage category, as planned outages would be scheduled for off-peak load periods. With the proliferation of non-dispatchable and intermittent resources such as solar PV and wind energy, the formula used by small utilities to calculate the target PRM has become more complex.

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

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

+ the dependable capacity of the Tynes Bay plant

+ the dependable capacity of the planned utility scale solar PV PPA (6 MW located at the Airport Finger site)

+ the aggregate dependable capacity of small scale solar PV resources

The Tynes Bay resource is included in the formula because its contractual power supply arrangement places no constraints on planned unit outages and contains no penalties for unavailability of capacity during peak demand periods. The energy output is provided to the grid on a “when available” basis. Likewise, the Phase 1 utility solar resource that is planned for the Airport Finger site is included in the formula because its power sale arrangement is assumed to be an energy only sale arrangement with no back-up, no constraints on outages during peak system demand periods and no penalties for unavailability during peak load periods. It is anticipated that future power sale arrangements will contain provisions geared towards maximizing solar resource availability during peak demand periods, enabling the requirement for the resource to be included separately in the reserve margin calculation to be dropped. The aggregate small scale resource is included in the reserve margin formula for reasons that are similar to the Phase 1 utility scale solar resource.

For the purpose of calculating the target Reserve Margin, the dependable capacity of the various resource types were established as follows:

Reciprocating Internal Combustion Engine (“RICE”) Generators – The dependable capacity of the RICE generating units was assumed to be the maximum continuous net output megawatt rating of the generating unit;

Tynes Bay Plant – The dependable capacity of the Tynes Bay plant was assumed to be 4.0 MW which is the contractual capacity out of the generating plant to the electric grid;

Solar PV Resources – Based on limited local weather data supplemented by proxy data from similarly located jurisdictions, Leidos performed an analysis that established the dependable capacity to be approximately 60 percent of the unit maximum output for the solar PV resources.

I.F Existing Resources

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

Modeling assumptions related to fuel conversion of existing resources and associated parameters (for assets that are scheduled to transition to natural gas or liquefied petroleum gas (“LPG”) when such fuel might become available) were developed in partnership with BELCO TD&R and are included as candidate resources in the production cost model.

Data on the timing of the potential alternate fuel conversion (to be based on the definition of the applicable expansion scenario), the capital and O&M cost of conversion (developed based on Leidos project cost database as well as information gathered via original equipment manufacturer (“OEM”)), and the associated changes in performance characteristics resulting from the conversion (e.g., heat rate) are compiled in the Supply Side Candidate Resources section of Appendix II.B. In addition, in the absence of actual data, Leidos based estimates for the emission rates of the existing resources on MAN 48/60B guarantees for the existing RICE units and on Solar Turbines Inc. new and clean emission rates for the existing combustion turbines (“CTs”).

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

Figure 12 below summarizes the electric system’s base load forecast net of the impacts of EE and EV (with and without reserve margin requirements) versus the existing electric system power supply resources, reflecting projected retirement dates, including Tynes Bay. The retirements are assumed to occur after the summer peak season of the year stated in the text boxes within the graph. Table 1 summarizes the electric system’s estimated capacity gaps, using the base case load forecast with reserve margin requirements as a basis.

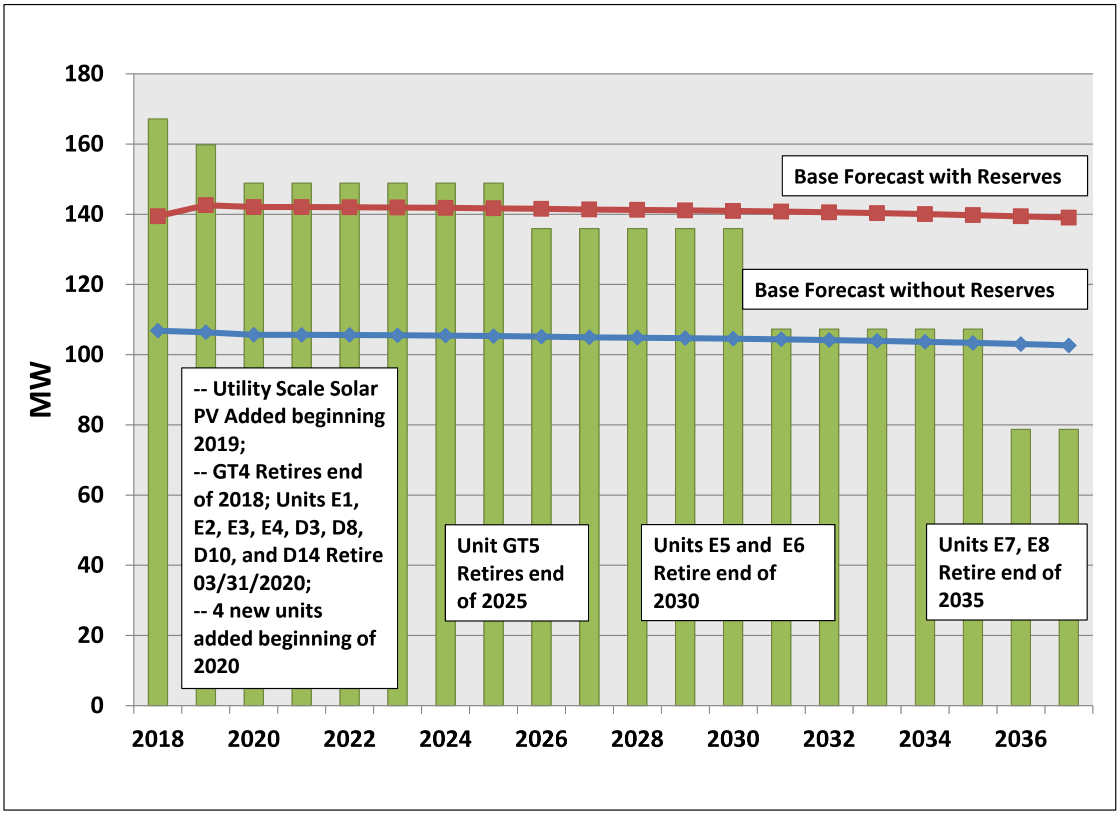

Figure 12 – Capacity vs. Load

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

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

I.G Power Supply Options

After a preliminary prescreening based on criteria such as maturity of technology and overall suitability for deployment on Bermuda, several types of resources were selected as potential candidates for the IRP. In preparation for more detailed screening and production cost modeling, Leidos utilized available sources to develop the required technical and cost parameters for each supply-side and demand-side resource option that was selected as a candidate.

I.G.1 Supply-Side Options

The following is a list of general assumptions used in the development of the key parameters for the supply-side options considered for this IRP evaluation. Appendix II.F of this IRP contains additional discussion surrounding other resource options that were deemed infeasible based on certain criteria as a supplement to this section.

- Leidos assumed that any new light fuel oil ("LFO")-fired resources will be supplied with fuel from existing oil storage facilities at the Central Plant.
- Based on the conceptual LNG regasification facility and NG delivery pipeline design, it is anticipated that gas compressors will not be required for the CT options.
- Due to the scarcity of fresh water on Bermuda, Leidos assumed an air-cooled condenser system in place of a traditional condenser and wet cooling tower configuration for all combined cycle ("CC") resource options.
- The CT and CC generating unit performance characteristics were developed based on the average high temperatures observed in Bermuda during the summer peak months of approximately 86°F.
- The construction cost estimates in the base case of each scenario are based on the assumption that no land costs or other site infrastructure improvements such as fire/water supply lines or significant site remediation requirements are necessary.
- Under the IPP development of future traditional generation sensitivity case for each scenario, Leidos included a WACC of 10 percent, included assumptions for the cost of land at approximately $5,000 per acre per annum, and interconnection costs based on information from BELCO TD&R. Under LPG scenario, it is assumed that all future traditional generation will occur off-site of the Central Plant and therefore these adjustments apply to the base case of this scenario.
- The construction cost estimates were developed on an EPC contract basis. The accuracy range of these estimates is + 30/-15 percent.

- ***Simple-Cycle MSD - HFO, Regasified LNG***
  - The NPS consists of four simple-cycle, dual fuel, medium speed RICE units which will initially burn HFO until such time as LNG is available for power generation. These units are planned to be installed in a natural gas optimized configuration in anticipation of conversion to operate in combined cycle when LNG is available. The technical performance and cost parameters are based on data provided by the OEM during the procurement process.
  - Using Leidos cost database and industry cost information, capital cost estimates for generic medium speed RICE, burning HFO as the primary fuel, were estimated. An adjustment was made to reflect the geographic pricing delta for similar EPC scopes of work based on available industry information. Leidos also included an adjustment factor for owner's costs and contingency.
  - The cost estimate for a generic RICE dual fuel (HFO/natural gas, "DF") fired medium speed reciprocating engine generating unit was developed in a similar manner
  - The estimated cost to convert the existing oil-fired medium speed reciprocating generating units E5, E6, E7 and E8 to DF (oil/natural gas) capability was prepared in a similar manner.
  - Capital cost estimates and performance parameters for the new candidate gas powered RICE units designed for natural gas-only operation are based on indicative pricing and data provided by an original equipment manufacturer. This candidate resource is modeled as a set of two units installed together and is only in the LCOE screening tool.
  - Heat rates and capacities oil fired and natural gas fired RICE units were developed based on data provided by the OEM. Leidos did not apply any allowance for guarantees or off-design performance.
  - Non-fuel O&M costs for the existing RICE generating units were developed based on information provided by BELCO. Non-fuel O&M costs for the candidate RICE generating units were developed based on BELCO's past experience, Leidos cost database information, and information provided by specific equipment vendors.

- ***Simple-Cycle and Combined Cycle – LFO and Regasified LPG/LNG***
  - Using information from a vendor, Leidos developed a capital cost estimate for a generic simple cycle CT. Leidos based the capital cost estimate for a CT on the vendor provided equipment quote for the combined cycle combustion turbine through adjustments to the equipment components included, as well as overall direct and indirect project cost estimates. In particular, the steam generating equipment, steam turbine and generator set and condensing equipment were excluded from the estimate in order to derive the CT cost estimates. Leidos used this adjusted quote to develop current capital cost estimates in U.S. dollars per

kilowatt. Leidos also applied an adjustment factor for owner's costs and contingency.

- The same vendor provided information regarding a CC electric generator. The vendor provided an estimate for a single combustion turbine paired with steam generating equipment and a single steam turbine (a "1x1" configuration) CC electric generator. The 1x1 CC estimate provided by the vendor was provided for locating the unit at an existing site and included: (i) Bermuda specific pricing for equipment delivery and construction; (ii) balance of plant ("BOP") costs; (iii) direct and indirect construction costs; (iv) project management and engineering costs; and (v) wet-cooling and steam condensing through a cooling tower. Leidos reviewed the quote and relied primarily upon the equipment costs, making adjustments to the construction and indirect costs based on Leidos' own experience. In addition, Leidos revised the assumption for cooling to reflect a dry-cooling system using an air-cooled condenser, which increased the cost of the original quote. Leidos used this adjusted quote to develop current capital cost estimates in US dollars per kilowatt. Leidos also applied an adjustment factor for owner's costs and contingency.
- The NPS is to consist of four dual fuel, medium speed, RICE units which will burn NG, once available for power generation, in combined cycle operation with a single, common steam turbine generator. The technical performance and cost parameters are based on data provided by the OEM during the procurement process.
- The capital costs and performance characteristics assumptions for the LPG CT and CC resource options were assumed to be similar to that of an NG resource.
- The capacity and heat rate for the CT and CC were developed based on information provided by the vendor to Leidos.
- Non fuel O&M costs for the CT and CC were developed based on discussions with the vendor.

- ***Biomass***
  - The capital costs were estimated for delivery to and installation in Bermuda. The estimated capital cost for a 54 MW biomass fluidized bed boiler with steam turbine generator is estimated to be approximately $264.6 million (2016 $).
  - The estimated fixed O&M annual cost is estimated to be approximately $11.9 million per year (2016 $).
  - The estimated variable O&M annual cost is estimated to be approximately $4.25/MWh.
  - The heat rate of 15,000 Btu/kWh is estimated based on typical ranges of heat rates for a biomass steam boiler which ranges from 14,000 Btu/kWh to 16,000 Btu/kWh.
  - The capacity factor is estimated to be 89 percent.

- The fuel cost of the feedstock is estimated at $12 per MMBtu delivered to Bermuda. This cost is assumed to be reflective of a feedstock source from the east coast of the U.S. and all taxes and duties for delivery to Bermuda.
- The biomass resource is only evaluated in the LCOE model.

- ***Utility-Scale Solar***
  - The AC capacity of the generic utility scale options was developed based on information supplied by BELCO TD&R and Leidos' own expertise and experience.
  - Based on discussions with BELCO TD&R the utility scale solar resource was modeled under a power purchase agreement ("PPA") and, therefore, no capital cost estimate has been provided.
  - In order to maintain a range of generic PV resource options for IRP modeling purposes, the study evaluates a Finger Phase I and Finger Phase II of solar PV at the airport and a series of small projects located throughout Bermuda. The Finger Phase I is modeled as 6 MW-AC and the Finger Phase II is modeled as 12 MW-AC. Both the Finger Phase I and the Finger Phase II are assumed to operate under a PPA. The total cost of these resources with associated grid interconnection is assumed to be $170/MWh. The remaining small projects located throughout Bermuda are assumed to be sized above the Bulk Renewable License threshold and between 1 MW-AC and 3 MW-AC under a PPA. The total cost of $250/MWh reflects the premium for smaller scale projects and potential added costs for interconnection given the ambiguity with respect to the site locations.

- ***Offshore Wind***
  - Cost and performance data for the off-shore wind energy resource option were derived from the 2014 report titled "Offshore Wind Energy in the Context of Multiple Ocean Uses on the Bermuda Platform" by the Bren School of Environmental Science and Management at the University of California, Santa Barbara (the "UCSB Report"). The UCSB Report was prepared for the Bermuda Government and provided to Leidos for use in the IRP exercise. The objectives of the UCSB Report were as follows:
    - Determine economic viability of off-shore wind energy with respect to Bermuda's current energy context.
    - Identify and characterize potential conflicts with ocean uses and ecological features.
    - Develop a spatial analysis model to identify potential locations for off-shore wind farms with acceptable risk of impacts.
  - The UCSB Report indicated a range of capital costs from $2,500/kW to $6,500/kW and, for purposes of the analysis performed in the UCSB Report, a capital cost of $5,600/kW was relied upon. This is comparable to the cost

estimate of $6,500/kW developed independently by Leidos, when considering the fact that the Leidos estimate does not include interconnection and/or network upgrades.

- The UCSB Report also indicated a reasonable annual O&M expense of approximately $40/MWh. This is essentially identical to the Leidos estimate of approximately $41/MWh.

- ***Battery Energy Storage***
  - Pursuant to BELCO's bulk generation licence, BELCO has previously submitted a proposal for the construction of replacement generation consisting of engines at the NPS and a BESS together known as the "Replacement Generation". Such Replacement Generation falls outside the scope of this IRP.
  - The capital cost for the battery resource was derived from firm pricing received from qualified vendors during a 2017 Request for Proposals for Battery Energy Storage Systems solicitation.
  - The battery resource option does not have a heat rate.
  - The capacity rating of the spinning reserve backup battery resource was selected to be capable of providing 10 MW for a duration of 30 minutes to provide ancillary services such as frequency regulation.
  - The battery resource has the capability to serve other functions, including firming of renewable resources, and has been included as a battery resource option in the analysis.
  - The O&M costs for the proposed battery system were derived from O&M offers received during the 2017 Request for Proposals for Battery Energy Storage Systems solicitation and were composed of fixed costs only. The O&M costs estimates do not include a restoration of energy storage capacity and it is not anticipate that such a restoration will be required under the contemplated use conditions during the Study Period. Leidos did include capital cost for renewal and replacement of certain major components which include inverter replacement.

I.G.2 Demand-Side Options

- ***Residential Solar Water Heating***
  - Hourly profiling for the solar thermal water heater system was developed based on weather data purchased from Weather Analytics, LLC, which provided TMY 2 (or 15-year based normalized hourly weather) for Bermuda. This data was coupled with two models to produce an hourly profile of energy draw (negative) or avoided grid energy (positive), the net of which resulted in annual energy for the incremental installation. Demand impacts were estimated based on an analysis of estimated hourly grid avoided demand during the hour of the Bermuda electric system peak.

- The modeling for the hourly profile was a function of the combination of two separate tools as follows:
  - The first tool is the SAM, as developed by NREL through a relationship with the DOE.
  - The second tool is called RET-Screen. This is also a publically available tool developed by Natural Resources Canada that contains built-in equipment specifications, including make/model numbers.
- Various combinations of solar thermal paired with solar PV were designed, and ultimately, a solar thermal pairing with 1,060 watt (DC) PV panels was selected as the demand-side resource candidate. Hourly energy modeling has been conducted as discussed above to reflect the estimated annual energy that can be expected from the updated PV panel rating.
- The capital cost of a solar thermal water heater system paired with a 1,060 watt PV panel, which is the sole option retained for IRP modeling purposes, was estimated by BELCO TD&R to be $9,000 per unit, inclusive of costs associated with monitoring potential pilot deployments.
- Leidos has assumed the use of micro-inverters and a 25-year warranty for the mechanical equipment, and modules, inclusive of the micro-inverters. Leidos estimated the overall fixed O&M cost to be around $1,000 over the life of the installation; and those costs are subject to significant uncertainty, and could be as much as two or three times the base estimate. In addition, Leidos accounted for cost contingency associated with mainland versus Bermuda cost.
- Refer to Appendix II.B for a complete set of assumptions related to the Solar Thermal water heater system. The peak demand and energy impact of this system will be netted out from the Bermuda electric system load forecast prior to dispatch against supply-side resources, and the cost will be added to the dispatch analysis as a discrete cost. Uptake of the program is based on information provided by BELCO TD&R.

- ***Small-Scale Solar PV Panels – Schools***
  - Capacity, capital costs, and fixed O&M costs for PV installations of a distributed nature for commercial installs were developed based on information provided by BELCO TD&R. Leidos has assumed the use of micro-inverters and a 25-year warranty for the modules, inclusive of the micro-inverters.
  - Analysis of annual energy and coincidence of solar output with the Bermuda electric system peak were developed based on (i) Leidos' parameterization and deployment of the NREL solar profile tool using a nearby mainland weather area, (ii) Leidos' review of the Castle Harbour feasibility study conducted for BELCO, and (ii) an analysis of the coincidence of the hourly solar output relative to the Bermuda electric system peak. As a result of the Castle Harbor study's use of Bermuda-specific weather data, Leidos used that study as the basis for the assumption related to coincidence of solar output to the Bermuda electric system

peak as well as for annual energy. Table 2 summarizes the most important solar PV assumptions on an incremental basis, the performance aspects of which also apply to utility-scale solar.

Table 2
Key Solar PV Assumptions

Assumption	Residential PV	Commercial PV
Rating of Installation (kW-DC)	2.00	100.00
Capital Cost ($/kW-DC)	$4,380	$4,000
AC Rating of Installation (kW-AC) (1)	1.72	86.00
Capital Cost ($/kW-AC)	$5,093	$4,651
Fixed O&M Cost ($/kW-AC-yr)	$36.40	$20.22
Annual Degradation Factor (%)	0.8%	0.8%
Dependable Capacity @ BELCO TD&R Peak	60%	60%

(1) Assumes a DC-AC ratio of approximately 1.16 based on "The Castle Harbour Solar Project" report.

- The peak demand and energy impact of all projected PV installs will be netted out from the Bermuda electric system load forecast prior to dispatch against supply-side resources. The cost estimates will be added to the LCOE analysis; however, for the PROMOD© simulation the capital and operating costs are assumed to be the burden of the end-user. In other words, the modeling approach recognizes that currently there is no program in place for BELCO TD&R to own and operate these resources and that the individual customer has the sole option to elect to install. Uptake of the program on a by-sector basis is based on information provided by BELCO TD&R.

- ***Small Scale Cogeneration***
  - The small scale cogeneration resource was assumed to be located at a major commercial customer's site, such as a hotel. The projection of electric load requirements of a large hotel were developed by Leidos based on information provided by BELCO TD&R. The thermal load requirements were developed by Leidos based on commercially available information and typical industry data.
  - In developing the IRP, the model will dispatch to the Bermuda electric system load inclusive of the reserve requirement (based on the criterion above) and select the portfolio of supply-side resources that meets the capacity and energy needs of the Bermuda electric system with the lowest NPV of power supply cost over the Study Period. Must-run resources or other unique dispatch constraints, as well as planned maintenance of each resource will be considered in the analysis. As noted above, it is Leidos' intention to net out the estimated impact of any

future DSM programs from the Bermuda electric system load forecast prior to performing the supply-side evaluation.

- ***Distributed Combined Cooling Heat and Power ("CCHP")***
  - This option selected to provide enough electric generation to meet the customer minimum load as well as provide thermal energy in support of cooling loads, heating loads and domestic hot water consumption using a micro turbine generator.
  - The micro turbine was assumed to operate on bulk LPG when LPG becomes available on the island.
  - The construction cost estimate for the CCHP was developed based on information obtained from a vendor in conjunction with Leidos' database of reference projects and excluded the use of gas compressors.
  - The capacity and heat rate were derived from information obtained from a vendor.
  - The O&M costs for the CCHP option is composed of variable costs only and was developed based on information from Leidos' database of reference projects.

- ***Distributed Combined Heat and Power ("CHP")***
  - This option has been based on sizing a reciprocating engine to meet the electrical load of a generic customer. Heat recovery equipment was selected to optimize the thermal waste energy of the exhaust of the reciprocating engine for use as energy to serve space heating and domestic hot water needs of a generic customer.
  - The reciprocating engine was assumed to operate on NG when bulk LNG becomes available on the island.
  - The construction cost estimate for the CHP was developed based on information received from discussions with a vendor.
  - The capacity and heat rate were derived from discussions with a vendor.
  - The O&M costs for the CHP option is composed of variable costs only and was developed based on information from commercially available tools used for approximating generator costs.
  - The price for sale of CHP byproducts was assumed to be equal to the cost of gas necessary to generate the equivalent amount of heat from the existing back-up boiler. Given that there is currently no power purchase agreement in place, it is possible that the rates assumed for purposes of this analysis may differ materially from actual rates resulting from the ultimate agreement, which when finalized will codify prices, terms, and conditions to off-take byproducts. The potential risks involved with byproduct sales are herein noted and should be reviewed carefully.

- A major overhaul of the CHP plant was assumed to not be necessary during the Study Period, given that the average capacity factor estimated for the CHP deployment does not result in the approximately 60,000 hour threshold for the first major overhaul (this would occur subsequent to the end of the Study Period).
- Byproduct sales have been assumed to begin coincident with the commercial operation date of the CHP asset, and concordantly, we have assumed that the ultimate agreement between the generator and the ultimate off-taker(s) will be fully in place prior to the online date of the unit(s).

I.G.3 DSM Portfolio Definition

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

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

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

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

I.G.4 Basis of Unit Operating Performance

Leidos provided net unit performance estimates (or net plant for the combined cycle options) for each option based on an assumed parasitic load for each unit. The basis of each net heat rate estimate reflects the HHV as opposed to the lower heating value ("LHV") basis. The difference between LHV and HHV is a function of the hydrogen content of the fuel and can be thought of as the usable energy versus the chemical energy in a fuel. When combusted, the chemical energy is released in the form of heat, with a portion of the heat in an unusable form for current technology when hydrogen combines with oxygen to form water vapor. If the water vapor is cooled below the saturation point, the energy in the water vapor is released. Currently, engines are not mechanically capable of extracting the remaining energy from the water vapor, and many engine manufacturers state that the maximum energy that is available for the engine is the LHV. Therefore, they prefer to state the performance on an LHV basis, which results in a calculated efficiency that appears to be higher than the efficiency calculated on an HHV basis. Typically, gaseous fuels are purchased on a higher heating value basis, thus Leidos has provided the generating unit performance estimates on a HHV basis.

Leidos assumed 1.06 as the conversion from LHV to HHV for fuel oils and 1.11 for natural gas. This estimates that approximately 6 percent of the chemical energy in fuel oil combustion products and 11 percent of the chemical energy in natural gas combustion products is water vapor.

I.H Projections and Detailed Fuel Model Development

Leidos engaged in the development of a detailed fuel delivery forecast model for each of the main candidate fuels in the IRP. The purpose of this detailed fuel model was to expand and enhance the transparency of the fuel forecast and compartmentalize the components of the build-out, so as to allow a platform for review and in-depth itemization of the aspects of the pricing. Appendix II Section C of this IRP contains the most recent vintage of the by-year fuel forecast for all key fuels, including the adjustment to fuel adder costs, including the cost normalized duty for LNG and LPG, based on feedback from BELCO. On a broad basis, the following list describes the key steps involved in the development of delivered fuel price projections as are anticipated to be input into the downstream IRP production cost simulations (note: all line items comprising the detailed fuel projection can be found in Appendix II Section C of this IRP):

- Leidos estimated the HFO, LFO, LPG Bulk, and LNG Bulk commodity pricing to be commensurate with the updated Annual Energy Outlook (“AEO”) from the EIA for those fuels; perspectives in the AEO have been combined with recent period forward markets information as extracted from NYMEX or OPIS commodity projection for near-term strips to better capture a blend between short-term price fluctuations and long term price level expectations. This was of particular importance for oil given recent price fluctuations for this commodity. In addition, with regard to the LPG fuel pricing, BELCO provided fuel delivery prices based on discussions with a major fuel supplier.
- BELCO provided, and Leidos relied upon, recent actual fuel commodity price data for HFO and LFO.
- Leidos modeled certain critical fuel adders associated with delivered pricing for Bermuda, including adders for through-put, freight and supply, duty, and other additional “taxes” with regard to HFO and LFO based on data provided by BELCO.
- BELCO provided, and Leidos relied upon, fuel supplier indicative commodity pricing for LPG Bulk fuel delivered to Bermuda. This supplier also included revised fuel cost adders for the LPG Bulk fuel supply.
- The estimated cost and schedule of the LNG infrastructure for the full conversion of generation to NG were developed on the basis of an updated to the input from the 2014 Liquefied Natural Gas Supply Feasibility Study Report, which reflected an LNG offloading, storage, regasification and natural gas pipeline infrastructure capital cost estimate of approximately $104M. The update adjusted the capital cost

estimates to reflect the current pricing under the same design assumptions, with scheduled completion in 2022.

- Each of the adders, as well as other values that were provided by BELCO in dollars per barrel or dollars per US gallon, have been converted to an “all-in” dollars per MMBtu using the ratio of MMBtu of fuel per unit input using HHV specifications as provided by BELCO. These adder amounts were then combined with the commodity component to produce the final delivered price forecast for each fuel. In general, adders have been escalated at inflation over the longer-term forecast horizon.

Figures 13 and 14 below contain a summary of the core commodity component (without any adders), as well as the all-in delivered price (with adders), associated with all of the fuel prepared for evaluation purposes. The all-in cost is shown with the impact of the normalized import duty as well as with the non-normalized import duty.

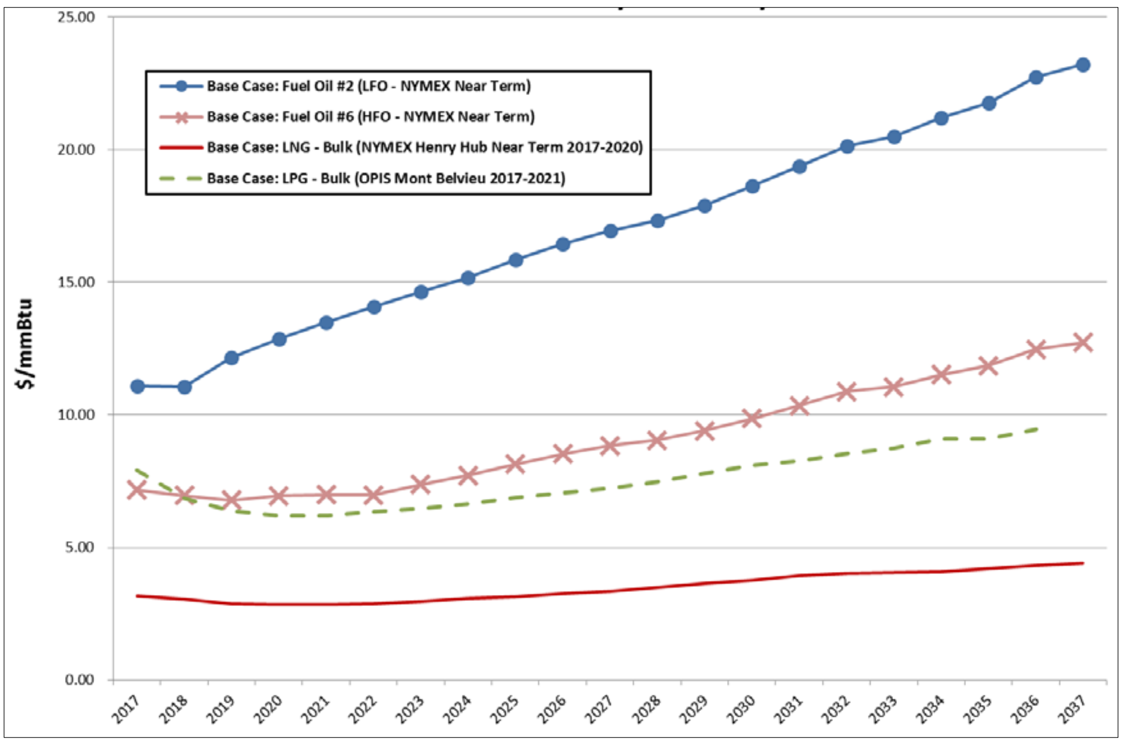

Figure 13 – Base Case Commodity Price Forecast

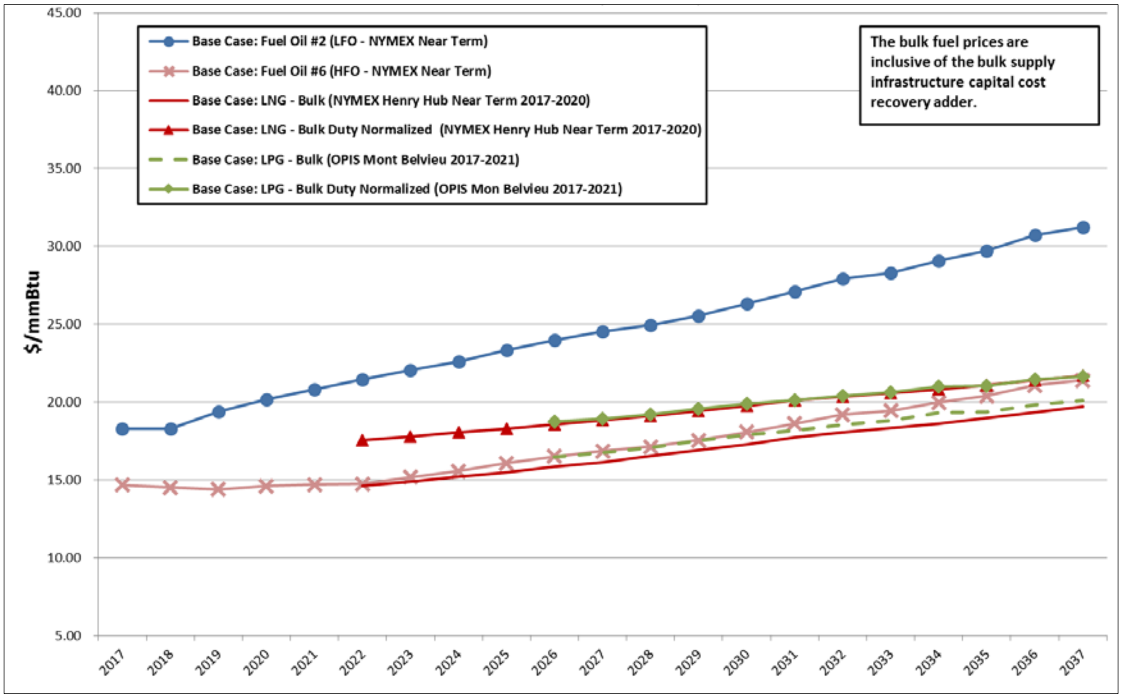

Figure 14 – Base Case All-in Delivered Fuel Forecast

The complete details for forecast development can be found in Appendix II Section C of this IRP. We understand that the fuel import duty is potentially subject to change in an effort to maintain "revenue neutrality" of the Bermudian Government. For purposes of dispatch modeling, the fuel import duty is to be included based on a normalization adjustment to the current rates as reported by BELCO TD&R. The current duty rates have been applied as a sensitivity to Scenario 3 and Scenario 4.

Fuel Price Volatility

Fuel price volatility was projected based upon the range of potential fuel prices reflected across cases presented in the EIA 2017 AEO. For this purpose, High Fuel Price and Low Fuel Price Scenarios have been developed based on AEO scenarios that represent the highest and lowest commodity price for each commodity that underpins the fuel in question. Table 3 below provides the key defining the AEO scenarios that have been used for the High and Low Fuel Price Scenarios utilized in the IRP. Figures 15 through 18 provide a graphical representation of the fuel price scenarios for each fuel type.

Table 3
Fuel Price Scenarios AEO Case Basis

Fuel Type	AEO Case for High Fuel Scenario	AEO Case for Low Fuel Scenario
LFO	High Oil Price	Low Oil Price
HFO	High Oil Price	Low Oil Price
LPG	High Oil Price	Low Oil Price
NG	Low Resource and Technology	High Resource and Technology

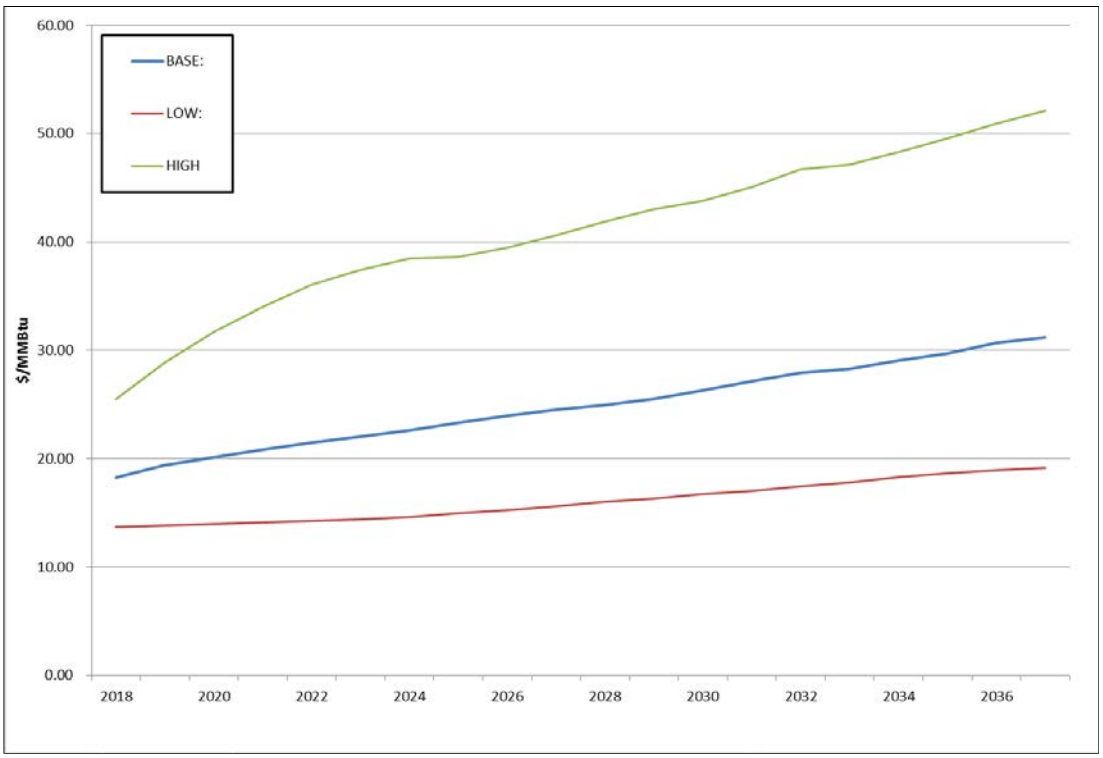

Figure 15 – Base, High and Low LFO All-in Delivered Fuel Forecasts

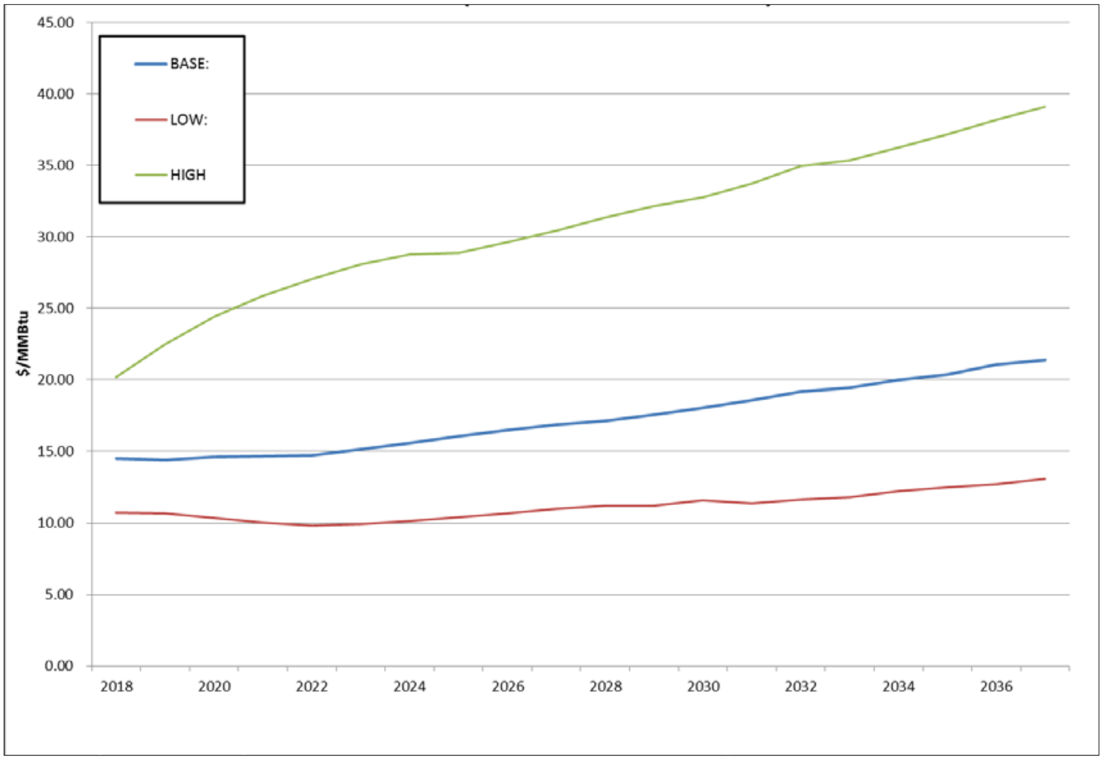

Figure 16 – Base, High and Low HFO All-in Delivered Fuel Forecasts

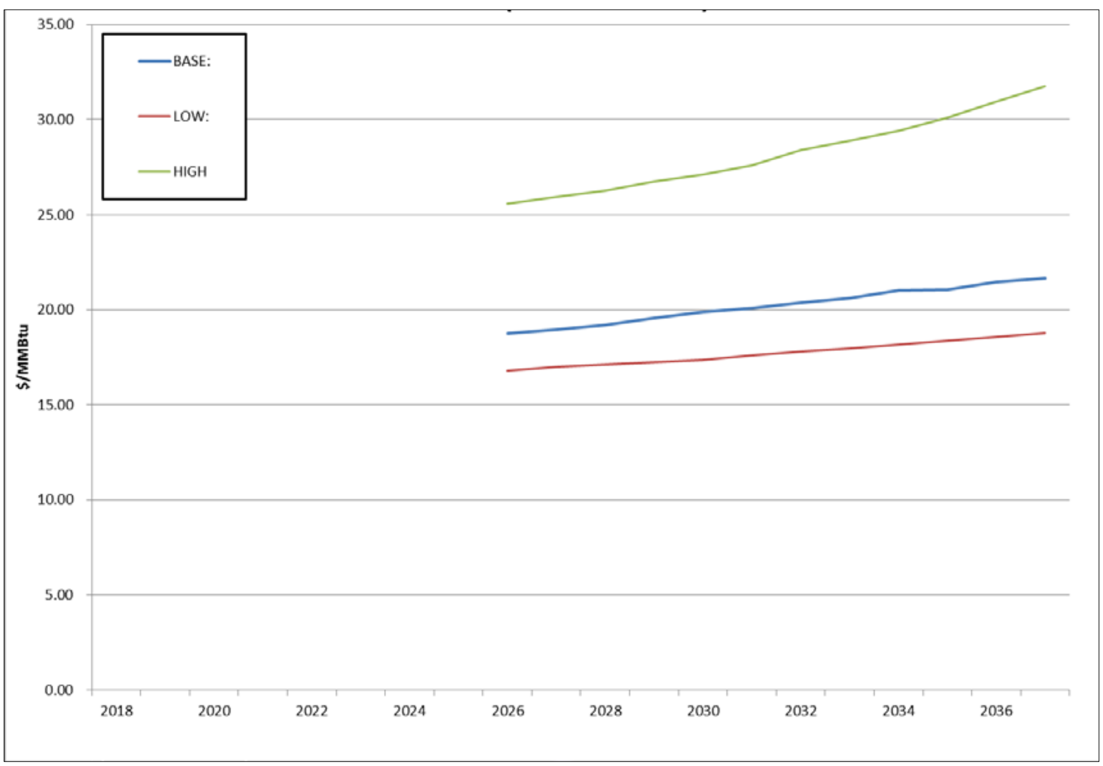

Figure 17 – Base, High, and Low LPG All-in Delivered Fuel Forecasts

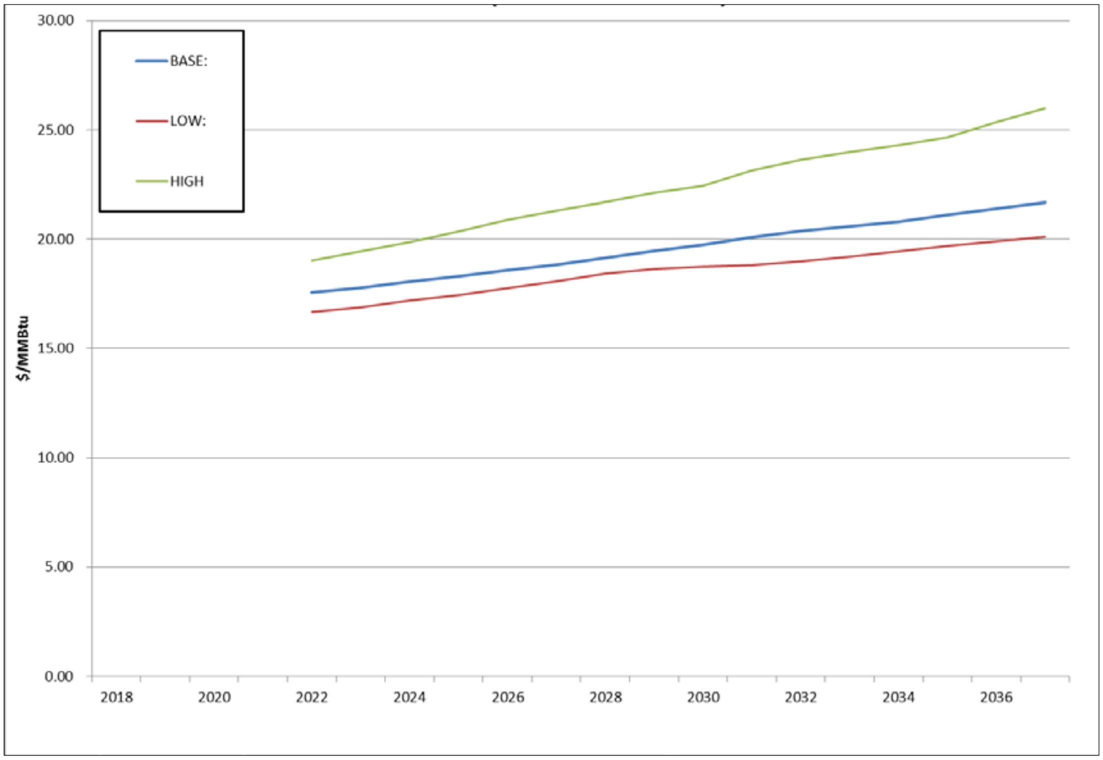

Figure 18 – Base, High, and Low LNG All-in Delivered Fuel Forecasts

It is critical to note that the volatility assumptions are being modeled such that they only impact the commodity portion of the overall fuel cost (i.e., the volatility assumptions would only be applied to the commodity component when developing the high and low fuel price forecasts). The other components of the fuel cost represent a significant portion of the fuel burden. For example, in the case of LNG, the commodity component of fuel cost ranges from 16-20 percent of the total delivered fuel cost over the Study Period, whereas the commodity component for LFO and HFO ranges from 49 up to 74 percent over the Study Period.

I.I Renewable Energy Portfolio Targets

There is currently no mandated Renewable Energy Portfolio Standard ("RPS") that applies to Bermuda. Candidate renewable energy resources were selected for evaluation on the basis of a number of criteria, including: (i) the outcome of previous feasibility studies performed by and on behalf of BELCO, (ii) the renewable resource potential that is available on Bermuda, (iii) the maturity and proven nature of the technology and (iv) The logistics associated with developing and operating the resource on Bermuda. Those selected candidate resources would then undergo a preliminary cost screening to determine which ones would be included in the planning scenarios for modeling. Appendix II.B provides a summary of the renewable energy technologies and capacity sizes that were selected for potential utility scale deployment.

I.J Qualitative Analysis of Candidate Resources

In order to provide a holistic evaluation of the supply-side and demand-side resources, and to ensure that non-monetary factors that are critical to the success of the IRP but not quantified in the load dispatch modeling are carefully considered, the IRP process includes a qualitative evaluation of each candidate resource. The qualitative assessment criteria used as a basis for the evaluation and the maximum scores that are allocated to each criterion have been developed specifically for this IRP and reflect BELCO TD&R's interpretation of their significance. The results of the qualitative evaluation were considered together with the results from the quantitative analysis in arriving at the recommendations for the action plan arising from this IRP exercise. The importance of the qualitative assessment is highlighted in the consideration of renewable energy resources for the preferred expansion plan to address the electric system's sustainability objective, since the least cost plan based on the quantitative (LCOE) analysis may exclude these resources. Descriptions of the criteria used for the qualitative assessment along with the maximum scores allocated to each one is provided in Table 4 as follows.

Table 4
Qualitative Assessment Criteria

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

The results of the qualitative analysis are presented in Section 2 of this IRP. The information gleaned from the qualitative analysis will be combined with the direct financial implications of the dispatch cases and LCOE screening to inform the recommended resource plan for the electric system

I.K Production Cost Scenario Definitions

Based on discussions with BELCO TD&R and the sum total of work conducted as delineated in this IRP, the following cases were the subject of the production cost modeling, as predicated on Base Case assumptions across each of the inputs to the IRP (e.g., load, fuel). It is important to note that while the definitions below capture certain decisions which were prescribed, or deterministic in nature, all of the potential resources considered in each case are defined. Some resources included in a case definition ultimately may not have been modeled within a case as a result of evaluating the LCOE tool results, among other indicators.

Table 5
BELCO TD&R 2018 IRP
Production Cost Modeling Scenarios

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

Table 5 BELCO TD&R 2018 IRP Production Cost Modeling Scenarios				
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Resource Fuel Conversions	None required	None required	Convert planned MSDs (adding steam turbine for combined cycle operation) and capable existing resources at central plant to NG operation.	Convert capable CT's at Central Plant to LPG operation
Candidate Fossil Fuel Resources	• MSDs on HFO (located at Central Power Plant) • CTs on LFO (located at Central Power Plant)	• MSDs on HFO (located at Central Power Plant) • CTs on LFO (located at Central Power Plant)	• MSDs on NG (located at Central Power Plant) • CTs on NG (located at Central Power Plant) • RICE – CHP (NG)	• MSDs on LPG (located at/near LPG fuel storage site) • CTs on LPG (located at/near LPG fuel storage site) • CT – CCHP (LPG)
Candidate Renewable Fuel Resources	None (no new additions after the planned Solar Finger Phase 1)	Solar (Up to 18 MW) • 12 MW (Phase II) Solar PV PPA at Finger. • 6 MW aggregate PPAs (Phase III) from other sites. Off-shore Wind (Up to 25 MW PPA	Solar (Up to 18 MW) • 12 MW (Phase II) Solar PV PPA at Finger. • 6 MW aggregate PPAs (Phase III) from other sites. Off-shore Wind (Up to 25 MW PPA	Solar (Up to 18 MW) • 12 MW (Phase II) Solar PV PPA at Finger. • 6 MW aggregate PPAs (Phase III) from other sites. Off-shore Wind (Up to 25 MW PPA
Candidate BESS Resources	None	As needed to support renewable resources	As needed to support renewable resources	As needed to support renewable resources
Candidate EE	Defined Realistic Achievable Potential.	Defined Realistic Achievable Potential.	Defined Realistic Achievable Potential.	Defined Realistic Achievable Potential.
Candidate EV	Defined EV Program	Defined EV Program	Defined EV Program	Defined EV Program
Distributed Renewables	None (organic growth already embedded in forecast	Solar • Solar PV rooftop (residential and commercial) • Solar thermal water heating	Solar • Solar PV rooftop (residential and commercial) • Solar thermal water heating	Solar • Solar PV rooftop (residential and commercial) • Solar thermal water heating

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

1. **Fuel Cost** (based on 2017 EIA AEO range) – High Fuel Price and Low Fuel Price Forecasts have been developed based on AEO scenarios that represent the highest and lowest commodity price for each commodity that underpins the fuel in question. As discussed further in Section 4.8, the scenario that represents the High Fuel Price Case for LFO, HFO, LPG, and NG is the 2017 AEO High Oil

Case; the Low Fuel Price Case is based on the AEO Low Oil Case for HFO, LFO, and LPG but is based on the AEO High Resource case for NG.

2. **Carbon Monetization –** Leidos has researched an updated March 2016 report from Synapse that captures a revised view on potential carbon prices – the Synapse Report's pricing is applied to each production cost model's results on the back end, in addition to reporting the actual tons of carbon emitted for each case.
3. **High and Low Load Forecast –** The IRP evaluated a "High" and "Low" forecast. The High Case reflects a long-term growth rate of 0.9 percent per year, while the Low Case reflects a resumption of the recent contraction in load, with a long-term rate of decline of 0.4 percent per year.
4. **Non-Normalized Custom's Duty on LPG and NG –** The amount of Custom's Duty applied to LPG and LNG is adjusted (lowered) to reflect the current rate applied by the Bermuda Government for import of those fuels.
5. **IPP Development of Future Fossil Fuel Resources –** The estimated cost of future fossil fuel resources is adjusted as necessary to reflect the development by an IPP at an east end site near the existing bulk fuel storage facilities.

I.L Carbon Monetization Pricing

Table 6 below summarizes the carbon pricing to be used in the Carbon Monetization sensitivities for the Base, High, and Low Cases as based on a March 2016 Synapse Report that estimates a hypothetical price for carbon emissions. The Synapse carbon projection is based on a series of analyses and assumptions regarding the possibility of a mature carbon market within the mainland US. The March 2016 projection takes the recent stay of the Clean Power Plan, the landmark carbon legislation proposed by the US Environmental Protection Agency, into consideration. However, the Synapse Report does not anticipate that the stay will ultimately reverse the trajectory towards some form of nationwide cap and trade system or carbon tax, and notes that some states continue to work towards compliance plans despite the stay, and amidst heightened uncertainty regarding the actual timing of compliance requirements. Prices are shown commensurate with the Study Period.

Table 6
Summary of Assumed Carbon Pricing

Year	Low Case ($2015 per ton)	Base Case ($2015 per ton)	High Case ($2015 per ton)
2017	-	-	-
2018	-	-	-
2019	-	-	-
2020	-	-	-
2021	-	-	-
2022	$15.00	$20.00	$25.00
2023	$15.75	$20.75	$26.00
2024	$16.50	$21.50	$27.00
2025	$17.25	$22.25	$28.00
2026	$18.00	$23.00	$29.00
2027	$18.75	$23.75	$30.00
2028	$19.50	$24.50	$34.25
2029	$20.25	$25.25	$38.50
2030	$21.00	$26.00	$42.75
2031	$21.75	$29.00	$47.00
2032	$22.50	$32.00	$51.25
2033	$23.25	$35.00	$55.50
2034	$24.00	$38.00	$59.75
2035	$24.75	$41.00	$64.00
2036	$25.50	$44.00	$68.25
2037	$26.25	$47.00	$72.50

I.M Principal Assumptions and Considerations

The results of the IRP as delineated in Section 2 must be interpreted in light of the following principal assumptions and considerations. Refer to other items of this Appendix I for a comprehensive listing of assumptions in terms of specific values, approaches, sources, and methodologies. In addition, this IRP has several appendices that detail the results of the various precursory analyses necessary to complete the IRP. The purpose of this section is not to re-summarize such inputs, but to shed light on key considerations that may impact the results of our evaluations. These considerations are as follows:

1. Unless specifically denoted in this IRP, all data taken as exogenous inputs to the Leidos load forecasting framework, LCOE screening model, and load dispatch

model, including key financial and performance information related to the existing asset base, or insights on future economic conditions provided by the BELCO Team, or SMEs retained by either party, is assumed to be appropriate for the purposes of this analysis. Leidos has not independently verified the entirety of this data, and to the extent such assumptions deviate from actual conditions, the results presented herein may concordantly vary.

2. Base-Case fuel projections are based on information regarding BELCO’s existing fuel component costs; information regarding BELCO contractual/bid/indicative pricing information (as applicable); information regarding short to medium term futures markets; and the 2017 EIA AEO. This information is assumed to be appropriate for purposes of this analysis. Any deviation from EIA forecasted prices or any fluctuations in BELCO’s other fuel component costs could materially impact the relative economic performance of competing resources, and consequently, the findings in this IRP.
3. This evaluation does not constitute a technology optimization analysis. Leidos did not review alternative combinations of technologies relative to the given future site or sites for deployment to determine if a given technology was the best available technology given site conditions or other factors, which are beyond the scope of this analysis. The IRP has been conducted with a level of rigor commensurate with the expectation that more detailed feasibility studies associated with the chosen resource portfolio/expansion path would be conducted to further evaluate siting issues. Leidos has provided additional support related to the capital cost estimate and siting feasibility associated with the onshore LNG infrastructure solution, which is subject to further study and refinement. Leidos has also preliminarily provided review of potential PV sites, but this IRP is predicated upon the modeling of a range of generic PV options.
4. The relationships posited by the econometric models developed to forecast long term load growth have been assumed to perpetuate into the Study Period.
5. The capital and operating costs associated with the resource options considered in this IRP have been subjected to review by Leidos subject matter experts. The values derived for purposes of this IRP assume no significant changes in the electric utility industry through the end of the Study Period other than those assumed and set forth in this IRP. Due to uncertainties caused by variable factors, including factors that influence the cost of all energy sources, we can give no assurance either as to the reasonableness of the rates of escalation with respect to fuel costs and operating costs. Additionally, changes in costs, technology, legislation and regulation could affect the considerations and assumptions herein, and it is possible that actual construction estimates for options that are selected for deployment will differ from those assumed herein. In particular, future fuel cost and environmental factors could affect the assumptions underpinning this analysis. In summary, any changes in costs, technology, legislation and regulation could affect the considerations and assumptions, which could impact the results of the analysis summarized herein.

6. DSM assumptions regarding consumer uptake for distributed PV (both commercial and residential), as well as the residential solar thermal program, were based entirely on non-firm estimates of uptake provided by an independent third party. Further analysis regarding market demand for these types of deployments, as well as alternative economic incentive models, should be the subject of downstream feasibility studies associated with implementation of one or more of such resource options.
7. The Base-Case analysis presented herein assumes no carbon tax in Bermuda during the Study Period.
8. Leidos has not reviewed the necessary permits or other compliance requirements involved in construction of any of the supply-side resource options analyzed herein; we have assumed that all permits will be procured in a timely manner consistent with the anticipated online date assumed for each individual resource option.

TD&R 2018-2037 Load Forecast: Base Case Excluding EE, EV

Historical and Projected Annual Energy for Load and System Peak Demand

(Years 2010-2037)

		Energy for Load					System Peak Demand					
	Year	Actual (MWh)	Percent Change	Wthr Norm (MWh)	Percent Change	Wthr Norm Impact	Actual (MW)	Percent Change	Load Factor	Wthr Norm (MW)	Percent Change	Wthr Norm Impact
Historical	2010	730,224		724,600		-0.8%	122.8		67.9%	123.3		0.4%
	2011	716,784	-1.8%	711,982	-1.7%	-0.7%	118.2	-3.7%	69.2%	116.2	-5.7%	-1.6%
	2012	688,179	-4.0%	691,902	-2.8%	0.5%	113.7	-3.8%	68.9%	111.6	-4.0%	-1.8%
	2013	665,204	-3.3%	669,289	-3.3%	0.6%	110.1	-3.2%	69.0%	108.6	-2.7%	-1.4%
	2014	648,863	-2.5%	651,471	-2.7%	0.4%	106.8	-3.0%	69.4%	108.8	0.2%	1.9%
	2015	662,307	2.1%	652,385	0.1%	-1.5%	108.0	1.1%	70.0%	105.2	-3.3%	-2.6%
	2016	641,965	-3.1%	635,866	-2.5%	-1.0%	110.6	2.4%	66.1%	107.9	2.5%	-2.5%
	2017	634,628	-1.1%	625,603	-1.6%	-1.4%	110.7	0.1%	65.4%	108.1	0.2%	-2.4%
Projected	2018*	626,474	-1.3%				107.2	-3.2%	66.7%			
	2019	626,173	0.0%				107.1	0.0%	66.7%			
	2020	627,126	0.2%				107.3	0.2%	66.7%			
	2021	628,079	0.2%				107.5	0.2%	66.7%			
	2022	629,034	0.2%				107.6	0.2%	66.7%			
	2023	629,991	0.2%				107.8	0.2%	66.7%			
	2024	630,949	0.2%				108.0	0.2%	66.7%			
	2025	631,908	0.2%				108.1	0.2%	66.7%			
	2026	632,869	0.2%				108.3	0.2%	66.7%			
	2027	633,831	0.2%				108.5	0.2%	66.7%			
	2028	634,795	0.2%				108.6	0.2%	66.7%			
	2029	635,760	0.2%				108.8	0.2%	66.7%			
	2030	636,727	0.2%				109.0	0.2%	66.7%			
	2031	637,695	0.2%				109.1	0.2%	66.7%			
	2032	638,665	0.2%				109.3	0.2%	66.7%			
	2033	639,636	0.2%				109.5	0.2%	66.7%			
	2034	640,608	0.2%				109.6	0.2%	66.7%			
	2035	641,582	0.2%				109.8	0.2%	66.7%			
	2036	642,558	0.2%				110.0	0.2%	66.7%			
	2037	643,535	0.2%				110.1	0.2%	66.7%			
AAGR	2010-2017		-2.0%					-1.5%	68.2%			
	2018-2027		0.1%					0.1%	66.7%			
	2028-2037		0.2%					0.2%	66.7%			

* Values for 2018 are based on the BELCO Budget Forecast.

TD&R 2018-2037 Load Forecast: Base Case Including EE, EV

Historical and Projected Annual Energy for Load and System Peak Demand

(Years 2010-2037)

	Year	Energy for Load				System Peak Demand			
		Base Energy (MWh)	EE (MWh)	EV (MWh)	Net Energy (MWh)	Base Demand (MW)	EE (MW)	EV (MW)	Net Demand (MW)
Historical	2010	730,224				122.8			
	2011	716,784				118.2			
	2012	688,179				113.7			
	2013	665,204				110.1			
	2014	648,863				106.8			
	2015	662,307				108.0			
	2016	641,965				110.6			
	2017	634,628				110.7			
Projected	2018*	626,474	(2,111)	46	624,409	107.2	(0.4)	0.0	106.8
	2019	626,173	(4,503)	115	621,785	107.1	(0.8)	0.0	106.4
	2020	627,126	(9,605)	195	617,716	107.3	(1.6)	0.0	105.7
	2021	628,079	(10,703)	281	617,657	107.5	(1.8)	0.0	105.6
	2022	629,034	(11,926)	418	617,526	107.6	(2.0)	0.0	105.6
	2023	629,991	(13,289)	602	617,304	107.8	(2.3)	0.0	105.5
	2024	630,949	(14,807)	831	616,973	108.0	(2.5)	0.0	105.4
	2025	631,908	(16,500)	1,106	616,514	108.1	(2.8)	0.0	105.3
	2026	632,869	(18,385)	1,534	616,018	108.3	(3.1)	0.0	105.1
	2027	633,831	(20,486)	2,116	615,461	108.5	(3.5)	0.0	105.0
	2028	634,795	(22,099)	2,852	615,548	108.6	(3.8)	0.0	104.8
	2029	635,760	(23,838)	3,741	615,663	108.8	(4.1)	0.0	104.7
	2030	636,727	(25,713)	4,783	615,797	109.0	(4.4)	0.0	104.6
	2031	637,695	(27,737)	5,979	615,937	109.1	(4.7)	0.0	104.4
	2032	638,665	(29,920)	7,216	615,961	109.3	(5.1)	0.0	104.2
	2033	639,636	(32,274)	8,477	615,839	109.5	(5.5)	0.0	103.9
	2034	640,608	(34,814)	9,737	615,531	109.6	(6.0)	0.0	103.7
	2035	641,582	(37,553)	10,997	615,026	109.8	(6.4)	0.0	103.4
	2036	642,558	(40,509)	12,257	614,306	110.0	(6.9)	0.0	103.0
	2037	643,535	(43,696)	13,517	613,356	110.1	(7.5)	0.0	102.6
AAGR	2010-2017	-2.0%			-2.0%	-1.5%			-1.5%
	2018-2027	0.1%			-0.2%	0.1%			-0.2%
	2028-2037	0.2%			0.0%	0.2%			-0.2%

* Values for 2018 are based on the BELCO Budget Forecast.

Plant Name Unit No	Units	E1	E2	E3	E4	E5	E6
Prime Mover (see below)		IC-SSD	IC-SSD	IC-MSD	IC-MSD	IC-MSD	IC-MSD
Primary Fuel Type (see below)		Oil-H (HFO)	Oil-H (HFO)	Oil-H (HFO)	Oil-H (HFO)	Oil-H (HFO)	Oil-H (HFO)
Secondary Fuel Type		Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)
Propane conversion possible		N	N	N	N	N	N
Natural gas conversion possible		N	N	N	N	Y	Y
Unit Status (see below)		OP	OP	OP	OP	OP	OP
Commercial In-Service Date		7/1/1984	3/1/1985	11/1/1989	9/1/1989	4/1/2000	4/1/2000
Hours Run (as of Feb 2013)		200,602	187,001	159,585	156,461	97,359	96,360
Planned Retirement Date After Peak of Year		2019	2019	2019	2019	2030	2030
Must Run?	Y/N	Y	Y	N	N	N	N
Cogen?	Y/N	N	N	N	N	N	N
Minimum Load Net Capability							
Summer / Winter	MW	8.00	8.00	5.00	5.00	7.00	7.00
Full-Load Net Capability							
Max Rating	MW	12.20	11.20	10.10	9.50	14.30	14.30
%'age of time at rating (2012)							
4 - 5	MW						
5 - 6	MW				1.7%		
6 - 7	MW			5.1%	0.0%		
7 - 8	MW			37.3%	0.0%		
8 - 9	MW			0.5%	6.6%		
9 - 10	MW	2.5%		14.0%	91.6%		1.3%
10 - 11	MW	0.0%	6.0%	42.9%			0.1%
11 - 12	MW	94.3%	93.4%			10.5%	7.6%
12 - 13	MW	3.1%				24.7%	1.8%
13-14	MW					10.5%	2.3%
>14	MW					53.8%	86.4%
Average Net Heat Rate at Max Rating	Btu/kWh	8,984	9,070	8,521	8,336	8,156	8,132
Average Net Heat Rate at Min Rating	Btu/kWh	8,984	9,070	8,737	9,162	8,718	8,711
Incremental Heat Rate at Max Rating	Btu/kWh						
Emission Rates (after control):							
SO2 Emission Rate	lbs/MMBtu	4.66	4.66	4.76	4.76	5.70	5.70
NOx Emission Rate	lbs/MMBtu	9.00	9.00	9.19	9.19	10.35	10.35
CO2 Emission Rate	lbs/MMBtu	173.72	173.72	173.72	173.72	173.72	173.72
O&M Costs:							
Variable O&M (w/o Emiss or Start Costs)	$/MWh	17.88	15.16	17.51	16.91	9.08	12.30
Fixed O&M	$/kW-month	2.00	2.00	1.50	1.50	1.50	1.50
Fixed O&M	$/kW-yr	24.00	24.00	18.00	18.00	18.00	18.00
Startup:							
Startup Maint. & Labor	$/start	n/a	n/a	n/a	n/a	n/a	n/a
Start Fuel	MMBtu/start	n/a	n/a	n/a	n/a	n/a	n/a
Typical Operation	hours/start	n/a	n/a	n/a	n/a	n/a	n/a
Debt Service							
Existing Debt Service	$/kW-yr	n/a	n/a	n/a	n/a	n/a	n/a
Net Book Value		0	0	0	0	6,389,509	6,389,509
Final Depreciation Date		2004	2004	2009	2009	2029	2029
Years of Debt Service Remaining (2014 on)	Years	0	0	0	0	15	15
Transmission/Distribution Costs	$/kW-yr						
Actual Availability:							
2011		81.7%	87.5%	89.8%	94.2%	93.2%	83.3%
2012		76.4%	83.4%	79.5%	89.0%	86.9%	82.8%
2013		77.7%	76.4%	94.1%	92.1%	81.6%	88.4%
2014		83.4%	76.0%	78.2%	67.5%	88.4%	82.9%
2015		73.6%	85.5%	88.1%	85.8%	80.8%	84.9%
2016		84.1%	77.0%	73.3%	77.3%	87.1%	80.5%
2017 YTD		76.8%	82.2%	58.1%	93.4%	79.2%	91.9%
Planned Availability (i.e. planned scheduled maintenance outage time)							
2011		92.6%	94.3%	94.0%	96.4%	96.2%	94.3%
2012		88.8%	91.5%	98.4%	96.4%	92.6%	91.8%
2013		91.0%	84.7%	98.1%	98.1%	91.5%	95.3%
2014		93.4%	91.8%	93.2%	95.1%	95.6%	95.1%
2015		84.7%	92.3%	97.8%	95.6%	91.5%	96.7%
2016		92.3%	83.3%	94.0%	89.6%	94.3%	89.1%
2017 YTD		86.1%	89.8%	89.8%	96.4%	89.8%	96.4%
Scheduled Maintenance Period/Description		Every 3,000 hours	Every 3,000 hours	Every 4,500 hours	Every 4,500 hours	Every 3,000 hours	Every 3,000 hours
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)		12,000 hours	12,000 hours	13,500 hours	13,500 hours	12,000 hours	12,000 hours

Plant Name / Unit No	Units	E7	E8	D3	D8	D10	D14
Prime Mover (see below)		IC-MSD	IC-MSD	IC-MSD	IC-MSD	IC-MSD	IC-MSD
Primary Fuel Type (see below)		Oil-H (HFO)	Oil-H (HFO)	Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)
Secondary Fuel Type		Oil-L (LFO)	Oil-L (LFO)	n/a	n/a	n/a	n/a
Propane conversion possible		N	N	N	N	N	N
Natural gas conversion possible		Y	Y	Y	Y	Y	Y
Unit Status (see below)		OP	OP	OP	OP	OP	OP
Commercial In-Service Date		4/1/2005	4/1/2005	12/1/1982	11/1/1979	2/1/1980	11/1/1995
Hours Run (as of Feb 2013)		55,316	60,203	190,098	198,204	199,732	48,573
Planned Retirement Date After Peak of Year		2035	2035	2019	2019	2019	2019
Must Run?	Y/N	N	N	N	N	N	N
Cogen?	Y/N	N	N	N	N	N	N
Minimum Load Net Capability							
Summer / Winter	MW	7.00	7.00	4.00	4.00	4.00	3.00
Full-Load Net Capability							
Max Rating	MW	14.30	14.30	7.00	7.00	7.00	4.50
%'age of time at rating (2012)							
4 - 5	MW					62.2%	100.0%
5 - 6	MW			10.3%	13.4%	32.6%	
6 - 7	MW			65.2%	1.0%	0.0%	
7 - 8	MW			24.5%	85.6%	5.2%	
8 - 9	MW	0.6%					
9 - 10	MW	3.5%					
10 - 11	MW	0.0%					
11 - 12	MW	0.4%					
12 - 13	MW	0.3%	9.4%				
13-14	MW	6.6%	0.0%				
>14	MW	88.7%	90.6%				
Average Net Heat Rate at Max Rating	Btu/kWh	7,948	7,900	9,364	9,028	9,072	9,645
Average Net Heat Rate at Min Rating	Btu/kWh	8,420	8,200	9,790	9,197	9,346	9,906
Incremental Heat Rate at Max Rating	Btu/kWh						
Emission Rates (after control):							
SO2 Emission Rate	lbs/MMBtu	5.51	5.51	6.41	6.41	6.41	6.17
NOx Emission Rate	lbs/MMBtu	10.00	10.00	11.62	11.62	11.62	11.20
CO2 Emission Rate	lbs/MMBtu	173.72	173.72	161.27	161.27	161.27	161.27
O&M Costs:							
Variable O&M (w/o Emiss or Start Costs)	$/MWh	11.47	10.96	14.60	18.16	16.73	27.91
Fixed O&M	$/kW-month	1.50	1.50	1.50	1.50	1.50	1.50
Fixed O&M	$/kW-yr	18.00	18.00	18.00	18.00	18.00	18.00
Startup:							
Startup Maint. & Labor	$/start	n/a	n/a	n/a	n/a	n/a	n/a
Start Fuel	MMBtu/start	n/a	n/a	n/a	n/a	n/a	n/a
Typical Operation	hours/start	n/a	n/a	n/a	n/a	n/a	n/a
Debt Service							
Existing Debt Service	$/kW-yr	n/a	n/a	n/a	n/a	n/a	n/a
Net Book Value		3,157,628	3,157,628	0	0	0	1,424,465
Final Depreciation Date		2035	2035	1999	1999	1999	2020
Years of Debt Service Remaining (2014 on)	Years	21	21	0	0	0	6
Transmission/Distribution Costs	$/kW-yr						
Actual Availability:							
2011		85.7%	90.8%	94.4%	83.4%	95.9%	93.0%
2012		79.3%	76.2%	94.2%	81.4%	90.8%	79.5%
2013		88.8%	76.4%	85.7%	76.3%	81.6%	69.6%
2014		81.5%	80.4%	97.1%	95.0%	79.5%	50.5%
2015		89.2%	91.8%	83.0%	87.2%	82.5%	79.4%
2016		90.8%	85.7%	83.0%	87.2%	82.5%	79.4%
2017 YTD		78.9%	89.5%	90.6%	74.5%	97.7%	87.7%
Planned Availability (i.e. planned scheduled maintenance outage time)							
2011		93.7%	93.4%	96.2%	98.1%	98.1%	98.1%
2012		95.6%	94.0%	96.4%	96.2%	97.5%	97.8%
2013		95.3%	94.2%	98.9%	94.2%	95.3%	100.0%
2014		92.6%	90.1%	100.0%	98.4%	87.6%	100.0%
2015		94.0%	96.7%	98.4%	98.4%	88.8%	96.2%
2016		95.4%	89.9%	100.0%	98.4%	87.6%	100.0%
2017 YTD		87.2%	92.3%	96.0%	100.0%	100.0%	96.4%
Scheduled Maintenance Period/Description		Every 3,000 hours	Every 3,000 hours	Every 4,500 hours	Every 4,500 hours	Every 4,500 hours	Every 4,000 hours
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)		18,000 hours	18,000 hours	18,000 hours	18,000 hours	18,000 hours	16,000 hours

Plant Name Unit No		Units	GT6	GT7	GT8	GT4	GT5
Prime Mover (see below)			GT	GT	GT	GT	GT
Primary Fuel Type (see below)			Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)	Oil-L (LFO)
Secondary Fuel Type			n/a	n/a	n/a	n/a	n/a
Propane conversion possible			Y	Y	Y	N	Y
Natural gas conversion possible			Y	Y	Y	Y	Y
Unit Status (see below)			OP	OP	OP	OP	OP
Commercial In-Service Date			6/1/2010	6/1/2010	6/1/2010	7/1/1989	9/1/1995
Hours Run (as of Feb 2013)			1,523	1,774	1,590	51,117	31,250
Planned Retirement Date After Peak of Year			2040	2040	2040	2018	2025
Must Run?		Y/N	N	N	N	N	N
Cogen?		Y/N	N	N	N	N	N
Minimum Load Net Capability							
Summer / Winter		MW					
Full-Load Net Capability							
Max Rating		MW	4.50	4.50	4.50	11.00	13.00
%'age of time at rating (2012)							
	4 - 5	MW	100.0%	100.0%	100.0%		
	5 - 6	MW					
	6 - 7	MW					
	7 - 8	MW					
	8 - 9	MW					
	9 - 10	MW					
	10 - 11	MW					
	11 - 12	MW				100.0%	
	12 - 13	MW					
	13-14	MW					100.0%
	>14	MW					
Average Net Heat Rate at Max Rating		Btu/kWh	11,400	11,400	11,400	11,899	11,315
Average Net Heat Rate at Min Rating		Btu/kWh					
Incremental Heat Rate at Max Rating		Btu/kWh					
Emission Rates (after control):							
SO2 Emission Rate		lbs/MMBtu	0.87	0.87	0.87	0.91	0.91
NOx Emission Rate		lbs/MMBtu	0.11	0.11	0.11	0.12	0.12
CO2 Emission Rate		lbs/MMBtu	161.27	161.27	161.27	161.27	161.27
O&M Costs:							
Variable O&M (w/o Emiss or Start Costs)		$/MWh	47.00	39.69	66.22	75.59	55.40
Fixed O&M		$/kW-month	0.80	0.80	0.80	1.70	1.70
Fixed O&M		$/kW-yr	9.60	9.60	9.60	20.40	20.40
Startup:							
Startup Maint. & Labor		$/start	n/a	n/a	n/a	n/a	n/a
Start Fuel		MMBtu/start	n/a	n/a	n/a	n/a	n/a
Typical Operation		hours/start	n/a	n/a	n/a	n/a	n/a
Debt Service							
Existing Debt Service		$/kW-yr	n/a	n/a	n/a	n/a	n/a
Net Book Value			4,482,007	4,482,007	4,482,007	0	1,251,104
Final Depreciation Date			2035	2035	2035	2010	2016
Years of Debt Service Remaining (2014 on)		Years	21	21	21	0	0
Transmission/Distribution Costs		$/kW-yr					
Actual Availability:							
	2011		83.3%	99.0%	95.5%	91.9%	99.6%
	2012		66.6%	97.1%	97.2%	99.8%	99.0%
	2013		91.1%	95.3%	96.8%	88.5%	39.6%
	2014		77.0%	85.5%	81.1%	28.5%	58.7%
	2015		70.7%	95.3%	71.4%	89.2%	79.3%
	2016		94.0%	91.5%	94.4%	62.3%	82.9%
	2017 YTD		98.3%	99.3%	99.2%	77.7%	65.8%
Planned Availability (i.e. planned scheduled maintenance outage time)							
	2011						
	2012						
	2013		99.5%	99.5%	99.5%	100.0%	98.6%
	2014		98.1%	99.5%	99.5%	86.6%	58.9%
	2015		99.5%	99.5%	99.5%	99.6%	99.6%
	2016		98.4%	98.4%	98.4%	100.0%	91.3%
	2017 YTD		100.0%	100.0%	100.0%	100.0%	86.1%
Scheduled Maintenance Period/Description			Twice a year	Twice a year	Twice a year	Dependent on number of starts ~Every year	Dependent on number of starts ~Every year
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)							

Existing Unit No Candidate Resource	Units	PS-1a	PS-1b	PS-1c	PS-2a
Prime Mover (see below)		IC-MSD New - 1 unit	IC-MSD New - 1 unit	IC-MSD New - 1 unit	GT New
Make		MAN B&W	MAN B&W	MAN B&W	Solar
Model		51/60	51/60DF	51/60DF	Titan 130
Primary Fuel Type (see below)		Oil-H	Oil-H (HFO)	NG	Oil-L (LFO)
Commercial In-Service Date [2]		Jan-20	Jan-20	Jan-22	Jan-20
Planned Retirement Date		Jan-50	Jan-50	Jan-52	Jan-50
Must Run?	Y/N				
Cogen?	Y/N				
Minimum Load Net Capability					
Summer / Winter	kW	7,200	7,200	7,200	9,400
Full-Load Net Capability					
Max Gross Rating	kW	14,400	14,400	14,400	13,000
% Auxiliary Loads	%	2.5%	2.5%	2.5%	1.5%
Max Net Rating (net of auxiliary loads)	kW	14,000	14,000	14,000	12,800
Average Net Heat Rate at Max Rating	btu/kWh	8,500	8,300	8,500	11,100
Average Net Heat Rate at Min Rating	btu/kWh	8,600	8,500	9,300	14,900
Minimum Up Time	Hours	6.00	6.00	6.00	none
Minimum Down Time	Hours	none	none	none	none
Ramp-Up Rate	MW/min	1.75	1.75	1.75	4.80
Ramp-Down Rate	MW/min	1.75	1.75	1.75	4.80
Emission Rates (after control):					
SO2 Emission Rate	lbs/mmBtu	2.12	2.12	0.04	0.79
NOx Emission Rate	lbs/mmBtu	3.79	3.79	0.71	8.10
CO2 Emission Rate	lbs/mmBtu	173.72	173.72	116.98	161.27
O&M Costs:					
Variable O&M (w/o Emiss or Start Costs)	$/MWh	11.516	11.516	11.516	0.000
Fixed O&M	$/kW-month	1.57	1.57	1.57	1.66
Fixed O&M	$/kW-yr	18.845	18.845	18.845	19.892
Startup:					
Startup Maint. & Labor	$/start	N/A	N/A	N/A	N/A
Start Fuel	MMBtu/start	N/A	N/A	N/A	N/A
Typical Operation	hours/start	N/A	N/A	N/A	N/A
Capital Cost					
EPC Cost (exclusive of IDC; NO Owner's Costs, non fuel)	$/kW	1,680	1,800	1,800	1,140
Owner's Cost	%	10%	10%	10%	10%
All In Capital Cost (inclusive of IDC; non fuel)	$/kW	1,850	1,980	1,980	1,250
Transmission/Distribution Costs	$/kW				
Transmission/Distribution Costs	$				
Availability:		90.0%	90.0%	90.0%	95.0%
Annual Forced Outage Rate	%	4.0%	4.0%	4.0%	3.0%
Scheduled Maintenance Period/Description		Every 3,000 hours	Every 3,000 hours	Every 3,000 hours	2 outages per year + 30K Major
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)					
Coincidence Peak Factor	%				
Degradation Factor	%/yr				
Major Maintenance Capital Cost	$				
Capacity Factor	%				
Emissions Factor	%				
Notes:					

1. Values reported are on an AC basis.
2. Assumes decision to move forward Q4 2018.

Existing Unit No Candidate Resource	Units	PS-2b	PS-2c	PS-3a	PS-3b
Prime Mover (see below)		GT New	GT New	CC (1x1) New - 1 unit	CC (1x1) New - 1 unit
Make		Solar	Solar	Solar	Solar
Model		Titan 130	Titan 130	Titan 130	Titan 130
Primary Fuel Type (see below)		LPG	NG	Oil-L (LFO)	LPG Bulk
Commercial In-Service Date [2]		Earliest	Jan-22	Jan-20	Earliest
Planned Retirement Date		+30 yrs	Jan-52	Jan-50	+30 yrs
Must Run?	Y/N				
Cogen?	Y/N				
Minimum Load Net Capability					
Summer / Winter	kW	9,400	9,400	11,600	12,700
Full-Load Net Capability					
Max Gross Rating	kW	13,000	13,000	16,800	16,800
% Auxiliary Loads	%	1.5%	1.5%	3.5%	3.5%
Max Net Rating (net of auxiliary loads)	kW	12,800	12,800	16,200	16,200
Average Net Heat Rate at Max Rating	btu/kWh	11,500	11,500	8,900	9,300
Average Net Heat Rate at Min Rating	btu/kWh	15,400	15,400	11,000	11,400
Minimum Up Time	Hours	none	none	6.00	none
Minimum Down Time	Hours	none	none	none	none
Ramp-Up Rate	MW/min	4.80	4.80	4.80	4.8
Ramp-Down Rate	MW/min	4.80	4.80	4.80	4.8
Emission Rates (after control):					
SO2 Emission Rate	lbs/mmBtu	0.29	0.29	0.57	0.21
NOx Emission Rate	lbs/mmBtu	2.99	2.99	5.86	2.17
CO2 Emission Rate	lbs/mmBtu	139.05	116.98	161.27	139.05
O&M Costs:					
Variable O&M (w/o Emiss or Start Costs)	$/MWh	0.000	0.000	3.141	3.141
Fixed O&M	$/kW-month	1.66	1.66	7.26	7.26
Fixed O&M	$/kW-yr	19.892	19.892	87.062	87.062
Startup:					
Startup Maint. & Labor	$/start	N/A	N/A	N/A	N/A
Start Fuel	MMBtu/start	N/A	N/A	N/A	N/A
Typical Operation	hours/start	N/A	N/A	N/A	N/A
Capital Cost					
EPC Cost (exclusive of IDC; NO Owner's Costs, non fuel)	$/kW	1,140	1,140	1,590	1,590
Owner's Cost	%	10%	10%	10%	10%
All In Capital Cost (inclusive of IDC; non fuel)	$/kW	1,250	1,250	1,750	1,750
Transmission/Distribution Costs	$/kW				
Transmission/Distribution Costs	$				
Availability:		95%	95.0%	90.0%	90.0%
Annual Forced Outage Rate	%	3%	3.0%	5.0%	5.0%
Scheduled Maintenance Period/Description		2 outages per year + 30K Major	2 outages per year + 30K Major	2 outages per year + 30K Major	2 outages per year + 30K Major
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)					
Coincidence Peak Factor	%				
Degradation Factor	%/yr				
Major Maintenance Capital Cost	$				
Capacity Factor	%				
Emissions Factor	%				
Notes:					

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Existing Unit No Candidate Resource	Units	PS-3c	PS-4 a[1]	PS-4 b[1]	PS-5
Prime Mover (see below)		CC (1x1) New - 1 unit	SL Utility (PPA)	SL Utility (PPA)	WT
Make		Solar	Finger	Other	
Model		Titan 130	Ph I & Ph II	Up to 6MWac	
Primary Fuel Type (see below)		NG	SOL	SOL	WND
Commercial In-Service Date [2]		Jan-22	Apr-19	Apr-19	Jun-22
Planned Retirement Date		Jan-52	Mar-44	Mar-44	Jun-42
Must Run?	Y/N				
Cogen?	Y/N				
Minimum Load Net Capability					
Summer / Winter	kW	11,600			
Full-Load Net Capability					
Max Gross Rating	kW	16,800	6,000	6,000	36,000
% Auxiliary Loads	%	3.5%			
Max Net Rating (net of auxiliary loads)	kW	16,200	6,000	6,000	36,000
Average Net Heat Rate at Max Rating	btu/kWh	9,300			
Average Net Heat Rate at Min Rating	btu/kWh	11,400			
Minimum Up Time	Hours	6.00			
Minimum Down Time	Hours	none			
Ramp-Up Rate	MW/min	4.80			
Ramp-Down Rate	MW/min	4.80			
Emission Rates (after control):					
SO2 Emission Rate	lbs/mmBtu	0.21	none	none	none
NOx Emission Rate	lbs/mmBtu	2.17	none	none	none
CO2 Emission Rate	lbs/mmBtu	116.98	none	none	none
O&M Costs:					
Variable O&M (w/o Emiss or Start Costs)	$/MWh	3.141	170.000	250.000	
Fixed O&M	$/kW-month	7.26	0.00	0.00	10.47
Fixed O&M	$/kW-yr	87.062			125.631
Startup:					
Startup Maint. & Labor	$/start	N/A	N/A	N/A	N/A
Start Fuel	MMBtu/start	N/A	N/A	N/A	N/A
Typical Operation	hours/start	N/A	N/A	N/A	N/A
Capital Cost					
EPC Cost (exclusive of IDC; NO Owner's Costs, non fuel)	$/kW	1,590			7,270
Owner's Cost	%	10%			8%
All In Capital Cost (inclusive of IDC; non fuel)	$/kW	1,750	0	0	7,820
Transmission/Distribution Costs	$/kW			250	767
Transmission/Distribution Costs	$			1,500,000	27,600,000
Availability:		90.0%	99.0%	99.0%	95.0%
Annual Forced Outage Rate	%	5.0%	1.0%	1.0%	3.0%
Scheduled Maintenance Period/Description		2 outages per year + 30K Major			2 outages per year
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)					
Coincidence Peak Factor	%		60.0%	60.0%	
Degradation Factor	%/yr		0.8%	0.8%	
Major Maintenance Capital Cost	$				
Capacity Factor	%				35.0%
Emissions Factor	%				
Notes:					

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2. Assumes decision to move forward Q4 2018.

Existing Unit No Candidate Resource	Units	PS-6 [1]	E5 PS-7a	E6 PS-7b	E7 PS-7c
Prime Mover (see below)		BY SpinRes Backup	IC-MSD Refuel	IC-MSD Refuel	IC-MSD Refuel
Make		anciliary services	MAN B&W	MAN B&W	MAN B&W
Model		Lithium	48/60 A	48/60 A	48/60 B
Primary Fuel Type (see below)		OTH	NG	NG	NG
Commercial In-Service Date [2]		Nov-18	Jan-22	Jan-22	Jan-22
Planned Retirement Date		Nov-38	Jan-31	Jan-31	Jan-36
Must Run?	Y/N				
Cogen?	Y/N				
Minimum Load Net Capability					
Summer / Winter	kW		7,000	7,000	7,000
Full-Load Net Capability					
Max Gross Rating	kW	10MW@30min	13,700	13,700	14,400
% Auxiliary Loads	%		2.5%	2.5%	2.5%
Max Net Rating (net of auxiliary loads)	kW	10MW@30min	13,400	13,400	14,000
Average Net Heat Rate at Max Rating	btu/kWh		8,900	8,900	8,600
Average Net Heat Rate at Min Rating	btu/kWh		9,400	9,400	9,100
Minimum Up Time	Hours	none	6.00	6.00	6.00
Minimum Down Time	Hours	none	none	none	none
Ramp-Up Rate	MW/min	none	1.75	1.75	1.75
Ramp-Down Rate	MW/min	none	1.75	1.75	1.75
Emission Rates (after control):					
SO2 Emission Rate	lbs/mmBtu	none	0.03	0.03	0.04
NOx Emission Rate	lbs/mmBtu	none	0.67	0.67	0.71
CO2 Emission Rate	lbs/mmBtu	none	116.98	116.98	116.98
O&M Costs:					
Variable O&M (w/o Emiss or Start Costs)	$/MWh		11.516	11.516	11.516
Fixed O&M	$/kW-month	2.32	1.57	1.57	1.57
Fixed O&M	$/kW-yr	27.891	18.845	18.845	18.845
Startup:					
Startup Maint. & Labor	$/start	N/A	N/A	N/A	N/A
Start Fuel	MMBtu/start	N/A	N/A	N/A	N/A
Typical Operation	hours/start	N/A	N/A	N/A	N/A
Capital Cost					
EPC Cost (exclusive of IDC; NO Owner's Costs, non fuel)	$/kW	700	360	360	360
Owner's Cost	%	8%	10%	10%	10%
All In Capital Cost (inclusive of IDC; non fuel)	$/kW	760	400	400	400
Transmission/Distribution Costs	$/kW				
Transmission/Distribution Costs	$				
Availability:		98.0%	90.0%	90.0%	90.0%
Annual Forced Outage Rate	%	1.0%	4.0%	4.0%	4.0%
Scheduled Maintenance Period/Description			Every 3,000 hours	Every 3,000 hours	Every 3,000 hours
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)		Capacity replenish at year 10. Inverter major maintenance at year 10			
Coincidence Peak Factor	%				
Degradation Factor	%/yr				
Major Maintenance Capital Cost	$	1,755,519			
Capacity Factor	%				
Emissions Factor	%				
Notes:					

1. Values reported are on an AC basis.
2. Assumes decision to move forward Q4 2018.

Existing Unit No Candidate Resource	Units	E8 PS-7d	GT6 PS-8a	GT7 PS-8b	GT8 PS-8c
Prime Mover (see below)		IC-MSD Refuel	GT Refuel	GT Refuel	GT Refuel
Make		MAN B&W	Centrax (Rolls Royce)	Centrax (Rolls Royce)	Centrax (Rolls Royce)
Model		48/60 B	501-KB7	501-KB7	501-KB7
Primary Fuel Type (see below)		NG	LPG delivered	LPG delivered	LPG delivered
Commercial In-Service Date [2]		Jan-22	Earliest	Earliest	Earliest
Planned Retirement Date		Jan-36	+30 yrs	+30 yrs	+30 yrs
Must Run?	Y/N				
Cogen?	Y/N				
Minimum Load Net Capability					
Summer / Winter	kW	7,000	2,600	2,600	2,600
Full-Load Net Capability					
Max Gross Rating	kW	14,400	5,300	5,300	5,300
% Auxiliary Loads	%	2.5%	1.5%	1.5%	1.5%
Max Net Rating (net of auxiliary loads)	kW	14,000	5,200	5,200	5,200
Average Net Heat Rate at Max Rating	btu/kWh	8,600	11,700	11,700	11,700
Average Net Heat Rate at Min Rating	btu/kWh	9,100	15,600	15,600	15,600
Minimum Up Time	Hours	6.00	6.0	6.0	6.0
Minimum Down Time	Hours	none	none	none	none
Ramp-Up Rate	MW/min	1.75			
Ramp-Down Rate	MW/min	1.75			
Emission Rates (after control):					
SO2 Emission Rate	lbs/mmBtu	0.04	4.57	4.57	4.57
NOx Emission Rate	lbs/mmBtu	0.71	0.01	0.01	0.01
CO2 Emission Rate	lbs/mmBtu	116.98	139.05	139.05	139.05
O&M Costs:					
Variable O&M (w/o Emiss or Start Costs)	$/MWh	11.516	8.166	8.166	8.166
Fixed O&M	$/kW-month	1.57	0.84	0.84	0.84
Fixed O&M	$/kW-yr	18.845	10.050	10.050	10.050
Startup:					
Startup Maint. & Labor	$/start	N/A	N/A	N/A	N/A
Start Fuel	MMBtu/start	N/A	N/A	N/A	N/A
Typical Operation	hours/start	N/A	N/A	N/A	N/A
Capital Cost					
EPC Cost (exclusive of IDC; NO Owner's Costs, non fuel)	$/kW	360	150	150	150
Owner's Cost	%	10%	10%	10%	10%
All In Capital Cost (inclusive of IDC; non fuel)	$/kW	400	170	170	170
Transmission/Distribution Costs	$/kW				
Transmission/Distribution Costs	$				
Availability:		90.0%	95%	95%	95%
Annual Forced Outage Rate	%	4.0%	2%	2%	2%
Scheduled Maintenance Period/Description		Every 3,000 hours	Twice a year	Twice a year	Twice a year
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)					
Coincidence Peak Factor	%				
Degradation Factor	%/yr				
Major Maintenance Capital Cost	$				
Capacity Factor	%				
Emissions Factor	%				
Notes:					

1. Values reported are on an AC basis.
2. Assumes decision to move forward Q4 2018.

Existing Unit No Candidate Resource	Units	GT5 PS-9d	GT6 PS-9a	GT7 PS-9b	GT8 PS-9c
Prime Mover (see below)		GT Refuel	GT Refuel	GT Refuel	GT Refuel
Make		ABB Stall	Centrax (Rolls Royce)	Centrax (Rolls Royce)	Centrax (Rolls Royce)
Model		GT 35	501-KB7	501-KB7	501-KB7
Primary Fuel Type (see below)		LPG delivered	NG	NG	NG
Commercial In-Service Date [2]		Earliest	Jan-22	Jan-22	Jan-22
Planned Retirement Date		+30 yrs	Jan-41	Jan-41	Jan-41
Must Run?	Y/N				
Cogen?	Y/N				
Minimum Load Net Capability					
Summer / Winter	kW	6,500	2,600	2,600	2,600
Full-Load Net Capability					
Max Gross Rating	kW	13,000	5,300	5,300	5,300
% Auxiliary Loads	%	1.5%	1.5%	1.5%	1.5%
Max Net Rating (net of auxiliary loads)	kW	12,800	5,200	5,200	5,200
Average Net Heat Rate at Max Rating	btu/kWh	11,300	11,700	11,700	11,700
Average Net Heat Rate at Min Rating	btu/kWh	15,000	15,600	15,600	15,600
Minimum Up Time	Hours	1.00	1.00	1.00	1.00
Minimum Down Time	Hours	none	none	none	none
Ramp-Up Rate	MW/min				
Ramp-Down Rate	MW/min				
Emission Rates (after control):					
SO2 Emission Rate	lbs/mmBtu	4.57	4.57	4.57	4.57
NOx Emission Rate	lbs/mmBtu	0.01	0.01	0.01	0.01
CO2 Emission Rate	lbs/mmBtu	139.05	116.98	116.98	116.98
O&M Costs:					
Variable O&M (w/o Emiss or Start Costs)	$/MWh	6.910	8.166	8.166	8.166
Fixed O&M	$/kW-month	1.78	0.84	0.84	0.84
Fixed O&M	$/kW-yr	21.357	10.050	10.050	10.050
Startup:					
Startup Maint. & Labor	$/start	N/A	N/A	N/A	N/A
Start Fuel	MMBtu/start	N/A	N/A	N/A	N/A
Typical Operation	hours/start	N/A	N/A	N/A	N/A
Capital Cost					
EPC Cost (exclusive of IDC; NO Owner's Costs, non fuel)	$/kW	150	150	150	150
Owner's Cost	%	10%	10%	10%	10%
All In Capital Cost (inclusive of IDC; non fuel)	$/kW	170	170	170	170
Transmission/Distribution Costs	$/kW				
Transmission/Distribution Costs	$				
Availability:		95.0%	95.0%	95.0%	95.0%
Annual Forced Outage Rate	%	2.0%	2.0%	2.0%	2.0%
Scheduled Maintenance Period/Description		Dependent on number of starts ~Every year	Twice a year	Twice a year	Twice a year
Major Service at :					
(Major service planned duration ~2-3 weeks)					
(Intermediate service planned duration ~1-2 weeks)					
Coincidence Peak Factor	%				
Degradation Factor	%/yr				
Major Maintenance Capital Cost	$				
Capacity Factor	%				
Emissions Factor	%				

Notes:
1. Values reported are on an AC basis.
2. Assumes decision to move forward Q4 2018.

Existing Unit No Candidate Resource	Units	GT5 PS-9d	PS-10a
Prime Mover (see below)		GT Refuel	IC-Recip New - 4 units
Make		ABB Stall	MAN 4x
Model		GT 35	51/60 DF
Primary Fuel Type (see below)		NG	HFO
Commercial In-Service Date [2]		Jan-22	Jan-20
Planned Retirement Date		Jan-26	Jan-50
Must Run?	Y/N		
Cogen?	Y/N		
Minimum Load Net Capability			
Summer / Winter	kW	6,500	7,200
Full-Load Net Capability			
Max Gross Rating	kW	13,000	57,600
% Auxiliary Loads	%	1.5%	4.0%
Max Net Rating (net of auxiliary loads)	kW	12,800	55,300
Average Net Heat Rate at Max Rating	btu/kWh	11,300	8,300
Average Net Heat Rate at Min Rating	btu/kWh	15,000	8,500
Minimum Up Time	Hours	1.00	6.00
Minimum Down Time	Hours	none	none
Ramp-Up Rate	MW/min		1.75
Ramp-Down Rate	MW/min		1.75
Emission Rates (after control):			
SO2 Emission Rate	lbs/mmBtu	4.57	2.12
NOx Emission Rate	lbs/mmBtu	0.01	3.79
CO2 Emission Rate	lbs/mmBtu	116.98	173.72
O&M Costs:			
Variable O&M (w/o Emiss or Start Costs)	$/MWh	6.910	6.300
Fixed O&M	$/kW-month	1.78	3.01
Fixed O&M	$/kW-yr	21.357	36.166
Startup:			
Startup Maint. & Labor	$/start	N/A	N/A
Start Fuel	MMBtu/start	N/A	N/A
Typical Operation	hours/start	N/A	N/A
Capital Cost			
EPC Cost (exclusive of IDC; NO Owner's Costs, non fuel)	$/kW	150	1,700
Owner's Cost	%	10%	8%
All In Capital Cost (inclusive of IDC; non fuel)	$/kW	170	1,840
Transmission/Distribution Costs	$/kW		87
Transmission/Distribution Costs	$		5,000,000
Availability:		95.0%	94.0%
Annual Forced Outage Rate	%	2.0%	2.0%
Scheduled Maintenance Period/Description		Dependent on number of starts ~Every year	Every 1500 hours
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)			
Coincidence Peak Factor	%		
Degradation Factor	%/yr		0.0%
Major Maintenance Capital Cost	$		
Capacity Factor	%		
Emissions Factor	%		
Notes:			

1. Values reported are on an AC basis.
2. Assumes decision to move forward Q4 2018.

Plant Name **Unit No**	**Units**	**DSM-1a [1]**	**DSM-1b [1]**	**DSM-2b**	**DSM-2d**	**DSM-3a [1]**	**DSM-3b [1]**	**DSM-3c [1]**
Prime Mover (see below)		SL	SL	CCHP	CHP	SL	SL	SL
Make		Dist Elec	Dist Elec			Dist H2O	Dist H2O	Dist H2O
Model		Res	Comm			Res	Res	Res
						Base	High	Low
Primary Fuel Type (see below)		SOL		LPG Bulk	LNG Bulk	SOL	SOL	SOL
Commercial In-Service Date		Jan-18	Jan-18	Earliest	Jan-22	Jan-18	Jan-18	Jan-18
Planned Retirement Date		Jan-43	Jan-43	+30 yrs	Jun-36	Jan-38	Jan-38	Jan-38
Must Run?	Y/N							
Cogen?	Y/N							
Full-Load Net Capability								
Max Rating	kW	1.720	86.000	1,870	2,469	3.240	3.240	3.240
Electric cooling load displaced	kW			360	0			
Total Load Impact	kW			2,230	2,469			
Average Net Heat Rate at Max Rating	btu/kWh							
Average Net Heat Rate at Min Rating	btu/kWh							
Emission Rates (after control):								
SO2 Emission Rate	lbs/mmBtu			0.29	0.29			
NOx Emission Rate	lbs/mmBtu			0.12	0.90			
CO2 Emission Rate	lbs/mmBtu			381.21	376.89			
O&M Costs:								
Variable O&M (w/o Emiss or Start Costs)	$/MWh							
Fixed O&M	$/kW-month							
Fixed O&M	$/kW-yr							
Startup:								
Startup Maint. & Labor	$/start							
Start Fuel	MMBtu/start							
Typical Operation	hours/start							
Capital Cost								
EPC Cost (exclusive of IDC; NO Owner's Costs, non fuel)	$/kW							
All In Capital Cost (inclusive of IDC; non fuel)	$/kW							
Interconnection/Installation Cost (other than capital)	$/kW-yr							
Availability:		99.0%	99.0%	92.0%	93.0%	100.0%	100.0%	100.0%
Annual Forced Outage Rate	%	1.0%	1.0%	5.0%	5.0%	0.0%	0.0%	0.0%
Scheduled Maintenance Period/Description				Minor O/H @ 30k & Major @ 80k op hours	Minor O/H @ 40k op hours & Major @ 85k op hours	None	None	None
Major Service at : (Major service planned duration ~2-3 weeks) (Intermediate service planned duration ~1-2 weeks)				Minor O/H @ 30k & Major @ 80k op hours	Major service 7 days, Minor service 3 days	Replace major components in year 13	Replace major components in year 13	Replace major components in year 13
Cost of Major Maintenance (if applicable)	$							
Duration Major Maintenance (if applicable)	Hrs or Wks/Yr							
Steam byproduct								
temperature	F			250				
flow rate	lb/hr			3,500				
mmBtu/hr	MMBtu/Hr			8.000	3.434			
price	$/mmBtu							
Coincidence Peak factor	%	60.0%	60.0%			3.9%	4.3%	3.2%
Degradation Factor	%/Yr	0.8%	0.8%			1.0%	1.0%	1.0%

1. Values report are on an AC basis.

Base Case Fuel Price Projections (Includes Fuel Import Duty)

Delivered Fuel Price Projections	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case: Fuel Oil #2 (LFO - NYMEX Near Term)													
Commodity													
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	14.16	16.19	17.42	18.07	18.58	19.03	19.37	19.68	20.19	20.53	20.73	20.79
Inflation Factor	**2.00%**	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27
EIA AEO Price Forecast (Nominal $)	$/mmBtu	14.45	16.84	18.49	19.56	20.52	21.43	22.25	23.05	24.13	25.03	25.78	26.36
EIA Annual Percent Change	%	22.2%	16.6%	9.8%	5.8%	4.9%	4.5%	3.8%	3.6%	4.7%	3.7%	3.0%	2.3%
Gulf Coast USLD Platts NYMEX Near Term Strip	$/gal	1.57	1.56										
NYMEX Annual Percent Change	%	19.0%	-0.2%										
Volume Conversion	gal/bbl	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00
Gulf Coast USLD Platts NYMEX Near Term Strip	$/bbl	65.76	65.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commodity Price for IRP	$/bbl	65.76	65.64	72.07	76.24	79.97	83.53	86.73	89.85	94.05	97.55	100.46	102.74
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Commodity Price for IRP	$/mmBtu	11.10	11.08	12.16	12.86	13.49	14.09	14.63	15.16	15.87	16.46	16.95	17.33
Adders													
Through-put	$/bbl	5.39	5.50	5.61	5.72	5.84	5.96	6.07	6.20	6.32	6.45	6.58	6.71
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Through-put	$/mmBtu	0.91	0.93	0.95	0.97	0.99	1.00	1.02	1.05	1.07	1.09	1.11	1.13
Freight & Supply	$/bbl	4.94	5.04	5.14	5.24	5.35	5.45	5.56	5.67	5.79	5.90	6.02	6.14
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Freight & Supply	$/mmBtu	0.83	0.85	0.87	0.88	0.90	0.92	0.94	0.96	0.98	1.00	1.02	1.04
Duty	$/L	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Liter per Oil Barrel	L/bbl	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00
Duty	$/bbl	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Duty	$/mmBtu	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Unesco Tax	$/bbl	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Unesco Tax	$/mmBtu	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
All-In	$/mmBtu	18.27	18.29	19.41	20.15	20.81	21.45	22.03	22.60	23.34	23.97	24.51	24.93

Base Case Fuel Price Projections (Includes Fuel Import Duty)

Delivered Fuel Price Projections	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case: Fuel Oil #6 (HFO - NYMEX Near Term)													
Commodity													
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	9.12	10.18	10.56	10.60	10.47	10.24	10.60	10.88	11.26	11.57	11.74	11.79
Inflation Factor	2.00%	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27
EIA AEO Price Forecast (Nominal $)	$/mmBtu	9.30	10.59	11.21	11.48	11.56	11.53	12.18	12.75	13.46	14.10	14.60	14.95
EIA Annual Percent Change	%	16.5%	13.8%	5.9%	2.4%	0.7%	-0.3%	5.6%	4.7%	5.6%	4.8%	3.5%	2.4%
Gulf Coast No. 6 Fuel Oil 3% (MF) NYMEX Near Term Strip	$/bbl	45.07	43.75	42.65									
NYMEX Annual Percent Change	%	40.9%	-2.9%	-2.5%									
Commodity Price for IRP	$/bbl	45.07	43.75	42.65	43.66	43.98	43.87	46.34	48.51	51.21	53.66	55.53	56.89
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Commodity Price for IRP	$/mmBtu	7.17	6.96	6.78	6.95	7.00	6.98	7.37	7.72	8.15	8.53	8.83	9.05
Adders													
Through-put	$/bbl	6.79	6.93	7.07	7.21	7.35	7.50	7.65	7.80	7.96	8.12	8.28	8.45
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Through-put	$/mmBtu	1.08	1.10	1.12	1.15	1.17	1.19	1.22	1.24	1.27	1.29	1.32	1.34
Freight & Supply	$/bbl	8.20	8.36	8.53	8.70	8.88	9.05	9.23	9.42	9.61	9.80	10.00	10.20
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Freight & Supply	$/mmBtu	1.30	1.33	1.36	1.38	1.41	1.44	1.47	1.50	1.53	1.56	1.59	1.62
Duty	$/L	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Liter per Oil Barrel	L/bbl	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00
Duty	$/bbl	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Duty	$/mmBtu	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06
Unesco Tax	$/bbl	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Unesco Tax	$/mmBtu	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
All-In	$/mmBtu	14.68	14.51	14.39	14.60	14.70	14.73	15.18	15.58	16.06	16.51	16.86	17.14

TD&R 2018 IRP
Base Case Fuel Price Projections (Includes Fuel Import Duty)

Delivered Fuel Price Projections	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case: LNG - Bulk (NYMEX Henry Hub Near Term 2017-2020)													
Commodity													
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	2.99	3.41	3.92	4.48	4.43	4.37	4.40	4.48	4.51	4.58	4.61	4.72
Inflation Factor	2.00%	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27
EIA AEO Price Forecast (Nominal $)	$/mmBtu	3.05	3.54	4.16	4.85	4.89	4.92	5.05	5.25	5.39	5.58	5.73	5.98
EIA Annual Percent Change	%	22.3%	16.2%	17.3%	16.6%	0.8%	0.8%	2.6%	4.0%	2.5%	3.6%	2.7%	4.4%
Henry Hub Natural Gas (NG) NYMEX Near Term Strip	$/mmBtu	3.16	3.03	2.86	2.83								
NYMEX Annual Percent Change	%	28.4%	-4.0%	-5.7%	-1.1%								
Commodity (HH)	$/mmBtu	3.16	3.03	2.86	2.83	2.85	2.87	2.95	3.07	3.14	3.26	3.35	3.49
Adders													
Shipping + Margin	$/mmBtu	5.75	5.87	5.98	6.10	6.22	6.35	6.48	6.60	6.74	6.87	7.01	7.15
Commodity Adder	$/mmBtu	0.41	0.39	0.37	0.37	0.37	0.37	0.38	0.40	0.41	0.42	0.43	0.45
Pipeline Transportation (intended to represent mainland)	$/mmBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Infrastructure O&M Fee	$/mmBtu	0.50	0.51	0.52	0.53	0.54	0.55	0.56	0.57	0.59	0.60	0.61	0.62
Duty	%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Duty	$/mmBtu	2.33	2.32	2.30	2.32	2.36	2.40	2.45	2.52	2.57	2.64	2.70	2.77
Unesco Tax	$/liter	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025
BELCO fuel spec (HHV)	Btu/liter	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25
Unesco Tax	$/mmBtu	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
LNG Storage & Regasification Capital Cost Estimate (available 2020)													
WACC	%						8.00%						
All-In Capital Cost	$(000)						117,091						
Repayment Period	yr						20						
First Payment Year	yr						2022						
Annual Capital Cost Debt Service	$(000)	0	0	0	0	0	11,926	11,926	11,926	11,926	11,926	11,926	11,926
Annual System Energy from Forecast	MWh	634,628	624,409	621,785	617,716	617,657	617,526	617,304	616,973	616,514	616,018	615,461	615,548
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,859,912	1,829,962	1,822,274	1,810,346	1,810,175	1,809,791	1,809,139	1,808,169	1,806,825	1,805,371	1,803,739	1,803,994
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	6,346,281	6,244,088	6,217,854	6,177,156	6,176,572	6,175,262	6,173,037	6,169,726	6,165,140	6,160,178	6,154,611	6,155,479
LNG Storage & Regasification Infrastructure Cost	$/mmBtu - gas	0.00	0.00	0.00	0.00	0.00	1.93	1.93	1.93	1.93	1.94	1.94	1.94
All-In	$/mmBtu	0.00	0.00	0.00	0.00	0.00	14.59	14.87	15.21	15.50	15.84	16.15	16.54

Base Case Fuel Price Projections (Includes Fuel Import Duty)

Delivered Fuel Price Projections	**Units**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Base Case: LNG - Bulk Duty Normalized (NYMEX Henry Hub Near Term 2017-2020)													
Commodity													
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	2.99	3.41	3.92	4.48	4.43	4.37	4.40	4.48	4.51	4.58	4.61	4.72
Inflation Factor	2.00%	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27
EIA AEO Price Forecast (Nominal $)	$/mmBtu	3.05	3.54	4.16	4.85	4.89	4.92	5.05	5.25	5.39	5.58	5.73	5.98
EIA Annual Percent Change	%	22.3%	16.2%	17.3%	16.6%	0.8%	0.8%	2.6%	4.0%	2.5%	3.6%	2.7%	4.4%
Henry Hub Natural Gas (NG) NYMEX Near Term Strip	$/mmBtu	3.16	3.03	2.86	2.83								
NYMEX Annual Percent Change	%	28.4%	-4.0%	-5.7%	-1.1%								
Commodity (HH)	$/mmBtu	3.16	3.03	2.86	2.83	2.85	2.87	2.95	3.07	3.14	3.26	3.35	3.49
Adders													
Shipping + Margin	$/mmBtu	5.75	5.87	5.98	6.10	6.22	6.35	6.48	6.60	6.74	6.87	7.01	7.15
Commodity Adder	$/mmBtu	0.41	0.39	0.37	0.37	0.37	0.37	0.38	0.40	0.41	0.42	0.43	0.45
Pipeline Transportation (intended to represent mainland)	$/mmBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Infrastructure O&M Fee	$/mmBtu	0.50	0.51	0.52	0.53	0.54	0.55	0.56	0.57	0.59	0.60	0.61	0.62
Duty	%												
Duty	$/mmBtu	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Unesco Tax	$/liter	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025
BELCO fuel spec (HHV)	Btu/liter	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25
Unesco Tax	$/mmBtu	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
LNG Storage & Regasification Capital Cost Estimate (available 2020)													
WACC	%						8.00%						
All-In Capital Cost	$(000)						**117,091**						
Repayment Period	yr						20						
First Payment Year	yr						2022						
Annual Capital Cost Debt Service	$(000)	0	0	0	0	0	11,926	11,926	11,926	11,926	11,926	11,926	11,926
Annual System Energy from Forecast	MWh	634,628	624,409	621,785	617,716	617,657	617,526	617,304	616,973	616,514	616,018	615,461	615,548
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,859,912	1,829,962	1,822,274	1,810,346	1,810,175	1,809,791	1,809,139	1,808,169	1,806,825	1,805,371	1,803,739	1,803,994
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	6,346,281	6,244,088	6,217,854	6,177,156	6,176,572	6,175,262	6,173,037	6,169,726	6,165,140	6,160,178	6,154,611	6,155,479
LNG Storage & Regasification Infrastructure Cost	$/mmBtu - gas	0.00	0.00	0.00	0.00	0.00	1.93	1.93	1.93	1.93	1.94	1.94	1.94
All-In	$/mmBtu	0.00	0.00	0.00	0.00	0.00	17.56	17.78	18.06	18.29	18.57	18.82	19.14

Delivered Fuel Price Projections	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case: LPG - Bulk (OPIS Mont Belvieu 2017-2021)													
Commodity													
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	13.97	13.93	13.92	14.32	14.54	14.61	14.64	14.74	14.96	15.02	15.07	15.26
Inflation Factor	2.00%	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27
EIA AEO Price Forecast (Nominal $)	$/mmBtu	14.24	14.49	14.77	15.50	16.06	16.46	16.81	17.27	17.88	18.31	18.74	19.36
EIA Annual Percent Change	%	2.1%	1.8%	1.9%	4.9%	3.6%	2.5%	2.2%	2.7%	3.5%	2.4%	2.3%	3.3%
OPIS Mont Belvieu Non-TET Propane plus $0.40/Usgal	$/USgal	0.72	0.63	0.58	0.57	0.57							
Commodity Price for IRP	$/USgal	0.72	0.63	0.58	0.57	0.57	0.58	0.59	0.61	0.63	0.65	0.66	0.68
Fuel Spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Commodity Price for IRP	$/mmBtu	7.92	6.84	6.37	6.20	6.19	6.34	6.48	6.66	6.89	7.06	7.22	7.46
Adders													
LPG Bulk Local Supplier Adder	$/mmBtu	0.78	0.80	0.81	0.83	0.84	0.86	0.88	0.90	0.91	0.93	0.95	0.97
Supplier Commodity Charge	$/USgal	0.47	0.47	0.47	0.48	0.48	0.49	0.49	0.49	0.49	0.49	0.49	0.50
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Supplier Commodity Charge	$/mmBtu	5.16	5.17	5.19	5.20	5.22	5.32	5.34	5.36	5.38	5.40	5.41	5.43
Annual Infrastructure O&M Fee	$/USgal	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Annual Infrastructure O&M Fee	$/mmBtu	0.35	0.36	0.37	0.38	0.38	0.39	0.40	0.41	0.41	0.42	0.43	0.44
Duty	%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Duty	$/USgal	0.30	0.27	0.26	0.26	0.26	0.27	0.27	0.27	0.28	0.28	0.29	0.29
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Duty	$/mmBtu	3.27	3.00	2.89	2.85	2.85	2.92	2.96	3.00	3.07	3.11	3.16	3.22
Unesco Tax	$/USgal	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
BELCO fuel spec (HHV)	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Unesco Tax	$/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
LPG Bulk Supply Infrastructure Capital Cost Estimate (available 2018)													
WACC	%										8.00%		
All-In Capital Cost	$(000)										17,575		
Repayment Period	yr										20		
First Payment Year	yr										2026		
Annual Capital Cost Debt Service	$(000)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,790.04	1,790.04	1,790.04
Annual Assumed Energy Generation by LPG Primemover	MWh	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600
LPG Bulk Supply Infrastructure Cost	$/Usgal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
LPG Bulk Supply Infrastructure Cost	$/mmBtu - gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.40	0.40
All-In	$/mmBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.49	16.73	17.06

Base Case Fuel Price Projections (Includes Fuel Import Duty)

Delivered Fuel Price Projections	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case: LPG - Bulk Duty Normalized (OPIS Mon Belvieu 2017-2021)													
Commodity													
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	13.97	13.93	13.92	14.32	14.54	14.61	14.64	14.74	14.96	15.02	15.07	15.26
Inflation Factor	2.00%	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27
EIA AEO Price Forecast (Nominal $)	$/mmBtu	14.24	14.49	14.77	15.50	16.06	16.46	16.81	17.27	17.88	18.31	18.74	19.36
EIA Annual Percent Change	%	2.1%	1.8%	1.9%	4.9%	3.6%	2.5%	2.2%	2.7%	3.5%	2.4%	2.3%	3.3%
OPIS Mont Belvieu Non-TET Propane plus $0.40/Usgal	$/USgal	0.72	0.63	0.58	0.57	0.57							
Commodity Price for IRP	$/USgal	0.72	0.63	0.58	0.57	0.57	0.58	0.59	0.61	0.63	0.65	0.66	0.68
Fuel Spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Commodity Price for IRP	$/mmBtu	7.92	6.84	6.37	6.20	6.19	6.34	6.48	6.66	6.89	7.06	7.22	7.46
Adders													
LPG Bulk Local Supplier Adder	$/mmBtu	0.78	0.80	0.81	0.83	0.84	0.86	0.88	0.90	0.91	0.93	0.95	0.97
Supplier Commodity Charge	$/USgal	0.47	0.47	0.47	0.48	0.48	0.49	0.49	0.49	0.49	0.49	0.49	0.50
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Supplier Commodity Charge	$/mmBtu	5.16	5.17	5.19	5.20	5.22	5.32	5.34	5.36	5.38	5.40	5.41	5.43
Annual Infrastructure O&M Fee	$/USgal	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Annual Infrastructure O&M Fee	$/mmBtu	0.35	0.36	0.37	0.38	0.38	0.39	0.40	0.41	0.41	0.42	0.43	0.44
Duty	%												
Duty	$/USgal	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Duty	$/mmBtu	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Unesco Tax	$/USgal	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
BELCO fuel spec (HHV)	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Unesco Tax	$/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
LPG Bulk Supply Infrastructure Capital Cost Estimate (available 2018)													
WACC	%										8.00%		
All-In Capital Cost	$(000)										17,575		
Repayment Period	yr										20		
First Payment Year	yr										2026		
Annual Capital Cost Debt Service	$(000)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,790.04	1,790.04	1,790.04
Annual Assumed Energy Generation by LPG Primemover	MWh	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600
LPG Bulk Supply Infrastructure Cost	$/Usgal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
LPG Bulk Supply Infrastructure Cost	$/mmBtu - gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.40	0.40
All-In	$/mmBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.75	18.93	19.20

Delivered Fuel Price Projections	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case: LPG - Bulk delivered to existing central plant (OPIS Mont Belvieu 2017-2021)													
Commodity													
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	13.97	13.93	13.92	14.32	14.54	14.61	14.64	14.74	14.96	15.02	15.07	15.26
Inflation Factor	2.00%	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27
EIA AEO Price Forecast (Nominal $)	$/mmBtu	14.24	14.49	14.77	15.50	16.06	16.46	16.81	17.27	17.88	18.31	18.74	19.36
EIA Annual Percent Change	%	0.1%	1.8%	1.9%	4.9%	3.6%	2.5%	2.2%	2.7%	3.5%	2.4%	2.3%	3.3%
OPIS Mont Belvieu Non-TET Propane plus $0.40/Usgal	$/USgal	0.72	0.63	0.58	0.57	0.57							
Commodity Price for IRP	$/USgal	0.72	0.63	0.58	0.57	0.57	0.58	0.59	0.61	0.63	0.65	0.66	0.68
Fuel Spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Commodity Price for IRP	$/mmBtu	7.92	6.84	6.37	6.20	6.19	6.34	6.48	6.66	6.89	7.06	7.22	7.46
Adders													
LPG Bulk Local Supplier Adder	$/mmBtu	0.78	0.80	0.81	0.83	0.84	0.86	0.88	0.90	0.91	0.93	0.95	0.97
Supplier Commodity Charge	$/USgal	0.47	0.47	0.47	0.48	0.48	0.49	0.49	0.49	0.49	0.49	0.49	0.50
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Supplier Commodity Charge	$/mmBtu	5.16	5.17	5.19	5.20	5.22	5.32	5.34	5.36	5.38	5.40	5.41	5.43
Annual Infrastructure O&M Fee	$/USgal	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Annual Infrastructure O&M Fee	$/mmBtu	0.35	0.36	0.37	0.38	0.38	0.39	0.40	0.41	0.41	0.42	0.43	0.44
ISO container	$/USgal	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.15
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
ISO container	$/mmBtu	1.28	1.31	1.34	1.36	1.39	1.42	1.45	1.47	1.50	1.53	1.57	1.60
Inland Freight - BM	$/USgal	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Inland Freight - BM	$/mmBtu	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.55	0.56	0.57	0.58	0.59
Duty	%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Duty	$/USgal	0.30	0.27	0.26	0.26	0.26	0.27	0.27	0.27	0.28	0.28	0.29	0.29
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Duty	$/mmBtu	3.27	3.00	2.89	2.85	2.85	2.92	2.96	3.00	3.07	3.11	3.16	3.22
Unesco Tax	$/USgal	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
BELCO fuel spec (HHV)	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Unesco Tax	$/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
LPG Bulk Supply Infrastructure Capital Cost Estimate (available 2018)													
WACC	%										8.00%		
All-In Capital Cost	$(000)										17,575		
Repayment Period	yr										20		
First Payment Year	yr										2026		
Annual Capital Cost Debt Service	$(000)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,790.04	1,790.04	1,790.04
Annual Assumed Energy Generation by LPG Primemover	MWh	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600
LPG Bulk Supply Infrastructure Cost	$/Usgal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
LPG Bulk Supply Infrastructure Cost	$/mmBtu - gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.40	0.40
All-In	$/mmBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.59	18.87	19.25

Delivered Fuel Price Projections	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case: LPG - Bulk Duty Normalized delivered to existing central plant (OPIS Mont Belvieu 2017-2021)													
Commodity													
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	13.97	13.93	13.92	14.32	14.54	14.61	14.64	14.74	14.96	15.02	15.07	15.26
Inflation Factor	2.00%	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27
EIA AEO Price Forecast (Nominal $)	$/mmBtu	14.24	14.49	14.77	15.50	16.06	16.46	16.81	17.27	17.88	18.31	18.74	19.36
EIA Annual Percent Change	%	0.1%	1.8%	1.9%	4.9%	3.6%	2.5%	2.2%	2.7%	3.5%	2.4%	2.3%	3.3%
OPIS Mont Belvieu Non-TET Propane plus $0.40/Usgal	$/USgal	0.72	0.63	0.58	0.57	0.57							
Commodity Price for IRP	$/USgal	0.72	0.63	0.58	0.57	0.57	0.58	0.59	0.61	0.63	0.65	0.66	0.68
Fuel Spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Commodity Price for IRP	$/mmBtu	7.92	6.84	6.37	6.20	6.19	6.34	6.48	6.66	6.89	7.06	7.22	7.46
Adders													
LPG Bulk Local Supplier Adder	$/mmBtu	0.78	0.80	0.81	0.83	0.84	0.86	0.88	0.90	0.91	0.93	0.95	0.97
Supplier Commodity Charge	$/USgal	0.47	0.47	0.47	0.48	0.48	0.49	0.49	0.49	0.49	0.49	0.49	0.50
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Supplier Commodity Charge	$/mmBtu	5.16	5.17	5.19	5.20	5.22	5.32	5.34	5.36	5.38	5.40	5.41	5.43
Annual Infrastructure O&M Fee	$/USgal	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Annual Infrastructure O&M Fee	$/mmBtu	0.35	0.36	0.37	0.38	0.38	0.39	0.40	0.41	0.41	0.42	0.43	0.44
ISO container	$/USgal	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.15
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
ISO container	$/mmBtu	1.28	1.31	1.34	1.36	1.39	1.42	1.45	1.47	1.50	1.53	1.57	1.60
Inland Freight - BM	$/USgal	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Inland Freight - BM	$/mmBtu	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.55	0.56	0.57	0.58	0.59
Duty	%												
Duty	$/USgal	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Duty	$/mmBtu	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Unesco Tax	$/USgal	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
BELCO fuel spec (HHV)	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Unesco Tax	$/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
LPG Bulk Supply Infrastructure Capital Cost Estimate (available 2018)													
WACC	%										8.00%		
All-In Capital Cost	$(000)										17,575		
Repayment Period	yr										20		
First Payment Year	yr										2026		
Annual Capital Cost Debt Service	$(000)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,790.04	1,790.04	1,790.04
Annual Assumed Energy Generation by LPG Primemover	MWh	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600
LPG Bulk Supply Infrastructure Cost	$/Usgal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
LPG Bulk Supply Infrastructure Cost	$/mmBtu - gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.40	0.40
All-In	$/mmBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.85	21.08	21.39

Base Case Fuel Price Projections (Includes Fuel Import Duty)

Delivered Fuel Price Projections	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case: Fuel Oil #2 (LFO - NYMEX Near Term)										
Commodity										
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	21.04	21.46	21.91	22.31	22.25	22.59	22.73	23.28	23.28
Inflation Factor	**2.00%**	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
EIA AEO Price Forecast (Nominal $)	$/mmBtu	27.22	28.32	29.49	30.63	31.16	32.26	33.11	34.60	35.29
EIA Annual Percent Change	%	3.3%	4.0%	4.1%	3.9%	1.7%	3.5%	2.7%	4.5%	2.0%
Gulf Coast USLD Platts NYMEX Near Term Strip	$/gal									
NYMEX Annual Percent Change	%									
Volume Conversion	gal/bbl	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00	42.00
Gulf Coast USLD Platts NYMEX Near Term Strip	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commodity Price for IRP	$/bbl	106.09	110.37	114.92	119.39	121.43	125.72	129.06	134.84	137.54
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Commodity Price for IRP	$/mmBtu	17.90	18.62	19.39	20.14	20.49	21.21	21.77	22.75	23.21
Adders										
Through-put	$/bbl	6.84	6.98	7.12	7.26	7.40	7.55	7.70	7.86	8.02
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Through-put	$/mmBtu	1.15	1.18	1.20	1.22	1.25	1.27	1.30	1.33	1.35
Freight & Supply	$/bbl	6.27	6.39	6.52	6.65	6.78	6.92	7.06	7.20	7.34
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Freight & Supply	$/mmBtu	1.06	1.08	1.10	1.12	1.14	1.17	1.19	1.21	1.24
Duty	$/L	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Liter per Oil Barrel	L/bbl	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00
Duty	$/bbl	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Duty	$/mmBtu	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Unesco Tax	$/bbl	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
BELCO fuel spec (HHV)	mmBtu/bbl	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
Unesco Tax	$/mmBtu	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
All-In	$/mmBtu	25.54	26.31	27.12	27.92	28.31	29.09	29.70	30.72	31.23

Base Case Fuel Price Projections (Includes Fuel Import Duty)

Delivered Fuel Price Projections	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case: Fuel Oil #6 (HFO - NYMEX Near Term)										
Commodity										
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	12.01	12.35	12.71	13.09	13.06	13.32	13.45	13.88	13.88
Inflation Factor	2.00%	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
EIA AEO Price Forecast (Nominal $)	$/mmBtu	15.54	16.30	17.11	17.97	18.28	19.03	19.60	20.63	21.04
EIA Annual Percent Change	%	3.9%	4.9%	5.0%	5.0%	1.7%	4.1%	3.0%	5.2%	2.0%
Gulf Coast No. 6 Fuel Oil 3% (MF) NYMEX Near Term Strip	$/bbl									
NYMEX Annual Percent Change	%									
Commodity Price for IRP	$/bbl	59.13	62.01	65.09	68.36	69.55	72.39	74.57	78.48	80.05
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Commodity Price for IRP	$/mmBtu	9.40	9.86	10.35	10.87	11.06	11.51	11.86	12.48	12.73
Adders										
Through-put	$/bbl	8.61	8.79	8.96	9.14	9.32	9.51	9.70	9.89	10.09
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Through-put	$/mmBtu	1.37	1.40	1.43	1.45	1.48	1.51	1.54	1.57	1.61
Freight & Supply	$/bbl	10.40	10.61	10.82	11.04	11.26	11.48	11.71	11.95	12.18
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Freight & Supply	$/mmBtu	1.65	1.69	1.72	1.76	1.79	1.83	1.86	1.90	1.94
Duty	$/L	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Liter per Oil Barrel	L/bbl	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00	159.00
Duty	$/bbl	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80	31.80
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Duty	$/mmBtu	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06	5.06
Unesco Tax	$/bbl	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
BELCO fuel spec (HHV)	mmBtu/bbl	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29	6.29
Unesco Tax	$/mmBtu	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
All-In	$/mmBtu	17.55	18.07	18.62	19.20	19.46	19.97	20.39	21.08	21.40

Base Case Fuel Price Projections (Includes Fuel Import Duty)

Delivered Fuel Price Projections	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case: LNG - Bulk (NYMEX Henry Hub Near Term 2017-2020)										
Commodity										
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	4.81	4.86	5.00	5.02	4.98	4.91	4.95	4.98	4.98
Inflation Factor	2.00%	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
EIA AEO Price Forecast (Nominal $)	$/mmBtu	6.22	6.42	6.74	6.89	6.97	7.01	7.21	7.39	7.54
EIA Annual Percent Change	%	4.0%	3.1%	5.0%	2.3%	1.1%	0.6%	2.8%	2.6%	2.0%
Henry Hub Natural Gas (NG) NYMEX Near Term Strip	$/mmBtu									
NYMEX Annual Percent Change	%									
Commodity (HH)	$/mmBtu	3.63	3.74	3.93	4.02	4.07	4.09	4.21	4.31	4.40
Adders										
Shipping + Margin	$/mmBtu	7.29	7.44	7.59	7.74	7.89	8.05	8.21	8.38	8.54
Commodity Adder	$/mmBtu	0.47	0.49	0.51	0.52	0.53	0.53	0.55	0.56	0.57
Pipeline Transportation (intended to represent mainland)	$/mmBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Infrastructure O&M Fee	$/mmBtu	0.63	0.65	0.66	0.67	0.69	0.70	0.71	0.73	0.74
Duty	%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Duty	$/mmBtu	2.85	2.92	3.01	3.07	3.12	3.17	3.24	3.31	3.38
Unesco Tax	$/liter	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025
BELCO fuel spec (HHV)	Btu/liter	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25
Unesco Tax	$/mmBtu	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
LNG Storage & Regasification Capital Cost Estimate (available 2020)										
WACC	%									
All-In Capital Cost	$(000)									
Repayment Period	yr									
First Payment Year	yr									
Annual Capital Cost Debt Service	$(000)	11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926
Annual System Energy from Forecast	MWh	615,663	615,797	615,937	615,961	615,839	615,531	615,026	614,306	613,356
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,804,331	1,804,723	1,805,134	1,805,203	1,804,846	1,803,945	1,802,465	1,800,354	1,797,569
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	6,156,631	6,157,968	6,159,370	6,159,606	6,158,387	6,155,313	6,150,263	6,143,058	6,133,558
LNG Storage & Regasification Infrastructure Cost	$/mmBtu - gas	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94
All-In	$/mmBtu	16.93	17.29	17.75	18.08	18.35	18.60	18.97	19.35	19.70

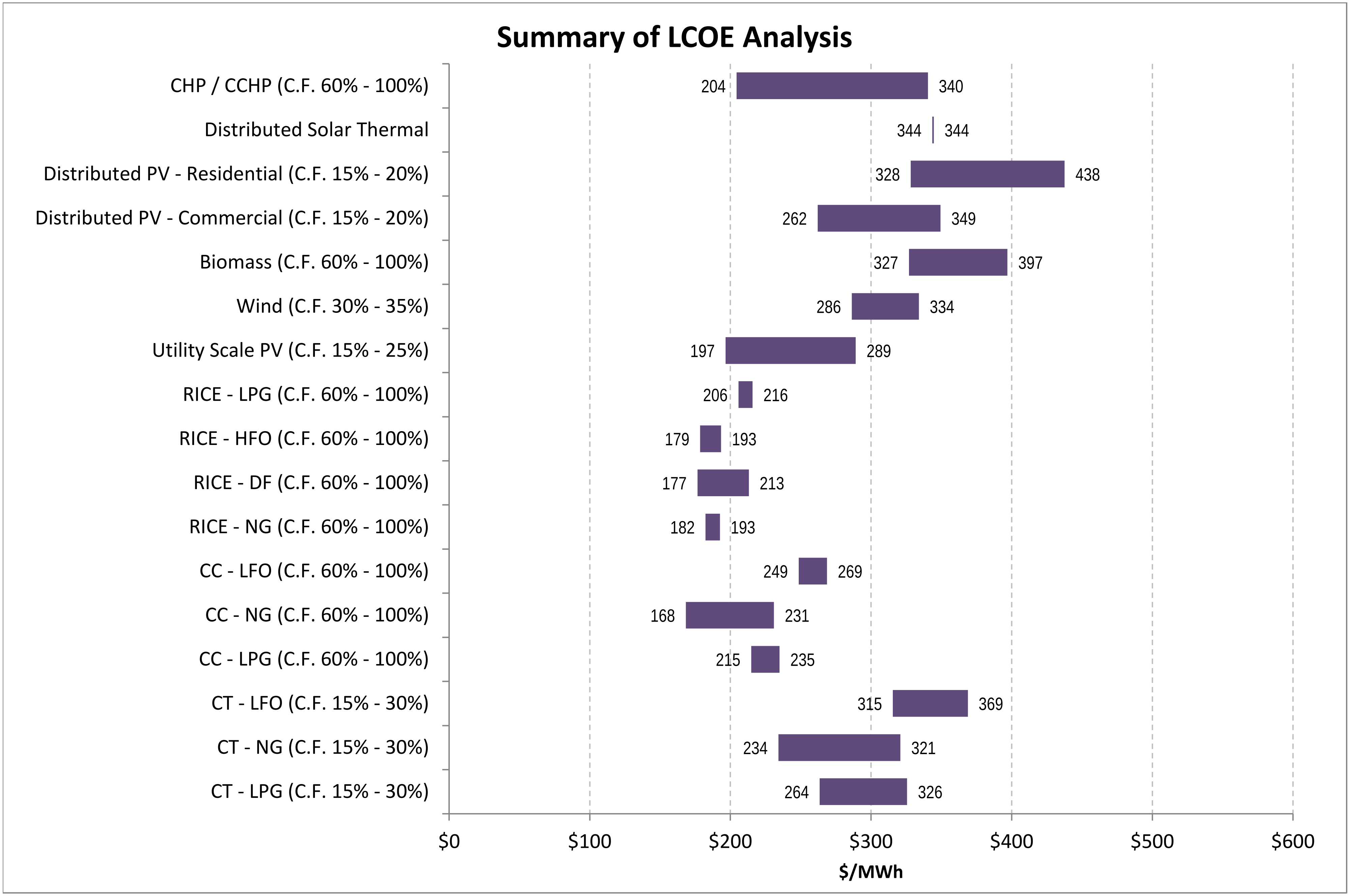
Delivered Fuel Price Projections	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case: LNG - Bulk Duty Normalized (NYMEX Henry Hub Near Term 2017-2020)										
Commodity										
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	4.81	4.86	5.00	5.02	4.98	4.91	4.95	4.98	4.98
Inflation Factor	2.00%	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
EIA AEO Price Forecast (Nominal $)	$/mmBtu	6.22	6.42	6.74	6.89	6.97	7.01	7.21	7.39	7.54
EIA Annual Percent Change	%	4.0%	3.1%	5.0%	2.3%	1.1%	0.6%	2.8%	2.6%	2.0%
Henry Hub Natural Gas (NG) NYMEX Near Term Strip	$/mmBtu									
NYMEX Annual Percent Change	%									
Commodity (HH)	$/mmBtu	3.63	3.74	3.93	4.02	4.07	4.09	4.21	4.31	4.40
Adders										
Shipping + Margin	$/mmBtu	7.29	7.44	7.59	7.74	7.89	8.05	8.21	8.38	8.54
Commodity Adder	$/mmBtu	0.47	0.49	0.51	0.52	0.53	0.53	0.55	0.56	0.57
Pipeline Transportation (intended to represent mainland)	$/mmBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Infrastructure O&M Fee	$/mmBtu	0.63	0.65	0.66	0.67	0.69	0.70	0.71	0.73	0.74
Duty	%									
Duty	$/mmBtu	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Unesco Tax	$/liter	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025	0.0025
BELCO fuel spec (HHV)	Btu/liter	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25	21,832.25
Unesco Tax	$/mmBtu	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
LNG Storage & Regasification Capital Cost Estimate (available 2020)										
WACC	%									
All-In Capital Cost	$(000)									
Repayment Period	yr									
First Payment Year	yr									
Annual Capital Cost Debt Service	$(000)	11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926	11,926
Annual System Energy from Forecast	MWh	615,663	615,797	615,937	615,961	615,839	615,531	615,026	614,306	613,356
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,804,331	1,804,723	1,805,134	1,805,203	1,804,846	1,803,945	1,802,465	1,800,354	1,797,569
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	6,156,631	6,157,968	6,159,370	6,159,606	6,158,387	6,155,313	6,150,263	6,143,058	6,133,558
LNG Storage & Regasification Infrastructure Cost	$/mmBtu - gas	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94
All-In	$/mmBtu	19.45	19.73	20.11	20.37	20.59	20.79	21.10	21.40	21.68

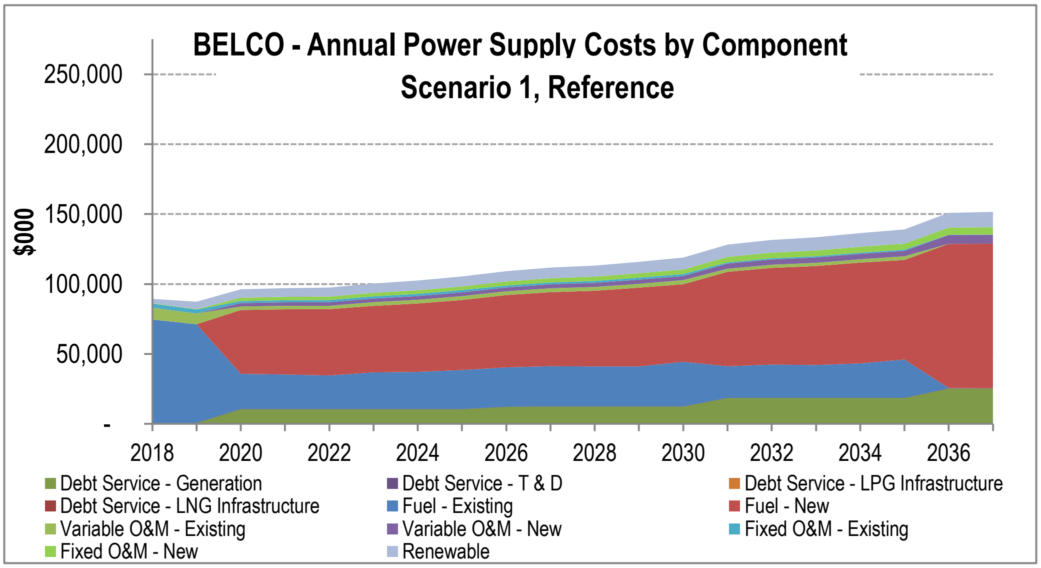
Delivered Fuel Price Projections	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case: LPG - Bulk (OPIS Mont Belvieu 2017-2021)										
Commodity										
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	15.65	15.90	15.95	16.12	16.19	16.51	16.19	16.51	16.51
Inflation Factor	2.00%	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
EIA AEO Price Forecast (Nominal $)	$/mmBtu	20.25	20.98	21.47	22.13	22.68	23.58	23.59	24.53	25.03
EIA Annual Percent Change	%	4.6%	3.6%	2.3%	3.1%	2.5%	4.0%	0.0%	4.0%	2.0%
OPIS Mont Belvieu Non-TET Propane plus $0.40/Usgal	$/USgal									
Commodity Price for IRP	$/USgal	0.71	0.74	0.76	0.78	0.80	0.83	0.83	0.86	0.88
Fuel Spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Commodity Price for IRP	$/mmBtu	7.80	8.08	8.27	8.53	8.74	9.09	9.09	9.45	9.64
Adders										
LPG Bulk Local Supplier Adder	$/mmBtu	0.99	1.01	1.03	1.05	1.07	1.09	1.11	1.14	1.16
Supplier Commodity Charge	$/USgal	0.50	0.50	0.50	0.50	0.51	0.51	0.51	0.51	0.51
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Supplier Commodity Charge	$/mmBtu	5.45	5.47	5.49	5.51	5.53	5.56	5.58	5.60	5.62
Annual Infrastructure O&M Fee	$/USgal	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Annual Infrastructure O&M Fee	$/mmBtu	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53
Duty	%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Duty	$/USgal	0.30	0.31	0.31	0.32	0.33	0.33	0.34	0.34	0.35
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Duty	$/mmBtu	3.31	3.39	3.44	3.51	3.57	3.66	3.67	3.76	3.82
Unesco Tax	$/USgal	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
BELCO fuel spec (HHV)	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Unesco Tax	$/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
LPG Bulk Supply Infrastructure Capital Cost Estimate (available 2018)										
WACC	%									
All-In Capital Cost	$(000)									
Repayment Period	yr									
First Payment Year	yr									
Annual Capital Cost Debt Service	$(000)	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04
Annual Assumed Energy Generation by LPG Primemover	MWh	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600
LPG Bulk Supply Infrastructure Cost	$/Usgal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
LPG Bulk Supply Infrastructure Cost	$/mmBtu - gas	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
All-In	$/mmBtu	17.52	17.91	18.18	18.53	18.83	19.30	19.34	19.84	20.11

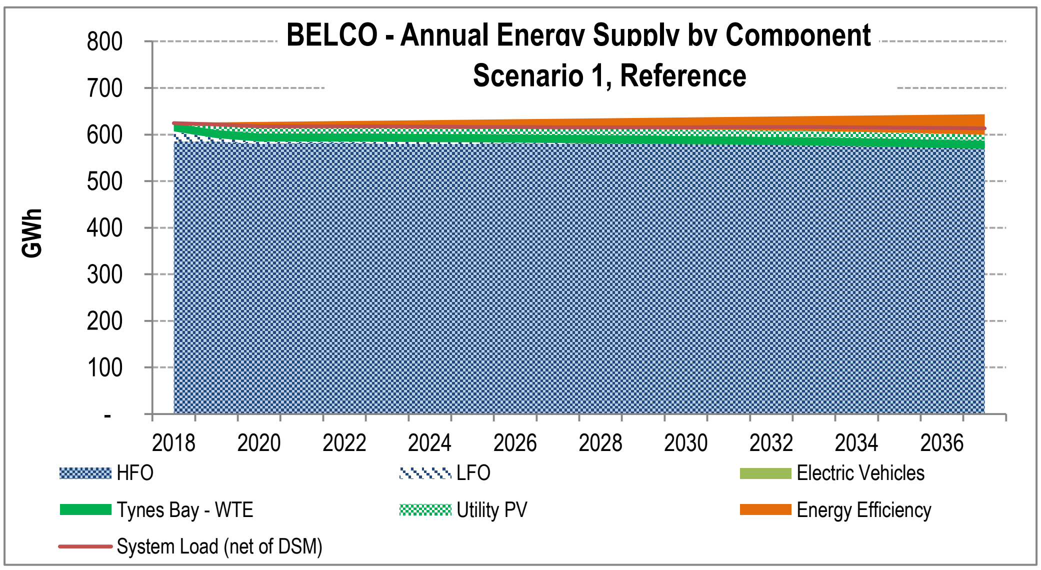
Delivered Fuel Price Projections	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case: LPG - Bulk Duty Normalized (OPIS Mon Belvieu 2017-2021)										
Commodity										
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	15.65	15.90	15.95	16.12	16.19	16.51	16.19	16.51	16.51
Inflation Factor	2.00%	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
EIA AEO Price Forecast (Nominal $)	$/mmBtu	20.25	20.98	21.47	22.13	22.68	23.58	23.59	24.53	25.03
EIA Annual Percent Change	%	4.6%	3.6%	2.3%	3.1%	2.5%	4.0%	0.0%	4.0%	2.0%
OPIS Mont Belvieu Non-TET Propane plus $0.40/Usgal	$/USgal									
Commodity Price for IRP	$/USgal	0.71	0.74	0.76	0.78	0.80	0.83	0.83	0.86	0.88
Fuel Spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Commodity Price for IRP	$/mmBtu	7.80	8.08	8.27	8.53	8.74	9.09	9.09	9.45	9.64
Adders										
LPG Bulk Local Supplier Adder	$/mmBtu	0.99	1.01	1.03	1.05	1.07	1.09	1.11	1.14	1.16
Supplier Commodity Charge	$/USgal	0.50	0.50	0.50	0.50	0.51	0.51	0.51	0.51	0.51
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Supplier Commodity Charge	$/mmBtu	5.45	5.47	5.49	5.51	5.53	5.56	5.58	5.60	5.62
Annual Infrastructure O&M Fee	$/USgal	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Annual Infrastructure O&M Fee	$/mmBtu	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53
Duty	%									
Duty	$/USgal	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Duty	$/mmBtu	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Unesco Tax	$/USgal	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
BELCO fuel spec (HHV)	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Unesco Tax	$/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
LPG Bulk Supply Infrastructure Capital Cost Estimate (available 2018)										
WACC	%									
All-In Capital Cost	$(000)									
Repayment Period	yr									
First Payment Year	yr									
Annual Capital Cost Debt Service	$(000)	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04
Annual Assumed Energy Generation by LPG Primemover	MWh	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600
LPG Bulk Supply Infrastructure Cost	$/Usgal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
LPG Bulk Supply Infrastructure Cost	$/mmBtu - gas	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
All-In	$/mmBtu	19.57	19.88	20.10	20.38	20.63	21.01	21.04	21.44	21.66

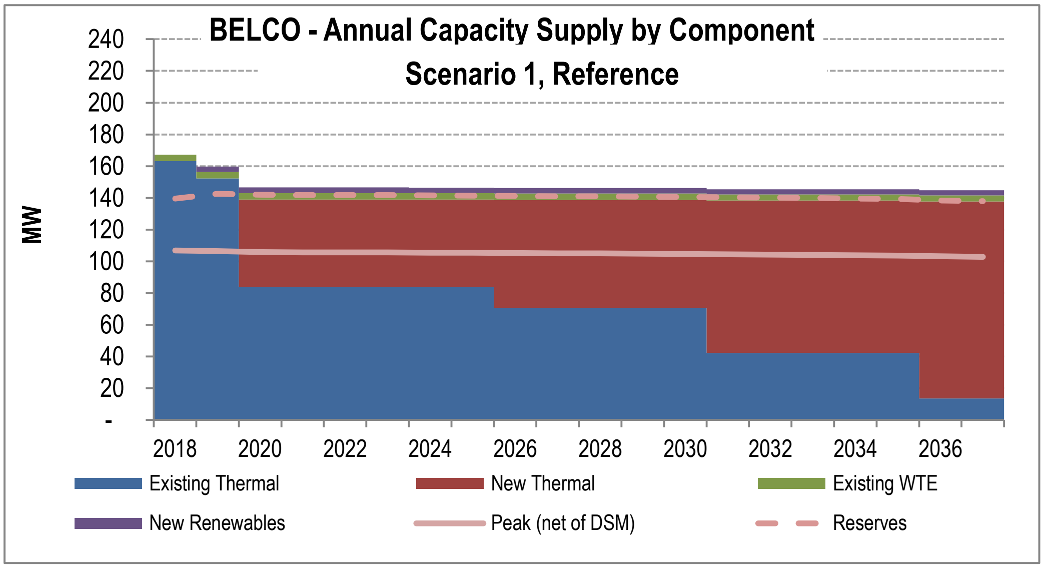
Delivered Fuel Price Projections	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case: LPG - Bulk delivered to existing central plant (OPIS Mont Belvieu 2017-2021)										
Commodity										
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	15.65	15.90	15.95	16.12	16.19	16.51	16.19	16.51	16.51
Inflation Factor	2.00%	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
EIA AEO Price Forecast (Nominal $)	$/mmBtu	20.25	20.98	21.47	22.13	22.68	23.58	23.59	24.53	25.03
EIA Annual Percent Change	%	4.6%	3.6%	2.3%	3.1%	2.5%	4.0%	0.0%	4.0%	2.0%
OPIS Mont Belvieu Non-TET Propane plus $0.40/Usgal	$/USgal									
Commodity Price for IRP	$/USgal	0.71	0.74	0.76	0.78	0.80	0.83	0.83	0.86	0.88
Fuel Spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Commodity Price for IRP	$/mmBtu	7.80	8.08	8.27	8.53	8.74	9.09	9.09	9.45	9.64
Adders										
LPG Bulk Local Supplier Adder	$/mmBtu	0.99	1.01	1.03	1.05	1.07	1.09	1.11	1.14	1.16
Supplier Commodity Charge	$/USgal	0.50	0.50	0.50	0.50	0.51	0.51	0.51	0.51	0.51
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Supplier Commodity Charge	$/mmBtu	5.45	5.47	5.49	5.51	5.53	5.56	5.58	5.60	5.62
Annual Infrastructure O&M Fee	$/USgal	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Annual Infrastructure O&M Fee	$/mmBtu	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53
ISO container	$/USgal	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
ISO container	$/mmBtu	1.63	1.66	1.69	1.73	1.76	1.80	1.83	1.87	1.91
Inland Freight - BM	$/USgal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Inland Freight - BM	$/mmBtu	0.60	0.61	0.63	0.64	0.65	0.66	0.68	0.69	0.71
Duty	%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Duty	$/USgal	0.30	0.31	0.31	0.32	0.33	0.33	0.34	0.34	0.35
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Duty	$/mmBtu	3.31	3.39	3.44	3.51	3.57	3.66	3.67	3.76	3.82
Unesco Tax	$/USgal	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
BELCO fuel spec (HHV)	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Unesco Tax	$/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
LPG Bulk Supply Infrastructure Capital Cost Estimate (available 2018)										
WACC	%									
All-In Capital Cost	$(000)									
Repayment Period	yr									
First Payment Year	yr									
Annual Capital Cost Debt Service	$(000)	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04
Annual Assumed Energy Generation by LPG Primemover	MWh	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600
LPG Bulk Supply Infrastructure Cost	$/Usgal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
LPG Bulk Supply Infrastructure Cost	$/mmBtu - gas	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
All-In	$/mmBtu	19.75	20.18	20.50	20.90	21.24	21.77	21.86	22.40	22.72

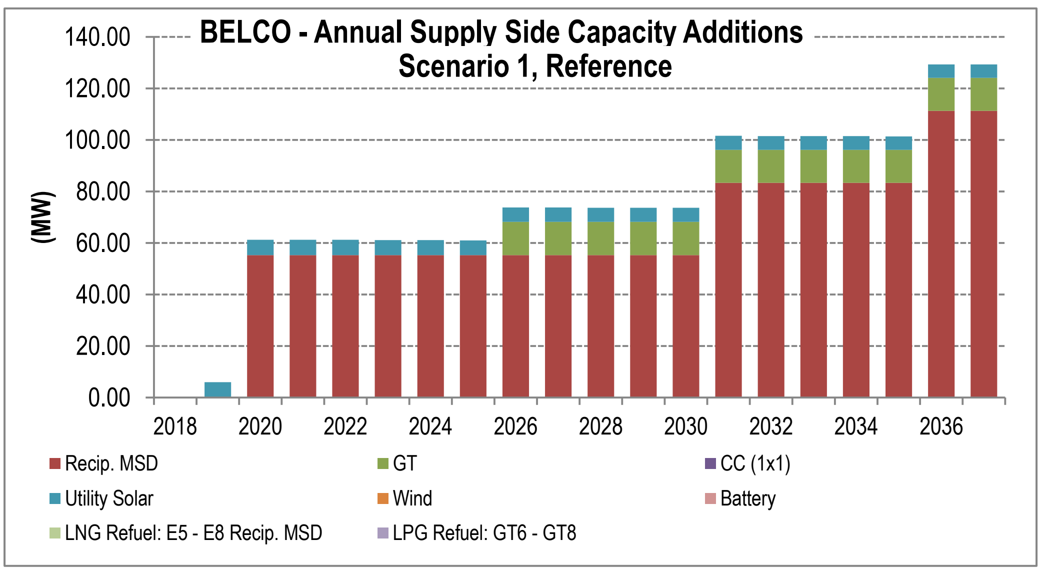
Delivered Fuel Price Projections	Units	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case: LPG - Bulk Duty Normalized delivered to existing central plant (OPIS Mont Belv										
Commodity										
EIA AEO Price Forecast (Real 2016$)	$/mmBtu	15.65	15.90	15.95	16.12	16.19	16.51	16.19	16.51	16.51
Inflation Factor	2.00%	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
EIA AEO Price Forecast (Nominal $)	$/mmBtu	20.25	20.98	21.47	22.13	22.68	23.58	23.59	24.53	25.03
EIA Annual Percent Change	%	4.6%	3.6%	2.3%	3.1%	2.5%	4.0%	0.0%	4.0%	2.0%
OPIS Mont Belvieu Non-TET Propane plus $0.40/Usgal	$/USgal									
Commodity Price for IRP	$/USgal	0.71	0.74	0.76	0.78	0.80	0.83	0.83	0.86	0.88
Fuel Spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Commodity Price for IRP	$/mmBtu	7.80	8.08	8.27	8.53	8.74	9.09	9.09	9.45	9.64
Adders										
LPG Bulk Local Supplier Adder	$/mmBtu	0.99	1.01	1.03	1.05	1.07	1.09	1.11	1.14	1.16
Supplier Commodity Charge	$/USgal	0.50	0.50	0.50	0.50	0.51	0.51	0.51	0.51	0.51
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Supplier Commodity Charge	$/mmBtu	5.45	5.47	5.49	5.51	5.53	5.56	5.58	5.60	5.62
Annual Infrastructure O&M Fee	$/USgal	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Annual Infrastructure O&M Fee	$/mmBtu	0.45	0.46	0.47	0.48	0.49	0.50	0.51	0.52	0.53
ISO container	$/USgal	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
ISO container	$/mmBtu	1.63	1.66	1.69	1.73	1.76	1.80	1.83	1.87	1.91
Inland Freight - BM	$/USgal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Inland Freight - BM	$/mmBtu	0.60	0.61	0.63	0.64	0.65	0.66	0.68	0.69	0.71
Duty	%									
Duty	$/USgal	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Duty	$/mmBtu	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37	5.37
Unesco Tax	$/USgal	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095	0.0095
BELCO fuel spec (HHV)	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
Unesco Tax	$/mmBtu	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
LPG Bulk Supply Infrastructure Capital Cost Estimate (available 2018)										
WACC	%									
All-In Capital Cost	$(000)									
Repayment Period	yr									
First Payment Year	yr									
Annual Capital Cost Debt Service	$(000)	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04	1,790.04
Annual Assumed Energy Generation by LPG Primemover	MWh	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760	446,760
Average Electric Generating Efficiency	%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Annual Fuel Consumption Estimate	MWh	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325	1,309,325
Conversion Factor	mmBtu/MWh	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Annual Fuel Consumption Estimate	mmbtu	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600	4,467,600
LPG Bulk Supply Infrastructure Cost	$/Usgal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
BELCO fuel spec	Btu/USgal	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00	91,410.00
LPG Bulk Supply Infrastructure Cost	$/mmBtu - gas	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
All-In	$/mmBtu	21.80	22.16	22.42	22.75	23.04	23.47	23.55	24.00	24.27


Summary of LCOE Analysis
CHP / CCHP (C.F. 60% - 100%)
204
340
Distributed Solar Thermal
344
344
Distributed PV - Residential (C.F. 15% - 20%)
328
438
Distributed PV - Commercial (C.F. 15% - 20%)
262
349
Biomass (C.F. 60% - 100%)
327
397
Wind (C.F. 30% - 35%)
286
334
Utility Scale PV (C.F. 15% - 25%)
197
289
RICE - LPG (C.F. 60% - 100%)
206
216
RICE - HFO (C.F. 60% - 100%)
179
193
RICE - DF (C.F. 60% - 100%)
177
213
RICE - NG (C.F. 60% - 100%)
182
193
CC - LFO (C.F. 60% - 100%)
249
269
CC - NG (C.F. 60% - 100%)
168
231
CC - LPG (C.F. 60% - 100%)
215
235
CT - LFO (C.F. 15% - 30%)
315
369
CT - NG (C.F. 15% - 30%)
234
321
CT - LPG (C.F. 15% - 30%)
264
326
$0
$100
$200
$300
$400
$500
$600
$/MWh


BELCO - Annual Power Supply Costs by Component
Scenario 1, Reference
$000
250,000
200,000
150,000
100,000
50,000
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Debt Service - Generation
Debt Service - T & D
Debt Service - LPG Infrastructure
Debt Service - LNG Infrastructure
Fuel - Existing
Fuel - New
Variable O&M - Existing
Variable O&M - New
Fixed O&M - Existing
Fixed O&M - New
Renewable


BELCO - Annual Energy Supply by Component
Scenario 1, Reference
GWh
800
700
600
500
400
300
200
100
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
HFO
LFO
Electric Vehicles
Tynes Bay - WTE
Utility PV
Energy Efficiency
System Load (net of DSM)


BELCO - Annual Capacity Supply by Component
Scenario 1, Reference
MW
240
220
200
180
160
140
120
100
80
60
40
20
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Existing Thermal
New Thermal
Existing WTE
New Renewables
Peak (net of DSM)
Reserves


BELCO - Annual Supply Side Capacity Additions
Scenario 1, Reference
(MW)
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Recip. MSD
GT
CC (1x1)
Utility Solar
Wind
Battery
LNG Refuel: E5 - E8 Recip. MSD
LPG Refuel: GT6 - GT8

TOTAL SYSTEM COSTS

Scenario 1, Reference

		Levelized	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																						
TOTAL DEMAND	GWH	**632**	**626**	**626**	**627**	**628**	**629**	**630**	**631**	**632**	**633**	**634**	**635**	**636**	**637**	**638**	**639**	**640**	**641**	**642**	**643**	**644**
AMORTIZED CAPITAL COSTS																						
Debt Service - Generation	$000	11,062	774	774	10,569	10,569	10,569	10,569	10,569	10,569	12,260	12,453	12,453	12,453	12,453	18,576	18,576	18,576	18,576	18,576	25,335	25,335
Debt Service - T & D	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LPG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Early Retirement Depreciation Cost	$000	19	-	-	237	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Costs	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS																						
Fuel - Existing	$000	33,531	73,848	70,468	25,209	24,772	24,080	26,266	26,666	27,950	28,156	28,821	28,625	28,650	31,962	22,630	23,837	23,541	24,694	27,487	347	146
Fuel - New	$000	46,181	-	-	45,663	46,591	47,405	47,544	48,875	50,082	51,711	52,926	54,112	56,335	55,397	67,548	69,121	70,775	72,042	71,180	103,020	103,385
Variable O&M - Existing	$000	3,474	8,394	7,741	2,522	2,483	2,422	2,673	2,664	2,795	2,692	2,789	2,745	2,745	3,015	2,199	2,291	2,282	2,377	2,657	67	27
Variable O&M - New	$000	2,523	-	-	2,444	2,527	2,616	2,598	2,655	2,690	2,737	2,786	2,881	2,971	2,899	3,709	3,750	3,854	3,903	3,839	6,302	6,349
Fixed O&M - Existing	$000	1,596	3,022	2,828	1,469	1,498	1,528	1,558	1,590	1,621	1,346	1,373	1,400	1,428	1,457	826	843	859	877	894	183	187
Fixed O&M - New	$000	2,561	279	284	2,353	2,400	2,448	2,497	2,547	2,598	2,947	3,006	3,066	3,127	3,190	3,930	4,009	4,089	4,171	4,254	5,086	5,188
Renewable	$000	7,011	3,079	5,284	6,034	6,219	6,431	6,648	6,975	7,114	7,361	7,625	7,913	8,175	8,564	8,779	9,129	9,441	9,793	10,161	10,574	10,956
DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL COSTS	**$000**	**107,958**	**89,396**	**87,379**	**96,500**	**97,059**	**97,498**	**100,354**	**102,540**	**105,419**	**109,210**	**111,780**	**113,196**	**115,885**	**118,937**	**128,196**	**131,556**	**133,418**	**136,432**	**139,047**	**150,916**	**151,573**
	$/MWh	**170.8**	**142.7**	**139.5**	**153.9**	**154.5**	**155.0**	**159.3**	**162.5**	**166.8**	**172.6**	**176.4**	**178.3**	**182.3**	**186.8**	**201.0**	**206.0**	**208.6**	**213.0**	**216.7**	**234.9**	**235.5**

ANNUAL CAPITAL REQUIREMENTS

Scenario 1, Reference

Nominal Dollars ($000)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																				
Generation																				
PS-10a_1	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_2	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_3	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_4	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-1a_1	-	-	-	-	-	-	-	-	-	-	-	-	-	34,462	-	-	-	-	-	-
PS-1a_2	-	-	-	-	-	-	-	-	-	-	-	-	-	34,462	-	-	-	-	-	-
PS-1a_3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38,048	-
PS-1a_4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38,048	-
PS-2a_1	-	-	-	-	-	-	-	-	19,039	-	-	-	-	-	-	-	-	-	-	-
Battery																				
PS-6a	7,600	-	-	-	-	-	-	-	-	1,900	-	-	-	-	-	-	-	-	-	-
T & D																				
Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Infrastructure																				
LPG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM																				
Distributed PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCHP / CHP (LNG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distributed Solar Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL CAPITAL REQUIREMENTS	**7,600**	**-**	**110,266**	**-**	**-**	**-**	**-**	**-**	**19,039**	**1,900**	**-**	**-**	**-**	**68,923**	**-**	**-**	**-**	**-**	**76,097**	**-**

SYSTEM GENERATION SUMMARY

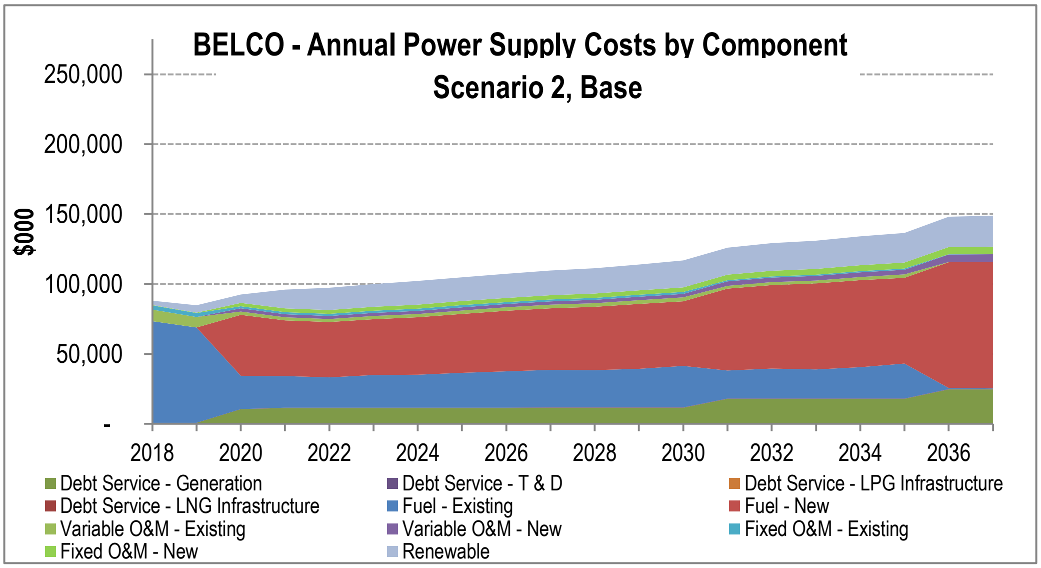
Scenario 1, Reference

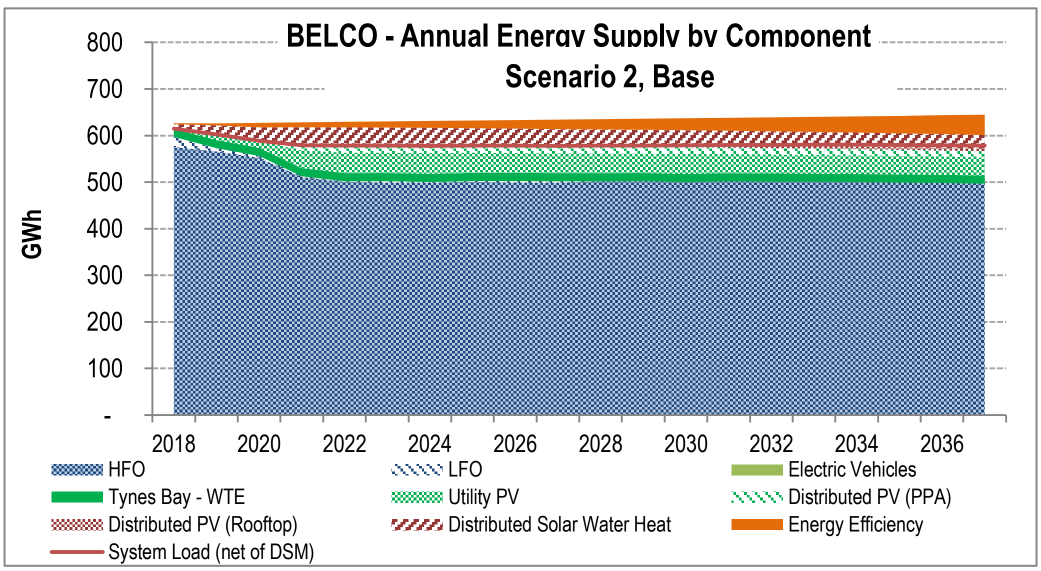
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																					
GENERATION MIX																					
HFO	GWH	585	585	581	582	583	580	581	580	582	580	582	582	582	583	583	583	583	582	582	581
LFO	GWH	22	7	4	4	3	5	4	5	3	4	2	3	2	2	1	2	2	2	2	2
Tynes Bay - WTE	GWH	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Utility PV	GWH	-	12	15	15	15	14	15	14	14	14	14	14	14	14	13	13	13	13	13	13
Energy Efficiency	GWH	2	5	10	11	12	13	15	16	18	20	22	24	26	28	30	32	35	38	41	44
Electric Vehicles	GWH	-	-	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)	(11)	(12)	(14)
Total	GWH	626	626	627	628	629	630	631	632	633	634	635	636	637	638	639	640	641	642	643	644
HFO	%	93.4%	93.4%	92.7%	92.6%	92.6%	92.2%	92.1%	91.8%	91.9%	91.5%	91.7%	91.5%	91.4%	91.5%	91.4%	91.2%	91.0%	90.8%	90.6%	90.3%
LFO	%	3.4%	1.2%	0.7%	0.6%	0.4%	0.8%	0.6%	0.7%	0.4%	0.6%	0.3%	0.4%	0.4%	0.2%	0.2%	0.3%	0.3%	0.3%	0.2%	0.3%
Tynes Bay - WTE	%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.7%	2.8%	2.7%	2.7%	2.7%	2.7%	2.7%
Utility PV	%	0.0%	1.9%	2.4%	2.3%	2.3%	2.3%	2.3%	2.3%	2.2%	2.2%	2.2%	2.2%	2.2%	2.1%	2.1%	2.1%	2.1%	2.0%	2.0%	2.0%
Energy Efficiency	%	0.3%	0.7%	1.5%	1.7%	1.9%	2.1%	2.4%	2.6%	2.9%	3.2%	3.5%	3.7%	4.0%	4.3%	4.7%	5.0%	5.4%	5.9%	6.3%	6.8%
Electric Vehicles	%	0.0%	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.1%	-0.2%	-0.2%	-0.3%	-0.5%	-0.6%	-0.8%	-0.9%	-1.1%	-1.3%	-1.5%	-1.7%	-1.9%	-2.1%
Total	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

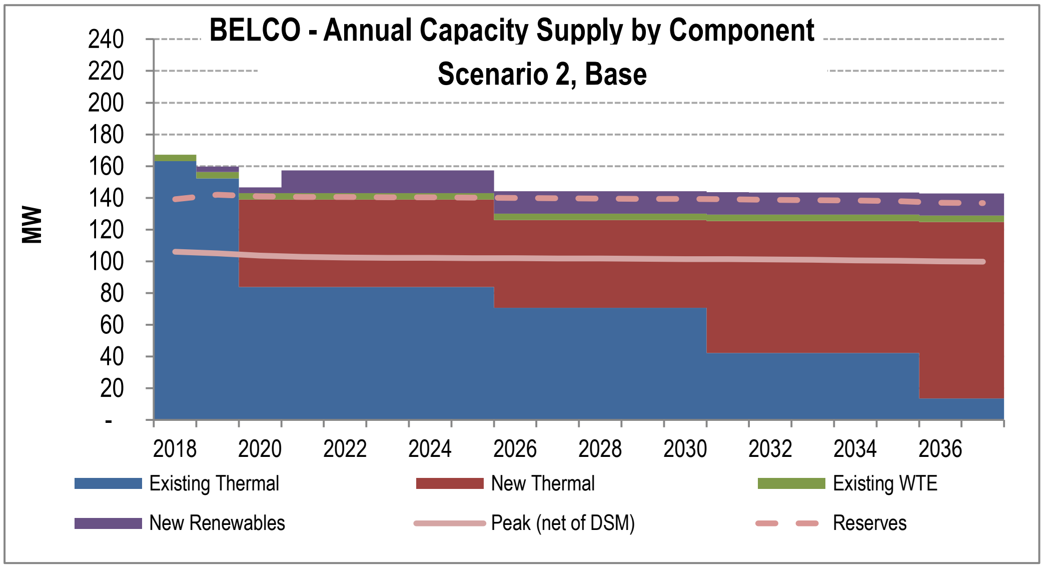
SYSTEM OPERATIONS SUMMARY

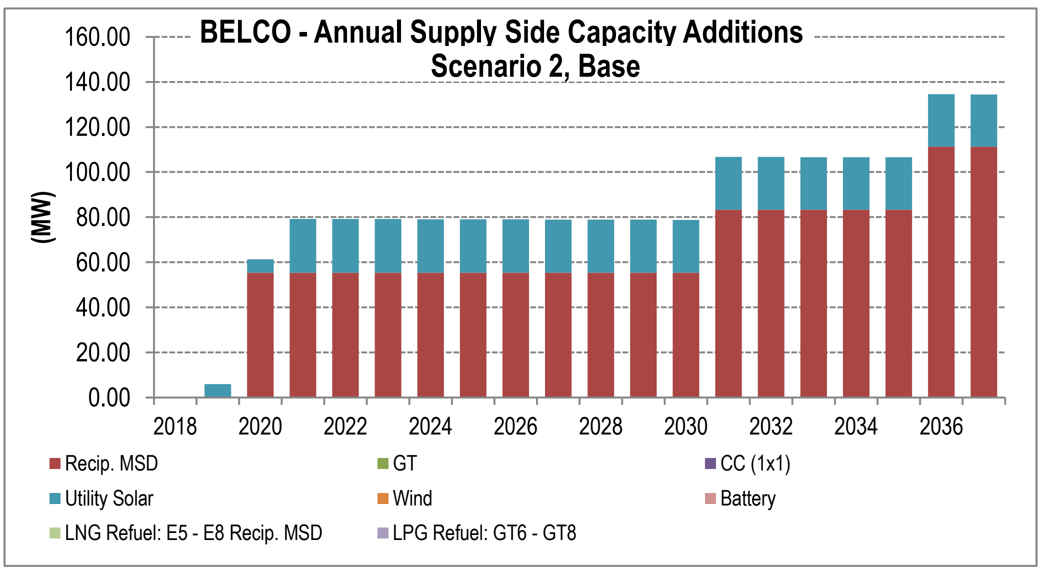
Scenario 1, Reference

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																					
ENERGY																					
Existing Thermal	GWH	607	592	209	204	199	209	207	210	209	209	205	200	217	151	154	150	154	167	1	0
New Thermal	GWH	-	-	376	381	387	377	377	375	375	375	379	384	367	434	431	435	431	417	583	583
Existing WTE	GWH	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
New Renewables	GWH	-	12	15	15	15	14	15	14	14	14	14	14	14	14	13	13	13	13	13	13
TOTAL ENERGY		624	622	618	618	618	617	617	616	616	615	615	616	616	616	616	616	616	615	614	613
Gross Energy	GWH	626	626	627	628	629	630	631	632	633	634	635	636	637	638	639	640	641	642	643	644
DSM / EE / EV	GWH	2	5	9	10	12	13	14	15	17	18	19	20	21	22	23	24	25	27	28	30
System Load	GWH	624	622	618	618	618	617	617	616	616	615	615	616	616	616	616	616	616	615	614	613
LOLH	HOURS	-	-	-	1	1	12	5	4	-	-	2	-	-	-	1	-	-	-	-	-
Dump Energy	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Energy	GWH	-	-	-	0.0	0.0	0.1	0.0	0.0	-	-	0.0	-	-	-	0.0	-	-	-	-	-
FUEL																					
HFO	BBL (000)	765	765	762	763	764	761	762	761	763	760	763	762	762	766	766	766	766	764	776	774
LFO	BBL (000)	39	12	8	7	5	9	7	9	5	8	4	6	5	3	3	4	4	5	3	4
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG (CHP)	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS																					
Energy from Renewables	%	3%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
CO_2	TONS (000)	436	423	420	420	420	420	419	420	419	419	418	419	419	420	420	420	420	419	425	424
CO_2 Intensity	LBS/MWH	1,390	1,351	1,339	1,337	1,335	1,333	1,329	1,328	1,324	1,322	1,318	1,318	1,315	1,316	1,314	1,313	1,310	1,307	1,323	1,319
NO_X	TONS (000)	24	24	14	14	14	14	14	14	14	14	14	14	15	13	13	13	13	13	9	9
SO_X	TONS (000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPM	TONS (000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPACITY																					
Existing Thermal	MW	163	152	84	84	84	84	84	84	71	71	71	71	71	42	42	42	42	42	14	14
New Thermal	MW	-	-	55	55	55	55	55	55	68	68	68	68	68	96	96	96	96	96	124	124
Existing WTE	MW	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
New Renewables	MW	-	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
TOTAL CAPACITY		167	160	147	147	147	147	146	146	146	146	146	146	146	145	145	145	145	145	145	145
PEAK DEMAND	MW	107	107	107	107	108	108	108	108	108	108	109	109	109	109	109	109	110	110	110	110
DSM / EE	MW	0	1	2	2	2	2	2	3	3	3	4	4	4	5	5	5	6	6	7	7
Peak (net of DSM)	MW	107	106	106	106	106	106	105	105	105	105	105	105	105	104	104	104	104	104	103	103
Reserves	MW	32.6	36.2	36.2	36.1	36.1	36.1	36.1	36.0	36.0	36.0	35.9	35.9	35.9	35.9	35.8	35.8	35.8	35.7	35.1	35.1
Total Capacity Requirements	MW	139	143	142	142	142	142	142	141	141	141	141	141	141	140	140	140	140	139	138	138
Surplus/(Deficiency)	MW	27.8	17.2	4.7	4.7	4.8	4.8	4.9	5.1	5.0	5.2	5.3	5.4	5.6	5.1	5.3	5.6	5.8	6.1	6.4	6.8


BELCO - Annual Power Supply Costs by Component
Scenario 2, Base
$000
250,000
200,000
150,000
100,000
50,000
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Debt Service - Generation
Debt Service - T & D
Debt Service - LPG Infrastructure
Debt Service - LNG Infrastructure
Fuel - Existing
Fuel - New
Variable O&M - Existing
Variable O&M - New
Fixed O&M - Existing
Fixed O&M - New
Renewable


BELCO - Annual Energy Supply by Component
Scenario 2, Base
GWh
800
700
600
500
400
300
200
100
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
HFO
LFO
Electric Vehicles
Tynes Bay - WTE
Utility PV
Distributed PV (PPA)
Distributed PV (Rooftop)
Distributed Solar Water Heat
Energy Efficiency
System Load (net of DSM)


BELCO - Annual Capacity Supply by Component
Scenario 2, Base
MW
240
220
200
180
160
140
120
100
80
60
40
20
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Existing Thermal
New Thermal
Existing WTE
New Renewables
Peak (net of DSM)
Reserves


BELCO - Annual Supply Side Capacity Additions
Scenario 2, Base
(MW)
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Recip. MSD
GT
CC (1x1)
Utility Solar
Wind
Battery
LNG Refuel: E5 - E8 Recip. MSD
LPG Refuel: GT6 - GT8

TOTAL SYSTEM COSTS

Scenario 2, Base

		Levelized	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																						
TOTAL DEMAND	GWH	**632**	**626**	**626**	**627**	**628**	**629**	**630**	**631**	**632**	**633**	**634**	**635**	**636**	**637**	**638**	**639**	**640**	**641**	**642**	**643**	**644**
AMORTIZED CAPITAL COSTS																						
Debt Service - Generation	$000	11,007	774	774	10,569	11,390	11,390	11,390	11,390	11,390	11,390	11,584	11,584	11,584	11,584	17,911	17,911	17,911	17,911	17,911	24,671	24,671
Debt Service - T & D	$000	154	-	-	-	209	209	209	209	209	209	209	209	209	209	209	209	209	209	209	209	209
Debt Service - LPG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Early Retirement Depreciation Cost	$000	19	-	-	237	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Costs	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS																						
Fuel - Existing	$000	31,469	72,679	68,160	23,825	22,609	21,679	23,340	23,569	24,930	25,986	26,853	26,653	27,600	29,652	20,060	21,436	20,830	22,436	25,017	812	501
Fuel - New	$000	39,584	-	-	43,566	39,811	39,568	39,925	41,097	42,107	43,301	43,996	45,280	46,390	46,225	58,538	59,713	61,492	62,236	61,308	89,911	90,420
Variable O&M - Existing	$000	3,271	8,258	7,503	2,378	2,229	2,146	2,324	2,317	2,443	2,528	2,631	2,575	2,676	2,826	1,999	2,125	2,057	2,223	2,468	157	92
Variable O&M - New	$000	2,155	-	-	2,330	2,155	2,179	2,177	2,227	2,257	2,301	2,335	2,412	2,460	2,429	3,194	3,215	3,331	3,352	3,294	5,364	5,434
Fixed O&M - Existing	$000	1,596	3,022	2,828	1,469	1,498	1,528	1,558	1,590	1,621	1,346	1,373	1,400	1,428	1,457	826	843	859	877	894	183	187
Fixed O&M - New	$000	2,673	279	284	2,353	2,696	2,750	2,805	2,861	2,918	2,977	3,036	3,097	3,159	3,222	3,963	4,043	4,123	4,206	4,290	5,123	5,225
Renewable	$000	14,310	3,079	5,284	6,034	13,415	15,903	16,233	16,987	16,935	17,293	17,668	18,090	18,446	19,289	19,288	19,773	20,175	20,649	21,137	21,694	22,169
DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL COSTS	**$000**	**106,238**	**88,092**	**84,833**	**92,762**	**96,012**	**97,352**	**99,961**	**102,247**	**104,811**	**107,331**	**109,684**	**111,300**	**113,952**	**116,893**	**125,988**	**129,267**	**130,988**	**134,100**	**136,529**	**148,124**	**148,908**
	$/MWh	**168.1**	**140.6**	**135.5**	**147.9**	**152.9**	**154.8**	**158.7**	**162.1**	**165.9**	**169.6**	**173.0**	**175.3**	**179.2**	**183.6**	**197.6**	**202.4**	**204.8**	**209.3**	**212.8**	**230.5**	**231.4**

ANNUAL CAPITAL REQUIREMENTS

Scenario 2, Base

Nominal Dollars ($000)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																				
Generation																				
PS-10a_1	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_2	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_3	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_4	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-1a_1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38,048	-
PS-1a_2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38,048	-
PS-1a_3	-	-	-	-	-	-	-	-	-	-	-	-	-	34,462	-	-	-	-	-	-
PS-1a_4	-	-	-	-	-	-	-	-	-	-	-	-	-	34,462	-	-	-	-	-	-
Battery																				
PS-6a	7,600	-	-	-	-	-	-	-	-	1,900	-	-	-	-	-	-	-	-	-	-
PS-6b	-	-	-	8,065	-	-	-	-	-	-	-	-	-	2,016	-	-	-	-	-	-
T & D																				
Upgrades	-	-	-	1,592	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Infrastructure																				
LPG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM																				
Distributed PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCHP / CHP (LNG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distributed Solar Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL CAPITAL REQUIREMENTS	**7,600**	**-**	**110,266**	**9,657**	**-**	**-**	**-**	**-**	**-**	**1,900**	**-**	**-**	**-**	**70,940**	**-**	**-**	**-**	**-**	**76,097**	**-**

SYSTEM GENERATION SUMMARY

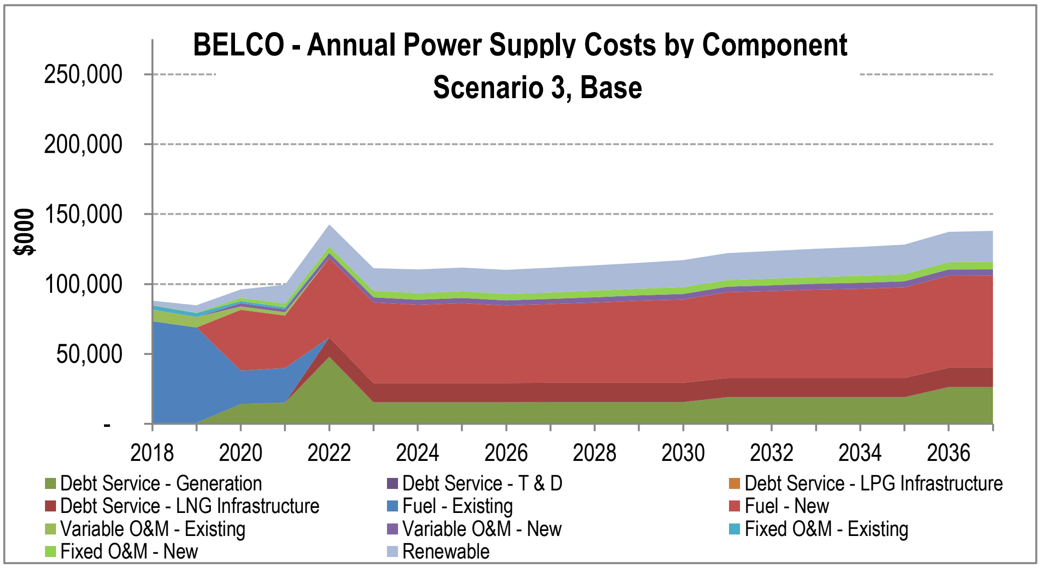
Scenario 2, Base

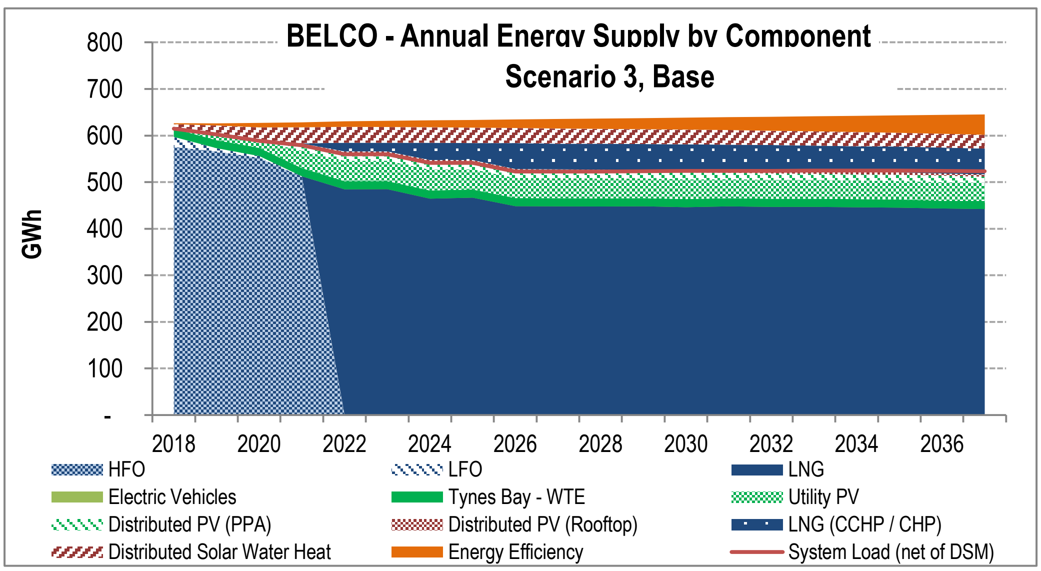
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																					
GENERATION MIX																					
HFO	GWH	576	566	552	511	501	500	499	501	500	500	502	502	502	505	505	507	507	507	508	509
LFO	GWH	21	7	4	2	1	2	2	2	4	4	3	4	3	3	3	2	3	3	2	1
Tynes Bay - WTE	GWH	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Utility PV	GWH	-	12	15	38	44	44	45	43	43	43	42	42	43	41	41	40	40	40	39	39
Distributed PV (PPA)	GWH	-	-	-	11	15	15	15	14	14	14	14	14	14	14	14	14	13	13	13	13
Distributed Solar Water Heat	GWH	9	17	26	34	34	34	33	33	33	32	32	32	31	31	31	30	30	30	30	30
Energy Efficiency	GWH	2	5	10	11	12	13	15	16	18	20	22	24	26	28	30	32	35	38	41	44
Electric Vehicles	GWH	-	-	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)	(11)	(12)	(14)
Distributed PV (Rooftop)	GWH	1	2	3	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total	GWH	626	626	627	628	629	630	631	632	633	634	635	636	637	638	639	640	641	642	644	645
HFO	%	91.9%	90.4%	88.1%	81.3%	79.6%	79.3%	79.0%	79.2%	79.0%	78.8%	79.0%	79.0%	78.8%	79.2%	79.1%	79.2%	79.0%	79.0%	78.9%	78.9%
LFO	%	3.4%	1.1%	0.6%	0.3%	0.2%	0.4%	0.3%	0.4%	0.6%	0.6%	0.5%	0.6%	0.5%	0.4%	0.4%	0.3%	0.5%	0.4%	0.4%	0.2%
Tynes Bay - WTE	%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
Utility PV	%	0.0%	1.9%	2.4%	6.0%	7.0%	7.0%	7.1%	6.8%	6.8%	6.7%	6.6%	6.6%	6.7%	6.4%	6.4%	6.3%	6.2%	6.2%	6.1%	6.0%
Distributed PV (PPA)	%	0.0%	0.0%	0.0%	1.8%	2.4%	2.3%	2.4%	2.3%	2.3%	2.2%	2.2%	2.2%	2.2%	2.2%	2.1%	2.1%	2.1%	2.1%	2.0%	2.0%
Distributed Solar Water Heat	%	1.4%	2.8%	4.1%	5.5%	5.4%	5.3%	5.3%	5.2%	5.2%	5.1%	5.1%	5.0%	4.9%	4.9%	4.8%	4.8%	4.7%	4.6%	4.6%	4.6%
Energy Efficiency	%	0.3%	0.7%	1.5%	1.7%	1.9%	2.1%	2.4%	2.6%	2.9%	3.2%	3.5%	3.7%	4.0%	4.3%	4.7%	5.0%	5.4%	5.8%	6.3%	6.8%
Electric Vehicles	%	0.0%	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.1%	-0.2%	-0.2%	-0.3%	-0.5%	-0.6%	-0.8%	-0.9%	-1.1%	-1.3%	-1.5%	-1.7%	-1.9%	-2.1%
Distributed PV (Rooftop)	%	0.2%	0.3%	0.5%	0.7%	0.8%	0.8%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Total	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

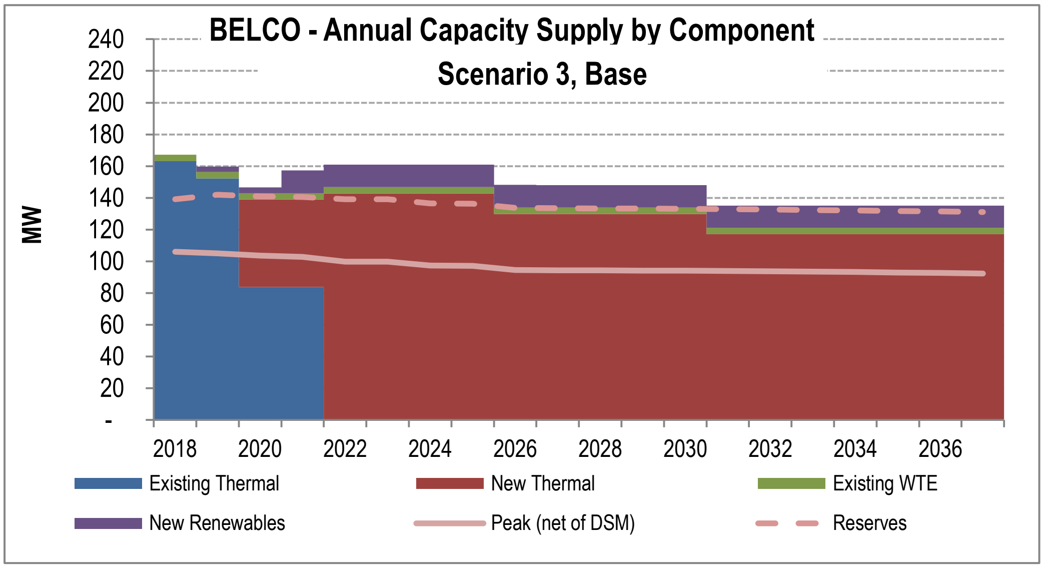
SYSTEM OPERATIONS SUMMARY

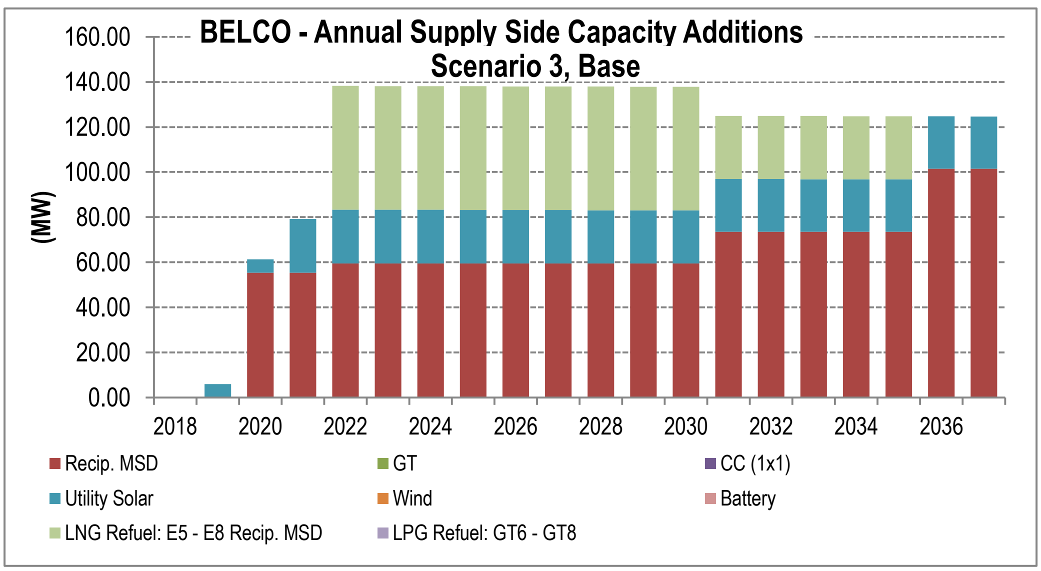
Scenario 2, Base

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																					
ENERGY																					
Existing Thermal	GWH	597	573	198	188	180	187	184	189	189	191	188	189	198	131	136	131	137	150	2	1
New Thermal	GWH	-	-	359	325	322	316	317	314	314	313	317	317	307	376	372	378	373	360	508	509
Existing WTE	GWH	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
New Renewables	GWH	-	12	15	49	59	59	60	58	57	57	56	56	57	55	54	54	53	53	53	52
TOTAL ENERGY		615	602	589	580	579	579	579	579	578	578	578	579	579	580	580	581	581	580	581	580
Gross Energy	GWH	626	626	627	628	629	630	631	632	633	634	635	636	637	638	639	640	641	642	643	644
DSM / EE / EV	GWH	12	24	38	49	51	52	53	54	55	56	57	57	58	58	59	60	61	62	63	65
System Load	GWH	615	602	589	579	578	578	578	578	578	578	578	579	579	580	580	580	580	580	579	579
LOLH	HOURS	-	-	-	-	-	9	-	4	3	11	2	-	1	1	-	3	5	6	-	-
Dump Energy	GWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emergency Energy	GWH	-	-	-	-	-	0.1	-	0.0	0.0	0.0	0.0	-	0.0	0.0	-	0.0	0.0	0.0	-	-
FUEL																					
HFO	BBL (000)	753	740	725	670	658	657	655	658	658	657	660	661	660	665	664	667	666	666	678	679
LFO	BBL (000)	38	11	8	4	2	5	4	5	7	8	6	7	6	5	6	4	6	5	5	3
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG (CHP)	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS																					
Energy from Renewables	%	3%	5%	6%	12%	13%	13%	13%	13%	13%	13%	13%	13%	13%	12%	12%	12%	12%	12%	12%	12%
CO_2	TONS (000)	429	409	399	368	360	361	360	361	363	363	363	364	363	365	365	366	367	366	373	372
CO_2 Intensity	LBS/MWH	1,369	1,307	1,273	1,172	1,146	1,145	1,140	1,143	1,146	1,145	1,144	1,146	1,140	1,145	1,145	1,145	1,145	1,142	1,160	1,157
NO_X	TONS (000)	24	23	14	13	12	13	12	13	13	13	13	13	13	11	11	11	11	12	8	8
SO_X	TONS (000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPM	TONS (000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPACITY																					
Existing Thermal	MW	163	152	84	84	84	84	84	84	71	71	71	71	71	42	42	42	42	42	14	14
New Thermal	MW	-	-	55	55	55	55	55	55	55	55	55	55	55	83	83	83	83	83	111	111
Existing WTE	MW	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
New Renewables	MW	-	4	4	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
TOTAL CAPACITY		167	160	147	157	157	157	157	157	144	144	144	144	144	143	143	143	143	143	143	143
PEAK DEMAND	MW	107	107	107	107	108	108	108	108	108	108	109	109	109	109	109	109	110	110	110	110
DSM / EE	MW	1	2	4	5	5	6	6	6	6	7	7	7	8	8	8	9	9	9	10	10
Peak (net of DSM)	MW	106	105	104	103	102	102	102	102	102	102	102	102	101	101	101	101	101	100	100	100
Reserves	MW	33.0	37.0	37.4	37.8	38.2	38.1	38.1	38.0	38.0	38.0	37.9	37.9	37.8	37.8	37.7	37.7	37.6	37.6	37.0	36.9
Total Capacity Requirements	MW	139	142	141	141	140	140	140	140	140	140	140	139	139	139	139	139	138	138	137	137
Surplus/(Deficiency)	MW	28.1	17.8	5.7	16.8	16.9	16.9	17.0	17.1	4.3	4.5	4.6	4.7	4.9	4.4	4.6	4.9	5.1	5.4	5.7	6.1


BELCO - Annual Power Supply Costs by Component
Scenario 3, Base
$000
250,000
200,000
150,000
100,000
50,000
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Debt Service - Generation
Debt Service - T & D
Debt Service - LPG Infrastructure
Debt Service - LNG Infrastructure
Fuel - Existing
Fuel - New
Variable O&M - Existing
Variable O&M - New
Fixed O&M - Existing
Fixed O&M - New
Renewable


BELCO - Annual Energy Supply by Component
Scenario 3, Base
GWh
800
700
600
500
400
300
200
100
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
HFO
LFO
LNG
Electric Vehicles
Tynes Bay - WTE
Utility PV
Distributed PV (PPA)
Distributed PV (Rooftop)
LNG (CCHP / CHP)
Distributed Solar Water Heat
Energy Efficiency
System Load (net of DSM)


BELCO - Annual Capacity Supply by Component
Scenario 3, Base
MW
240
220
200
180
160
140
120
100
80
60
40
20
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Existing Thermal
New Thermal
Existing WTE
New Renewables
Peak (net of DSM)
Reserves


BELCO - Annual Supply Side Capacity Additions
Scenario 3, Base
(MW)
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Recip. MSD
GT
CC (1x1)
Utility Solar
Wind
Battery
LNG Refuel: E5 - E8 Recip. MSD
LPG Refuel: GT6 - GT8

TOTAL SYSTEM COSTS

Scenario 3, Base

		Levelized	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																						
TOTAL DEMAND	GWH	**632**	**626**	**626**	**627**	**628**	**629**	**630**	**631**	**632**	**633**	**634**	**635**	**636**	**637**	**638**	**639**	**640**	**641**	**642**	**643**	**644**
AMORTIZED CAPITAL COSTS																						
Debt Service - Generation	$000	15,877	774	774	14,220	15,041	47,840	15,280	15,280	15,280	15,280	15,473	15,473	15,473	15,473	18,955	18,955	18,955	18,955	18,955	26,190	26,190
Debt Service - T & D	$000	154	-	-	-	209	209	209	209	209	209	209	209	209	209	209	209	209	209	209	209	209
Debt Service - LPG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - LNG Infrastructure	$000	9,114	-	-	-	-	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753	13,753
Debt Service - DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Early Retirement Depreciation Cost	$000	19	-	-	237	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Costs	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPERATING COSTS																						
Fuel - Existing	$000	16,585	72,679	68,160	23,825	24,747	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel - New	$000	45,397	-	-	43,566	37,499	56,769	57,547	55,940	57,097	55,453	56,283	57,357	58,605	59,533	61,209	62,074	63,036	63,700	64,691	65,834	65,888
Variable O&M - Existing	$000	1,805	8,258	7,503	2,378	2,386	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M - New	$000	2,920	-	-	2,330	2,030	3,693	3,765	3,635	3,734	3,639	3,707	3,780	3,868	3,954	4,021	4,103	4,213	4,289	4,376	4,462	4,525
Fixed O&M - Existing	$000	763	3,022	2,828	1,469	1,498	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed O&M - New	$000	3,587	279	284	2,353	2,696	4,482	4,572	4,663	4,756	4,534	4,625	4,717	4,811	4,908	4,697	4,791	4,887	4,984	5,084	5,186	5,290
Renewable	$000	14,310	3,079	5,284	6,034	13,415	15,903	16,233	16,987	16,935	17,293	17,668	18,090	18,446	19,289	19,288	19,773	20,175	20,649	21,137	21,694	22,169
DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL COSTS	**$000**	**110,530**	**88,092**	**84,833**	**96,413**	**99,520**	**142,649**	**111,359**	**110,468**	**111,765**	**110,161**	**111,719**	**113,379**	**115,167**	**117,119**	**122,132**	**123,658**	**125,228**	**126,540**	**128,205**	**137,328**	**138,024**
	$/MWh	**174.9**	**140.6**	**135.5**	**153.7**	**158.5**	**226.8**	**176.8**	**175.1**	**176.9**	**174.1**	**176.3**	**178.6**	**181.2**	**183.9**	**191.5**	**193.6**	**195.8**	**197.5**	**199.8**	**213.7**	**214.5**

ANNUAL CAPITAL REQUIREMENTS

Scenario 3, Base

Nominal Dollars ($000)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																				
Generation																				
PS-10a_1	-	-	37,843	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_2	-	-	37,843	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_3	-	-	37,843	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_4	-	-	37,843	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10b_1	-	-	-	-	671	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10b_2	-	-	-	-	671	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10b_3	-	-	-	-	671	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10b_4	-	-	-	-	671	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-1c_1	-	-	-	-	-	-	-	-	-	-	-	-	-	36,883	-	-	-	-	-	-
PS-1c_2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40,722	-
PS-1c_3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40,722	-
PS-7a	-	-	-	-	6,814	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-7b	-	-	-	-	6,814	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-7c	-	-	-	-	6,487	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-7d	-	-	-	-	6,487	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-9a	-	-	-	-	975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-9b	-	-	-	-	975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-9c	-	-	-	-	975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-9d	-	-	-	-	3,034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery																				
PS-6a	7,600	-	-	-	-	-	-	-	-	1,900	-	-	-	-	-	-	-	-	-	-
PS-6b	-	-	-	8,065	-	-	-	-	-	-	-	-	-	2,016	-	-	-	-	-	-
T & D																				
Upgrades	-	-	-	1,592	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Infrastructure																				
LPG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	-	-	-	-	117,091	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM																				
Distributed PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCHP / CHP (LNG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distributed Solar Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL CAPITAL REQUIREMENTS	**7,600**	**-**	**151,371**	**9,657**	**152,336**	**-**	**-**	**-**	**-**	**1,900**	**-**	**-**	**-**	**38,900**	**-**	**-**	**-**	**-**	**81,444**	**-**

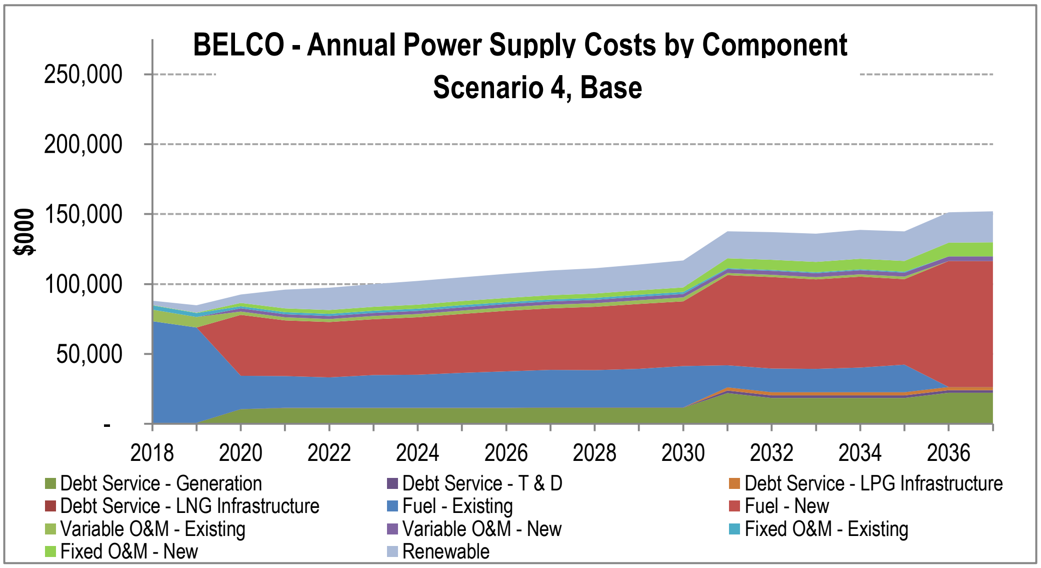
SYSTEM GENERATION SUMMARY

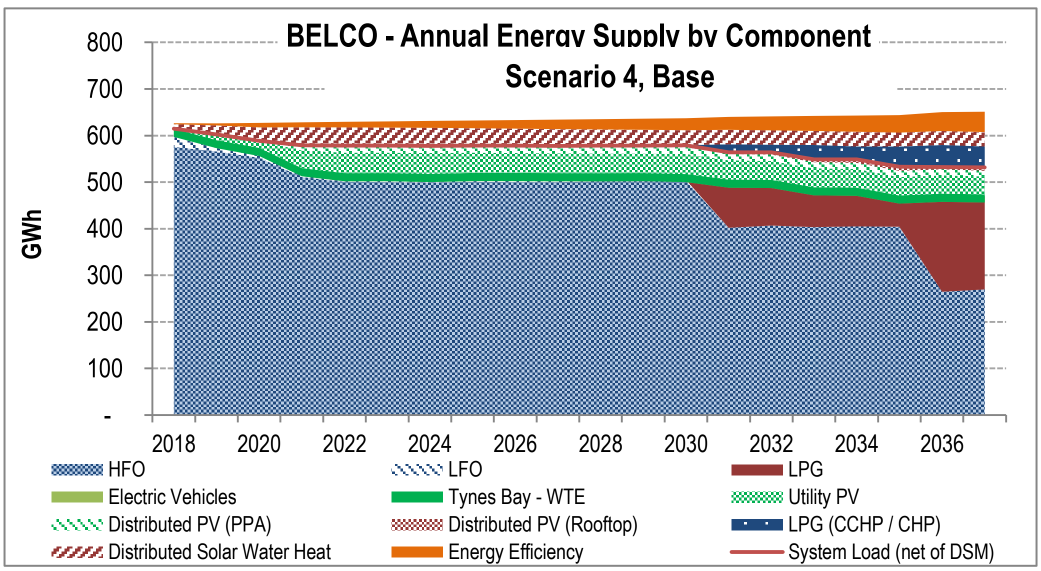
Scenario 3, Base

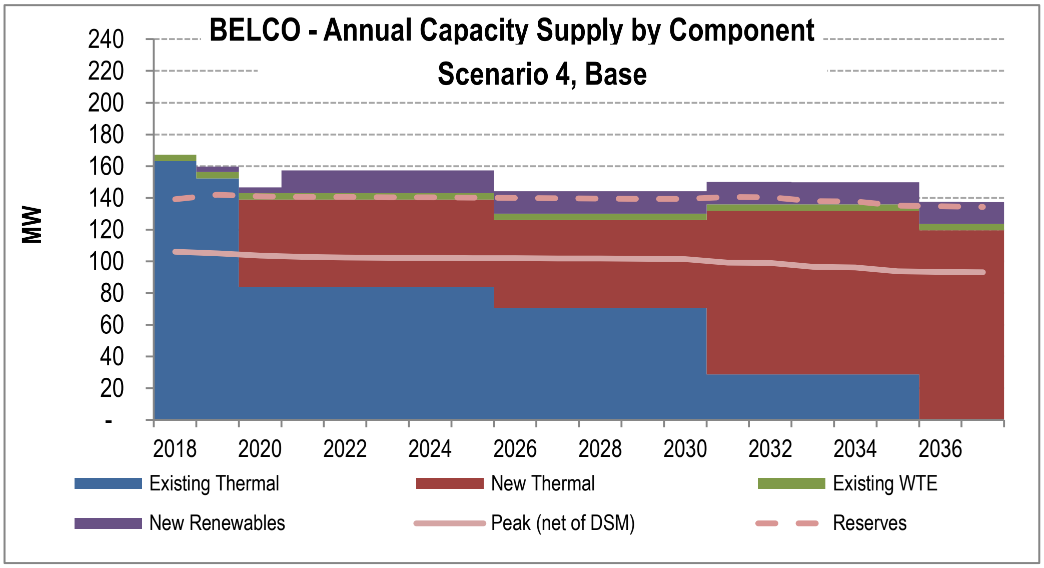
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																					
GENERATION MIX																					
HFO	GWH	576	566	552	512	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LFO	GWH	21	7	4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	GWH	-	-	-	-	485	485	465	468	450	450	451	452	451	454	454	455	456	456	456	456
LNG (CCHP / CHP)	GWH	-	-	-	-	18	18	37	37	55	55	55	55	55	55	55	55	55	55	55	55
Tynes Bay - WTE	GWH	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Utility PV	GWH	-	12	15	38	44	44	45	43	43	43	42	42	43	41	41	40	40	40	39	39
Distributed PV (PPA)	GWH	-	-	-	11	15	15	15	14	14	14	14	14	14	14	14	14	13	13	13	13
Distributed Solar Water Heat	GWH	9	17	26	34	34	34	33	33	33	32	32	32	31	31	31	30	30	30	30	30
Energy Efficiency	GWH	2	5	10	11	12	13	15	16	18	20	22	24	26	28	30	32	35	38	41	44
Electric Vehicles	GWH	-	-	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)	(11)	(12)	(14)
Distributed PV (Rooftop)	GWH	1	2	3	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total	GWH	626	626	627	628	631	632	633	633	635	636	636	637	638	640	640	641	642	643	644	645
HFO	%	91.9%	90.4%	88.1%	81.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LFO	%	3.4%	1.1%	0.6%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LNG (includes CHP)	%	0.0%	0.0%	0.0%	0.0%	79.8%	79.8%	79.4%	79.6%	79.6%	79.5%	79.5%	79.5%	79.3%	79.6%	79.5%	79.6%	79.5%	79.5%	79.3%	79.2%
Tynes Bay - WTE	%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
Utility PV	%	0.0%	1.9%	2.4%	6.0%	7.0%	7.0%	7.1%	6.8%	6.8%	6.7%	6.6%	6.6%	6.7%	6.4%	6.4%	6.3%	6.2%	6.2%	6.1%	6.0%
Distributed PV (PPA)	%	0.0%	0.0%	0.0%	1.8%	2.4%	2.3%	2.4%	2.3%	2.3%	2.2%	2.2%	2.2%	2.2%	2.2%	2.1%	2.1%	2.1%	2.1%	2.0%	2.0%
Distributed Solar Water Heat	%	1.4%	2.8%	4.1%	5.5%	5.4%	5.3%	5.3%	5.2%	5.1%	5.1%	5.0%	5.0%	4.9%	4.9%	4.8%	4.7%	4.7%	4.6%	4.6%	4.6%
Energy Efficiency	%	0.3%	0.7%	1.5%	1.7%	1.9%	2.1%	2.3%	2.6%	2.9%	3.2%	3.5%	3.7%	4.0%	4.3%	4.7%	5.0%	5.4%	5.8%	6.3%	6.8%
Electric Vehicles	%	0.0%	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.1%	-0.2%	-0.2%	-0.3%	-0.4%	-0.6%	-0.7%	-0.9%	-1.1%	-1.3%	-1.5%	-1.7%	-1.9%	-2.1%
Distributed PV (Rooftop)	%	0.2%	0.3%	0.5%	0.7%	0.8%	0.8%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Total	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

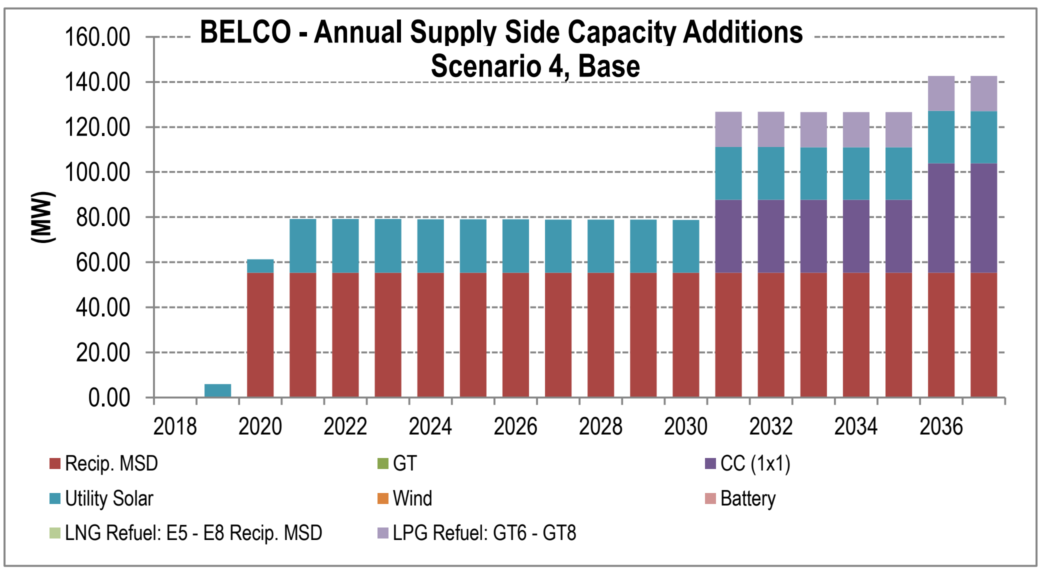
SYSTEM OPERATIONS SUMMARY — Scenario 3, Base

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																					
ENERGY																					
Existing Thermal	GWH	597	573	198	207	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Thermal	GWH	-	-	359	306	485	485	465	468	450	450	451	452	451	454	454	455	456	456	456	456
Existing WTE	GWH	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
New Renewables	GWH	-	12	15	49	59	59	60	58	57	57	56	56	57	55	54	54	53	53	53	52
TOTAL ENERGY		615	602	589	579	562	562	543	543	525	524	524	525	526	526	526	527	527	527	526	525
Gross Energy	GWH	626	626	627	628	629	630	631	632	633	634	635	636	637	638	639	640	641	642	643	644
DSM / EE / EV	GWH	12	24	38	49	69	70	90	90	110	111	112	112	113	113	114	115	116	117	119	120
System Load	GWH	615	602	589	579	560	560	541	541	523	523	523	524	524	524	524	525	525	525	524	523
LOLH	HOURS	-	-	-	5	-	-	-	-	-	-	-	-	-	-	8	3	1	-	3	-
Dump Energy	GWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emergency Energy	GWH	-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	-	0.0	-
FUEL																					
HFO	BBL (000)	753	740	725	670	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LFO	BBL (000)	38	11	8	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG	GBTU	-	-	-	-	3,632	3,631	3,469	3,490	3,334	3,334	3,335	3,347	3,345	3,369	3,367	3,378	3,378	3,376	3,383	3,372
LNG (CHP)	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS																					
Energy from Renewables	%	3%	5%	6%	12%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	13%	13%	13%
CO_2	TONS (000)	429	409	399	367	212	212	203	204	195	195	195	196	196	197	197	198	198	197	198	197
CO_2 Intensity	LBS/MWH	1,369	1,307	1,273	1,169	675	674	643	646	616	615	615	616	614	618	617	618	617	616	616	613
NO_X	TONS (000)	24	23	14	13	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
SO_X	TONS (000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPM	TONS (000)	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPACITY																					
Existing Thermal	MW	163	152	84	84	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New Thermal	MW	-	-	55	55	143	143	143	143	130	130	130	130	130	117	117	117	117	117	117	117
Existing WTE	MW	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
New Renewables	MW	-	4	4	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
TOTAL CAPACITY		167	160	147	157	161	161	161	161	148	148	148	148	148	135	135	135	135	135	135	135
PEAK DEMAND	MW	107	107	107	107	108	108	108	108	108	108	109	109	109	109	109	109	110	110	110	110
DSM / EE	MW	1	2	4	5	8	8	11	11	14	14	14	15	15	15	16	16	16	17	17	18
Peak (net of DSM)	MW	106	105	104	103	100	100	97	97	95	94	94	94	94	94	94	93	93	93	93	92
Reserves	MW	33.0	37.0	37.4	37.8	39.3	39.3	39.2	39.2	39.2	39.1	39.1	39.0	39.0	38.9	38.9	38.8	38.8	38.8	38.7	38.7
Total Capacity Requirements	MW	139	142	141	141	139	139	136	136	134	133	133	133	133	133	133	132	132	132	131	131
Surplus/(Deficiency)	MW	28.1	17.8	5.7	16.8	21.9	21.9	24.5	24.6	14.4	14.6	14.7	14.9	15.0	2.4	2.6	2.8	3.1	3.4	3.7	4.0


BELCO - Annual Power Supply Costs by Component
Scenario 4, Base
$000
250,000
200,000
150,000
100,000
50,000
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Debt Service - Generation
Debt Service - T & D
Debt Service - LPG Infrastructure
Debt Service - LNG Infrastructure
Fuel - Existing
Fuel - New
Variable O&M - Existing
Variable O&M - New
Fixed O&M - Existing
Fixed O&M - New
Renewable


BELCO - Annual Energy Supply by Component
Scenario 4, Base
GWh
800
700
600
500
400
300
200
100
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
HFO
LFO
LPG
Electric Vehicles
Tynes Bay - WTE
Utility PV
Distributed PV (PPA)
Distributed PV (Rooftop)
LPG (CCHP / CHP)
Distributed Solar Water Heat
Energy Efficiency
System Load (net of DSM)


BELCO - Annual Capacity Supply by Component
Scenario 4, Base
MW
240
220
200
180
160
140
120
100
80
60
40
20
-
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Existing Thermal
New Thermal
Existing WTE
New Renewables
Peak (net of DSM)
Reserves


BELCO - Annual Supply Side Capacity Additions
Scenario 4, Base
(MW)
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Recip. MSD
GT
CC (1x1)
Utility Solar
Wind
Battery
LNG Refuel: E5 - E8 Recip. MSD
LPG Refuel: GT6 - GT8

TOTAL SYSTEM COSTS

Scenario 4, Base

		Levelized	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																						
TOTAL DEMAND	GWH	**632**	**626**	**626**	**627**	**628**	**629**	**630**	**631**	**632**	**633**	**634**	**635**	**636**	**637**	**638**	**639**	**640**	**641**	**642**	**643**	**644**
AMORTIZED CAPITAL COSTS																						
Debt Service - Generation	$000	11,114	774	774	10,569	11,390	11,390	11,390	11,390	11,390	11,390	11,584	11,584	11,584	11,584	22,042	18,546	18,546	18,546	18,546	22,276	22,276
Debt Service - T & D	$000	473	-	-	-	209	209	209	209	209	209	209	209	209	209	1,843	1,843	1,843	1,843	1,843	1,843	1,843
Debt Service - LPG Infrastructure	$000	444	-	-	-	-	-	-	-	-	-	-	-	-	-	2,279	2,279	2,279	2,279	2,279	2,279	2,279
Debt Service - LNG Infrastructure	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Service - DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Early Retirement Depreciation Cost	$000	19	-	-	237	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Costs	$000	105	-	-	-	-	-	-	-	-	-	-	-	-	-	537	537	538	538	539	540	540
OPERATING COSTS																						
Fuel - Existing	$000	30,750	72,679	68,160	23,825	22,609	21,679	23,340	23,569	24,930	25,986	26,853	26,653	27,600	29,584	15,747	16,931	16,676	17,606	19,706	-	-
Fuel - New	$000	40,116	-	-	43,566	39,811	39,568	39,925	41,097	42,107	43,301	43,996	45,280	46,390	46,275	64,456	65,410	64,008	65,028	61,118	90,073	90,012
Variable O&M - Existing	$000	3,186	8,258	7,503	2,378	2,229	2,146	2,324	2,317	2,443	2,528	2,631	2,575	2,676	2,815	1,499	1,595	1,581	1,660	1,859	-	-
Variable O&M - New	$000	1,994	-	-	2,330	2,155	2,179	2,177	2,227	2,257	2,301	2,335	2,412	2,460	2,432	2,788	2,828	2,834	2,873	2,768	3,303	3,387
Fixed O&M - Existing	$000	1,562	3,022	2,828	1,469	1,498	1,528	1,558	1,590	1,621	1,346	1,373	1,400	1,428	1,457	660	673	687	700	714	-	-
Fixed O&M - New	$000	3,377	279	284	2,353	2,696	2,750	2,805	2,861	2,918	2,977	3,036	3,097	3,159	3,222	7,104	7,246	7,391	7,538	7,689	9,839	10,036
Renewable	$000	14,310	3,079	5,284	6,034	13,415	15,903	16,233	16,987	16,935	17,293	17,668	18,090	18,446	19,289	19,288	19,773	20,175	20,649	21,137	21,694	22,169
DSM	$000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL COSTS	**$000**	**107,449**	**88,092**	**84,833**	**92,762**	**96,012**	**97,352**	**99,961**	**102,247**	**104,811**	**107,331**	**109,684**	**111,300**	**113,952**	**116,867**	**138,242**	**137,660**	**136,556**	**139,260**	**138,197**	**151,845**	**152,541**
	$/MWh	**170.0**	**140.6**	**135.5**	**147.9**	**152.9**	**154.8**	**158.7**	**162.1**	**165.9**	**169.6**	**173.0**	**175.3**	**179.2**	**183.5**	**216.8**	**215.5**	**213.5**	**217.4**	**215.4**	**236.3**	**237.0**

ANNUAL CAPITAL REQUIREMENTS

Scenario 4, Base

Nominal Dollars ($000)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																				
Generation																				
PS-10a_1	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_2	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_3	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-10a_4	-	-	27,566	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PS-3b_1	-	-	-	-	-	-	-	-	-	-	-	-	-	38,032	-	-	-	-	-	-
PS-3b_2	-	-	-	-	-	-	-	-	-	-	-	-	-	38,032	-	-	-	-	-	-
PS-3b_3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41,990	-
PS-8a	-	-	-	-	-	-	-	-	-	-	-	-	-	1,166	-	-	-	-	-	-
PS-8b	-	-	-	-	-	-	-	-	-	-	-	-	-	1,166	-	-	-	-	-	-
PS-8c	-	-	-	-	-	-	-	-	-	-	-	-	-	1,166	-	-	-	-	-	-
Battery																				
PS-6a	7,600	-	-	-	-	-	-	-	-	1,900	-	-	-	-	-	-	-	-	-	-
PS-6b	-	-	-	8,065	-	-	-	-	-	-	-	-	-	2,016	-	-	-	-	-	-
T & D																				
Upgrades	-	-	-	1,592	-	-	-	-	-	-	-	-	-	16,362	-	-	-	-	-	-
Fuel Infrastructure																				
LPG	-	-	-	-	-	-	-	-	-	-	-	-	-	19,404	-	-	-	-	-	-
LNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM																				
Distributed PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCHP / CHP (LNG)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distributed Solar Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL CAPITAL REQUIREMENTS	**7,600**	**-**	**110,266**	**9,657**	**-**	**-**	**-**	**-**	**-**	**1,900**	**-**	**-**	**-**	**117,343**	**-**	**-**	**-**	**-**	**41,990**	**-**

SYSTEM GENERATION SUMMARY

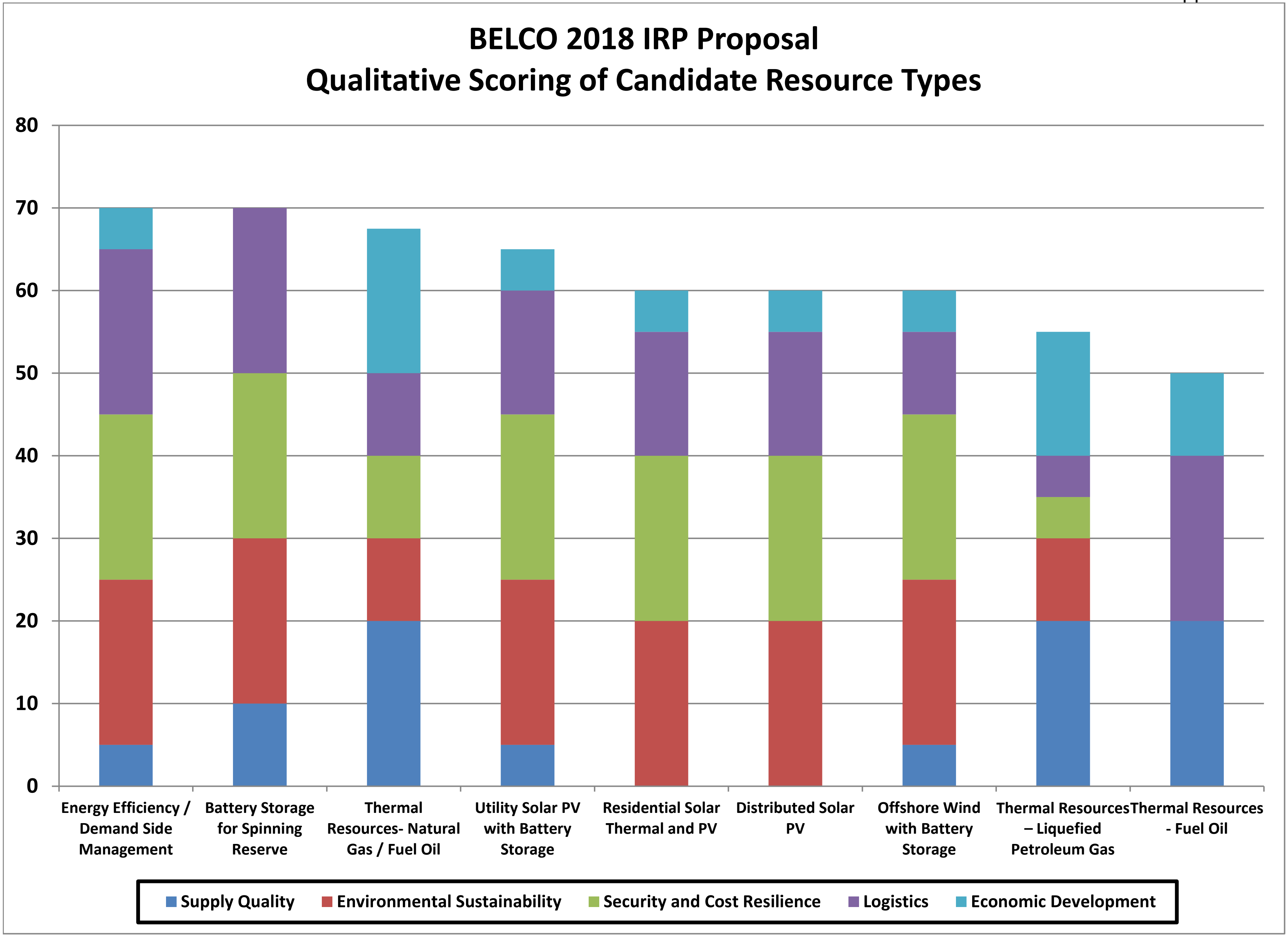
Scenario 4, Base

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																					
GENERATION MIX																					
HFO	GWH	576	566	552	511	501	500	499	501	500	500	502	502	502	402	407	403	405	404	265	270
LFO	GWH	21	7	4	2	1	2	2	2	4	4	3	4	3	-	-	-	-	-	-	-
LPG (CCHP / CHP)	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-	16	16	31	31	47	47	47
LPG	GWH	-	-	-	-	-	-	-	-	-	-	-	-	-	92	88	77	75	61	205	200
Tynes Bay - WTE	GWH	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Utility PV	GWH	-	12	15	38	44	44	45	43	43	43	42	42	43	41	41	40	40	40	39	39
Distributed PV (PPA)	GWH	-	-	-	11	15	15	15	14	14	14	14	14	14	14	14	14	13	13	13	13
Distributed Solar Water Heat	GWH	9	17	26	34	34	34	33	33	33	32	32	32	31	31	31	30	30	30	30	30
Energy Efficiency	GWH	2	5	10	11	12	13	15	16	18	20	22	24	26	28	30	32	35	38	41	44
Electric Vehicles	GWH	-	-	(0)	(0)	(0)	(1)	(1)	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(10)	(11)	(12)	(14)
Distributed PV (Rooftop)	GWH	1	2	3	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total	GWH	626	626	627	628	629	630	631	632	633	634	635	636	637	640	641	642	643	644	650	651
HFO	%	91.9%	90.4%	88.1%	81.3%	79.6%	79.3%	79.0%	79.2%	79.0%	78.8%	79.0%	79.0%	78.8%	62.8%	63.4%	62.8%	63.0%	62.8%	40.7%	41.4%
LFO	%	3.4%	1.1%	0.6%	0.3%	0.2%	0.4%	0.3%	0.4%	0.6%	0.6%	0.5%	0.6%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
LPG (includes CCHP)	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	16.8%	16.2%	16.8%	16.6%	16.7%	38.8%	37.9%
Tynes Bay - WTE	%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%
Utility PV	%	0.0%	1.9%	2.4%	6.0%	7.0%	7.0%	7.1%	6.8%	6.8%	6.7%	6.6%	6.6%	6.7%	6.4%	6.4%	6.3%	6.2%	6.2%	6.0%	6.0%
Distributed PV (PPA)	%	0.0%	0.0%	0.0%	1.8%	2.4%	2.3%	2.4%	2.3%	2.3%	2.2%	2.2%	2.2%	2.2%	2.2%	2.1%	2.1%	2.1%	2.1%	2.0%	2.0%
Distributed Solar Water Heat	%	1.4%	2.8%	4.1%	5.5%	5.4%	5.3%	5.3%	5.2%	5.2%	5.1%	5.1%	5.0%	4.9%	4.9%	4.8%	4.7%	4.7%	4.6%	4.6%	4.5%
Energy Efficiency	%	0.3%	0.7%	1.5%	1.7%	1.9%	2.1%	2.4%	2.6%	2.9%	3.2%	3.5%	3.7%	4.0%	4.3%	4.7%	5.0%	5.4%	5.8%	6.2%	6.7%
Electric Vehicles	%	0.0%	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.1%	-0.2%	-0.2%	-0.3%	-0.5%	-0.6%	-0.8%	-0.9%	-1.1%	-1.3%	-1.5%	-1.7%	-1.9%	-2.1%
Distributed PV (Rooftop)	%	0.2%	0.3%	0.5%	0.7%	0.8%	0.8%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.9%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%
Total	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

SYSTEM OPERATIONS SUMMARY

Scenario 4, Base

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BELCO																					
ENERGY																					
Existing Thermal	GWH	597	573	198	188	180	187	184	189	189	191	188	189	198	104	109	106	109	120	-	-
New Thermal	GWH	-	-	359	325	322	316	317	314	314	313	317	317	307	389	386	374	371	345	470	470
Existing WTE	GWH	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
New Renewables	GWH	-	12	15	49	59	59	60	58	57	57	56	56	57	55	54	54	53	53	53	52
TOTAL ENERGY		615	602	589	580	579	579	579	579	578	578	578	579	579	566	567	551	551	535	540	539
Gross Energy	GWH	626	626	627	628	629	630	631	632	633	634	635	636	637	638	639	640	641	642	643	644
DSM / EE / EV	GWH	12	24	38	49	51	52	53	54	55	56	57	57	58	74	75	91	92	109	110	112
System Load	GWH	615	602	589	579	578	578	578	578	578	578	578	579	579	564	564	549	549	533	532	532
LOLH	HOURS	-	-	-	-	-	9	-	4	3	11	2	-	1	-	-	-	-	-	1	2
Dump Energy	GWH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emergency Energy	GWH	-	-	-	-	-	0.1	-	0.0	0.0	0.0	0.0	-	0.0	-	-	-	-	-	0.0	0.0
FUEL																					
HFO	BBL (000)	753	740	725	670	658	657	655	658	658	657	660	661	660	533	539	535	536	534	361	367
LFO	BBL (000)	38	11	8	4	2	5	4	5	7	8	6	7	6	-	-	-	-	-	-	-
LNG	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG (CHP)	GBTU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EMISSIONS / RPS																					
Energy from Renewables	%	3%	5%	6%	12%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
CO_2	TONS (000)	429	409	399	368	360	361	360	361	363	363	363	364	363	354	354	344	344	333	336	336
CO_2 Intensity	LBS/MWH	1,369	1,307	1,273	1,172	1,146	1,145	1,140	1,143	1,146	1,145	1,144	1,146	1,140	1,109	1,109	1,076	1,075	1,038	1,046	1,044
NO_X	TONS (000)	24	23	14	13	12	13	12	13	13	13	13	13	13	10	10	10	10	10	6	6
SO_X	TONS (000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FPM	TONS (000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPACITY																					
Existing Thermal	MW	163	152	84	84	84	84	84	84	71	71	71	71	71	29	29	29	29	29	-	-
New Thermal	MW	-	-	55	55	55	55	55	55	55	55	55	55	55	103	103	103	103	103	120	120
Existing WTE	MW	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
New Renewables	MW	-	4	4	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
TOTAL CAPACITY		167	160	147	157	157	157	157	157	144	144	144	144	144	150	150	150	150	150	137	137
PEAK DEMAND	MW	107	107	107	107	108	108	108	108	108	108	109	109	109	109	109	109	110	110	110	110
DSM / EE	MW	1	2	4	5	5	6	6	6	6	7	7	7	8	10	10	13	13	16	17	17
Peak (net of DSM)	MW	106	105	104	103	102	102	102	102	102	102	102	102	101	99	99	96	96	94	93	93
Reserves	MW	33.0	37.0	37.4	37.8	38.2	38.1	38.1	38.0	38.0	38.0	37.9	37.9	37.8	41.6	41.5	41.5	41.4	41.4	41.4	41.3
Total Capacity Requirements	MW	139	142	141	141	140	140	140	140	140	140	140	139	139	141	140	138	138	135	135	134
Surplus/(Deficiency)	MW	28.1	17.8	5.7	16.8	16.9	16.9	17.0	17.1	4.3	4.5	4.6	4.7	4.9	9.4	9.6	12.0	12.3	14.8	2.7	3.1


BELCO 2018 IRP Proposal
Qualitative Scoring of Candidate Resource Types
80
70
60
50
40
30
20
10
0
Energy Efficiency / Demand Side Management
Battery Storage for Spinning Reserve
Thermal Resources- Natural Gas / Fuel Oil
Utility Solar PV with Battery Storage
Residential Solar Thermal and PV
Distributed Solar PV
Offshore Wind with Battery Storage
Thermal Resources – Liquefied Petroleum Gas
Thermal Resources - Fuel Oil
Supply Quality
Environmental Sustainability
Security and Cost Resilience
Logistics
Economic Development

BELCO 2018 IRP Proposal
Qualitative Scoring of Candidate Resource Types

Ln. No.	Qualitative Factor	Max Score	Energy Efficiency / Demand Side Management	Battery Storage for Spinning Reserve	Thermal Resources- Natural Gas / Fuel Oil	Utility Solar PV with Battery Storage	Residential Solar Thermal and PV	Distributed Solar PV	Offshore Wind with Battery Storage	Thermal Resources – Liquefied Petroleum Gas	Thermal Resources - Fuel Oil
1	Supply Quality	20	5	10	20	5	0	0	5	20	20
2	Environmental Sustainability	20	20	20	10	20	20	20	20	10	0
3	Security and Cost Resilience	20	20	20	10	20	20	20	20	5	0
4	Logistics	20	20	20	10	15	15	15	10	5	20
5	Economic Development	20	5	0	17.5	5	5	5	5	15	10
6	**TOTAL SCORE**	**100**	**70**	**70**	**67.5**	**65**	**60**	**60**	**60**	**55**	**50**

BELCO 2018 IRP Proposal
Qualitative Evaluation Matrix

	Qualitative Factor	Factor Description	Max Score	Thermal Resources - Fuel Oil	Thermal Resources- Natural Gas / Fuel Oil	Thermal Resources – Liquefied Petroleum Gas	Energy Efficiency / Demand Side Management	Residential Solar Thermal and PV	Distributed Solar PV	Utility Solar PV with Battery Storage	Offshore Wind with Battery Storage	Battery Storage for Spinning Reserve
1	**Supply Quality**	The degree to which the asset enhances or reinforces system reliability as a firm resource and is a proven technology directly under the utility's control as it relates to meeting system energy and demand requirements.		Units are based on mature technology for operation as firm, dispatchable resources providing high quality, reliable power.	Units are based on mature technology for operation as firm, dispatchable resources providing high quality, reliable power.	Units are based on mature technology for operation as firm, dispatchable resources providing high quality, reliable power.	Energy abatement is subject to reliability of demand response equipment and ability to achieve estimated savings from energy efficiency measures.	Resource power output is intermittent and not dispatchable.	Resource power output is intermittent and not dispatchable.	Resource is paired with battery energy storage system to address intermittent output but remains non- dispatchable.	Resource is paired with battery energy storage system to address intermittent output but remains non- dispatchable.	Resource has a fast response time and provides high levels of reliability and supply quality. It requires time to recharge after each operation.
		Score	20	20	20	20	5	0	0	5	5	10
2	**Environmental Sustainability**	The degree to which the asset will cause a reduction in the emission of Green House Gases by BELCO.		Resource will not cause a reduction in GHG emissions.	Operation on natural gas as a primary fuel will cause a reduction in GHG emissions relative to business as usual.	Operation on LPG as a primary fuel will cause a reduction in GHG emissions relative to business as usual.	Measures produce no GHG emissions.	Resource produces no GHG emissions.	Resource produces no GHG emissions.	Resource produces no GHG emissions.	Resource produces no GHG emissions.	Resource produces no GHG emissions.
		Score	20	0	10	10	20	20	20	20	20	20
3	**Security and Cost Resilience**	The degree to which the asset contributes to resource/fuel diversity to make Bermuda resilient to shocks caused by dramatic changes in the cost and availability of fuel.		Resource will not contribute to resource/fuel diversity.	Dual fuel resource will increase fuel diversity and cost resiliency.	Operation on LPG will increase fuel diversity and cost resiliency.	Measures are not dependent on any fuel source.	Fuel source is renewable and available at no cost.	Fuel source is renewable and available at no cost.	Fuel source is renewable and available at no cost.	Fuel source is renewable and available at no cost.	Resource is not dependent on any fuel source.
		Score	20	0	10	5	20	20	20	20	20	20
4	**Logistics**	The degree to which the asset provides for ease of logistics and implementation		Minimal logistical issues are anticipated. This would be a repeat of a process that is very familiar to BELCO.	Significant gas fuel handling and transportation infrastructure is required, creating permitting and siting challenges.	Significant gas fuel handling infrastructure is required, creating permitting and siting challenges. Transportation/handling risk are higher than liquefied natural gas. Resource to be co-located at gas storage facility site.	Minimal logistical issues are anticipated.	Some challenges are anticipated in siting these installations.	Some challenges are anticipated in siting these installations.	A primary potential site has been identified as being available.	The extensive shallow off-shore waters of Bermuda offer good potential for installation.	No siting issues are anticipated.
		Score	20	20	10	5	20	15	15	15	10	20
5	**Economic Development**	The degree to which the asset contributes to the economic Development for Bermuda with a focus on job creation.		Construction jobs would be created	Construction as well as long term O & M jobs would be created. Would create potential for piped gas distribution.	Construction as well as long term O & M jobs would be created.	Jobs associated with energy audits and equipment installations would be created.	Jobs associated with equipment installations would be created.	Jobs associated with equipment installations would be created.	Jobs associated with plant construction would be created.	Jobs associated with plant construction would be created.	Minimal short-term jobs associated with installation would be created.
		Score	20	10	17.5	15	5	5	5	5	5	0
	TOTAL SCORE		100	50	67.5	55	70	60	60	65	60	70

BELCO 2018 IRP Proposal
Combined Quantitative and Qualitative Scoring

Scenario #	Levelized Cost ($ M)	Raw Cost Score	Weighted Cost Score	Non-Cost Score	Raw Non-Cost Score	Weighted Non-Cost Score	Total Weighted Score	Rank
1	170.80	98.4%	78.7%	51.6%	81%	16.1%	94.8%	4
2	168.08	100.0%	80.0%	52.5%	82%	16.4%	96.4%	2
3	174.87	96.1%	76.9%	64.0%	100%	20.0%	96.9%	1
4	169.99	98.9%	79.1%	53.1%	83%	16.6%	95.7%	3

Appendix II.F
DISCUSSION DOCUMENT CANDIDATE RESOURCES
REQUIRING MORE IN-DEPTH STUDY

Appendix II.F
DISCUSSION DOCUMENT CANDIDATE RESOURCES REQUIRING MORE IN-DEPTH STUDY

Introduction

At the commencement of the IRP process, BELCO TD&R recognized that there exists an abundance of supply side and demand side generating resources that could be considered as potential candidates to assist BELCO TD&R in meeting its established objectives for the power system. However, it was determined that the choice of resources for the quantitative evaluation would focus on technologies (both to serve load as well as to abate load) and fuels that have been tested and proven, or display a high likelihood of technical and economic success based on a global energy industry outlook. The purpose of this document is to provide a high-level discussion of technologies that were not included in the quantitative analysis. BELCO TD&R will continue to monitor these options for improved economic attractiveness and/or improvements in technology that foster commercial deployment.

Fuel Cell Technology

Fuel cell technology was considered by BELCO TD&R as a preliminary candidate option as part of a gas centric fuel option since the fuel cell is typically fueled by natural gas. Natural gas infrastructure would be required to render the fuel cell a viable option for BELCO TD&R.

The candidate fuel cell facility utilizes multiple fuel cell units, each with a power output rating of between 100 to 3,000 kW, for a total output of 10 MW. The fuel cells convert chemical energy directly into electricity from natural gas and air vapor and produce heat and water vapor as by products. The fuel (the reactant) is introduced continuously to the anode side of the unit cell while air (the oxidant) is introduced continuously into the cathode side via a blower. Electricity is produced by ionic transfer across an electrolyte that separates the fuel from the air.

Since each fuel cell develops a relatively low voltage, the cells are stacked to produce a higher, more useful voltage. Depending on the type of fuel cell, high temperature waste heat from the process may be available for cogeneration application. Each fuel cell stack generates DC electric power. These stacks are connected to DC-to-AC inverters that produce an output of 60 cycles, three phase AC electric power ranging from 480 volts to 13,800 volts.

Natural gas for the fuel cells would be provided from the proposed LNG facility as discussed in the body of this report. The heat rate for a fuel cell facility is in the range of 7,500 – 8,500 BTU/kWh – Higher Heating Value (HHV). The capital cost estimate for a 10 MW fuel cell facility based on a North American installation is estimated at approximately $10,000/kW.

Considering the relatively high capital cost of this technology compared to other gas fueled candidate options, BELCO TD&R decided to exclude fuel cells from the options selected for the quantitative evaluation. Instead, BELCO TD&R will continue to monitor the capital cost of this technology with a view of including it as a candidate in future IRP iterations as the cost becomes competitive.

Offshore Wind Energy

BELCO TD&R has established through preliminary investigations that there are no suitable on-land sites available on Bermuda for the development of a utility scale wind energy project and is therefore considering an off-shore installation. Elsam Engineering A/S prepared a feasibility study for an off-shore wind energy resource that included a review of four potential sites as follows:

- The Northwest corner of Murray's Anchorage
- A limited area bounded to the north by the White flats and to the west and east by the North Channel and the Brackish Pond Flats respectively
- Two areas to the North of Murray's Anchorage

The Elsam report recommends the Murray's Anchorage and a site near the North Channel for further investigation.

The capacity of the wind farm would be a nominal 20 MW. However, no ambient data has been collected at either site to establish a wind profile and projected hourly generation profile. Leidos used wind data from the Bermuda airport to estimate the net generation profile for the off-shore wind resource. Leidos also used its database of costs to estimate the capital and O&M costs for the resource. Offshore wind energy was eliminated as a candidate resource based on the results of the LCOE screening.

Prior to proceeding with the development of this resource, Leidos recommends that the feasibility study be updated and that site data be collected for use in developing an hourly generation profile.

Biomass

Biomass power is derived from plants either directly using combustion or gasification to produce heat to drive a generator or indirectly through conversion to "biofuels" such as methane gas, ethanol or biodiesel. It is considered to be a renewable fuel in comparison to fossil fuels such as natural gas, petroleum and coal.

Wood is the most common form of biomass used for power generation, although agricultural crop wastes offer significant opportunity for "closed loop" fuel supply in many regions. In Bermuda, wood pellets shipped from the southeastern United States are the most likely biomass fuel source. Wood pellets can be shipped to a Bermuda port either as standard wood pellets available from a growing industry in the United States or as "torrified" pellets that are roasted to drive off volatile material, leaving a water-resistant product with a heating value closer to coal.

Current biomass power generation varies widely, depending on local climate and economy, and ranges from forest waste to sugar cane waste to rice hulls and animal wastes. In the United States, biomass power generation is greater than 10,000 MW and growing slowly but steadily, depending on the many economic factors affecting this type of project, including fuel supply, harvesting and transportation cost, trans-shipping in some cases, construction cost, energy off-take agreement terms, local environmental regulations, and operating and maintenance costs.

Biomass power projects typically range in size from 5 MW to 100 MW and are often involved in combined heat and power projects to provide both cogenerated heat and electric energy. Energy conversion technologies include oxidation combustion systems such as stoker-fired and fluidized bed boilers, partial oxidation gasification fluidized bed boilers, and smaller pyrolysis units generating a synthetic fuel gas in the absence of oxygen.

While Biomass is a potential candidate resource, the opportunity for significant reduction in emissions that could be achieved by converting to 100 percent gas fuel is eliminated.

Landfill Gas

A special subset of biomass power generation is landfill gas ("LFG") generation. LFG results from the decomposition of municipal solid waste buried in closed landfill cells under anaerobic (absence of oxygen) conditions. LFG is well-established as a significant renewable energy source because its capture and conversion to electrical or thermal energy avoids discharge of methane into the atmosphere, which is 28 times more potent than carbon dioxide as a greenhouse gas.

Use of LFG for power generation requires treatment to remove substances such as moisture, particulates and chemical impurities that can be harmful to prime mover generators. Boilers and internal combustion engines require the least treatment, while gas turbines require additional treatment to meet manufacturers' specifications.

There are more than 500 LFG power projects operating in the United States, having established a solid performance history since the late 1990s. Whether used to reduce the cost of landfill leachate treatment or to generate electricity, LFG projects are often profitable, even without renewable energy credits. Roughly speaking, one million tons of municipal solid waste can generate up to about 1 MW of electricity. Depending on the size of the landfill, electric generation equipment ranges from boilers and steam turbines to internal combustion engines. LFG can also be used for direct thermal applications such as kilns, dryers, and industrial heaters.

In Bermuda, municipal waste is incinerated in the government-owned Tynes Bay incinerator facility and the energy produced is purchased by BELCO under a Power Purchase Agreement. As a result, the landfill comprises largely horticultural waste and if harnessed for use in power generation, it is clear that the landfill gas can produce only a small fraction of Bermuda's energy needs.

Ice Storage

BELCO TD&R's concept for an ice storage system is based on a distributed energy storage solution that is used in conjunction with existing commercial direct expansion air conditioning ("AC") systems. The ice storage units would use energy from the BELCO TD&R system during off-peak (nighttime) periods, converting it into stored thermal energy in the form of ice, and use the ice to perform useful work for building cooling by displacing the operation of commercial AC condensing units during on-peak (daytime) periods. The ice storage equipment would be installed behind the utility meter at small to medium commercial customer sites including shopping centers, office buildings, restaurants, light industrial buildings, and guest houses.

As an example, a commercially available unit in a typical application will reportedly shift the electrical energy consumed by a five ton scroll compressor and its associated condensing unit fans operating under full load conditions, continuously, for five hours. Electrically, the unit reportedly shifts between 36 and 50 kilowatt-hours of electric energy to the off-peak hours, reducing between 6 and 9 kilowatts of electric on-peak demand for six hours. Thus, the ice storage units would provide a reliable reduction in demand for the Bermuda system.

While modeling parameters have been developed for the individual ice storage units based on technical data and cost information from the equipment supplier, additional work is required to quantify the potential number of installs for the ice storage units and establish their economic feasibility for Bermuda.

Ocean Power

Bermuda is surrounded by an abundance of seawater which has the potential to provide BELCO TD&R with continuous power from a clean, renewable energy resource. Several concepts that seek to harness the Ocean's energy potential are being developed. Such concepts include:

- Ocean Thermal Energy
- Wave Energy
- Tidal and Ocean Currents

Ocean Thermal Energy Conversion ("OTEC") utilizes the differential in temperature between the water near the surface and the water at depths of 3,000 feet or below. In tropical climates the differential is as high as 40 degrees Fahrenheit. Typically, the thermal efficiency of the process is very low and consequently, a very large volume of water is required to drive the thermodynamic cycle. Several small demonstration OTEC plants have been placed in successful operation in the Pacific area but no utility scale installations have been completed.

There are several types of wave energy conversion ("WEC") devices. Four of the more developed designs include the attenuator type, the point absorber type, the overtopping type and the oscillating water column type.

- The attenuator type consists of several devices that float on the surface of the ocean and are hinged together at their ends. The relative motions of these devices drive a hydraulic fluid that is used in turn to drive turbo-generators.
- The point absorber type is a device that typically has one end attached to the seabed and the other end at the surface. This device converts the vertical motion of the upper end device into electricity.
- The overtopping type can be fixed to the shore or can be floating. These devices collect water from wave motion in an elevated reservoir to drive low head turbo-generators.
- The oscillating water-column type is a semi-submerged device that captures the rising and falling motion of the water near the surface that alternately pressurizes and depressurizes a volume of air within the device. The alternating pressurized air passes (in both directions) through a turbo-generator to generate electricity.
- Tidal and ocean current energy conversion is a technology that utilizes the flow of water caused by tidal forces or ocean currents to drive a turbo-generator. In the case of Bermuda, the current flow in the offshore Gulf Stream is a significant resource. There are many different designs for tidal in-stream energy conversion devices, including vertical and horizontal turbines with either ducted or open systems.

None of the concepts that are designed to harness the ocean's potential as a source of electric power has achieved commercial deployment at this time. Several small demonstration installations have been placed in service for testing but no utility scale installations have been completed. Challenges that are being encountered in the development of ocean power conversion systems include protecting the devices from the forces of ocean storms, the corrosive effects of seawater, and minimizing the interactions with marine life.

The following status update and commentary was provided by Triton Renewable Energy Ltd, the developer of a wave energy technology:

1. Triton Renewable Energy Ltd has been exploring the potential of a commercial wave energy farm in Bermuda since 2008, actively working with Carnegie Wave Energy since 2010 using their proprietary CETO technology. Preliminary public consultation has been undertaken and an agreement with the Bermuda Government with regards to identifying suitable locations for installation is under discussion.
2. 12 months of in-water testing of Bermuda's wave energy regime has confirmed a wave climate suitable for the CETO technology.
3. Carnegie has successfully completed their 12-month CETO 5 demonstration project in Perth, Western Australia with over 14,000 cumulative operational hours. 3 units were installed and operated in a range of sea states and in waves up to 5.8 m. CETO 5 units were peak rated at 240kW.

4. This wealth of data has helped advance concept design of CETO 6, which has four times the peak output (1MW), and this is now complete. Electrical power is now generated within CETO 6, avoiding hydraulic transmission losses.
5. Preliminary design and procurement of CETO 6 is scheduled for later this year (2016), with the first demonstration site off Western Australia scheduled to come online in 2017.
6. CETO 6 commercialization is being targeted for 2018 in the UK.
7. Commercial roll out of CETO 6 for island jurisdictions is anticipated for 2020/2021.
8. Triton's longstanding relationship with Carnegie Wave Energy makes it, and Bermuda well positioned once the commercial viability of CETO 6 is proven.