REGULATORY AUTHORITY OF BERMUDA

Fairness • Innovation • Integrity

Bermuda Integrated Resource Plan

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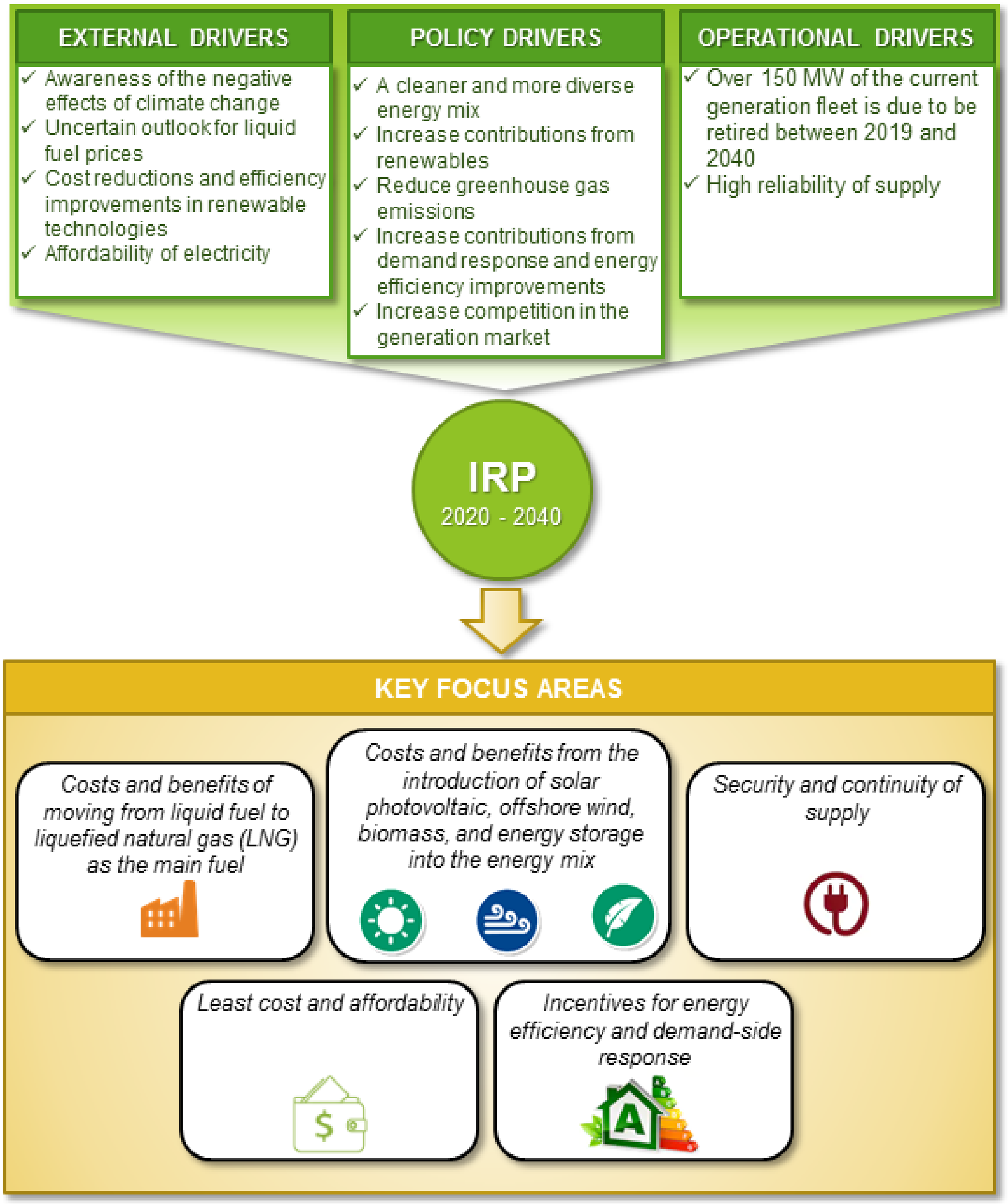
1 EXECUTIVE SUMMARY

Key drivers and main areas of focus of the Integrated Resource Plan

This Integrated Resource Plan ("IRP") is the first to be approved for Bermuda by the Regulatory Authority of Bermuda (the "Authority") pursuant to the Electricity Act 2016 ("EA"). It seeks to map out an energy plan for the supply of electricity in Bermuda that best meets a range of external and sector policy drivers – including meeting the requirements of the EA and achieving the objectives and targets in the National Electricity Sector Policy of Bermuda 2015 (the "Electricity Policy") and the National Fuels Policy 2018 (the "Fuels Policy"). The key focus areas are summarised in Figure 1.

Figure 1: Key drivers and main areas of focus for the IRP

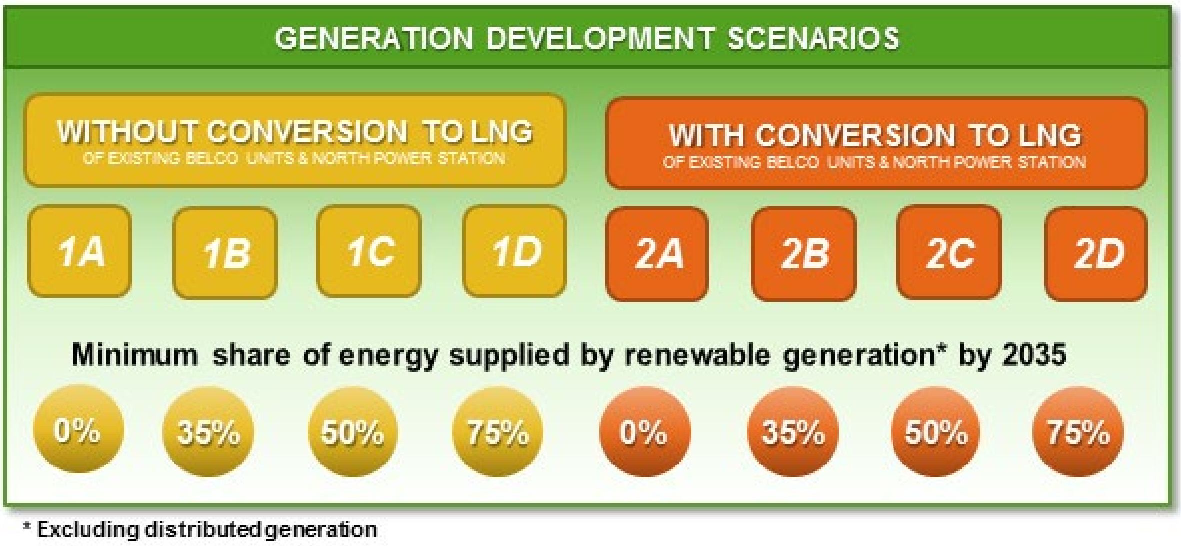


To meet the aims of the IRP, eight alternative scenarios for the future development of the electricity system in Bermuda have been identified. Each of these have been evaluated to determine which best meets the requirements of the EA and achieves the targets set in the Electricity Policy and the Fuels Policy. As outlined in Figure 2 below, the alternative scenarios are grouped into two categories:

- No conversion to liquefied natural gas ("LNG") - scenarios 1A to 1D;
- With conversion to LNG - scenarios 2A to 2D.

Within each group, there are a range of targets for contributions from renewable generators.

Figure 2: Portfolio of generation development scenarios evaluated in the IRP

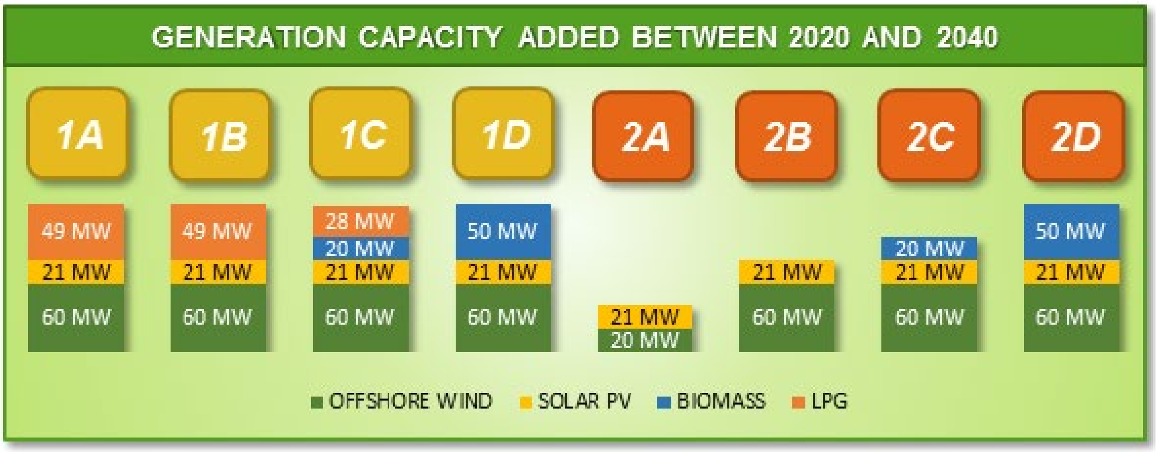


Least-cost generation expansion plan under each scenario

The least-cost combination of new capacity additions to the system was determined for a planning period from 2020 to 2040 (the "Planning Period"), initially using a set of base case assumptions and then for a series of sensitivity cases, for each of the generation development scenarios. It is important to note that the conversion to LNG fuel would involve a lifetime extension to the existing generators, which means that fewer generators would need to be retired in scenarios 2A to 2D.

Figure 3 indicates the generation plants that should be added to the system under each of the development scenarios to achieve the least-cost solution in each case.

Figure 3: Generation capacity added to the system under each development scenario



The main points from Figure 3 are:

- All of the scenarios involve commissioning 21 megawatts ("MW") of solar photovoltaic ("PV") (including the 6 MW project at the Finger);[1]
- Under all scenarios except 2A, the least-cost plan involves commissioning 60 MW of offshore wind by the end of the Planning Period;
- New combustion engines fuelled by liquified petroleum gas ("LPG") are required in scenarios 1A, 1B and 1C; and
- Additional biomass generators are added in scenarios 1C, 1D, 2C and 2D to meet the higher renewable penetration targets.

Technical and economic results

Figure 4 highlights the main results for each of the generation development scenarios, which are discussed below:

- All of the scenarios (except 2A) meet the Electricity Policy target of achieving 38% of electricity generated coming from renewable sources by 2035.
- All scenarios meet the target of reducing annual carbon emissions to no more than 294.7 kt CO_2e per year, again, by 2035.
- Of the scenarios where there is not conversion to LNG fuel, 1D has the lowest future system costs,[2] while 2B is the lowest of those where such conversion is undertaken (followed closely by 2A). The predicted costs of scenario 1D are about 6% higher than for 2A and 2B, but it offers other benefits, as described in the next section.
- The total capital investment costs (discounted) of the non-LNG scenarios are generally lower than those for the corresponding LNG-conversion scenarios.

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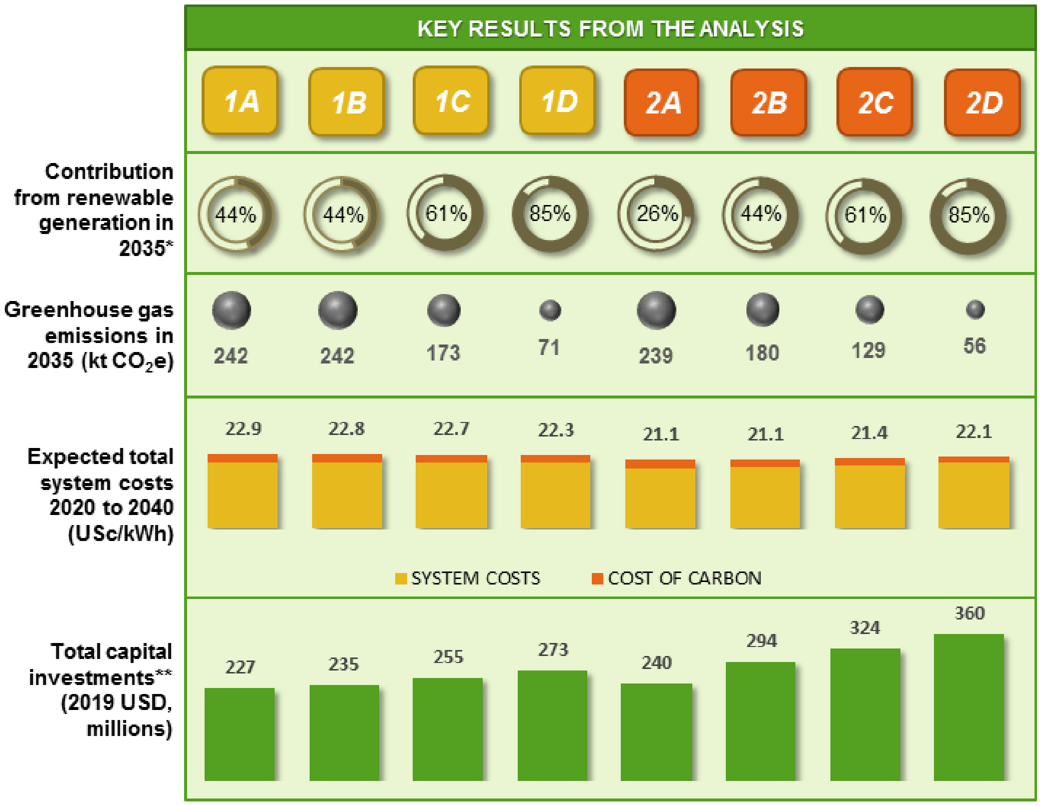
[1] The Airport solar PV project.

[2] Including capital costs, operational costs, fuel costs, infrastructure costs for handling and storing fuels, network reinforcement costs, and the monetisation of carbon emissions.

Figure 4: Technical and economic results for each scenario



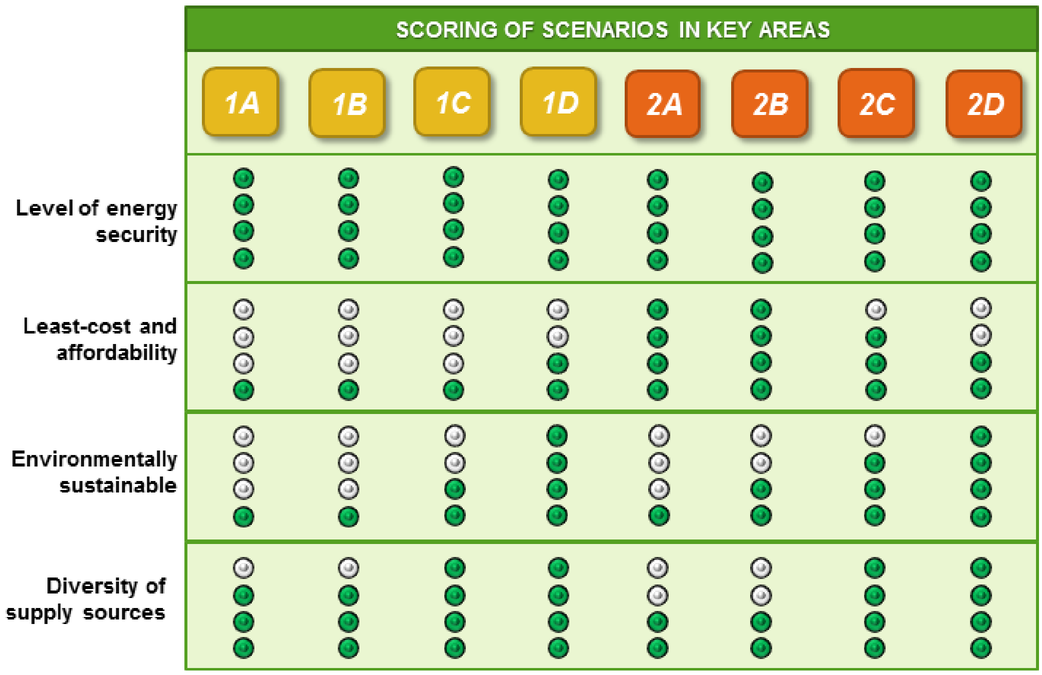
* Including bulk renewable energy sources and distributed generation

** Discounted

Comparing the generation development scenarios

Figure 5 gives a comparison of the characteristics of each of the generation development scenarios that were modelled. The green dots indicate a score out of four for each of the four criteria.

Figure 5: Comparison of generation expansion scenarios



All scenarios achieve the maximum score for level of energy security because the underlying analysis has been designed to ensure there is sufficient generation capacity to meet the demand of the system at peak time, together with a suitable reserve, throughout the Planning Period.

An analysis of the scenarios indicates that:

- The least-cost ranking of the scenarios is sensitive to the price forecasts for LNG and HFO and the cost estimates for LNG infrastructure.
- The base case modelling results indicate that the economic costs calculated for 2B (least-cost scenario with LNG conversion) are about 6% lower than those for 1D (least-cost scenario without LNG conversion).
- However, an increase of 25% of the LNG infrastructure and commodity costs would reverse the ranking.
- The significant investment in LNG infrastructure - estimated to be about USD 117 million[3] - represents a long-term commitment to LNG playing a central role in the Bermuda energy sector. Such a decision would influence energy policy and prices for up to 50 years into the future and would likely have significant economic consequences to reverse.
- Total capital investment requirements (i.e. financing needs) are predicted to be 8% higher for scenario 2B than for 1D. The selection of a non-LNG scenario would result in better alignment of the economic life of the assets with the physical life of the assets. Further, it would allow greater flexibility for significant changes in electricity generation in the future.
- By 2035, the energy mix for scenario 1D is more diverse than for scenario 2B.

The assessment of the scenarios produced some surprising results. In particular, the 75% renewables target scenarios produced a maximum of 85% renewables penetration, exceeding the target by 10% for an incremental increase in cost.

Therefore, scenario 1D, which does not involve conversion to LNG and aims for at least 75% contribution from renewables by 2035, has been selected as the approach to underpin future energy planning.

Further details about scenario 1D are provided in the next section.

Feasibility studies for wind and biomass generation should be initiated to confirm the project viability of these options and provide sufficient data to facilitate efficient and appropriate investment.

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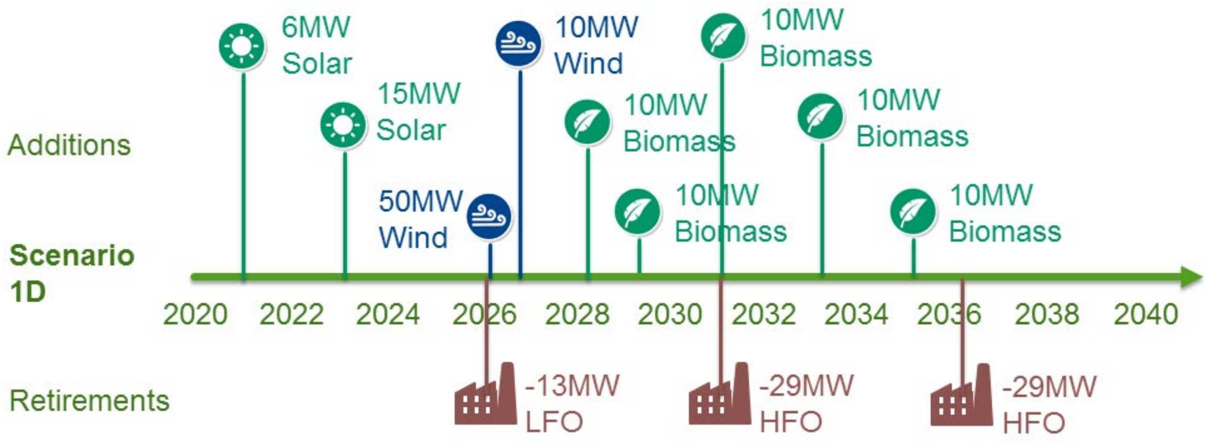
[3] All dollar amounts are in real 2019 USD, except where stated otherwise.

Power generation expansion plan

New capacity additions between 2020 and 2040

Under scenario 1D, all new generators installed between 2020 and 2040 would be renewable technologies, with 15 MW of solar photovoltaic installed around 2023 and 60 MW offshore wind installed around 2026. Subsequently, an additional 50 MW of biomass would be required (phased between 2028 and 2035), as shown in Figure 6.

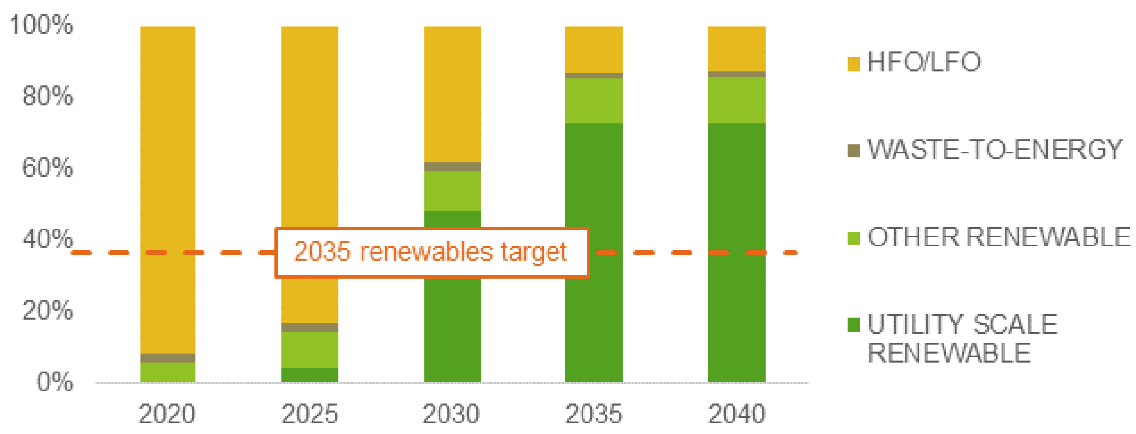
Figure 6: Procurement timeline for the selected plan.



Energy mix for the selected plan

This plan would result in a contribution of 85% from renewable sources by 2035 (as shown in Figure 7 below), which is more than double the Electricity Policy target of 38%.

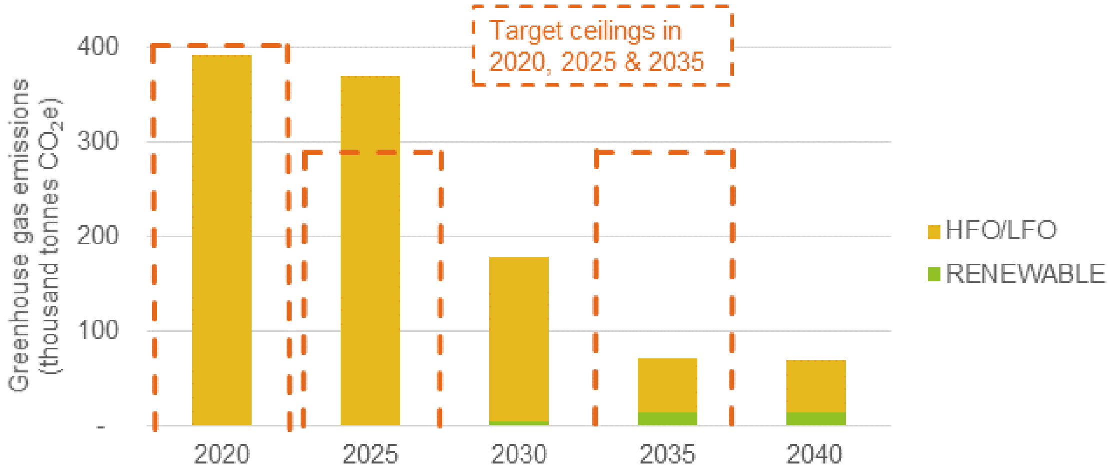
Figure 7: Energy mix for the selected plan with 2035 Electricity Policy target shown



Reduction of carbon emissions for the selected plan

Under this plan, greenhouse gas emissions from fossil fuel generation plants would be significantly curtailed between 2020 and 2040, as shown in Figure 8.

Figure 8: Annual carbon emissions for the selected plan, showing Electricity Policy target ceilings in 2020, 2025 and 2035



Ensuring continuity of supply with variable renewable energy

Thermal plants operating on liquid fuel are not expected to operate at full utilisation from 2026 onwards due to the relatively high contribution that is expected from renewable sources. However, technical analysis shows that these generators are required to ensure continuity of electricity supply when renewable resources are not available and during major system faults.

Demand-side resources

This IRP takes account of recent energy efficiency ("EE") initiatives (for example, the installation of more efficient streetlights), and a review of demand-side resources in BELCO's IRP Proposal. The conclusions of this review are summarised below:

1. Accelerated uptake of residential solar water heating systems paired with solar PV panels should be initiated.
2. Additional programmes should be initiated, such as:
   (a) Accelerated uptake of solar PV generation on rooftops of domestic, commercial, and/or industrial customers;
   (b) Accelerated uptake of small-scale cogeneration at commercial sites; and
   (c) Accelerated uptake of combined heat and power facilities.

   However, further technical studies would be required to make an informed decision on which of these to prioritise.
3. Anticipated electric vehicle ("EV") charging and usage is expected to have negligible impact on peak demand, but the impact on electricity consumption is difficult to predict.

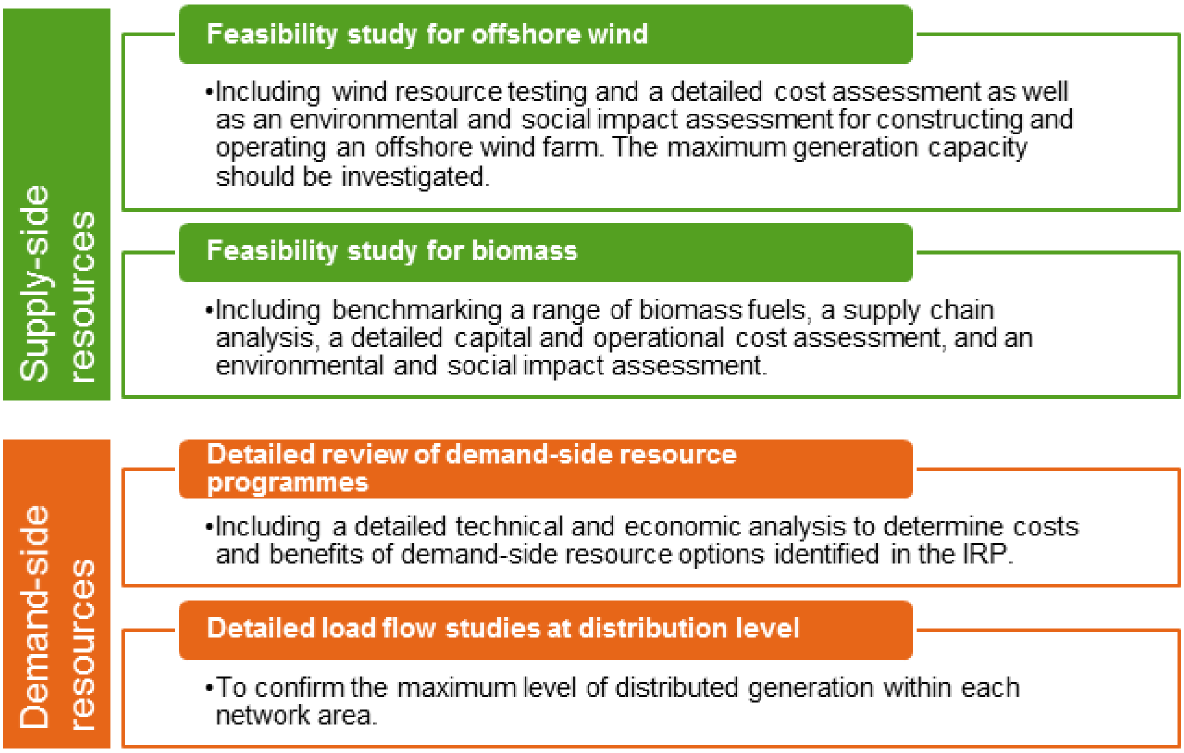
The demand forecast in this IRP includes an assumption of an annual 4% reduction to incorporate the aspects listed in items 1. and 2. above, while 3. is considered in a sensitivity case.

The IRP finds that distributed generation[4] should be limited to 30 MW, although this should be confirmed by detailed distribution system studies.

Next steps

This IRP relies on a set of technical and financial assumptions that are based on historical data, contributions from local stakeholders, and international experience under similar circumstances. Therefore, the plans within it should be validated by detailed pre-feasibility and/or feasibility studies ahead of formal implementation.

As a priority, the following studies should be conducted as soon as possible:



It can be reasonably expected that these studies will be completed within approximately two to three years. Once the results of the studies become available, and in view of their importance to the development of the system for the supply of electricity in Bermuda, they should be used as inputs to commence a new IRP process. This is in line with the requirements of the EA, which states that an IRP should be

[4] The description of “distributed generation” is derived from the definition provided in the EA. The current licence threshold is 500 kW, as set by the Minister pursuant to the Electricity (Licence Threshold) Regulations 2018.

undertaken at least every 5 years. The shorter period is justified by the significance of the results of these studies.

Stranded Generation Assets and Future Retail Tariff Reviews

The implementation of any of the scenarios which include alternative generation sources will likely result in stranded assets. This has been factored into each scenario. However, these under-utilised generation assets can offer an opportunity for Bermuda via economic development tariffs. Such tariffs would leverage marginal costs and a portion of the stranded and fixed costs for new business development. The result would be lower cost tariffs to stimulate new economic activity, grow demand and reduce price pressure on other tariff classes. The development of such a class of tariffs for economic development should be considered.

2 INTRODUCTION AND KEY CONCEPTS

2.1 Introduction

The EA requires that an IRP should be prepared for the supply of electricity in Bermuda. This is the first IRP to be approved by the Authority under the EA.

An IRP Proposal was requested from Bermuda Electric Light Company Limited ("BELCO") as the Transmission, Distribution and Retail ("TD&R") Licensee in November 2017, which BELCO submitted in February 2018.

The IRP Proposal was published for public consultation in 2018. Following this, eight proposals for bulk generation or demand side resources (the "Alternative Proposals") were received during the consultation process, and these were also published for consultation. The Authority reviewed the responses to both public consultations and in January 2019 requested BELCO to revise the IRP Proposal to take into account the responses received. BELCO submitted an addendum to the IRP Proposal in April 2019, which addressed some but not all of the Authority's requested revisions.

This IRP, produced by the Authority, is based on the current situation and provides informed estimates of future electricity demand, technology costs, fuel costs, etc. There are inherent uncertainties associated with such forecasts. The IRP evaluates the effect of these uncertainties using sensitivity analyses. Since these factors change as the industry evolves, the IRP needs to be reviewed regularly. This is one of the reasons that the EA requires that an IRP should be prepared for Bermuda at least every five years.

The IRP is a strategic plan that may include recommendations for further detailed investigations concerning possible investments in the future. As the time approaches for major investments to be made, the feasibility and business cases should be investigated in detail to confirm that the investments are necessary to achieve Government policy objectives and that the investments do not result in unnecessary costs for customers.

2.2 Requirements of the Electricity Act

This IRP has been prepared in accordance with the requirements listed in section 40 of the EA, as summarised in Table 1.

Table 1: IRP requirements listed in section 40 of the EA

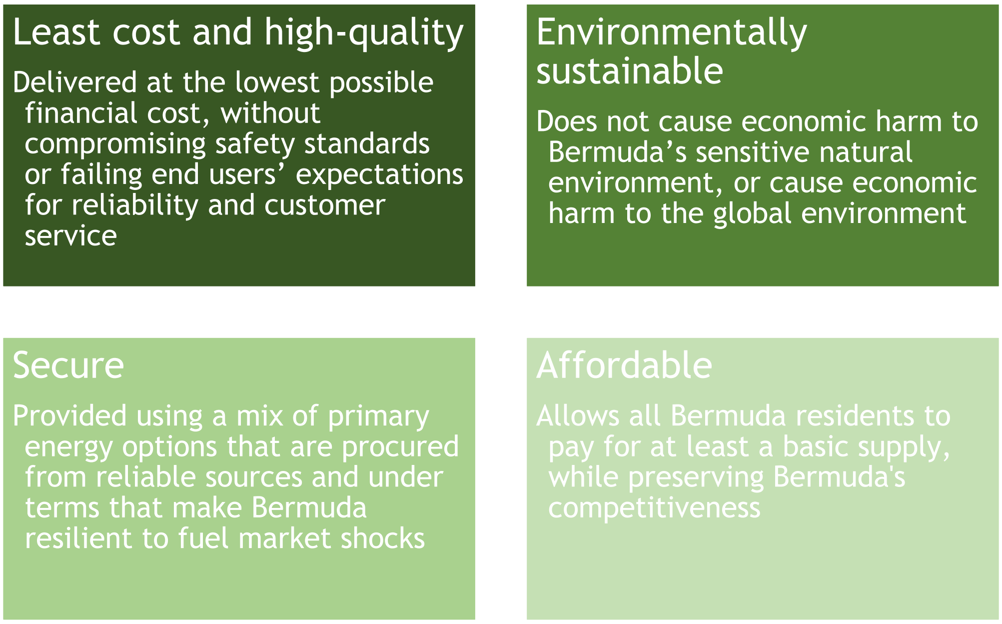
EA requirement	IRP reference
A resource plan that includes the expected demand for the period and the state of the TD&R Licensee's existing resources	i) The proposed resource plan is summarised in Section 7.3 ii) The expected demand for the period is shown in Section 5.6 iii) The state of the existing generation resources is summarised in Section 5.3
A procurement plan that details how the licensee proposes to meet this demand	The proposed procurement plan is shown in Section 8
All possible resources, including new generation capacity, demand side resources (including demand response and energy efficiency), and retirement of generation capacity should be considered	i) Proposed new generation capacity is summarised in Section 7.3 ii) Demand-side resources are discussed in Section 5.9 iii) Retirement of generation capacity is shown in Section 7.3
A range of renewable energy and efficient generation options, and a prudent diversification of the generation portfolio should be considered	i) The range of renewable energy and efficient generation options are discussed in Section 5.3 ii) Diversification of the generation portfolio is discussed as a key performance indicator in Section 6.10
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	The conclusions (Section 7) provide list of priority actions that most meet the purposes of the EA, conform to Ministerial directions, and are reasonably likely to supply electricity at least cost
Indicate recommendations regarding whether any resources will be procured through competitive bidding	The recommendations for resources to be procured by competitive bidding are presented in Section 8
Include proposed limits for total distributed generation capacity	The proposed limit for total distributed generation capacity is given in Section 6.12

2.3 Policy objectives and targets

In addition to the EA requirements listed in Section 2.2, this IRP has been developed with the aim of achieving a balance of the objectives of the Electricity Policy and the Fuels Policy. These objectives are consistent with, and support, the purposes of the EA, which are summarised in Section 3 of this IRP.

The Electricity Policy defines four objectives for electricity in Bermuda as shown in Figure 9.

Figure 9: Policy objectives for the electricity industry



The Electricity Policy sets out indicative targets for the future generation portfolio of the sector, as summarised in Table 2.

The Electricity Policy also highlights energy resources in addition to Bermuda's traditional bulk generation assets, including those shown in Figure 10 below:

Figure 10: Additional energy resources[5]

The goals described in the Fuels Policy include safeguarding fuel security, making fuels least cost, guaranteeing public safety and fuel quality, promoting environmental sustainability, fostering economic growth, ensuring affordability, and increasing

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[5] The description of "distributed generation" is derived from the definition provided in the EA, where the bulk generation licence threshold is 500 kW.

administrative effectiveness. The indicative targets in the Fuels Policy are summarised together with those of the Electricity Policy in Table 2.

Table 2: Summary of indicative targets for this IRP defined in relevant policies

Indicative target	Source
Increase the share of electricity generated from renewable sources in line with the following indicative targets: **8% in 2020** **35% in 2025** **38% in 2035**	National Electricity Sector Policy of Bermuda 2015
Reduction in greenhouse gas emissions* with the following indicative targets: **401,488 tCO_2e per annum in 2020** **289,980 tCO_2e per annum in 2025** **294,663 tCO_2e per annum in 2035** *** Even given that overall generation might increase in this period**	National Electricity Sector Policy of Bermuda 2015
Reduction in annual consumption per end-user with the following indicative targets:[6] **16.5 MWh in 2020 (approx. 94.8% of business-as-usual forecast)** **17.0 MWh in 2025 (approx. 94.8% of business-as-usual forecast)** **17.9 MWh in 2035 (approx. 94.8% of business-as-usual forecast)**	National Electricity Sector Policy of Bermuda 2015
Increased contribution from Independent Power Producers, demand side response and distributed generation to the energy resource mix (with no quantitative targets given)	National Electricity Sector Policy of Bermuda 2015
A reduction of 15% energy consumption from the electricity subsector between 2017 and 2035 compared to the business-as-usual scenario[7]	National Fuels Policy 2018

[6] Business-as-usual in the Electricity Policy is calculated for the purposes of that document and should not be confused with the business as usual policy scenario (1A) in this IRP.

[7] The Business-as-Usual scenario in the Fuels Policy is defined according to the assumptions therein and should not be confused with the business as usual policy scenario (1A) in this IRP.

Indicative target	Source
Replacement of heavy fuel oil and diesel with low carbon fuels in the electricity sub-sector by 2035** **** These include municipal and agricultural waste, biomass, biofuels, natural gas, LPG and hydrogen**	National Fuels Policy 2018
A reduction of 25% in greenhouse gas emissions from use of fuels in the electricity, transport and stationary use sub-sectors between 2017 and 2035 compared to the business-as-usual scenario[7]	National Fuels Policy 2018

In addition to the items listed above, Table 4.1 in the Electricity Policy also provides indicative targets for:

(a) share of generation by source (including thermal sources);
(b) share of peak demand by source; and
(c) energy efficiency targets.

Items (a) and (b) relate to the mix of resources. This IRP does not "target" a particular generation mix as an input to the analysis, but rather reports the mix that best achieves the broad range of objectives and targets laid out in the EA, Electricity Policy and Fuels Policy. Hence, the shares of generation and peak demand by source are reported as outputs of the analysis.

With regard to the energy efficiency targets, the Electricity Policy aims for a 5.2% reduction in energy consumption compared to a business-as-usual scenario, but the assumptions for the business-as-usual demand forecast are not provided. Therefore, this IRP is unable to measure performance against this target. Instead, the sensitivity cases consider how the results are affected when a range of energy efficiency cases are applied.

2.4 Investigating whether liquefied natural gas should be considered

The electricity generation plants in Bermuda currently operate on heavy fuel oil ("HFO") and light fuel oil ("LFO"). However, the modelling used in the Electricity Policy assumed that natural gas would be used for generation by 2018 and that HFO and LFO (referred to as diesel in the Electricity Policy) would be phased out by 2021. The Electricity Policy acknowledged that LNG would need to be imported and that a regasification terminal would be required. Therefore, a study entitled *Viability of Liquefied Natural Gas (LNG) in Bermuda*[8] was conducted on behalf of the Government in 2016 (the "LNG Study").

In addition, the Fuels Policy lays out an aspirational "National Fuels Policy Scenario", where LNG is assumed to be the only "low carbon fuel" (as defined in the Fuels Policy)

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[8] Castalia Limited, 2016, 'Viability of Liquefied Natural Gas (LNG) in Bermuda'. Available at URL: https://www.gov.bm/sites/default/files/Viability-of-Liquefied-Natural-Gas-in-Bermuda.pdf.

in 2035. However, it does make clear that LNG "is used as a proxy for the new [low carbon fuel] to be used in Bermuda, consistent with the aspirational energy matrix in the Electricity Policy (2015) …however…the Government does not prescribe that natural gas should be adopted to the exclusion of other options." It goes on to explain that the IRP should be used as a strategic tool to select low carbon fuel options that best meet the objectives of the Electricity Policy.

The benefits of natural gas over the current fossil fuels, HFO and LFO are:

- Natural gas emits negligible amounts of particulate matter when it is combusted, which means that the exhaust gases are cleaner;
- Natural gas emits about 15% less greenhouse gases per unit of electricity produced at point of use (but this does not account for the greenhouse gas emissions upstream of the generator) – See Appendix D.1;
- LNG prices are currently lower than those for HFO and LFO and are forecast to remain lower into the future – See Section 5.7 and Appendix D.2; and
- As the exhaust gases from natural gas combustion are cleaner, it is possible to incorporate heat recovery equipment into generation plants to increase the overall efficiency and output.

These benefits need to be weighed up against the risks of committing to LNG as a key component of Bermuda's energy strategy. Specialised plant and equipment are required to transfer the LNG from the vessel to land and convert it from a liquid to a gas (regasification) before it can be used in the generators. With an estimated capital cost of USD 117 million,[9] this infrastructure would represent a significant financial investment for the Island. Projects of such size and complexity are often subject to initial cost estimates being exceeded, sometimes substantially, which introduces a significant element of risk.

Once this infrastructure is installed, with prudent operation and maintenance, it should be useful for multiple decades. There would be an incentive to maximise its use so that the cost per unit of electricity produced is as low as possible. Although this is a rational approach, it could be a disincentive to pursuing other generation technologies, some of which may have the potential to further decrease Bermuda's reliance on fossil fuels.

The LNG Study and the IRP Proposal assume that the LNG regasification terminal as well as the generators would be onshore. The analysis in this IRP is done on the same basis. However, the Authority received an Alternative Proposal from Offshore Utilities LLC, which proposed a solution where LNG was regasified on a ship and used in electricity generators on the ship. The electricity would then be transmitted to shore by underwater cables, negating the need for onshore infrastructure.

[9] This capital cost estimate for LNG infrastructure is taken from the IRP Proposal (2018).

Although the Alternative Proposal by Offshore Utilities LLC did not provide enough data for the offshore LNG option to be analysed in this IRP, it is suggested that it should be further investigated in a detailed feasibility study into LNG for Bermuda, if required.

2.5 The purpose of this IRP

The purpose of this IRP is to propose a resource plan for Bermuda that aligns with the purposes of the EA and satisfies its requirements, whilst aiming to achieve the targets set forth in the Electricity Policy and the Fuels Policy.

2.6 Key concepts to aid understanding of this report

There are multiple competing constraints that need to be balanced in an IRP, especially when certain policy objectives are targeted. Appendix A.3 provides a brief overview of some of the key concepts that were considered in the preparation of this IRP. They include:

- The difference between installed capacity and electricity volume;
- Managing intermittent supply from variable renewable sources; and
- Capacity reserve margin.

Readers that are not familiar with these concepts are encouraged to read Appendix A.3 to aid their understanding of the IRP.

2.7 How this report is structured

The remainder of this report is structured as follows:

Section	Description
3. Legislative context	Explains the legal and regulatory background to the IRP
4. Methodology	Describes the steps taken to develop the IRP model
5. Key assumptions	Summarises the input assumptions for the modelling
6. Results	Presents the results from the base case model and sensitivity analysis
7. Conclusions and recommendations	Provides conclusions and recommends further steps for the next iteration of the IRP
8. Recommended procurement plan	Presents the recommended procurement plan for the IRP
Appendices A to J	Contain the detailed data underpinning the IRP analysis

3 LEGISLATIVE CONTEXT

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".[10]

In June 2015, the Ministry of Economic Development published the Electricity Policy. The Electricity Policy set out the groundwork for the institution of the subsequent EA and the desired structure of the Bermuda electricity sector.

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.

The Minister responsible for electricity is currently the Minister of Home Affairs (the "Minister"). The Minister can issue Ministerial directions to the Authority that establish policies for the electricity sector,[11] or regarding any matter within his authority as regards the electricity sector.[12] In formulating Ministerial directions, the Minister shall set priorities and resolve trade-offs or conflicts that arise from the purpose of the EA in a way that he thinks best serves the public interest.[13]

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.[14] 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;

(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;

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[10] RAA, preamble.

[11] EA, Section 7(2).

[12] EA, Section 8(3).

[13] EA, Section 9.

[14] EA, Section 14(2)(a).

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

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).

In accordance with the Electricity Policy, 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.

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.

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. 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.

The Authority is also required to request the submission of Alternative Proposals pursuant to sections 42(2) and 42(3) of the EA. 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 as many meetings as the Authority decides is necessary with the proponent of each Alternative Proposal, the TD&R Licensee and any other persons that the Authority considers relevant to assess the Alternative Proposals.

Section 44 of the EA requires the TD&R Licensee to prepare a final draft 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. Section 45 of the EA requires the Authority to publish the approved IRP on its official website.

4 METHODOLOGY

The analysis for this IRP has been done in seven steps, as described below. Further details can be found in Appendix B.

4.1 Step 1 - Definition of policy scenarios

The first step was to define a range of scenarios for Bermuda's energy future. The aim was to define a reference scenario, which represented "business-as-usual" where the electricity system continued to operate as it has done for the last few decades. This allowed the costs of other options to be compared in order to investigate how these relate to each other on an economic basis. This was done as described in steps 2 to 4 below. This also provided insight into the relative costs and benefits of achieving Bermuda's policy objectives.

The policy scenarios for this IRP are defined in Section 5.1 and Appendix G.

4.2 Step 2 - Technology screening

In the second step, a range of electricity generation technologies were selected for analysis using a "levelised cost of energy" approach.[15] This approach estimated the lifecycle costs of different generation technologies, considering the capital costs, fuel costs (if applicable) and operation and maintenance costs of a typical plant over its lifetime.

4.3 Step 3 - Forecasting future demand

The electricity demand forecast is central to the IRP because it defines whether additional generation units are required to match supply and demand in each year of the Planning Period, including taking account of an appropriate reserve margin. The same demand forecast was used in each scenario in the model so that they could be compared against each other on a consistent basis.

The results of the base case model were compared against three alternative demand forecasts in the sensitivity analysis to investigate how differences in demand affect the least-cost plan.

4.4 Step 4 - Addition of renewable generators to achieve policy targets

Steps four and five use a method called "dispatch modelling" for each year in the Planning Period. This uses algorithms to match supply to the predicted demand in a least-cost way for each year in the Planning Period, starting with the first year.

In step four, the model checked whether targets for renewable generation had been defined for that year in the policy scenario. If so, then it checked whether the renewable

[15] Such technologies are required to be in commercial operation in another jurisdiction, in accordance with the EA.

targets could be achieved with the current generation mix. If not, then the modelling assumed that sufficient new renewable plant(s) were installed to achieve the target.

4.5 Step 5 - Addition of generators to meet forecast demand

Step five checked, after assuming that any new renewable plants to meet targets identified in step three were installed, whether the resulting generation mix could supply enough electricity to meet the forecast demand for that year. If not, then the model assumed that sufficient new generation plant(s) were installed in order of increasing cost, starting with the cheapest, until supply was able to match demand in that year. These generators could be renewable generators or fossil-fuel generators; the only consideration being cost, and the limitations defined by the model for the maximum allowable number of units for each generation technology (based on the level of resource availability).

The model then moved on to the next year and repeated steps three and four until it reached the end of the Planning Period.

When more generation plants were required on the system, it was important to check that the network was able to transmit the electricity from the generator to the consumers. Network studies were done in parallel with the dispatch modelling to check whether the network needed to be upgraded to accommodate the new generators. Sometimes additional investment was required to upgrade the network, which resulted in increased system costs for that scenario. These costs were considered when comparing scenarios in steps five and six.

4.6 Step 6 - Comparison of system costs

Step six considered the overall "system cost" for each scenario over the Planning Period - i.e. the cost of installing enough generation to meet forecast demand, subject to the renewable targets being met for each scenario plus the costs to upgrade the network (if any) to accommodate those generation plants.

The system costs were analysed in two stages:

- Stage 6.1: On an economic basis without quantifying the cost of greenhouse gas emissions; and
- Stage 6.2: By incorporating "social costs of carbon"[16] to quantify the environmental impact of producing greenhouse gas emissions.

The policy scenarios were ranked from least cost to highest cost in stages 6.1 and 6.2 to show how incorporating environmental costs influenced the results.

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[16] See Section 5.8.2 for an explanation of the social cost of carbon.

4.7 Step 7 - Sensitivity analysis

A sensitivity analysis was conducted in step seven to investigate how sensitive the levelised system costs were to changes in key input assumptions. This enabled the testing of how robust the results were to changes in the assumptions, and hence to determine the level of confidence that can be made regarding the conclusions.

4.8 Key performance indicators for policy objectives and targets

Table 3 below lists the key performance indicators ("KPIs") that can be used to assess progress against the objectives and targets in the Electricity Policy and Fuels Policy.

Table 3: Key performance indicators for policy objectives and targets

No.	KPI	Title	Objective/Target	Discussion
1	Ranking by overall system cost (incl. carbon costs)	Least cost and high-quality	Electricity Policy objective	The levelised cost of electricity approach is central to this IRP and is used as the primary metric for ranking scenarios in terms of least cost.
2	See KPIs for the relevant policy targets below	Environmentally sustainable	Electricity Policy objective	This objective is primarily addressed by aiming to achieve the following policy targets: • Share of renewable generation (No. 5 in this table) • Greenhouse gas emissions – Electricity Policy (No. 6 in this table) • Energy efficiency – Electricity Policy (No. 7 in this table) • Energy efficiency – Fuels Policy (No. 9 in this table) • Eliminate high-carbon fossil fuels (No. 10 in this table) • Greenhous gas emissions – Fuels Policy (No. 11 in this table)

No.	KPI	Title	Objective/Target	Discussion
3	Shannon-Wiener Index[17] for each scenario in 2035.	Secure (diversity of energy resource mix)	Electricity Policy objective	Although the description in the Electricity Policy focusses on procurement elements (reliable sources and favourable terms), security of supply can also be improved by having a diverse mix of primary energy sources. This reduces the impact of shocks or volatility within a single commodity market because it enables the system to substitute fuel inputs in response to market conditions. The IRP uses the Shannon-Wiener Measure[17] to quantify the diversity of resources in 2035.
4	Overall system cost for each policy scenario	Affordable	Electricity Policy objective	This IRP addresses the affordability objective by ranking policy scenarios in terms of overall system cost. The equitability and regulatory aspects of affordability are addressed in the Retail Tariff Methodology, which is outside the scope of this IRP.
5	Share of electricity generated from renewable sources in 2020, 2025 and 2035 for each policy scenario.	Share of renewable generation	Electricity Policy target	In the Electricity Policy, “renewable generation” includes waste-to-energy, distributed solar PV and solar water heaters as well as grid-connected renewable energy plants. The share of electricity generated by these sources will be calculated for each policy scenario in 2020, 2025 and 2035.

[17] The Shannon-Wiener Index is used by energy economists to quantify the degree of diversity in a system’s mix of primary energy resources. Appendix B.5 provides details of how the metric is calculated.

No.	KPI	Title	Objective/Target	Discussion
6	Greenhouse gas emissions in 2020, 2025 and 2035 for each policy scenario.	Greenhouse gas emissions – Electricity Policy	Electricity Policy target	The greenhouse gas emissions from grid-connected generation plants will be calculated for each policy scenario in 2020, 2025 and 2035.
7	A KPI is not used for this target.	Energy efficiency – Electricity Policy	Electricity Policy target	In the IRP, the annual consumption per end-user is an input assumption to the demand forecast, as described in Section 4.3. The base case demand forecast applies the same assumptions as the IRP Proposal.
8	Percentage of electricity generated in 2035 by generators that were competitively procured.	Diverse and competitive ownership of resources	Electricity Policy target	To evaluate performance for this target, it will be assumed that the following plants would be owned by BELCO as the incumbent bulk generation licensee because the fuel supply characteristics are suited to a common centralised location: • Existing and committed reciprocating engine generators to the end of their lives • New reciprocating engines operating on LNG • New reciprocating engines operating on HFO
9	Cumulative fuel consumption between 2020 and 2035 as a percentage of the case where HFO and LFO are the only energy resources.	Energy efficiency – Fuels Policy	Fuels Policy target	The target is that cumulative fuel consumption from electricity generation between 2017 and 2035 should be less than 85% relative to a case where HFO and LFO are the only energy resources for the electricity sector.

No.	KPI	Title	Objective/Target	Discussion
10	Pass/fail for each scenario in 2035.	Eliminate high-carbon fossil fuels by 2035	Fuels Policy target	The achievement of this target is measured by checking whether HFO or LFO remains part of the fuel mix in 2035 for each scenario.
11	Greenhouse gas emissions for each policy scenario expressed as a percentage of emissions in the case where LFO and HFO are the sole energy resources in 2035.	Greenhouse gas emissions – Fuels Policy	Fuels Policy target	This target is measured relative to a case where HFO and LFO are the sole energy resources for the electricity sector. To be consistent with this approach, a scenario is defined in this IRP to reflect this future. Although the results for this scenario are not reported in the IRP, it is used to measure performance against this Fuels Policy target.

5 KEY ASSUMPTIONS

This section explains the key input assumptions for the IRP modelling. As an isolated island, the Bermuda electricity system has characteristics and faces challenges that might not be the case for jurisdictions that have interconnections with neighbouring systems. Furthermore, this IRP is not starting with a “clean slate”; the Bermuda system has a history dating back to 1907 and millions of dollars-worth of existing generation and network assets, which need to be considered in the planning and modelling.

Therefore, the assumptions described in the following sections are unique to Bermuda. They have been defined with the current system in mind but looking into the future at what might be required to achieve the Government’s policy objectives whilst complying with the requirements of the EA.

Detailed tables of the input assumptions are provided in the appendices, as noted in the sections below.

5.1 Policy scenarios for modelling

Two sets of four policy scenarios have been devised to investigate the lowest cost approach to achieving the targets of the Electricity Policy and the Fuels Policy, in accordance with the purposes of the EA. These are summarised in the paragraphs below and detailed in Appendix G.

The first set of four scenarios consider a future where LNG is not pursued, so the fossil fuel options are HFO, LFO and LPG. With this underlying assumption, the existing generators will continue to operate on HFO and/or LFO until the end of their useful lives. Different renewable targets are defined for each of the scenarios, as described in Table 4.

Table 4: Summary of policy scenarios 1A to 1D used in this IRP (no LNG conversion)

Scenario	Approach for future investment in generation
Scenario 1A: Business as Usual	Selected in order of lowest cost with no specific targets for the penetration of renewable generation.
Scenario 1B: Moderate Renewables	Selected to meet the Government's policy objective to achieve the following targets for the penetration of renewable generation:[18] • 10% in 2022 • 15% by 2025 • 25% by 2030 • 35% by 2035 If required to meet demand forecasts, other generators are selected in order of lowest cost.
Scenario 1C: High Renewables	Selected to exceed the Government's policy objectives by achieving the following targets for the penetration of renewable generation[18]: • 15% in 2022 • 20% by 2025 • 35% by 2030 • 50% by 2035 If required to meet demand forecasts, other generators are selected in order of lowest cost.
Scenario 1D: Very High Renewables	Selected to exceed the Government's policy objectives by achieving the following targets for the penetration of renewable generation[18]: • 20% in 2022 • 25% by 2025 • 50% by 2030 • 75% by 2035 If required to meet demand forecasts, other generators are selected in order of lowest cost.

The second set of four scenarios considers a future where LNG is pursued. For these scenarios, existing generators operate on HFO and/or LFO, but are converted to operate on LNG as early as is feasible (this is assumed to be 2025 in the model). The four sets of renewable targets given in Table 5 mirror those defined for Scenarios 1A to 1D.

[18] The basis for these targets is "the amount of total energy generated (in GWh) that comes from renewable energy sources" per year, in accordance with the definition given in Section 4.1 of the Electricity Policy.

Table 5: Summary of policy scenarios 2A to 2D used in this IRP (LNG conversion)

Scenario	Approach for future investment in generation
Scenario 2A: **LNG Conversion**	Selected in order of lowest cost with no specific targets for the penetration of renewable generation.
Scenario 2B: **LNG with Moderate Renewables**	Selected to meet the Government's policy objective to achieve the following targets for the penetration of renewable generation[18]: • 10% in 2022 • 15% by 2025 • 25% by 2030 • 35% by 2035 If required to meet demand forecasts, other generators are selected in order of lowest cost.
Scenario 2C: **LNG with High Renewables**	Selected to exceed the Government's policy objectives by achieving the following targets for the penetration of renewable generation[18]: • 15% in 2022 • 20% by 2025 • 35% by 2030 • 50% by 2035 If required to meet demand forecasts, other generators are selected in order of lowest cost.
Scenario 2D: **LNG with Very High Renewables**	Selected to exceed the Government's policy objectives by achieving the following targets for the penetration of renewable generation[18]: • 20% in 2022 • 25% by 2025 • 50% by 2030 • 75% by 2035 If required to meet demand forecasts, other generators are selected in order of lowest cost.

The adoption of LNG as a fuel would require significant investment in fuel offloading, processing and piping facilities. The IRP Proposal submitted by BELCO includes a capital cost estimate of USD 117 million for LNG fuel infrastructure.

Considering the significant costs associated with providing LNG infrastructure, there is a minimum threshold of annual gas consumption below which adoption of LNG is not viable. In its report, *Small Scale LNG,*[19] the International Gas Union estimates the minimum threshold to be about 100,000 m^3 per year. To achieve this level of consumption, all the BELCO generators that are planned to be operational in 2025 (the existing units plus new units currently under construction) will need to be converted to

[19] International Gas Union, 2015, 'Small Scale LNG', IGU, Paris. Available at URL: http://www.igu.org/sites/default/files/node-page-field_file/SmallScaleLNG.pdf.

operate on LNG. In addition, once the LNG infrastructure is installed, all future thermal generators should use LNG to benefit from the lower fuel costs (see Section 5.7).

5.2 Planning Period

The Planning Period for this IRP is assumed to start in 2020 and end in 2040.

5.3 State of existing generation resources

The existing generation resources that are expected to be operational in the Planning Period are listed in Appendix C.1. BELCO reported in IRP Proposal that the existing resources are suitable for operation[20] until the dates listed in Table 6 when they will be removed from the system ("retired") unless there is an intervention to extend their economic life further.

Table 6: Planned years of retirement for existing generation resources

Name of generator	Planned year of retirement
Reciprocating engine E5	2030
Reciprocating engine E6	2030
Reciprocating engine E7	2035
Reciprocating engine E8	2035
Gas turbine GT5	2025
Gas turbine GT6	2040
Gas turbine GT7	2040
Gas turbine GT8	2040
Tynes Bay Waste-to-Energy	2047

5.4 Electricity generation technologies considered

In addition to the generation plants that are currently operational (see list in Appendix C.1) and those that are under development or construction (see list in Appendix C.2), this section describes the possible new generation technologies that have been considered in this IRP. They are listed in Table 7.

The greenhouse gas emission intensity for each technology is also given in Table 7. This represents the amount of greenhouse gases released into the atmosphere by the generator per unit of electricity produced.[21] This is calculated at the point of generation and not on a lifecycle basis, which would consider emissions at every stage in the

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[20] Subject to prudent operation and maintenance practices.

[21] The calculation uses the greenhouse gas emissions intensities and fuel calorific values listed in Appendix D.1 together with the thermal efficiencies for the technologies listed in Appendix C.4.

supply chain of the fuel and hence would be higher than the figures quoted below. Detailed input assumptions are listed in Appendices C.3 and C.4.

Table 7: List of generation technologies considered in this IRP

Technology	Description of assumptions	Greenhouse gas emissions intensity
Solar photovoltaic	Up to 15 MW of bulk generation solar PV capacity in addition to the 6 MW plant planned at the Finger. See Note 1 after this table for further discussion.	0 gCO_2e/kWh
Offshore wind	Up to 60 MW of wind capacity at a suitable location offshore with transmission connection at a central location. See Note 2 after this table for further discussion.	0 gCO_2e/kWh
Biomass	Up to 70 MW made up of 10 MW boiler/steam cycle generators, which use imported wood pellets as a fuel. See Note 3 after this table for further discussion.	45 gCO_2e/kWh
Reciprocating engines - LNG	Medium speed reciprocating engines with a maximum unit size of 7 MW operating on natural gas. It is assumed that all new units would be located centrally to reduce piping infrastructure costs. See Note 4 after this table for further discussion.	480 gCO_2e/kWh
Reciprocating engines - LPG	Medium speed reciprocating engines with a maximum unit size of 7 MW operating on LPG. It is assumed that new units would be located near the existing fuel terminal to reduce piping infrastructure and/or land transport costs. See Note 4 after this table for further discussion.	530 gCO_2e/kWh
Reciprocating engines - HFO	Medium speed reciprocating engines with a maximum unit size of 7 MW operating on HFO. It is assumed that all new units would be located centrally to reduce piping infrastructure costs. See Note 4 after this table for further discussion.	660 gCO_2e/kWh
Reciprocating engines - LFO	High speed reciprocating engines with a maximum unit size of 2.5 MW operating on LFO. It is assumed that new units would be owned by Independent Power Producers. See Note 5 after this table for further discussion.	670 gCO_2e/kWh

Notes to Table 7 above

Note 1: The limit set for installed capacity for solar PV is a realistic maximum for Bermuda due to the limited availability of land. This value is only for plants greater than 500 kW. Distributed generation is accounted for in the IRP model by reducing forecast demand. Floating solar PV was not considered in this study because the risk of damage from storms and hurricanes is assumed to be too high. Concentrating solar technologies were not considered due to the limited availability of land.

Note 2: There is limited data available about the maximum practicable capacity of an offshore wind farm in Bermuda. A study was conducted in 2014 by the University of California, Santa Barbara entitled *"Offshore wind energy in the context of multiple ocean uses on the Bermuda platform*",[22] which included a theoretical assessment of the potential for offshore wind at an appropriate offshore location. The study concluded that up to 100 MW of capacity could be installed "with minimal risk of impact to marine habitat and fisheries". However, a detailed feasibility study including environmental impact assessment and detailed energy yield assessment has not been conducted. Therefore, this IRP takes a more conservative approach of limiting the maximum capacity of each technology type at about the level of the cumulative capacity gap forecast for 2040, which is approximately 60 MW. Onshore wind farms are not considered due to limited availability of land and the risk of objections from local communities.

Note 3: The Alternative Proposal submitted by Enviva and Albioma proposed 3 biomass generation units of 17 MW each. However, units of this size would be too large for the Bermuda system because a relatively large reserve margin would be required to maintain security of supply, which would increase overall system costs.

Note 4: The medium speed engines for LNG, LPG and HFO have been assumed to have a unit size of 7 MW, which is better suited to the Bermuda context in the future than larger units. The primary reasons for this assumption are that smaller units should result in a smaller reserve margin after the existing larger generators are retired and multiple smaller units create more flexibility to provide back-up supply in cases of high penetrations of variable renewable generators.

Note 5: The high-speed engines for LFO have been assumed to have a unit size of 2.5 MW, which is likely to suit Independent Power Producers in various locations around Bermuda. High speed units are flexible so are able to provide

[22] Available at URL: https://www.bren.ucsb.edu/research/2014Group_Projects/documents/BermudaWind_Final_Report_2014-05-07.pdf.

fast start capability and can respond quickly when there are fluctuations in output from variable renewable generators.

An Alternative Proposal submitted by Bermuda General Agency Ltd proposes the use of wave energy. Although it is acknowledged that marine generators, including wave and tidal generation technologies, have potential for the Bermuda context, there was insufficient evidence of commercial operation in another jurisdiction at grid scale to justify their inclusion in this IRP. A review of the international market for marine technologies also revealed that the costs are currently too high to compete with the technologies listed in Table 7.

5.5 Other infrastructure investments to support the generation plan

The electricity network in Bermuda has been designed with most of the generation units located centrally at BELCO's site in Pembroke and the Tyne's Bay waste-to-energy plant. However, the Electricity Policy and EA aim for competition within a generation market as well as increased generation from renewable sources. The realisation of these two aims are likely to result in generation plants being spread around Bermuda rather than being concentrated centrally.

The trend towards decentralised generation is a common theme in countries around the world and generally results in a more diverse and robust electricity system. However, the Bermuda network is likely to require upgrading to facilitate increased supply from decentralised bulk generators without compromising on reliability of supply to customers.

Therefore, this IRP includes electricity network studies that identify and quantify the types of investment that might be required for each of the eight scenarios to be a reality. These investments could include any combination of the following items:

- substations and cables;
- energy storage (e.g. batteries);
- specialised devices to control the quality of supply.

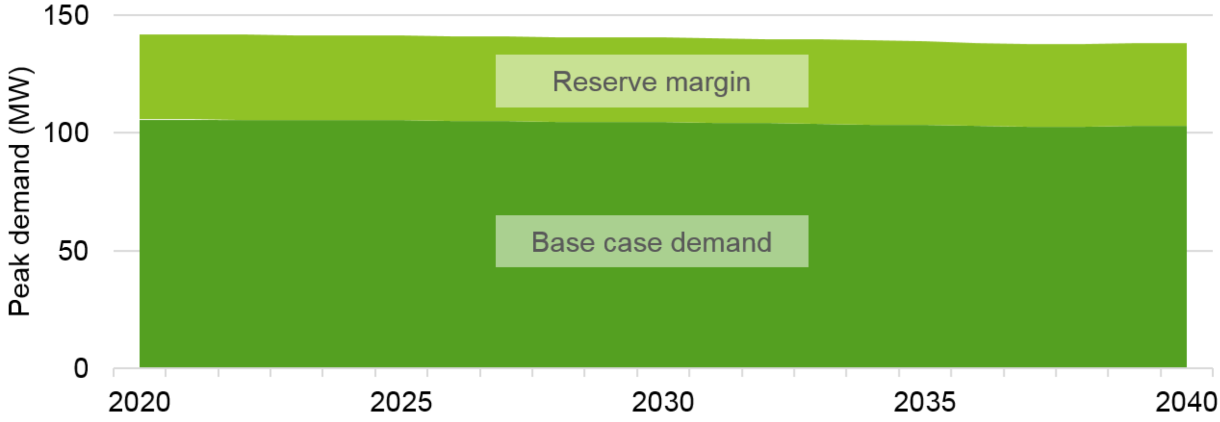
In addition, some scenarios would require investment in significant fuel supply infrastructure. The LNG regasification terminal and pipeline have already been mentioned, and investment in LPG infrastructure might also be required, depending on whether LPG units are selected in the plan.

The costs of network and fuel infrastructure investments are included in the calculation of total system costs, depending on the optimal generation mix within each scenario.

5.6 Demand forecast

The base case electricity demand forecast uses similar assumptions to those adopted in the IRP Proposal, updated to reflect the actual demand in 2018. The resulting demand forecast is shown in Figure 11. The underlying assumptions are provided in Appendix E together with the demand forecasts used in the sensitivity analysis.

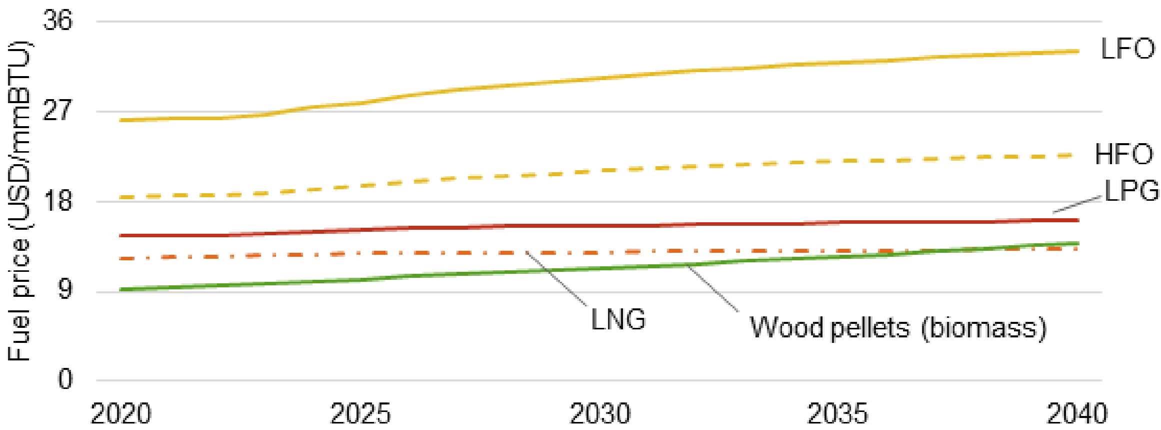
Figure 11: Base case demand forecast for IRP modelling



5.7 Fuel prices

The base case fuel price forecasts for the various fuels are given in Figure 12. The make-up of these fuel price forecasts is detailed in Appendix D. They include liquid fuel price forecasts derived from Brent crude oil forecasts within the U.S. Energy Information Administration's Annual Energy Outlook 2019 (EIA AEO, 2019),[23] which predict rising prices of HFO and LFO over the Planning Period.

Figure 12: Base case fuel price forecasts for the Planning Period



Alternative fuel price forecasts are applied in the sensitivity analysis to investigate how robust the IRP results are to changes in fuel price assumptions.

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[23] Available at URL: https://www.eia.gov/outlooks/aeo/excel/aeotab_12.xlsx.

5.8 Economic assumptions

5.8.1 Social discount rate

The calculation of future system costs in step 6 (see Section 4.6) used a discounting approach to account for the following aspects:

i. Uncertainty: costs projections for the end of the period could be influenced by multiple known and unknown factors, whereas there is more certainty for projections early in the Planning Period because they are not as far away; and

ii. The “time value” of money, which says that money that you have today is more valuable than the same amount of money in the future due to inflation.

A “social discount rate” is used in the analysis to discount future costs to account for the two aspects above and represent the benefit of the investments to the overall economy. Hence, it is typically set at a lower rate than the return that an investor might expect.

A social discount rate of 10% was applied in keeping with the World Bank’s standard for electricity sector projects.[24] The sensitivity analysis investigates the effect on the results of applying 5%, 8% and 12% respectively.

5.8.2 Social cost of carbon

The “social cost of carbon”[25] represents in monetary terms the negative impacts of greenhouse gas emissions on society and the environment. It is expressed as a dollar value per unit of polluting gas and is derived from multiple studies into the economic and social impact of greenhouse gases. It is different from the market price of carbon in carbon trading schemes that have been set up in various jurisdictions around the world to limit the amount of greenhouse gases produced.

The economic costs considered in this analysis capture the social costs of carbon emissions by generators, but not the environmental impact over the lifecycle of the fuels. For example, the risk of methane leaks in the LNG supply chain has not been considered. Methane is a more potent greenhouse gas than carbon dioxide.

[24] See World Bank (2017) “Power Sector Investment Projects: Guidelines for Economic Analysis”.

[25] The social cost of carbon is a measure of the economic harm from those impacts, expressed as the dollar value of the total damages from emitting one ton of carbon dioxide into the atmosphere. Social cost of carbon of 37 USD/ton of CO_2e in 2017 was applied with a 3% growth per year in real terms.

Sources: The Economics of Climate Change: The Stern Review, Cambridge University Press, 2007; Revisiting the social cost of carbon, William D. Nordhaus, 2017

5.9 Demand-side resources

The Electricity Policy states that demand side resources should be considered in the IRP. These are defined in the Electricity Policy as "conservation measures to limit or reschedule electricity use so that the size and number of generating facilities can be reduced or delayed…and can include reducing overall energy consumption (energy efficiency), shifting consumption to off-peak times (peak load shifting), and reducing consumption during peak times (interruptible load)."

This IRP acknowledges recent EE initiatives (for example, the installation of more efficient streetlights, residential lighting exchange programme, etc.), and a review of demand-side resources in the IRP Proposal. The conclusions of this review are summarised below:

1. Accelerated uptake of residential solar water heating systems paired with solar PV panels should be initiated.
2. Additional programmes should be initiated, such as:
   (a) Accelerated uptake of solar PV generation on rooftops of domestic, commercial, and/or industrial customers;
   (b) Accelerated uptake of small-scale cogeneration at commercial sites; and
   (c) Accelerated uptake of combined heat and power facilities.
   (d) Accelerated uptake of energy efficient appliances and LED lightbulbs.

   However, further technical studies would be required to make an informed decision on which of these to prioritise.
3. Anticipated EV charging and usage is expected to have negligible impact on peak demand, but the impact on electricity consumption is difficult to predict.

The demand forecast in this IRP includes an assumption of an annual 4% reduction to incorporate the aspects listed in items 1. and 2. above (see also Appendix E), while 3. is considered in a sensitivity case.

However, peak load shifting and reducing consumption during peak times have not been considered in this IRP. There is currently insufficient information available to be able to establish the possible capacity that might be available. BELCO has indicated that it has plans to investigate demand side resource opportunities but was not able to provide results in the timeframes required to publish this IRP. Such a study should be conducted before the next version of the IRP so that the findings can be incorporated into the modelling at that stage.

6 RESULTS

6.1 Introduction to results

The results of the IRP modelling are presented in this section as follows:

Section	Description
6.2. Levelised cost screening of generation technologies	Presents the results for the levelised cost of electricity calculated for 2020 using the base case assumptions. This gives an indication of the relative lifecycle costs for the various generation technologies.
6.3. Costs of network upgrades	Provides a summary of the network upgrades that would be required to accommodate the planned generators.
6.4. Ranking of policy scenarios	Shows how the policy scenarios compare in economic terms. This is done in two steps: firstly, without considering carbon emissions; and secondly, including a cost to account for carbon emissions.
6.5. Expected greenhouse gas emissions	Summarises the expected greenhouse gas emissions for the eight scenarios.
6.6. Generation capacity added	Gives an overview of the generation plants that would be installed for each scenario.
6.7. Capital investment	Provides an overview of the expected financing needs for the eight scenarios.
6.8. Share of renewables in 2020, 2025 and 2035	Gives the expected amount of electricity from renewable sources in 2020, 2025 and 2035, which are milestone years in the Electricity Policy.
6.9. Plant utilisation for dispatchable generators	Illustrates the expected utilisation of fossil fuel generators in 2035, a milestone year in the Electricity Policy.
6.10. Performance against policy key indicators	Summarises how the IRP scenarios perform against the targets of the Electricity Policy and Fuels Policy.
6.11. Results from sensitivity analysis	Shows how the results of the study are affected in response to changes in key input assumptions. This helps to indicate how uncertainties about the future might affect the conclusions of this IRP.
6.12. Proposed limits for total distributed generation capacity	Gives the proposed limits for total distributed generation capacity for the Planning Period.

6.2 Levelised cost screening of generation technologies

Ranges for the levelised costs of energy for the various generation technologies in the base year of 2020 are summarised in Figure 13. These figures are calculated using the base case input assumptions listed in Appendix C.

Figure 13: Levelised costs of energy for generation technologies in 2020 (the values shown are for the base case assumptions).

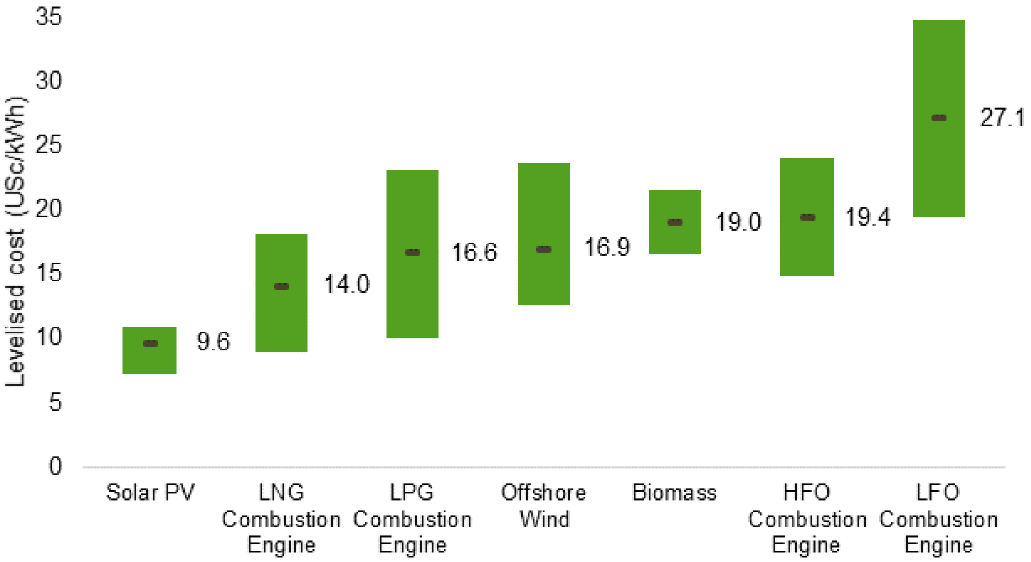


Figure 13 gives an indication of the relative lifecycle costs of the technologies, including capital, operating, maintenance and fuel costs. It shows that solar PV has the lowest lifecycle cost by some margin. This is primarily due to significant reductions in capital costs in recent years and very low operating and maintenance costs over the plant life compared with fossil fuel and biomass plants.

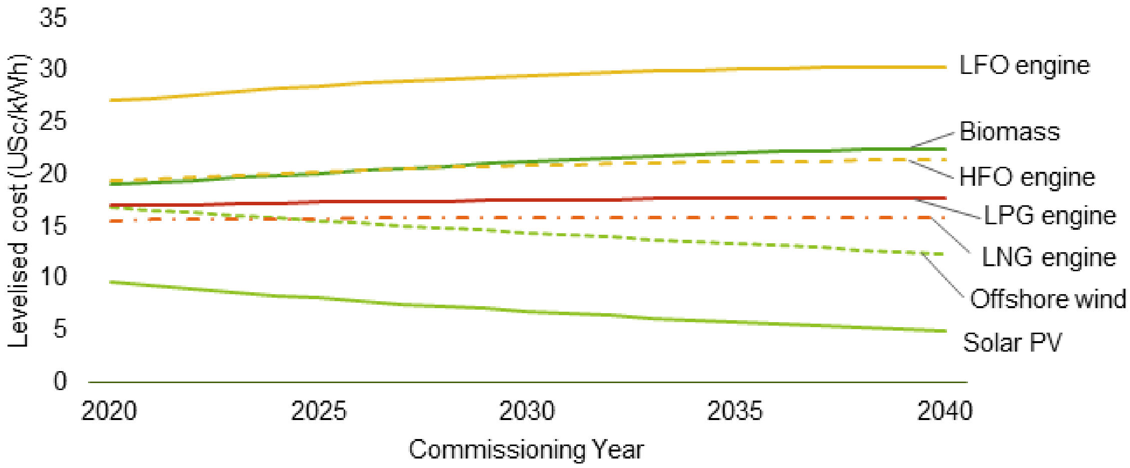
The next five technologies are ranked as follows in terms of levelised cost in 2020, from lowest cost to highest cost:

1. Combustion engines on LNG;
2. Combustion engines on LPG;
3. Offshore wind;
4. Biomass;
5. Combustion engines on HFO.

The levelised costs of engines fuelled by LNG and LPG as well as offshore wind are grouped quite close together, while the costs of biomass and engines utilising HFO are slightly higher. The levelised cost of combustion engines operating on LFO is significantly higher than the other technologies considered.

The levelised costs of energy change over time as capital and fuel costs vary in accordance with the forecasts provided in the appendices. Since this study considers a 20-year horizon, it is useful to see the progression of the costs over time, because the ranking could be different in the future. Figure 14 shows the levelised cost trends for the various technologies over the Planning Period.

Figure 14: Levelised cost of energy trends for generation technologies from 2020 to 2040



Solar PV and LFO engines remain the lowest cost and highest cost options respectively over the Planning Period. However, the relative rankings of the middle five technologies change over time.

The levelised cost of offshore wind is predicted to fall below that for LNG engines from about 2024. Figure 14 also shows that the levelised costs of biomass plants and HFO engines are very similar over the Planning Period. Although the levelised cost of biomass is less than HFO engines at the start of the period, the ranking is predicted to switch in the late 2020's.

It should be noted that the relative rankings of LPG engines and LNG engines on the one hand and HFO engines and biomass on the other, are sensitive to the fuel price forecasts over the Planning Period. Since fuel prices are difficult to predict, the relative ranking of options increases in uncertainty as the time horizon increases. This is one of the reasons the EA requires that an IRP should be conducted at least every five years. The sensitivity analysis in Section 6.9 shows how the ranking of scenarios is affected by changes to fuel price forecast assumptions.

6.3 Costs of network upgrades

Technical studies of the network were conducted to check whether it would have the capacity to transfer electricity from all of the proposed generation plants to customers without bottlenecks and reductions in quality of supply. In cases where further investment would be required in the network to accommodate the new generation plants, the capital costs of these investments have been estimated.

The network studies also investigated the ability of the network to remain stable and maintain quality of supply in the event of a fault on the network without loss of supply to customers.

The conclusions of the network studies are summarised in Table 8.

Table 8: Summary of network study conclusions

Policy Scenario	Capital investment required to accommodate generation plants?	Estimated capital investment (USD)	Network stability test (Pass/Fail)
Scenario 1A: Business as usual	**Yes**	895,900	**Pass**
Scenario 1B: Moderate renewables	**Yes**	895,900	**Pass**
Scenario 1C: High renewables	**Yes**	895,900	**Pass**
Scenario 1D: Very high renewables	**Yes**	895,900	**Pass**
Scenario 2A: LNG Conversion	**Yes**	895,900	**Pass**
Scenario 2B: LNG with Moderate renewables	**Yes**	895,900	**Pass**
Scenario 2C: LNG with High Renewables	**Yes**	895,900	**Pass**
Scenario 2D: LNG with Very High Renewables	**Yes**	895,900	**Pass**

Table 9 provides a breakdown of the equipment included in the estimated cost of network upgrades. These are the same for all scenarios.

Table 9: Breakdown of network reinforcement costs

Item	Units	Cost (USD)
Two sets of new cables between existing substations	800m x 2	320,000
New transformer between existing substations	1	370,500
New reactor between existing substations	1	205,400
TOTAL		**895,900**

6.4 Ranking of policy scenarios

This section presents the results from the analysis using base case assumptions. The policy scenarios are ranked here in order of overall system costs over the Planning Period, as distinct to the levelised cost of energy for individual technologies described in Section 6.2. The ranking is presented firstly excluding carbon costs, and secondly with social costs of carbon included.

6.4.1 Without carbon costs

The total levelised system costs (as defined in Appendix B.4) for the policy scenarios before incorporating carbon costs are given in Table 10.

Table 10: Total levelised system costs of policy scenarios for the period 2020 to 2040, excluding carbon costs

Policy Scenario	Power Generation Cost USc/kWh (1)	Additional Network Costs USc/kWh[26] (2)	Levelised System Cost USc/kWh (3) = (1) + (2)	Difference to Reference Case (%)
Scenario 1A: Business as usual	20.18	0.01	**20.19**	**0.0%**
Scenario 1B: Moderate renewables	20.12	0.01	**20.13**	**-0.3%**
Scenario 1C: High renewables	20.14	0.01	**20.15**	**-0.2%**
Scenario 1D: Very high renewables	20.14	0.01	**20.15**	**-0.2%**
Scenario 2A: LNG Conversion	18.58	0.01	**18.59**	**-7.9%**
Scenario 2B: LNG with Moderate renewables	18.70	0.01	**18.71**	**-7.3%**
Scenario 2C: LNG with High Renewables	19.22	0.01	**19.23**	**-4.7%**
Scenario 2D: LNG with Very High Renewables	20.12	0.01	**20.13**	**-0.3%**

[26] Adder reflecting network reinforcement costs estimated in Section 6.3.

The two least cost scenarios – 2A and 2B – are grouped closely together. They both involve conversion of the thermal units to LNG in 2025. The main difference between these scenarios is the share of renewable sources that are installed to achieve policy targets. Scenario 2A does not define any renewable targets, whereas scenario 2B aims for at least 35% utility-scale renewables in 2035.

There is little difference between the levelised system costs for the four non-LNG scenarios (scenarios 1A to 1D).

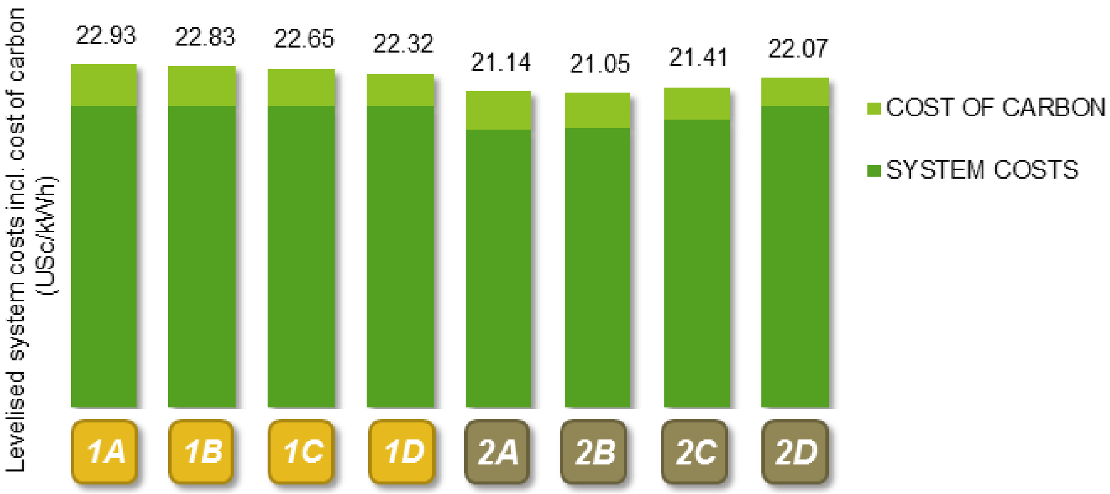
6.4.2 With carbon costs

When carbon costs are factored into the analysis, the ranking of the top two scenarios is reversed, with 2B having the lowest cost as shown in Table 11 and in Figure 15. However, the cost difference between 2A and 2B remains very small and they remain very closely grouped together. Within the non-LNG scenarios, 1D has the lowest cost with the other three being grouped together quite closely.

Table 11: Total levelised system costs for policy scenarios for the period 2020 to 2040, including the cost of carbon

Policy Scenario	Power Generation Cost USc/kWh (1)	Additional Network Costs USc/kWh (2)	Social Cost of Carbon (3)	Levelised System Cost USc/kWh (4) = (1) + (2) + (3)	Difference to Reference Case (%)
Scenario 1A: Business as usual	20.18	0.01	2.75	**22.94**	**0.0%**
Scenario 1B: Moderate renewables	20.12	0.01	2.70	**22.83**	**-0.5%**
Scenario 1C: High renewables	20.14	0.01	2.50	**22.65**	**-1.2%**
Scenario 1D: Very high renewables	20.14	0.01	2.17	**22.32**	**-2.7%**
Scenario 2A: LNG Conversion	18.58	0.01	2.55	**21.14**	**-7.8%**
Scenario 2B: LNG with Moderate renewables	18.70	0.01	2.34	**21.05**	**-8.2%**
Scenario 2C: LNG with High Renewables	19.22	0.01	2.18	**21.41**	**-6.6%**
Scenario 2D: LNG with Very High Renewables	20.12	0.01	1.94	**22.07**	**-3.8%**

Figure 15: Total levelised system costs for policy scenarios for the period 2020 to 2040, including the cost of carbon

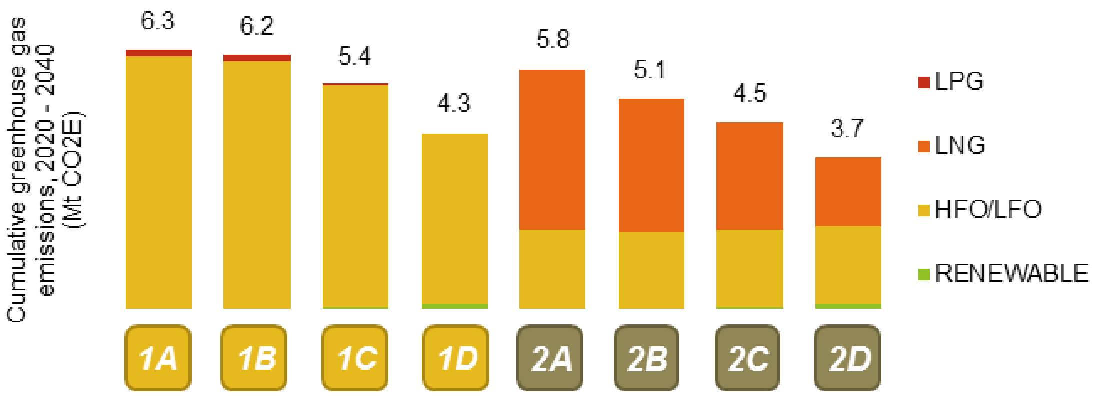


The top four rankings in terms of least cost are claimed by the LNG scenarios, followed by the non-LNG scenarios. When carbon costs are factored in, the cost of scenario 2B is marginally lower than for 2A. Scenario 2B has the additional benefit of achieving the Electricity Policy's share of renewables in 2035, whereas scenario 2A does not. Scenario 2C with high renewables targets is ranked a close third, followed closely by 2D.

6.5 Expected greenhouse gas emissions

The results in Table 11 are calculated based on the expected aggregate carbon emissions calculated for each scenario over the Planning Period, as shown in Figure 16.

Figure 16: Cumulative carbon emissions for each scenario from 2020 to 2040



In both scenario groups, the carbon emissions are seen to decrease with increasing share of renewables, as expected. However, the LNG scenarios have lower carbon emissions than the corresponding non-LNG scenarios over the Planning Period.

Table 12 focuses on the expected greenhouse gas emissions from electricity generation for the scenarios in 2035. It also shows the reduction from the estimated 2019 value (392 kt CO_2e).

Table 12: Expected greenhouse gas emissions in 2035 and proportion of estimated 2019 value

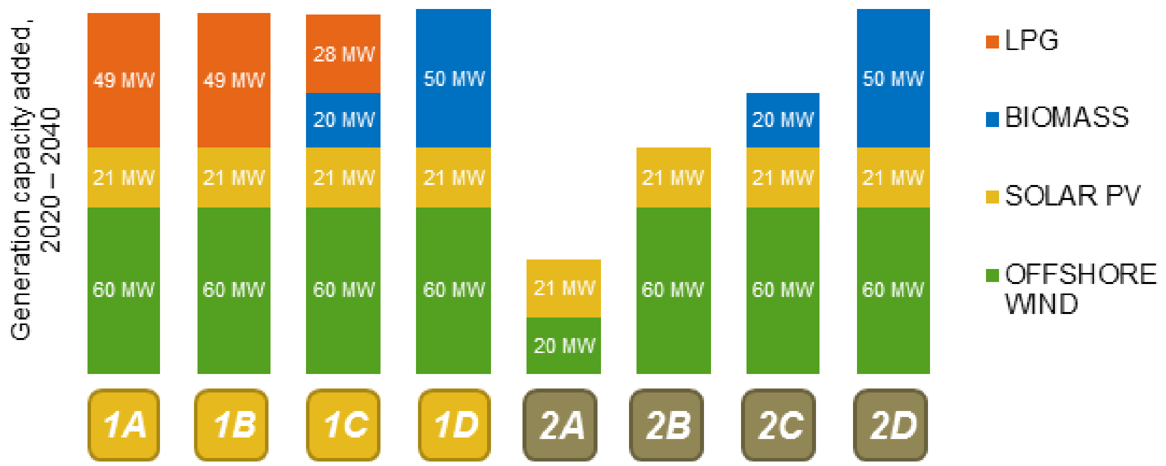
	1A	1B	1C	1D	2A	2B	2C	2D
Expected greenhouse gas emissions in 2035 (kt CO_2e)	242	242	173	71	239	180	129	56
Expressed as a proportion of the estimated 2019 value	62%	62%	44%	18%	61%	46%	33%	14%

All of the scenarios are below the Electricity Policy target ceiling for emissions in 2035 (294.7 kt CO_2e). Scenarios 1D and 2D are particularly successful in reducing emissions from electricity generation due to their high aspirations for contributions from renewable sources.

6.6 Generation capacity added

The proposed additions of generation plants for each scenario are summarised in Figure 17. Detailed timelines for each of the scenarios are provided in Appendix I.

Figure 17: Generation capacity added for each generation expansion scenario



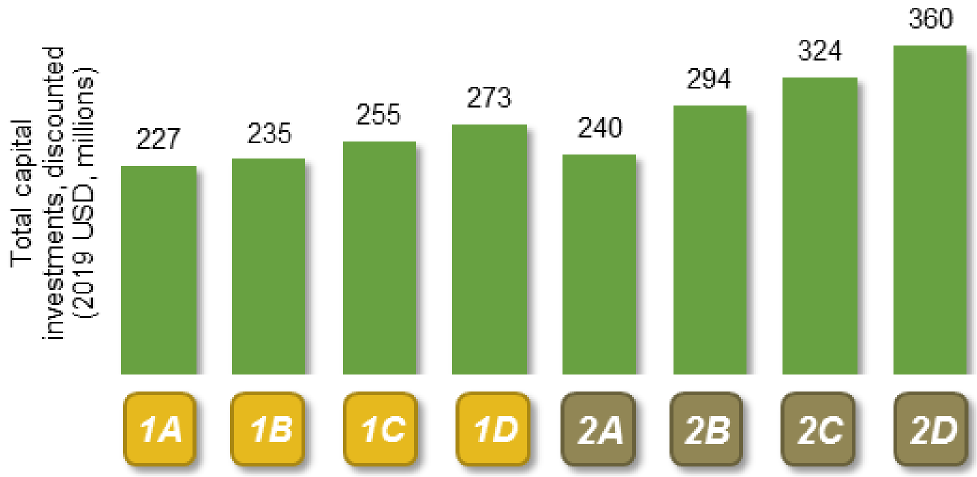
The main points from Figure 17 are:

- All of the scenarios involve commissioning 21 MW of solar photovoltaic PV (including the 6 MW project at the Finger);
- Under all scenarios except 2A, the least-cost plan involves commissioning 60 MW of offshore wind by the end of the Planning Period;
- The remaining capacity requirements in scenarios 1A to 1C are met by a combination of LPG-fuelled combustion engines and biomass (in scenarios 1C, 1D); and
- Additional biomass generators are added in scenarios 2C and 2D towards the end of the Planning Period to meet the renewable penetration targets.

6.7 Capital investment

The discounted total capital investment needs for each scenario between 2020 and 2040 are summarised in Figure 18.

Figure 18: Total capital investment needs under each generation expansion scenario (discounted and expressed in millions of 2019 USD)



The total capital investment costs of the non-LNG scenarios (1A to 1D) are generally lower than for the corresponding LNG-conversion scenarios (2A to 2D). The total capital investment cost for Scenario 2B, which has the lowest levelised system cost of the LNG conversion scenarios (see Figure 15), is 8% higher than for scenario 1D, which has the lowest cost of the scenarios without LNG conversion.

6.8 Share of renewables in 2020, 2025 and 2035

This section examines the share of renewables[27] for the scenarios in the Electricity Policy milestone years 2020, 2025 and 2035, as summarised in Table 13.

Table 13: Share of renewables in the energy mix in 2020, 2025, 2035 for the eight scenarios (including waste-to-energy, distributed generation and solar water heaters)

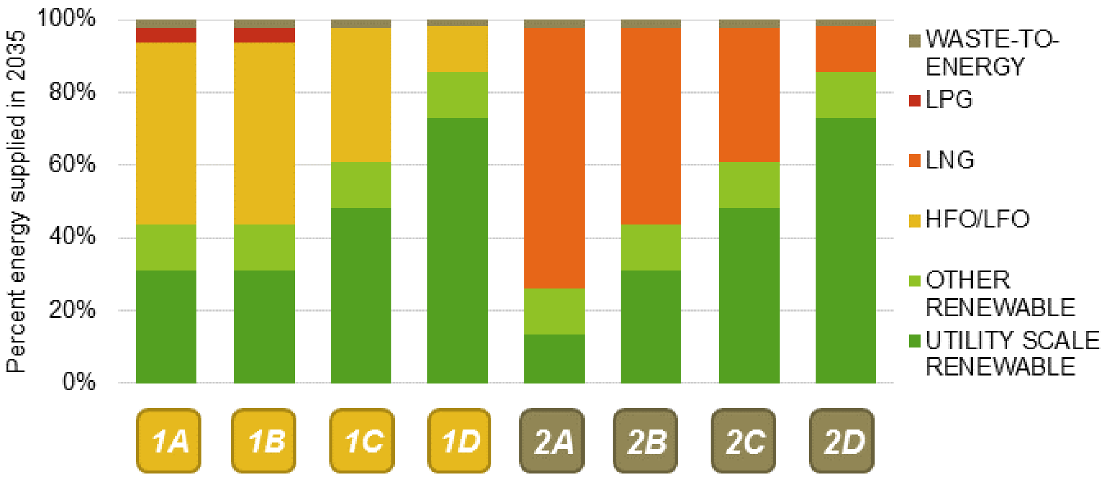
	Electricity Policy target	1A	1B	1C	1D	2A	2B	2C	2D
Share of renewables in 2020	8%	6%	6%	6%	6%	6%	6%	6%	6%
Share of renewables in 2025	35%	11%	15%	15%	15%	11%	15%	15%	15%
Share of renewables in 2035	38%	44%	44%	61%	85%	26%	44%	61%	85%

[27] In accordance with the Electricity Policy, this includes utility-scale solar PV, offshore wind, biomass and waste-to-energy, distributed generation and solar water heaters

Considering the remaining life of the current generation assets and new plants that are expected to come online in 2020 and 2021, pursuing the Electricity Policy target of 35% renewables by 2025 would be difficult to deliver in the available time and would not result in a least cost outcome. However, seven of the eight policy scenarios would be expected to exceed the 2035 goal of 38% comfortably.

Figure 19 provides a summary of the predicted generation mix for the eight scenarios in 2035.

Figure 19: Contributions of the various sources to energy supply in 2035



The share of renewables in non-LNG scenario 1A is higher than for the analogous LNG scenario 2A because the existing reciprocating engine plants benefit from a major overhaul when they are converted to operate on LNG. This means that their operational life is extended beyond 2040 and they do not need to be replaced in the Planning Period. By contrast in scenario 1A, two of the existing HFO engines are retired in 2031, which provides an opportunity to install a further 30 MW of offshore wind because it is the least-cost available option in that year.

The share of renewables is equal for the pairs of analogous scenarios (i.e. 1B and 2B, 1C and 2C, 1D and 2D) because identical assets are installed to meet the defined renewables targets.

6.9 Plant utilisation for dispatchable generators

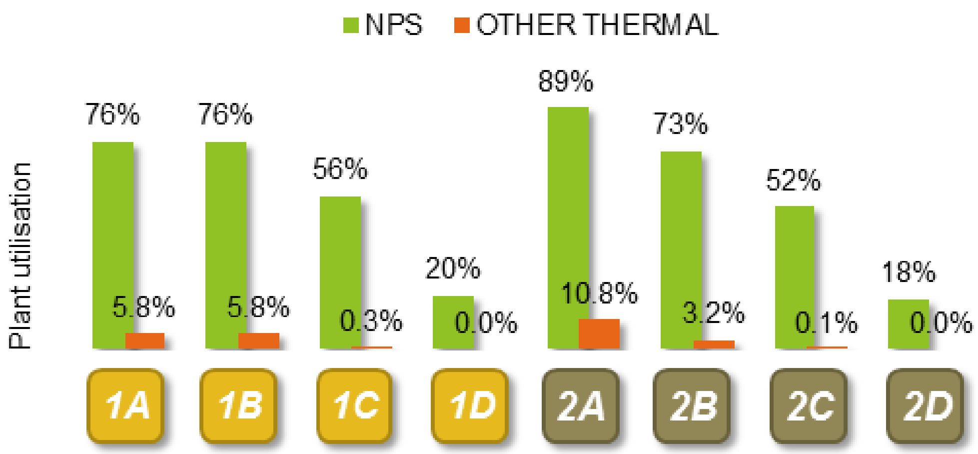
When ambitious targets for renewable generation are pursued, it is likely that the electricity generated by existing dispatchable generation plants will be below their full potential. This would result in some generation plants being partially "stranded", where they are not operated to the fullest extent possible.

Plant utilisation is a measure of how extensively a generator is used. It is calculated by dividing the amount of electricity expected to be generated by the plant's full potential. Here, "full potential" makes allowances for unavailability during maintenance.

Some plants in an electricity system could be designated as “peaking” plants, which are required to provide back-up to the renewable generators that have variable output. These types of plants are designed to operate at relatively low utilisation rates but are necessary to provide security of supply when the sun is not shining, and/or the wind is not blowing.

The average utilisation rates of the North Power Station (“NPS”), which is currently under construction, and other fossil-fuel plants are provided in Figure 20 for 2035.

Figure 20: Plant utilisation rates (expressed as a percentage of maximum) in 2035



In scenarios 1A, 1B, 2A, 2B (with lower contributions from renewables), the reciprocating engine generators within the new North Power Station operate at relatively high utilisation rates (greater than 70%). The older existing generators provide more of a peaking service, supporting the other generators in periods of peak demand and/or when output from renewable generators is low. The utilisation rates of all generators fall as the contribution of renewables increases.

6.10 Performance against policy key indicators

The key performance indicators for the policy scenarios in achieving the Electricity Policy and Fuels Policy targets (see Sections 2.3 and 4.8) are summarised in Table 14. Blue cells indicate that the indicator is exceeded or the scenario is ranked highest; whereas orange cells show cases where the target is not achieved.

Table 14: Summary of the key performance indicators for each scenario

No.	Title	Performance indicator	Target	1A	1B	1C	1D	2A	2B	2C	2D
1	Least cost and high-quality	Ranking by overall system cost (incl. carbon costs)	N/A	8	7	6	5	2	1	3	4
3	Secure (diversity of energy resource mix)	Shannon-Wiener Index for each scenario in 2035 (higher is better).	N/A	1.07	1.07	1.30	1.22	0.64	0.90	1.29	1.22
5.1	Share of renewable generation	Share of electricity generated from renewable sources in 2020.	8%	6	6	6	6	6	6	6	6
5.2	Share of renewable generation	Share of electricity generated from renewable sources in 2025.	35%	11	15	15	15	11	15	15	15
5.3	Share of renewable generation	Share of electricity generated from renewable sources in 2035.	38%	44	44	61	85	26	44	61	85
6.1	Greenhouse gas emissions – Electricity Policy	Greenhouse gas emissions in 2020.	401.5 $ktCO_2e$	390.9	390.9	390.9	390.9	390.9	390.9	390.9	390.9
6.2	Greenhouse gas emissions – Electricity Policy	Greenhouse gas emissions in 2025.	290 $ktCO_2e$	384.0	369.7	369.7	369.7	285.1	274.2	274.2	274.2
6.3	Greenhouse gas emissions – Electricity Policy	Greenhouse gas emissions in 2035.	294.7 $ktCO_2e$	242.2	242.2	173.4	71.2	238.9	180.2	128.7	55.6

No.	Title	Performance indicator	Target	1A	1B	1C	1D	2A	2B	2C	2D
8	Diverse and competitive ownership of resources	Percentage of electricity generated in 2035 by generators that were competitively procured.[28]	N/A	38	38	58	85	18	38	58	85
9	Energy efficiency – Fuels Policy	Cum. fuel consumption between 2020 and 2035 as a percentage of the case where HFO and LFO are the only energy resources.	Less than 85%	83	81	78	75	71	65	63	64
10	Eliminate high-carbon fossil fuels by 2035.	Pass/fail for each scenario in 2035.	Pass	Fail	Fail	Fail	Fail	Pass	Pass	Pass	Pass
11	Greenhouse gas emissions – Fuels Policy	Greenhouse gas emissions as a percentage of emissions in the case where LFO and HFO are the only energy resources in 2035.	Less than 75%	64	64	46	19	63	48	34	15

[28] The calculation assumes that BELCO, as the incumbent bulk generation licensee, would own centralised plant that runs on HFO and LNG.

As described in Section 6.4, scenarios 2A (LNG conversion with no renewable targets) and 2B (LNG conversion with moderate renewable targets) are the lowest cost with only a marginal cost difference between them.

Of these two highest ranked scenarios, only scenario 2B exceeds the Electricity Policy target for renewable generation in 2035 (no. 5.3 in Table 14). Across all scenarios, the indicators for generation from renewable sources show that the least cost path to exceeding the targets for 2035 involves missing the targets for 2020 and 2025 (5.1 and 5.2 in Table 14).

The indicator of energy resource diversity (No. 3 in Table 14) shows that scenario 2B would result in a more diverse mix than scenario 2A and would therefore make Bermuda more resistant to supply shocks in fuel markets.

Rows 6.1 to 6.3 in Table 14 show that the greenhouse gas emissions targets for 2020 are predicted to be achieved, but that conversion to LNG would be required to have a reasonable chance of achieving the 2025 targets. All scenarios are predicted to exceed the 2035 emissions targets comfortably, with scenarios 1D and 2D performing best.

Table 14 also shows that only the LNG scenarios could achieve all of the Fuel Policy targets for the electricity sector.

6.11 Results from sensitivity analysis

A sensitivity analysis was performed to check how robust the scenario rankings are to changes in the input assumptions. A summary of the sensitivity cases is presented in Table 15, which are divided into two sets:

- Set 1: Where the procurement plans for the base case scenarios were fixed and the input assumptions were changed to investigate the change to the rankings (items 1 to 22 in Table 15).
- Set 2: Where the procurement plans were allowed to change to determine a new optimal procurement plan for each scenario (items 23 to 29 in Table 15).

The sensitivity analysis investigated how the total system costs are affected by changes to key input assumptions. As noted in the previous sections, total system cost is only one of the key performance indicators used in this IRP, whereas the full range of objectives (listed in the EA, Electricity Policy and Fuels Policy) should be considered when selecting the best plan on balance.

Table 15: Summary of sensitivity cases

ID.	Set	Input varied	Details of change
1	Set 1	Discount Rate	5% Discount Rate
2	Set 1	Discount Rate	8% Discount Rate
3	Set 1	Discount Rate	12% Discount Rate
4	Set 1	Liquid Fuel Prices	Base Case derived from WB
5	Set 1	Liquid Fuel Prices	High Liquid Fuel Prices (+20%)
6	Set 1	Liquid Fuel Prices	Low Liquid Fuel Prices (-20%)
7	Set 1	Liquid Fuel Prices	Very High Liquid Fuel Prices (+50%)
8	Set 1	Liquid Fuel Prices	Very Low Liquid Fuel Prices (-50%)
9	Set 1	Commodity Prices and Infrastructure Costs for LNG	High LNG Costs (+20%)
10	Set 1	Commodity Prices and Infrastructure Costs for LNG	Low LNG Costs (-20%)
11	Set 1	Commodity Prices and Infrastructure Costs for LNG	Very High LNG Costs (+50%)
12	Set 1	Commodity Prices and Infrastructure Costs for LNG	Very Low LNG Costs (-50%)
13	Set 1	Commodity Prices and Infrastructure Costs for LPG	High LPG Costs (+20%)
14	Set 1	Commodity Prices and Infrastructure Costs for LPG	Low LPG Costs (-20%)
15	Set 1	Commodity Prices and Infrastructure Costs for LPG	Very High LPG Costs (+50%)
16	Set 1	Commodity Prices and Infrastructure Costs for LPG	Very Low LPG Costs (-50%)
17	Set 1	Biomass Prices	High Biomass Prices (+20%)
18	Set 1	Biomass Prices	Low Biomass Prices (-20%)
19	Set 1	Procurement	All wind units commissioned together
20	Set 1	Plant factors for renewable sources	Low plant factor for offshore wind (30%)
21	Set 1	Plant factors for renewable sources	Very low plant factor for offshore wind (25%)
22	Set 1	Plant factors for renewable sources	Low plant factor for solar PV (15%)
23	Set 2	Demand	Base Case without Energy Efficiency
24	Set 2	Demand	Base Case with Energy Efficiency and EV uptake
25	Set 2	Demand	Base Case + 10 MW distributed generation
26	Set 2	Demand	High Demand
27	Set 2	Demand	Low Demand + 10 MW distributed generation + 10 MW demand side resources
28	Set 2	Battery Storage	10 MW Battery commissioned with wind farm
29	Set 2	Battery Storage	20 MW Battery commissioned with wind farm

The battery storage facilities listed in sensitivity cases 28 and 29 were assumed to be sized with a storage capacity equivalent to 30 minutes of discharge at rated MW output.

6.11.1 Scenario rankings within sensitivity set 1

The results from the set 1 sensitivities are presented in Appendix J, with a summary of the results provided in Table 16 for the case where carbon costs are not included in the analysis.

Table 16: Summary of scenario rankings where carbon costs are not included

	1A	1B	1C	1D	2A	2B	2C	2D
Number of sensitivity cases where the scenario was ranked first or second in terms of least cost	1	2	0	1	21	21	0	0

Scenarios 2A and 2B (LNG without renewable targets, and with 35% penetration target by 2035) are almost consistently the lowest cost. The two sensitivities where they are not the highest ranked are the very low HFO/LFO prices (50% below base case forecasts) and the very high LNG prices (50% above base case forecasts).

For most of these sensitivity cases, the total system cost of scenario 2B is within 2% of that for scenario 2A.

Table 17 provides a summary of the results for the case where carbon costs are incorporated into the analysis.

Table 17: Summary of scenario rankings where carbon costs are incorporated

	1A	1B	1C	1D	2A	2B	2C	2D
Number of sensitivity cases where the scenario was ranked first or second in terms of least cost	1	1	1	1	20	21	1	0

When carbon costs are incorporated, scenario 2B and 2A are still almost consistently the lowest cost. For most of these sensitivity cases the total system cost of scenario 2B remains within 2% of that for scenario 2A.

6.11.2 Testing the effect of procuring all offshore wind generators at one time

The IRP assumes that wind generators can be installed in discrete steps of 10 MW (see Appendix C.4). However, it might be more economical to build the entire wind farm with total capacity of 60 MW at one time to save on demobilisation and re-mobilisation costs during construction. A potential disadvantage of installing all offshore wind generators at one time is that the system does not benefit from predicted reductions in capital costs between phases of development.

A sensitivity was examined within set 1 to investigate whether there is a significant cost or benefit to installing the offshore wind generators at one time. The results are shown in Table 18.

Table 18: Predicted effect on overall system costs if wind generators are installed at once rather than in a phased approach as suggested in the base case model

	1A	1B	1C	1D	2A	2B	2C	2D
Predicted cost increase if all wind generators are installed at once	-0.7%	-0.5%	-0.2%	N/A*	N/A*	0.4%	0.2%	N/A*

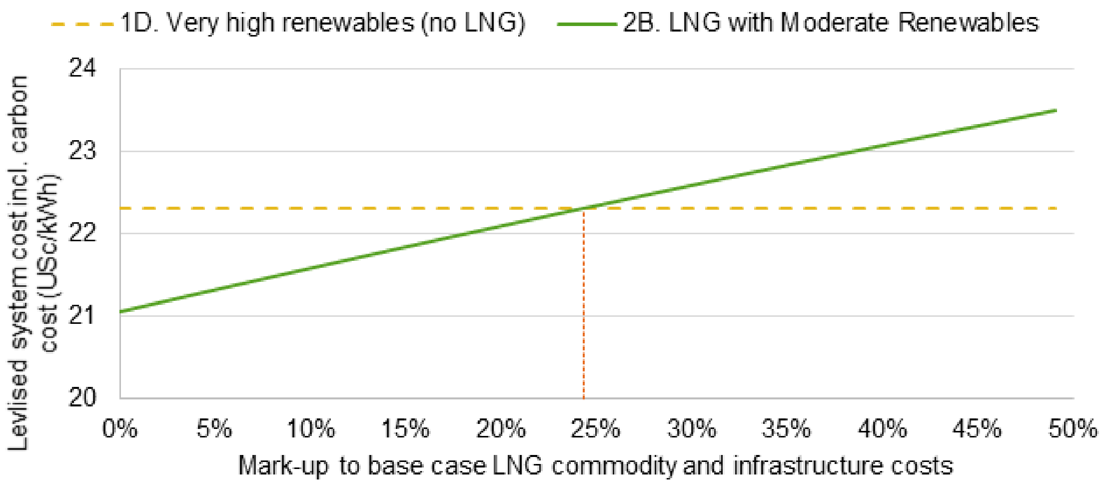
*Not applicable for this scenario because all wind generators are installed at one time in the base case plan.

The results indicate that there could be a marginal benefit to installing wind generators at once if the non-LNG approach is pursued (scenarios 1A to 1D); whereas, there is potentially a marginal cost increase for the LNG scenarios (2A to 2D).

6.11.3 Magnitude of LNG cost increase to affect scenario rankings

An investigation was conducted to check of the sensitivity of total costs (including carbon costs) to LNG commodity and infrastructure costs. Sensitivity case 9 (High LNG costs) was extended to test a range of increases over the base case LNG costs between 0% and 50%. The intention was to identify the point at which the system cost of scenario 2B (least-cost with LNG conversion) exceeded the least cost non-LNG scenario, 1D. The results are shown in Figure 21.

Figure 21: Total system costs (including social cost of carbon) for scenarios 1D and 2B, where the LNG costs are varied



The results indicate that if LNG costs (including infrastructure costs and commodity costs) exceed the base case assumptions by 25% or more, then scenario 1D becomes the least cost option.

6.11.4 Scenario rankings within sensitivity set 2

Five sensitivity cases were investigated in set 2. Three cases looked at how changes in demand affect the generation plan and two cases considered the effect of installing battery storage together with the offshore wind farm. The rankings in terms of least cost across the scenarios (including the cost of carbon) are summarised in Table 19.

Table 19: Rankings of scenarios for sensitivity cases within set 2

	1A	1B	1C	1D	2A	2B	2C	2D
23. Base Case without Energy Efficiency	8	7	6	5	**1**	**2**	3	4
24. Base Case with Energy Efficiency and EV uptake	8	7	6	5	**1**	**2**	3	4
25. Base Case + 10 MW distributed generation	8	7	6	5	**2**	**1**	3	4
26. High Demand	8	7	6	5	**1**	**2**	3	4
27. Low Demand + 10 MW distributed generation + 10 MW demand side resources	8	7	5	4	3	**1**	**2**	6
28. 10 MW Battery commissioned with wind farm	8	7	6	5	**2**	**1**	3	4
29. 20 MW Battery commissioned with wind farm	8	7	6	5	**2**	**1**	3	4

In all cases except “High Demand”, scenarios 2A and 2B continue to be the least cost. In the “High Demand” case (case 27), the least cost scenarios are 2B and 2C.

Table 20 gives the total system costs expressed as a percentage of the base case results for each scenario.

Table 20: Results from sensitivity set 2 - Total system costs expressed as a percentage of the base case

	1A	1B	1C	1D	2A	2B	2C	2D
23. Base Case without Energy Efficiency	1.1%	0.9%	1.2%	1.3%	0.6%	1.5%	1.1%	0.9%
24. Base Case with Energy Efficiency and EV uptake	0.0%	-0.1%	0.0%	-0.1%	-0.1%	0.4%	0.0%	0.0%
25. Base Case + 10 MW distributed solar PV	0.1%	0.1%	0.1%	0.9%	1.1%	1.2%	1.0%	0.6%
26. High Demand	1.7%	2.1%	2.4%	2.9%	-0.4%	1.2%	0.9%	0.5%
27. Low Demand + 10 MW distributed generation + 10 MW demand side resources	4.1%	0.0%	-0.4%	0.5%	5.9%	5.4%	3.8%	2.9%
28. 10 MW Battery commissioned with wind farm	0.3%	-0.2%	0.1%	0.3%	0.3%	0.3%	0.3%	0.3%
29. 20 MW Battery commissioned with wind farm	0.5%	0.0%	-0.1%	0.6%	0.6%	0.6%	0.6%	0.6%

The implementation of energy efficiency measures included in the base case assumptions (case 23) is expected to reduce system costs by about 1%– although the costs of implementing those measures is not included in the IRP analysis.

A moderate and gradual uptake of EV between 2020 and 2040 (case 24) would have a negligible impact on total system costs.

Installation of a 10 MW or 20 MW battery with the wind farm is found to have an economic benefit of 0.6% or less (cases 28 and 29). This indicates that the batteries would not necessarily reduce the capital costs of the proposed generation plan if they are used as a back-up to renewables. However, batteries have other functions that can be valuable in a system with high proportions of renewable generation (e.g. frequency response). These functions have not currently been considered but warrant separate investigation.

As mentioned previously, economic benefit is only one of the aspects considered in this IRP, and batteries could provide benefits for other objectives in the EA, Electricity Policy and Fuels Policy.

6.12 Proposed limits for total distributed generation capacity

The proposed methodology for setting an upper limit for distributed generation (in this context, as defined in the EA) aims to ensure that distributed generation does not reduce demand for electricity from the grid to such a low level that grid-connected generation assets are made redundant.

Based on this methodology, the proposed upper limit for distributed generation is 30 MW.

It is important to note that those limits should be validated by detailed and locational system studies at distribution level.

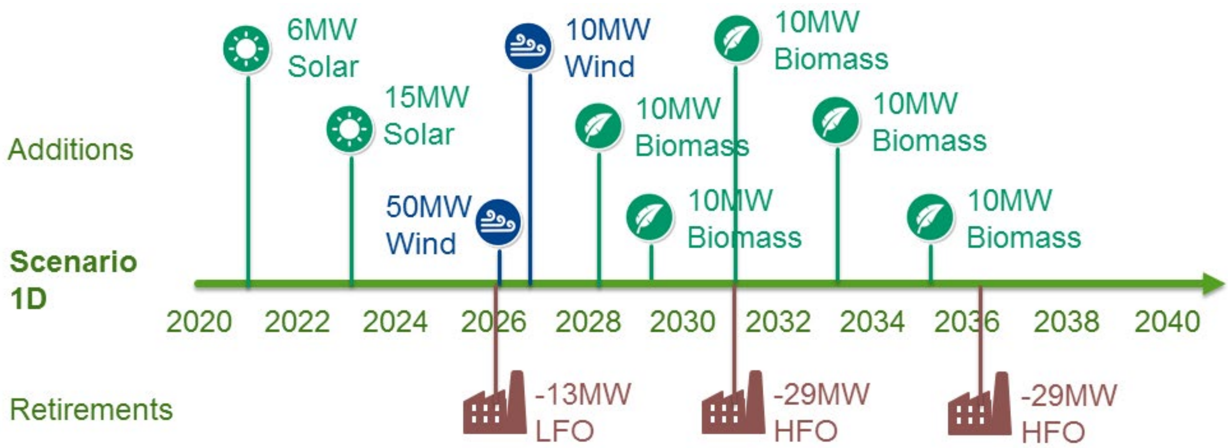
7 CONCLUSIONS AND RECOMMENDATIONS

1. Although the LNG scenarios are expected to have lower system costs than the non-LNG scenarios under the base case assumptions, there are disadvantages in pursuing LNG; mainly driven by the significant investment required in fuel infrastructure. Since this IRP relies on cost projections, including fuel price forecasts, over the 20-year Planning Period, there is inherent uncertainty in the analysis of future costs. If the future costs of LNG and HFO are very different from those assumed in the IRP, then there is a risk of regretting the decision to invest in LNG. For example, an increase of 25% over the assumed LNG infrastructure and commodity costs would result in the cost of the non-LNG scenario being lower in the long run. The risk of regret in the non-LNG scenario is reduced because the infrastructure investment requirements are smaller.

2. The challenge of balancing the objectives of the Electricity Act becomes apparent when the most beneficial scenario without LNG conversion (1D, targeting 75% renewables by 2035) is compared with the most beneficial LNG scenario (2B targeting 35% renewables by 2035) across the key performance indicator range. The LNG scenario scores higher in terms of cost and achieves the aim in the Fuels Policy to eliminate high-carbon fossil fuels (HFO, for example) by 2035. Although the preferred scenario without LNG conversion is expected to have about 6% higher costs than the least expensive LNG scenario, it scores higher for diversity of energy resources, has a much higher contribution from renewables and results in lower greenhouse gas emissions in 2035.

3. Taking account of all of these factors it is judged that scenario 1D (without LNG conversion, targeting 75% renewables by 2035) best meets the broad range of objectives set out in the Electricity Act. The corresponding resource plan is shown in Figure 22.

Figure 22: IRP resource plan (representing scenario 1D)



4. Work should start immediately in establishing the arrangements for procuring additional solar generators because these are common to both the LNG and non-LNG plans and would accelerate the transition required to achieve Bermuda's renewable targets.

5. To strengthen the knowledge base on which this decision is made, the following detailed feasibility studies should be undertaken immediately and completed as soon as possible:

(i) *The level of offshore wind resource available together with the development of the business cases and environmental assessments for the opportunities identified*. Offshore wind technology is a promising renewable technology for Bermuda following significant cost reductions on global markets in recent years. All of the scenarios in this IRP indicate that offshore wind would be required due to anticipated further reductions in costs. A detailed feasibility study for an offshore wind farm should be conducted urgently to enable an informed investment decision. The study should include wind resource testing, detailed cost assessment as well as an environmental and social impact assessment for constructing and operating an offshore wind farm. The maximum optimal capacity for the wind farm should be investigated in the study.

(ii) *Biomass technologies and their supporting business cases for application in Bermuda*. A feasibility study into biomass generation plants should also be conducted in view of its anticipated role in the energy mix by the late 2020's.

(iii) *Possible demand side resources*. The Electricity Policy requires that demand side resources should be considered in the energy resource mix. Insufficient data is available about the potential market for demand side resources within Bermuda currently. It is recommended that a study should be conducted to establish the possible resources and potential value of those resources, which could be included in the next iteration of the IRP.

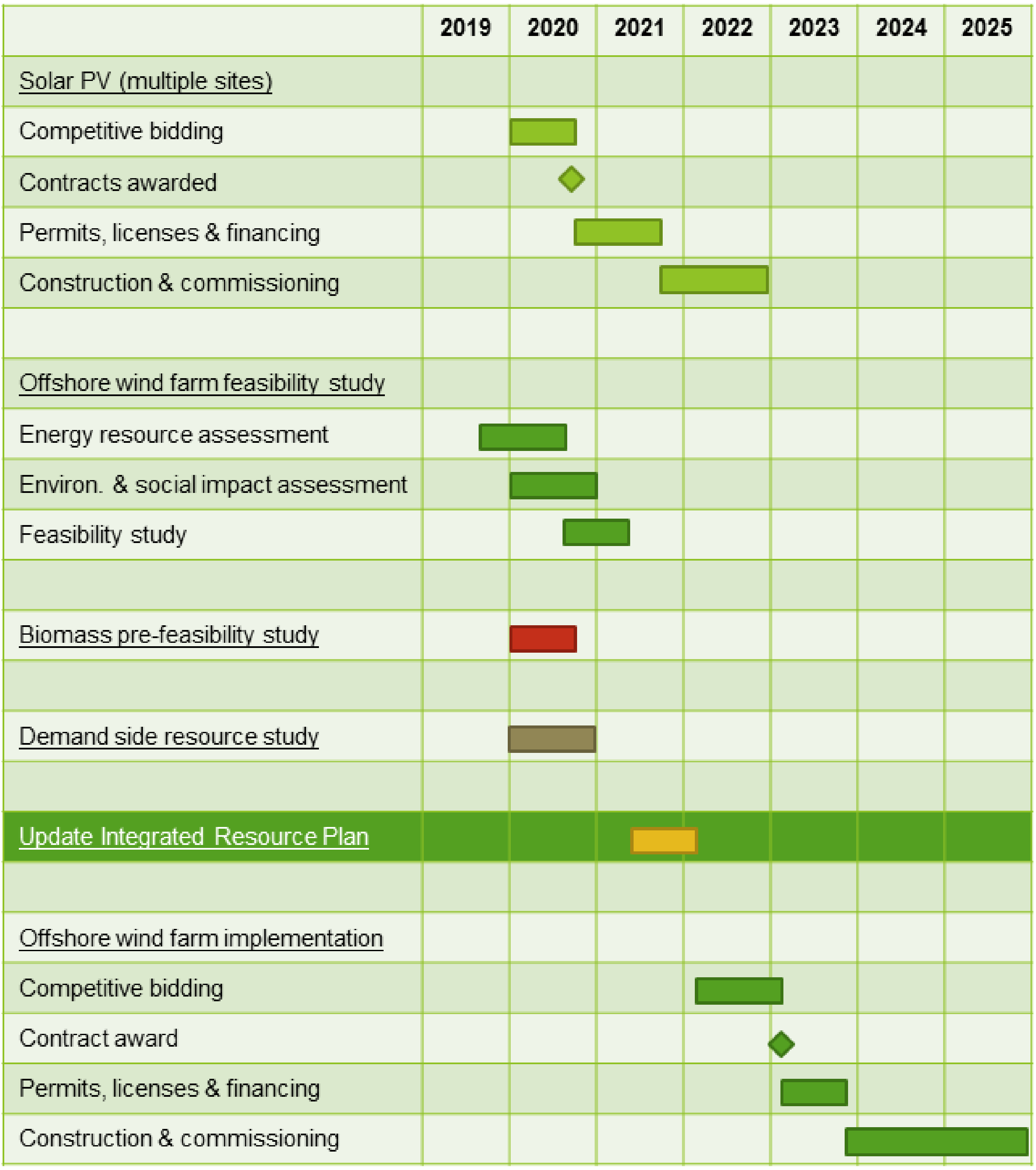
6. The Authority anticipates commencing a further IRP in about two to three years, taking account of the results of these studies and any other changes that may have occurred.

7. Under the EA, the IRP is required to determine the upper limit for distributed generation. At this stage, this is set at 30 MW.

8 RECOMMENDED PROCUREMENT PLAN

The conclusions and recommendations given in the previous section are expressed in the medium-term procurement plan presented in Figure 23.

Figure 23: Recommended medium-term procurement plan



The implementation of the offshore wind farm and biomass plants are dependent on the findings of the updated IRP to be conducted after the feasibility studies.

The offshore wind farm, biomass plants, and solar PV generators are expected to be procured by competitive bidding.

APPENDIX A: ACRONYMS, DEFINITIONS AND KEY CONCEPTS

A.1. Acronyms

CAPEX	Capital expenditure
CO_2e	Carbon dioxide equivalent
EA	Electricity Act 2016
EE	Energy efficiency
EV	Electric vehicles
HFO	Heavy fuel oil
IRP	Integrated Resource Plan
KPI	Key performance indicator
Kt	Kilotonnes
kW	Kilowatts
kWh	Kilowatt-hours
LFO	Light fuel oil
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
mmBTU	Million British thermal units
Mt	Megatonnes
MW	Megawatts
MWh	Megawatt-hours
NPS	North Power Station
NPV	Net present value
OPEX	Operational expenditure
PV	Photovoltaic
RAA	Regulatory Authority Act 2011
RICE	Reciprocating internal combustion engine
TD&R	Transmission, distribution and retail
USc	United States cents
USD	United States Dollars

A.2. Definitions

Term	Applicable to	Definition
Adder (in USD/mmBTU)	Fuel	Amount added to the commodity fuel price to incorporate costs of freight, supply, storage, and/or regasification, as required.
All-in fuel price (in USD/mmBTU)	Fuel	Sum of Commodity Fuel Price and Adder.
Alternative Proposal	Electricity Act	Proposal for bulk generation or demand side resources submitted in accordance with Section 42 of the EA.
Availability at peak (in %)	Generation plant/unit	Ratio of net available capacity at peak over installed capacity. This is a measure of the amount of electricity a plant can be expected to supply during peak demand (also known as firm net capacity).
Capital costs (in USD/kW installed)	Generation plant/unit	Total cost of the asset including project development, engineering, procurement, construction, commissioning and financing costs, but excluding interest during construction.
Commodity fuel price (in USD/mmBTU)	Fuel	Price of fuel on the open market, excluding Adders.
Dispatchable	Generation plant/unit	The ability of a generation technology to increase or decrease load in response to instructions from an operator, as opposed to intermittent energy resources like wind and solar. Examples include reciprocating engines and biomass boiler plant.
Earliest commissioning year	Generation plant/unit	Earliest year that the plant could be commissioned, considering project development and installation timelines, as well as time required for permitting and licensing (if required).
Economic life (in years)	Generation plant/unit	Total expected life of the asset assumed for the economic analysis, assuming operation and maintenance is conducted according to good engineering practice.
Fixed OPEX (in USD/kW/annum)	Generation plant/unit	The operational and maintenance costs that are incurred regardless of the amount of electricity the asset supplies to the grid. This typically includes staff salaries, administration costs, lease fees, etc. See also variable OPEX.
Installed capacity (in MW)	Generation plant/unit	The maximum amount of electricity that the asset can supply to the system at a time. In this study, this is the 'gross' capacity of the asset (i.e. the capacity measured at the generator terminals before subtracting electricity consumption of the plant itself and step-up transformer losses).
IRP Proposal	Electricity Act	Integrated Resource Plan proposal submitted by the TD&R Licensee in accordance with Section 41 of the EA.

Term	Applicable to	Definition
Latest decommissioning year	Generation plant/unit	The latest year that an asset can be decommissioned (i.e. stop operation), considering the commissioning year and economic life, and assuming there are no overhauls to extend the life of the asset.
Market price of carbon (in USD/tCO_2e)	Carbon costing	The price of carbon emissions in a carbon-trading market.
Maximum plant factor (in %)	Generation plant/unit	The maximum achievable ratio of net available capacity over installed capacity that the asset can achieve considering its technical and/or resource limitations.
Net available capacity at peak (in MW)	Generation plant/unit	The amount of electricity that the asset is expected to supply to the system during peak demand, after subtracting electricity consumption of the plant itself and step-up transformer losses.
Peak demand + network losses, gross (in MW)	Demand	The maximum demand of electricity required by consumers simultaneously in a given year, including network losses.
Planning Period	Entire IRP	The period from 2020 to 2040, which is covered by this IRP.
Plant factor (in %)	Generation plant/unit	Ratio of net available capacity (averaged over a year) over installed capacity. This is a measure of how much electricity the asset supplies to the system compared to its potential. The actual value for dispatchable units is calculated in the dispatch modelling, but a maximum value is defined in the IRP model so that the theoretical values do not exceed achievable performance in practice. For non-dispatchable technologies, the value is an input into the IRP model to define the amount of energy delivered by the assets over the year.
Social cost of carbon (in USD/tCO_2e)	Carbon costing	A quantification of the full cost to the environment of an incremental unit of carbon emitted in monetary terms. This is by nature a subjective estimate, which is dependent on multiple assumptions. It is generally higher than the market price of carbon.
Thermal efficiency (in %)	Fuel-burning generation plant/unit	The ratio of the amount of energy supplied by an asset as electricity over the energy content of the fuel consumed to produce that amount of electricity. In this study, thermal efficiency is calculated based on operation of the installed capacity of the asset (i.e. the capacity measured at the generator terminals before subtracting electricity consumption of the plant itself and step-up transformer losses) and the lower heating value of the fuel.

Term	Applicable to	Definition
Variable OPEX (in USD/kWh)	Generation plant/unit	The operational and maintenance costs (expenditure) that are incurred in proportion of the amount of electricity the asset supplies to the grid. This typically includes consumables, an allowance for regular maintenance, etc. In this study, variable OPEX does not include fuel costs unless stated otherwise. See also fixed OPEX.

A.3. Key concepts

This section describes some of the key concepts that influence how electricity systems are planned. It summarises the constraints that planners deal with when making decisions about the system. Further definitions are provided in Appendix A.

The difference between installed capacity and electricity volume

The "installed capacity" of generation plant – usually measured in MW– represents the maximum electricity output that the equipment can supply at a point in time. A generation plant is unlikely to produce its installed capacity all the time. If it is controllable (i.e. it is not dependent on an intermittent resource such as the wind or sun), it will generate in line with a profile to match the demand.

Wind, solar or other variable renewable generation plants will only generate electricity at the installed capacity for short periods, and the amount generated will be dependent on whether the wind is blowing, or the sun is shining.

On the other hand, the "volume of electricity" supplied is usually measured in megawatt-hours ("MWh") and is the amount of electricity produced by the plant. Effectively, it is the product of the portion of the installed capacity generated at particular times (in MW) and the amount of time that generation is at that level (in hours).

To use an analogy, installed capacity is like the bandwidth of your data connection, whereas electricity volume can be likened to the amount of data that you use.

Managing intermittent supply from variable renewable sources

The intermittent and variable nature of renewable resources, such as wind, solar, and marine, can pose challenges to the operation of the electricity system.

Power supply and demand must be balanced at all times across the system, which is relatively simple with dispatchable generation (i.e. plant with controllable output, which as previously mentioned means where it is not dependent on an intermittent source), as the output of the plant can be adjusted to match demand.

However, it is difficult to control the output of plants that rely on renewable sources, like wind, solar or marine because it is determined by the availability of the resource (i.e. how much the wind is blowing, the sun is shining, or the availability of wave or tidal energy). Therefore, approaches are needed to continue to ensure the balance between supply and demand is maintained, no matter what the renewable resource is at any given time.

Ways of doing this include, for example:

- Back up generation – Controllable generation such as reciprocating engines or gas turbines can be used as back up for intermittent generation to provide electricity at times when the output from renewable plants is low. Sizing the back-up generation should be considered carefully; too little back-up could result in power cuts, and too much back-up means that investment is made in infrastructure that is rarely used.
- Storage – Energy can be stored when there is excess electricity and discharged when there is a shortfall. This approach depends on the renewable generation being able to meet the total energy requirements over time, even if there are times of over-generation and under-resource within that. Various types of storage are available, but lithium ion batteries have become more favoured recently due to recent cost reductions. Bermuda's first grid-connected battery was commissioned in 2019.
- Demand Side Response – This approach aims to influence the demand for electricity rather than only adjusting supply from generators. For example, it might be possible to time the use of controllable demand to coincide with sunny or windy conditions. This requires the existence of controllable demands, which are usually demands that serve a purpose, but where the timing of their energy use is flexible. Examples of this include electric vehicles, washing machines, and a range of commercial and industrial uses. This approach is likely to need devices to control power management within the limits of user preferences. This concept requires both technical enablement and societal acceptance to be successful but is likely to be a cost-effective solution to support significant uptake of renewable generation.

It is likely that in order to support significant uptake of intermittent renewable generation, an optimal solution will include more than one of these solutions.

Beyond simply being a controllable energy source, traditional generation also contributes to the stability of the system through providing "system inertia". Existing conventional generation plants (such as those fuelled by HFO and LFO) include large rotating masses which spin at the same frequency as the grid. The rotational inertia of these helps to overcome instantaneous imbalances between supply and demand. Without this 'system inertia', there is a risk that even slight imbalances in supply and demand could result in power system instability, and there will not be the time required for the control systems to correct for them, potentially leading to major power outages.

Most renewable generation plant cannot supply system inertia in this traditional manner. This does not matter where there is the proportion of renewables is small compared to dispatchable generation. However, alternative solutions are required to support the network where there is a significant uptake of renewable resources. These include the provision of "synthetic inertia", where storage or renewable generation plants are carefully controlled to provide the benefits of system inertia. It should be noted, however, that this a potentially significant issue, and requires careful attention as greater levels of renewable generation are achieved.

Reserve margin

In order to maintain system reliability, generation capacity must be greater than the peak expected demand. This allows for the system to be resilient to unexpected rises in demand (for example, unusual weather patterns, events, or rapid adoption of new technologies). This capacity in excess of that required to meet demand is known as the reserve margin or system reserve and can also be used in cases where there has been an unexpected outage in existing power plant - for example, where there has been a malfunction of a generator that would otherwise be expected to operate.

System reserve should be forward-looking, and care should be taken in predicting future load growth, as it takes some time to plan and build new generating plant.

APPENDIX B: DETAILED METHODOLOGY

Future asset needs in the electricity sector are mainly determined by the future forecast for electricity demand. The key factor to ensure supply sustainability is to ensure that there is enough generation capacity and enough network capacity to supply the maximum demand forecast on the system in every year over the Planning Period.

A development plan has been determined for the period 2020 to 2040 for Bermuda, based on the set of assumptions presented in Appendices C to G.

The steps in this process are described in the subsections below.

B.1. Technology screening using levelised costs

Identification of a selection of suitable candidate projects and ranking them based on their individual Levelised Cost of Energy (LCOE, in USc/kWh) for every year of the simulation period.

The Plant LCOE for individual candidate project is calculated using the following formula:

$$Plant\ LCOE\ (\frac{USc}{kWh}) = \frac{NPV(Total\ Generation\ Costs)}{NPV(Max\ Energy\ Output)}$$

where:

- NPV is the Net Present Value of generation costs calculated over the economic lifetime of the asset at a defined discount rate, and for a selected commissioning year, in USD;
- Total Generation Costs = Generation Capital Expenditure (CAPEX) + Non-fuel Operational Expenditure (OPEX) + Fuel Costs, calculated for operation at the maximum energy output throughout the economic life of the plant, in USD;
- Maximum Energy Output
  = Available generation capacity * Maximum Plant Factor.

B.2. Additions to meet policy targets

(a) Determination of renewable energy shortfalls against the selected policy target, for every year of the simulation period, based on demand and energy requirement forecasts, decommissioning schedules for existing assets, and committed plans to commission new plants.

(b) For every year where there is a renewable energy shortfall, the shortfall is filled by candidate plants (limited to renewable technology sources), selected in order of increasing LCOE, subject to the maximum installed capacity limit defined for each technology source.

B.3. Additions to meet demand requirements

(a) Determination of additional supply needs, for every year of the simulation period, based on demand and energy requirement forecasts, decommissioning schedules for existing assets, committed plans to commission new plants, assets commissioned in step 2, and reserve margin targets;

(b) For every year where there are additional capacity needs, the deficit in supply is met by candidate plants (at the level at which they are assumed to be available at system peak time), selected in order of increasing LCOE, subject to the maximum installed capacity limit defined for each technology source.

B.4. Calculation of total system levelised cost

The System LCOE (in USc/kWh) is calculated for the simulation period using the following inputs:

(a) the discounted cost of generation for existing plants, committed plants, and candidate plants selected in steps 2 and 3 – based on actual dispatch estimates;

(b) estimated network reinforcement costs needed to accommodate the capacity mix obtained after steps 2 and 3; and

(c) the economic cost of carbon emissions evaluated for the resulting energy mix.

The System LCOE has been calculated using the following formula:

$$System\ LCOE\ (\frac{USc}{kWh}) = \frac{NPV(Total\ Generation\ Costs + Network\ Costs + Carbon\ Costs)}{NPV(Total\ Energy\ Output)}$$

where:

- NPV is the Net Present Value of generation costs calculated over the simulation period,[29] at a defined discount rate, in USD; and
- Total Generation Costs = Generation Capital Expenditure (CAPEX) + Non-fuel Operational Expenditure (OPEX) + Fuel Costs, calculated for all plants on the system, operating at the estimated energy output based on dispatch simulations, for each year of the simulation period, in USD; and
- Total Energy Output = Total output from the combination of power plants operating on the system, based on dispatch simulations, for each year of the simulation period.

Whilst calculating the “net present value” of energy output is difficult to theoretically explain, it is a standard element in the calculation of the levelised cost of electricity. In effect, this mimics the concept of the “time value of money” (i.e. money available now is more valuable than money received in the future) which underpins financial

[29] This accounts for the residual value of assets at the end of the simulation period.

net present value calculations. In this case the discounting of the generation of electricity is a consequence of the methodology and reflects that the energy generated implicitly corresponds to its value and the further that such generation is placed in the future the lower is that value.

B.5. Calculation of the Shannon-Wiener Measure KPI

The Shannon-Wiener Index (or Shannon-Weaver Index) is a commonly used measure of species diversity within a given population. In the field of energy economics, it can be applied to the diversity of energy resources (fuels and renewable sources) within a given resource mix. In this IRP, it is calculated as follows:

$$Shannon - Wiener = -\sum(p_i) \times \ln(p_i)$$

Where p_i is the proportion of resource i within the mix.

Larger numbers indicate more diversity, while smaller numbers indicate less diversity.

APPENDIX C: POWER GENERATION PLANT ASSUMPTIONS

The input assumptions for power generation plants are listed in this appendix. The acronym "RICE" is used to refer to reciprocating internal combustion engines to be consistent with nomenclature used in the BELCO IRP Proposal. All financial assumptions are expressed in 2019 USD.

C.1. Existing plants[30]

The technical assumptions for the existing generation plants are listed in Table C-1.

Table C-1: Technical assumptions for existing generation plants

Name of unit	Type of technology and fuel	Installed Capacity[31] (MW)	Availability at peak (% of installed capacity)	Maximum Plant Factor (%)	Thermal efficiency (%)	Latest decommissioning year (1st January of)
E1	RICE - HFO	12.2	100%	90%	38.0%	2020
E2	RICE - HFO	11.2	100%	90%	37.6%	2020
E3	RICE - HFO	10.1	100%	90%	40.0%	2020
E4	RICE - HFO	9.5	100%	90%	40.9%	2020
E5	RICE - HFO	14.5	98.6%	90%	41.8%	2031
E6	RICE - HFO	14.5	98.6%	90%	42.0%	2031
E7	RICE - HFO	14.5	98.6%	90%	42.9%	2036
E8	RICE - HFO	14.5	98.6%	90%	43.2%	2036
D3	RICE - LFO	7.0	100%	90%	36.4%	2020
D8	RICE - LFO	7.0	100%	90%	37.8%	2020

[30] Unless otherwise stated, the data in this section is taken from the BELCO IRP Proposal (February 2018) and Addendum 1 to the IRP Proposal (April 2019).

[31] Data obtained from Ricardo Energy & Environment's Generation Asset Lifecycle Review in 2017.

Name of unit	Type of technology and fuel	Installed Capacity[31] (MW)	Availability at peak (% of installed capacity)	Maximum Plant Factor (%)	Thermal efficiency (%)	Latest decommissioning year (1st January of)
D10	RICE - LFO	7.0	100%	90%	37.6%	2020
D14	RICE - LFO	4.5	100%	90%	35.4%	2020
GT4	GT - LFO	11.0	100%	90%	28.7%	2019
GT5	GT - LFO	13.0	100%	90%	30.2%	2026
GT6	GT - LFO	4.5	100%	90%	29.9%	2041
GT7	GT - LFO	4.5	100%	90%	29.9%	2041
GT8	GT - LFO	4.5	100%	90%	29.9%	2041
Tyne's Bay	Waste-to-Energy	6.5	31%	90%	29.4%	2048

The financial assumptions for the existing generation plants are listed in Table C-2.

Table C-2: Financial assumptions for existing generation plants

Name of unit	Fixed OPEX (USD/kW/annum)	Non-fuel variable OPEX (USD/kWh)
E1	24.00	9.40
E2	24.00	9.40
E3	18.00	11.10
E4	18.00	11.10
E5	18.00	11.10
E6	18.00	11.10
E7	18.00	11.10
E8	18.00	11.10
D3	18.00	11.10
D8	18.00	11.10
D10	18.00	11.10

Name of unit	Fixed OPEX (USD/kW/annum)	Non-fuel variable OPEX (USD/kWh)
D14	18.00	11.10
GT4	20.40	6.60
GT5	20.40	6.60
GT6	9.60	7.80
GT7	9.60	7.80
GT8	9.60	7.80
Tyne's Bay	270.00	0.43

C.2. Committed plants[32]

The technical assumptions for generation plants that are currently in the advanced development or construction phases are listed in Table C-3. This includes the four new reciprocating engine units at the NPS, which is currently under construction.

Table C-3: Technical assumptions for committed generation plants

Name of unit	Type of technology and fuel	Installed Capacity per unit (MW)	Availability at peak (% of installed capacity)	Maximum Plant Factor (%)	Thermal efficiency (%)	Commissioning year (1st January of)	Economic life (years)
NPS units 1 to 4	RICE – HFO or LNG	On HFO: 14.4 On LNG: 15.5[33]	On HFO: 97.2% On LNG: 97.1%	90%	On HFO: 41.1% On LNG: 40.1%	For HFO: 2020 For LNG: 2025	30
Finger solar plant	Solar PV	6	10%[34]	17%[35]	N/A	2021	20

The financial assumptions for the committed generation plants are listed in Table C-4.

[32] Unless otherwise stated, the data in this section is taken from the BELCO IRP Proposal (February 2018) and Addendum 1 to the IRP Proposal (April 2019).

[33] Conversion to LNG will provide an opportunity to install heat recovery equipment and a steam turbine/generator to increase the amount of electricity generated. For the sake of the modelling, the generation capacity of the steam turbine/generator (4.2 MW) has been divided by four and added to the capacity of the reciprocating engine generators.

[34] This value reflects the fact that peak tends to occur between 17.00 and 20.00 in summer when horizontal irradiance from the sun is relatively small.

[35] For solar, this is the expected energy yield from solar irradiance. Source: World Bank's Global Solar Atlas for Bermuda.

Table C-4: Financial assumptions for committed generation plants

Name of unit	Capital costs (in USD/kW installed)	Schedule for disbursement of capital (Y = commissioning year)	Fixed OPEX (USD/kW/annum)	Non-fuel variable OPEX (USD/kWh)
NPS units 1 to 4	1,942	Y: 100%	On HFO: 36.93 On LNG: 34.31	On HFO: 6.43 On LNG: 6.43
Finger solar plant	1,700[36]	Y: 100%	19.9	0

C.3. Fuel conversion of existing and committed plants[37]

The four policy scenarios 2A to 2D are based on a move from HFO and LFO to LNG. This will involve conversion of existing generators from HFO/LFO to be able to operate on LNG – with the exception of GT5, due for decommissioning in 2026. This will involve a major overhaul of units E5 to E8, which will effectively extend the expected lifetime of these units by 20 years.

The technical assumptions for the existing generation plants are listed in Table C-5.

Table C-5: Technical assumptions for conversion of existing and committed generation plants to LNG

Name of unit	Type of technology and fuel	Installed Capacity (MW)	Availability at peak (% of installed capacity)	Maximum Plant Factor (%)	Thermal efficiency (%)	Latest decommissioning year[38] (1st January of)
E5 refuel LNG	RICE - LNG	13.7	97.8%	90%	38.3%	2045
E6 refuel LNG	RICE - LNG	13.7	97.8%	90%	38.3%	2045
E7 refuel LNG	RICE - LNG	14.4	97.2%	90%	39.7%	2045

[36] Source: IRENA (2019) “Global weighted average total investment costs” for 2017, increased by 20% to reflect relatively higher capital cost for infrastructure projects in Bermuda. Available at URL: http://resourceirena.irena.org.

[37] Unless otherwise stated, the data in this section is taken from the BELCO IRP Proposal (February 2018) and Addendum 1 to the IRP Proposal (April 2019).

[38] Assuming conversion to LNG in 2024 for operation to start on 1 January 2025.

Name of unit	Type of technology and fuel	Installed Capacity (MW)	Availability at peak (% of installed capacity)	Maximum Plant Factor (%)	Thermal efficiency (%)	Latest decommissioning year[38] (1st January of)
E8 refuel LNG	RICE - LNG	14.4	97.2%	90%	39.7%	2045
GT6 refuel LNG	GT - LFO	5.3	98.1%	90%	29.2%	2041
GT7 refuel LNG	GT - LFO	5.3	98.1%	90%	29.2%	2041
GT8 refuel LNG	GT - LFO	5.3	98.1%	90%	29.2%	2041
NPS units 1 to 4 refuel LNG	RICE - LNG	14.3	97.2%	90%	40.1%	2055

The financial assumptions for the existing generation plants are listed in Table C-6.

Table C-6: Financial assumptions for conversion of existing and committed generation plants to LNG

Name of unit	Capital costs for the conversion (in USD/kW installed)	Fixed OPEX (USD/kW/annum)	Non-fuel variable OPEX (USD/kWh)
E5 refuel LNG	400	18.85	11.52
E6 refuel LNG	400	18.85	11.52
E7 refuel LNG	400	18.85	11.52
E8 refuel LNG	400	18.85	11.52
GT5 refuel LNG	170	21.36	6.91
GT6 refuel LNG	170	10.05	8.20
GT7 refuel LNG	170	10.05	8.20
GT8 refuel LNG	170	10.05	8.20
NPS units 1 to 4 refuel LNG	10.8	34.31	6.43

C.4. Candidate plants

Candidate plants are assets that could reasonably be installed on the Bermuda system between 2020 and 2040. The technical assumptions for these candidate plants are listed in Table C-7.

Table C-7: Technical assumptions for candidate generation plants

Name of candidate	Type of technology and fuel	Maximum Installed Capacity (MW)[39]	Incremental change in Installed Capacity (MW)	Availability at peak (% of installed capacity)	Maximum net plant factor (%)	Thermal efficiency (%)	Earliest commissioning year	Economic life (years)
Solar PV	Ground-mounted solar PV	15[40]	3	10%[41]	17%[42]	N/A	2022	20
Wind offshore	Offshore wind farm	60	10	80%	35%[43]	N/A	2026	20
Biomass	Boiler & steam turbine – wood pellets	70	10	90%	80%[44]	31.0%[45]	2022	25
Reciprocating engine - HFO	Med. speed RICE – HFO	63	7	97.2%	90%	41.1%	2022	30

[39] For solar candidates, this is essentially determined by physical constraints (as described in the BE Solar Alternative Proposal); for other candidates, this has been capped to be no higher than the cumulative capacity gap in the base case scenario by 2040 (i.e. approximately 60 MW).

[40] Source: List of potential sites identified in BE Solar IRP contribution (p.32).

[41] This value reflects the fact that peak tends to occur between 17.00 and 20.00 in summer when horizontal irradiance from the sun is relatively small.

[42] For solar, this is the expected energy yield from solar irradiance. Source: World Bank's Global Solar Atlas for Bermuda.

[43] Source: MERRA database, assuming hub height of 80m.

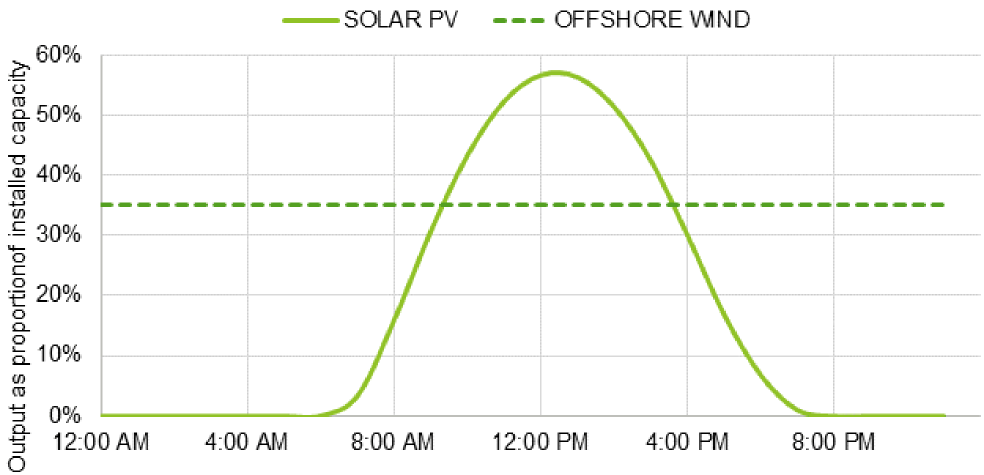
[44] Based on international experience in similar circumstances.

[45] Source: Enviva-Albioma Alternative Proposal (p.8).

Name of candidate	Type of technology and fuel	Maximum Installed Capacity (MW)[39]	Incremental change in Installed Capacity (MW)	Availability at peak (% of installed capacity)	Maximum net plant factor (%)	Thermal efficiency (%)	Earliest commissioning year	Economic life (years)
Reciprocating engine - LPG	Med. speed RICE – LPG	63	7	97.2%	90%	40.1%	2025	30
Reciprocating engine - LNG[46]	Med. speed RICE – LNG	63	7	97.2%	90%	40.1%	2025	30
Reciprocating engine - LFO	High speed RICE– LFO	60	2.5	97.2%	90%	38.0%	2022	30

The normalised generation profiles for non-dispatchable sources are shown in Figure C-1. Simplifying assumptions were made for wind and biomass candidates where output is assumed to be constant at a level equal to the maximum plant factor.

Figure C-1: Assumed normalised generation profiles for non-dispatchable sources (Source: MERRA-2 database for solar profile)



[46] Only considered in the case of LNG conversion in Scenarios 2A to 2D.

The financial assumptions for the candidate generation plants are listed in Table C-4.

Table C-8: Financial assumptions for candidate generation plants

Name of unit	Capital costs (in USD/kW installed) – for installation in 2019	Future reduction of capital costs in nominal terms (annual % change)	Schedule for disbursement of capital (Y = commissioning year)	Fixed OPEX (USD/kW/annum)	Non-fuel variable OPEX (USD/kWh)
Solar PV	1,200[47]	-4%[48]	Y: 100%	19.9	0
Wind offshore	3,700	-2%[49]	Y-1: 80%; Y: 20%	100.0	0
Biomass[50]	2,700	0%	Y-1: 80%; Y: 20%	126.0	5.0
Reciprocating engine - HFO	1,525[51]	0%	Y-1: 80%; Y: 20%	36.93[52]	6.43[53]
Reciprocating engine - LPG	1,525[54]	0%	Y-1: 80%; Y: 20%	34.31[55]	6.43[56]

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[47] Source: Experience in similar jurisdictions.

[48] Source: IRENA and Bloomberg New Energy Finance.

[49] Source: IRENA.

[50] Source: All financial assumptions for biomass are taken from the Enviva-Albioma Alternative Proposal.

[51] Source: IRP contribution from BEESG, assuming no diseconomies of scale.

[52] Assumed to be similar to those of NPS operating on HFO.

[53] Assumed to be similar to those of NPS operating on HFO.

[54] Experience in similar conditions indicates that there should not be any material difference between reciprocating engines of the same capacity operating on different gaseous fossil fuels.

[55] Assumed to be similar to those of NPS operating on LNG.

[56] Assumed to be similar to those of NPS operating on LNG.

Name of unit	Capital costs (in USD/kW installed) – for installation in 2019	Future reduction of capital costs in nominal terms (annual % change)	Schedule for disbursement of capital (Y = commissioning year)	Fixed OPEX (USD/kW/annum)	Non-fuel variable OPEX (USD/kWh)
Reciprocating engine - LNG[57]	1,525[58]	0%	Y-1: 80%; Y: 20%	34.31[59]	6.43[60]
Reciprocating engine - LFO	1,600[61]	0%	Y-1: 80%; Y: 20%	36.93[62]	6.43[63]

57 Only considered in the case of LNG conversion in Scenarios 2A to 2D.

58 Source: IRP contribution from BEESG, assuming no diseconomies of scale.

59 Assumed to be similar to those of NPS operating on LNG.

60 Assumed to be similar to those of NPS operating on LNG.

61 Source: Experience in similar conditions.

62 Assumed to be similar to those of NPS operating on HFO.

63 Assumed to be similar to those of NPS operating on HFO.

APPENDIX D: FUEL ASSUMPTIONS

The inputs assumptions for fuels are presented in this appendix.

D.1. Fuel characteristics

The calorific values and carbon emissions characteristics are summarised in Table D-1. Unless otherwise stated, these values are taken from the UK Government's Conversion Factors for greenhouse gas reporting, 2018.

Table D-1: Calorific values and carbon emissions characteristics for fuels considered

Fuel	Gross calorific value (MJ/kg)	Gross calorific value (GJ/m^3)	Greenhouse gas emissions intensity at point of generation (tCO_2e/t)
Heavy fuel oil	43.1	-	3.229
Light fuel oil	45.6	-	3.209
Liquefied petroleum gas	49.3	-	2,937
Liquefied natural gas	-	23.0[64]	2.747
Wood pellets (biomass)	18.3	-	0.070

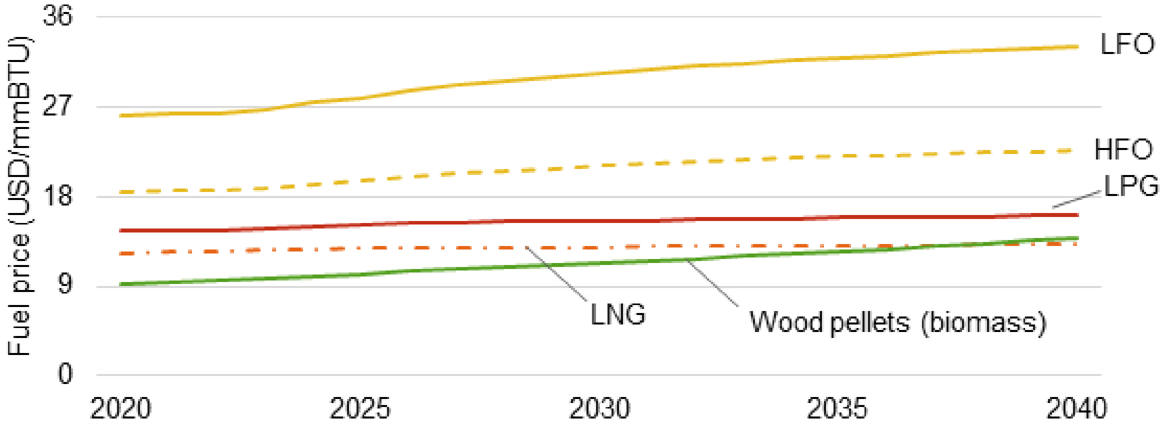
D.2. Summary of fuel price forecasts

A summary of the base case fuel price forecasts for the various fuels over the Planning Period is given in Figure D-1. The make-up of these fuel price forecasts is detailed in the following sections of this appendix. They include liquid fuel price forecasts derived from Brent crude oil forecasts within the U.S. Energy Information Administration's Annual Energy Outlook 2019 (EIA AEO, 2019).[65]

[64] Source: Based on value of 21,832 Btu/litre quoted in BELCO IRP Proposal, Appendix II.C.

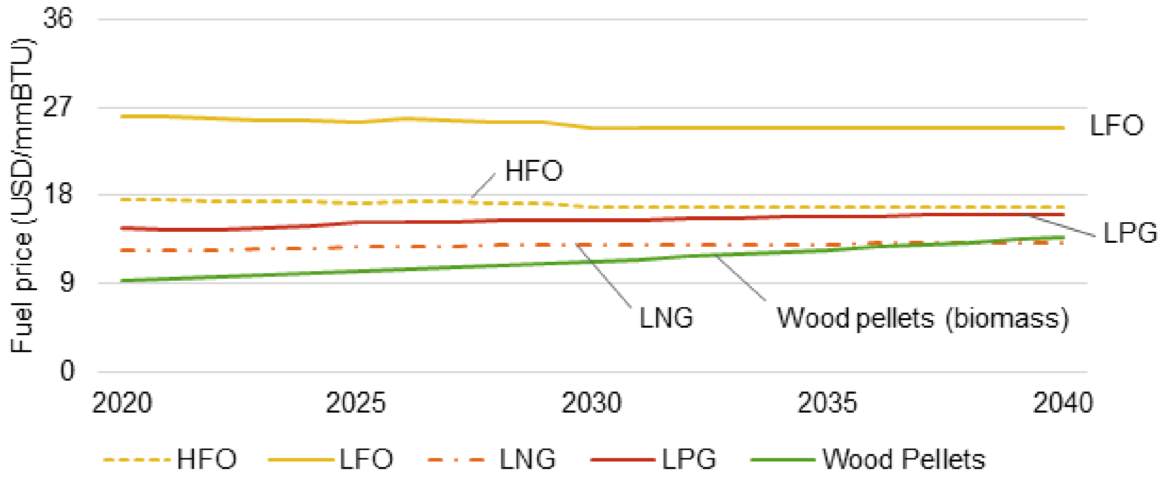
[65] Available at URL: https://www.eia.gov/outlooks/aeo/excel/aeotab_12.xlsx.

Figure D-1: Base case fuel cost forecasts over the Planning Period, derived from crude oil and gas pricing projections by the U.S. Energy Information Administration



Alternative liquid fuel price forecasts were applied in a sensitivity case (see Section 6.9 of the IRP report). They are based on forecasts by the World Bank.[66] These are summarised in Figure D-2.

Figure D-2 Alternative fuel cost forecasts over the Planning Period, derived from crude oil pricing projections by the World Bank and gas pricing projections by the U.S. Energy Information Administration



[66] Available at URL: http://pubdocs.worldbank.org/en/598821555973008624/CMO-April-2019-Forecasts.pdf.

D.3. HFO price forecast

Year	Revised commodity price forecast – real 2019 USD/mmBTU[67]	Adder to cover freight and supply – 2019 USD/mmBTU[68]	All-in HFO price forecast – 2019 USD/mmBTU
2019	9.3	9.1	18.4
2020	9.3	9.1	18.4
2021	9.4	9.1	18.6
2022	9.4	9.1	18.6
2023	9.7	9.1	18.8
2024	10.1	9.1	19.2
2025	10.4	9.1	19.5
2026	10.8	9.1	20.0
2027	11.2	9.1	20.3
2028	11.4	9.1	20.6
2029	11.7	9.1	20.8
2030	11.9	9.1	21.0
2031	12.1	9.1	21.3
2032	12.3	9.1	21.5
2033	12.5	9.1	21.6
2034	12.7	9.1	21.8
2035	12.8	9.1	22.0
2036	13.0	9.1	22.1
2037	13.1	9.1	22.3
2038	13.3	9.1	22.4
2039	13.4	9.1	22.5
2040	13.5	9.1	22.6

[67] Source: Brent crude oil forecasts from EIA AEO, 2019; HFO commodity prices derived from regression using dataset from Insee spanning from 1990 to 2017, assuming a sulphur content of 3.5%; fuel specifications extracted from BELCO IRP Proposal.

[68] Adjusted with historical HFO price delivered in Bermuda, as quoted in BCM Alternative Proposal.

D.4. LFO price forecast

Year	Revised commodity price forecast – real 2019 USD/mmBTU[69]	Adder to cover freight and supply – 2019 USD/mmBTU[70]	All-in LFO price forecast – 2019 USD/mmBTU
2019	16.2	9.9	26.1
2020	16.2	9.9	26.1
2021	16.4	9.9	26.4
2022	16.4	9.9	26.3
2023	16.8	9.9	26.7
2024	17.5	9.9	27.4
2025	18.0	9.9	27.9
2026	18.7	9.9	28.6
2027	19.2	9.9	29.1
2028	19.6	9.9	29.6
2029	20.0	9.9	30.0
2030	20.4	9.9	30.3
2031	20.8	9.9	30.7
2032	21.1	9.9	31.0
2033	21.4	9.9	31.3
2034	21.7	9.9	31.6
2035	22.0	9.9	31.9
2036	22.2	9.9	32.1
2037	22.4	9.9	32.4
2038	22.7	9.9	32.6
2039	22.8	9.9	32.8
2040	23.0	9.9	32.9

[69] Source: Brent crude oil forecasts from EIA AEO, 2019; LFO commodity prices derived from regression using dataset from Insee spanning from 1990 to 2017; fuel specifications extracted from BELCO IRP Proposal.

[70] Adjusted with historical HFO price delivered in Bermuda, as quoted in as quoted in BCM IRP Alternative Proposal.

D.5. LPG price forecast

Year	Revised commodity price forecast – real 2019 USD/mmBTU[71]	Adder to cover shipping, pipeline, duty, and storage – 2019 USD/mmBTU[72]	All-in LPG price forecast – 2019 USD/mmBTU
2019	5.9	9.4	15.3
2020	5.6	9.4	15.0
2021	5.5	9.4	14.9
2022	5.5	9.4	14.9
2023	5.7	9.4	15.1
2024	5.9	9.4	15.3
2025	6.2	9.4	15.6
2026	6.3	9.4	15.7
2027	6.3	9.4	15.8
2028	6.4	9.4	15.9
2029	6.4	9.4	15.8
2030	6.5	9.4	15.9
2031	6.4	9.4	15.9
2032	6.6	9.4	16.1
2033	6.7	9.4	16.1
2034	6.8	9.4	16.2
2035	6.8	9.4	16.3
2036	6.9	9.4	16.4
2037	7.0	9.4	16.4
2038	7.0	9.4	16.4
2039	7.0	9.4	16.4
2040	7.1	9.4	16.5

[71] Source: BP Annual Energy Outlook 2019 and BELCO IRP Proposal– annual increase extracted from long-term energy price forecasts for industrial use from EIA AEO, 2019, forecasts until 2021 extracted from BELCO IRP Proposal.

[72] Source: BELCO IRP Proposal.

D.6. LNG price forecast

Year	Revised commodity price forecast – real 2019 USD/mmBTU[73]	Adder to cover shipping, pipeline, duty, storage, and regasification – 2019 USD/mmBTU[74]	All-in LNG price forecast – 2019 USD/mmBTU
2019	2.6	11.7	14.3
2020	2.6	11.7	14.3
2021	2.6	11.7	14.3
2022	2.7	11.7	14.4
2023	2.8	11.7	14.5
2024	2.9	11.7	14.6
2025	3.0	11.7	14.7
2026	3.0	11.7	14.8
2027	3.1	11.7	14.8
2028	3.1	11.7	14.8
2029	3.1	11.7	14.9
2030	3.1	11.7	14.9
2031	3.2	11.7	14.9
2032	3.2	11.7	14.9
2033	3.2	11.7	14.9
2034	3.3	11.7	15.0
2035	3.3	11.7	15.0
2036	3.3	11.7	15.0
2037	3.3	11.7	15.1
2038	3.3	11.7	15.1
2039	3.4	11.7	15.1
2040	3.4	11.7	15.1

D.7. Wood pellets (biomass) price forecast

A fuel cost of USD/mmBTU 9.1 was assumed for 2019, with 2% increase per year in real terms. This value was taken from the Enviva-Albioma Alternative Proposal (p.8) and checked against publicly available international biomass prices.

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[73] Source: BP Annual Energy Outlook 2019 – annual increase extracted from long-term energy price forecasts for industrial use, 2019 forecast equal to from Henry Hub forecasts. Available at URL: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019.pdf.

[74] Source: BELCO IRP Proposal.

D.8. Fuel infrastructure costs

When calculating total system costs, costs associated with infrastructure dedicated to fuel handling, regasification, and storage of LNG and LPG have been removed from the respective fuel price Adder, and instead accounted for as a separate fixed capital expenditure - corresponding to small-scale LNG/LPG infrastructure of a typical size. This is to represent that regardless of the volume of gas needed for existing and planned units to operate, there will be a minimum level of capital investment corresponding to infrastructure development. Corresponding assumptions are summarised in Table D-1. Unless otherwise stated, these values are taken from BELCO's IRP.

Table D-2: Infrastructure costs for LPG and LNG

Fuel	Total CAPEX (in 2019 USD)	Schedule for disbursement of capital (Y = commissioning year)	Reduction in fuel adder (USD/mmBTU)
Liquefied petroleum gas	17,575,000	Y-1: 100%	-0.4
Liquefied natural gas	117,091,000	Y-1: 100%	-1.9

D.9. Network reinforcement costs

The technical analysis carried out for this IRP has enabled the Authority to estimate the costs of additional network reinforcements required to accommodate the capacity mix recommended under each scenario. Those costs are of a similar level for all scenarios and are reported in the table below, and the commissioning of those reinforcements have been set to be synchronised with the commissioning of the first of the wind turbines of the offshore windfarm (differs between scenarios).

Table D-3: Network reinforcement costs

Total CAPEX (in 2019 USD)	Schedule for disbursement of capital (Y = commissioning year)
895,900	Y-1: 100%

Table D-4: Breakdown of network reinforcement costs

Item	Units	Cost (USD)
Two sets of new cables between existing substations	800m x 2	320,000
New transformer between existing substations	1	370,500
New reactor between existing substations	1	205,400
TOTAL		**895,900**

APPENDIX E: ELECTRICITY DEMAND ASSUMPTIONS

E.1. Base case demand forecast

The assumptions for the base case electricity demand forecast are summarised in Table E-1 below.

Table E-1: Assumptions for the base case electricity demand forecast

Year	Peak demand + Losses – net of EE uptake (MW)[75,76]	Reserve Margin (MW)[77]	Peak Demand + Losses + Reserve Margin (MW)	Energy requirements + Losses – net of EE (MWh) [78]
2019	106.3	36.2	**142.5**	**621,670**
2020	105.7	36.2	**141.9**	**617,521**
2021	105.7	36.1	**141.8**	**617,376**
2022	105.6	36.1	**141.7**	**617,108**
2023	105.5	36.1	**141.6**	**616,702**
2024	105.5	36.1	**141.6**	**616,142**
2025	105.3	36.0	**141.3**	**615,408**
2026	105.2	36.0	**141.2**	**614,484**
2027	105	36.0	**141.0**	**613,345**
2028	104.8	35.9	**140.7**	**612,696**
2029	104.7	35.9	**140.6**	**611,922**
2030	104.6	35.9	**140.5**	**611,014**
2031	104.4	35.9	**140.3**	**609,958**
2032	104.2	35.8	**140.0**	**608,745**
2033	104	35.8	**139.8**	**607,362**
2034	103.6	35.8	**139.4**	**605,794**
2035	103.4	35.7	**139.1**	**604,029**
2036	103.1	35.1	**138.2**	**602,049**
2037	102.6	35.1	**137.7**	**599,839**
2038	102.8	35.1	**137.9**	**600,778**
2039	102.9	35.1	**138.0**	**601,659**
2040	103.1	35.1	**138.2**	**602,639**

[75] Note: the base case does not cater for distributed generation and EV uptake – this is considered in sensitivity scenarios only.

[76] Source: Base Case from BELCO IRP Proposal.

[77] Assumed to be equal to 24% of the peak demand before accounting for EE measures – in 2019, this corresponds to twice the net size of the largest existing BELCO unit (E8), i.e. a "N-2" reliability margin.

[78] Source: Base Case from BELCO IRP Proposal.

E.2. Demand forecast without Energy Efficiency (Sensitivity 23)

The assumptions for the electricity demand forecast without incremental energy efficiency measures are summarised in Table E-2 below, as applied in sensitivity case 23.

Table E-2: Assumptions for the electricity demand forecast without incremental energy efficiency measures

Year	Peak demand + Losses (MW)	Reserve Margin (MW)[79]	Peak Demand + Losses + Reserve Margin (MW)	Energy requirements + Losses (MWh)
2019	105.5	36.2	**141.7**	**617,108**
2020	104.1	36.3	**140.3**	**606,522**
2021	103.8	36.3	**140.1**	**603,456**
2022	103.5	36.4	**139.8**	**599,738**
2023	103.0	36.4	**139.5**	**595,933**
2024	102.8	36.5	**139.3**	**592,598**
2025	102.2	36.5	**138.8**	**587,990**
2026	101.8	36.6	**138.4**	**583,923**
2027	101.1	36.7	**137.8**	**579,230**
2028	100.6	36.7	**137.3**	**575,189**
2029	100.1	36.8	**136.9**	**571,749**
2030	99.7	36.8	**136.5**	**568,332**
2031	99.2	36.9	**136.0**	**564,364**
2032	98.5	36.9	**135.5**	**560,287**
2033	97.9	37.0	**134.9**	**556,072**
2034	96.9	37.0	**134.0**	**550,568**
2035	96.3	37.1	**133.4**	**545,989**
2036	95.4	37.2	**132.6**	**540,651**
2037	94.3	37.2	**131.5**	**533,995**
2038	94.4	37.3	**131.7**	**532,908**
2039	94.5	37.3	**131.8**	**531,761**
2040	94.6	37.4	**132.0**	**530,702**

[79] Assumed to be equal to 24% of the peak demand before accounting for EE measures – in 2019, this corresponds to twice the net size of the largest existing BELCO unit (E8), i.e. a "N-2" reliability margin.

E.3. Demand forecast with Energy Efficiency and EV uptake (Sensitivity 24)

The assumptions for the electricity demand forecast with energy efficiency measures and with a moderate and gradual uptake of EV consumption, are summarised in Table E-3 below, as applied in sensitivity case 24.

Table E-3: Assumptions for the electricity demand forecast with energy efficiency and EV uptake

Year	Peak demand + Losses (MW)	Reserve Margin (MW)[80]	Peak Demand + Losses + Reserve Margin (MW)	Energy requirements + Losses (MWh)
2019	**106.3**	36.2	**142.5**	**621,785**
2020	**105.7**	36.2	**141.9**	**617,716**
2021	**105.7**	36.1	**141.8**	**617,657**
2022	**105.6**	36.1	**141.7**	**617,526**
2023	**105.5**	36.1	**141.6**	**617,304**
2024	**105.5**	36.1	**141.6**	**616,973**
2025	**105.3**	36.0	**141.3**	**616,514**
2026	**105.2**	36.0	**141.2**	**616,018**
2027	**105.0**	36.0	**141.0**	**615,461**
2028	**104.8**	35.9	**140.7**	**615,548**
2029	**104.7**	35.9	**140.6**	**615,663**
2030	**104.6**	35.9	**140.5**	**615,797**
2031	**104.4**	35.9	**140.3**	**615,937**
2032	**104.2**	35.8	**140.0**	**615,961**
2033	**104.0**	35.8	**139.8**	**615,839**
2034	**103.6**	35.8	**139.4**	**615,531**
2035	**103.4**	35.7	**139.1**	**615,026**
2036	**103.1**	35.1	**138.2**	**614,306**
2037	**102.6**	35.1	**137.7**	**613,356**
2038	**102.8**	35.1	**137.9**	**614,295**
2039	**102.9**	35.1	**138.0**	**615,176**
2040	**103.1**	35.1	**138.2**	**616,156**

[80] Assumed to be equal to 24% of the peak demand before accounting for EE measures – in 2019, this corresponds to twice the net size of the largest existing BELCO unit (E8), i.e. a “N-2” reliability margin.

E.4. Demand forecast with increased distributed generation (Sensitivity 20)

The assumptions for the electricity demand forecast with increased distributed generation are summarised in Table E-4 below, as applied in sensitivity case 20.

Table E-4: Assumptions for the electricity demand forecast with increased distributed generation

Year	Peak demand + Losses – net of EE and EV uptake (MW)	Reserve Margin (MW)[81]	Peak Demand + Losses + Reserve Margin (MW)	Energy requirements + Losses – net of EE and EV uptake (MWh)
2019	105.5	36.2	**141.7**	**617,108**
2020	104.1	36.3	**140.3**	**606,522**
2021	103.8	36.3	**140.1**	**603,456**
2022	103.5	36.4	**139.8**	**599,738**
2023	103.0	36.4	**139.5**	**595,933**
2024	102.8	36.5	**139.3**	**592,598**
2025	102.2	36.5	**138.8**	**587,990**
2026	101.8	36.6	**138.4**	**583,923**
2027	101.1	36.7	**137.8**	**579,230**
2028	100.6	36.7	**137.3**	**575,189**
2029	100.1	36.8	**136.9**	**571,749**
2030	99.7	36.8	**136.5**	**568,332**
2031	99.2	36.9	**136.0**	**564,364**
2032	98.5	36.9	**135.5**	**560,287**
2033	97.9	37.0	**134.9**	**556,072**
2034	96.9	37.0	**134.0**	**550,568**
2035	96.3	37.1	**133.4**	**545,989**
2036	95.4	37.2	**132.6**	**540,651**
2037	94.3	37.2	**131.5**	**533,995**
2038	94.4	37.3	**131.7**	**532,908**
2039	94.5	37.3	**131.8**	**531,761**
2040	94.6	37.4	**132.0**	**530,702**

[81] Assumed to be equal to 24% of the peak demand before accounting for EE measures – in 2019, this corresponds to twice the net size of the largest existing BELCO unit (E8), i.e. a “N-2” reliability margin.

E.5. Demand forecast – High case (Sensitivity 21)

The assumptions for the high case electricity demand forecast are summarised in Table E-5 below, as applied in sensitivity case 21.

Table E-5: Assumptions for the high case electricity demand forecast

Year	Peak demand + Losses – net of EE and EV uptake (MW)	Reserve Margin (MW)[82]	Peak Demand + Losses + Reserve Margin (MW)	Energy requirements + Losses – net of EE and EV uptake (MWh)
2019	105.5	35.9	**141.4**	**617,108**
2020	106.8	36.6	**143.5**	**624,516**
2021	108.8	37.4	**146.2**	**636,182**
2022	110.8	38.1	**148.9**	**648,028**
2023	112.8	38.9	**151.7**	**660,040**
2024	114.9	39.7	**154.5**	**672,205**
2025	116.9	40.5	**157.4**	**684,511**
2026	119.0	41.3	**160.3**	**697,052**
2027	121.0	42.1	**163.1**	**709,811**
2028	123.2	42.9	**166.2**	**723,498**
2029	125.5	43.8	**169.3**	**737,503**
2030	127.8	44.7	**172.4**	**751,822**
2031	130.1	45.6	**175.7**	**766,449**
2032	132.4	46.5	**178.9**	**781,267**
2033	134.8	47.4	**182.2**	**796,253**
2034	137.1	48.4	**185.4**	**811,374**
2035	139.5	49.3	**188.9**	**826,624**
2036	141.9	50.3	**192.3**	**841,992**
2037	144.3	51.3	**195.6**	**857,470**
2038	147.4	52.3	**199.7**	**875,223**
2039	150.5	53.4	**203.8**	**893,331**
2040	153.6	54.5	**208.1**	**911,801**

[82] Assumed to be equal to 24% of the peak demand before accounting for EE measures – in 2019, this corresponds to twice the net size of the largest existing BELCO unit (E8), i.e. a “N-2” reliability margin.

E.6. Demand forecast – Low case with increased distributed generation (Sensitivity 22)

The assumptions for the low case electricity demand forecast are summarised in Table E-6 below, as applied in sensitivity case 22.

Table E-6: Assumptions for the low case electricity demand forecast

Year	Peak demand + Losses – net of EE and EV uptake (MW)	Reserve Margin (MW)[83]	Peak Demand + Losses + Reserve Margin (MW)	Energy requirements + Losses – net of EE and EV uptake (MWh)
2019	105.5	35.9	**141.4**	**617,108**
2020	102.0	35.2	**137.2**	**594,764**
2021	99.2	34.5	**133.7**	**576,893**
2022	96.5	33.8	**130.3**	**559,397**
2023	93.7	33.1	**126.9**	**542,247**
2024	91.1	32.5	**123.6**	**525,415**
2025	88.5	31.8	**120.3**	**508,869**
2026	85.9	31.2	**117.0**	**492,691**
2027	83.2	30.6	**113.8**	**476,844**
2028	80.7	30.0	**110.7**	**462,025**
2029	78.3	29.4	**107.6**	**447,608**
2030	75.9	28.8	**104.7**	**433,572**
2031	73.6	28.2	**101.8**	**419,897**
2032	71.2	27.6	**98.8**	**406,450**
2033	68.8	27.1	**95.9**	**393,194**
2034	66.4	26.5	**93.0**	**380,079**
2035	64.2	26.0	**90.2**	**367,085**
2036	61.9	25.5	**87.4**	**354,186**
2037	59.5	25.0	**84.5**	**341,360**
2038	57.8	24.5	**82.3**	**330,756**
2039	56.2	24.0	**80.1**	**320,440**
2040	54.5	23.5	**78.0**	**310,404**

[83] Assumed to be equal to 24% of the peak demand before accounting for EE measures – in 2019, this corresponds to twice the net size of the largest existing BELCO unit (E8), i.e. a "N-2" reliability margin.

APPENDIX F: ECONOMIC ASSUMPTIONS

The IRP model is defined in real terms.

A social discount rate of 10% was used for discounting the costs of all existing, committed and candidate plants.

Carbon costing was derived from an assumed value for the social cost of carbon. A cost of carbon of 37 USD/ton of CO2e in 2017 was used, with a 3% growth per year in real terms.[84]

The social cost of carbon aims to reflect the full global cost to the environment of an incremental unit of carbon emitted and tends to be higher than the market price of carbon – which reflects the per unit price of traded carbon emissions (e.g. on the EU Emissions Trading System).

Year	Carbon Cost – Base Case (USD/tCO_2e)
2019	39.3
2020	40.4
2021	41.6
2022	42.9
2023	44.2
2024	45.5
2025	46.9
2026	48.3
2027	49.7
2028	51.2
2029	52.8
2030	54.3
2031	56.0
2032	57.6
2033	59.4
2034	61.2
2035	63.0
2036	64.9
2037	66.8
2038	68.8
2039	70.9
2040	73.0

[84] Sources: The Economics of Climate Change: The Stern Review, Cambridge University Press, 2007; Revisiting the social cost of carbon, William D. Nordhaus, 2017.

APPENDIX G: DEFINITION OF POLICY SCENARIOS

The first set of four scenarios considers the case where LNG is not pursued, so the fossil fuel options are HFO, LFO and LPG. With this underlying assumption the existing generators will continue to operate on HFO or LFO until the end of their useful lives, and four different renewable targets are defined as described in Table G-1.

Table G-1: Summary of policy scenarios for the case where LNG is not pursued

	BELCO existing units	Conversion of BELCO units to natural gas	Fuel type for North Power Station	Renewables penetration constrained (bulk energy only)	Selection criteria for other future units
1A	HFO (engines) & LFO (gas turbines) to retirement	N/A	HFO	No targets or constraints, but includes 6 MW at Finger (committed)	Candidates selected by increasing order of levelised cost, subject to maximum capacity limits
1B	HFO (engines) & LFO (gas turbines) to retirement	N/A	HFO	10% in 2022 15% by 2025 25% by 2030 35% by 2035	Candidates selected by increasing order of levelised cost, subject to maximum capacity limits
1C	HFO (engines) & LFO (gas turbines) to retirement	N/A	HFO	15% in 2022 20% by 2025 35% by 2030 50% by 2035	Candidates selected by increasing order of levelised cost, subject to maximum capacity limits
1D	HFO (engines) & LFO (gas turbines) to retirement	N/A	HFO	20% in 2022 25% by 2025 50% by 2030 75% by 2035	Candidates selected by increasing order of levelised cost, subject to maximum capacity limits

The second set of four scenarios considers the case where LNG is pursued. With this underlying assumption the existing generators will operate on HFO or LFO until 2024 when they will be converted to operate on LNG. This will involve a major overhaul, which will extend their useful lives by 20 years. The same set of four different renewable targets are defined as described in Table G-2.

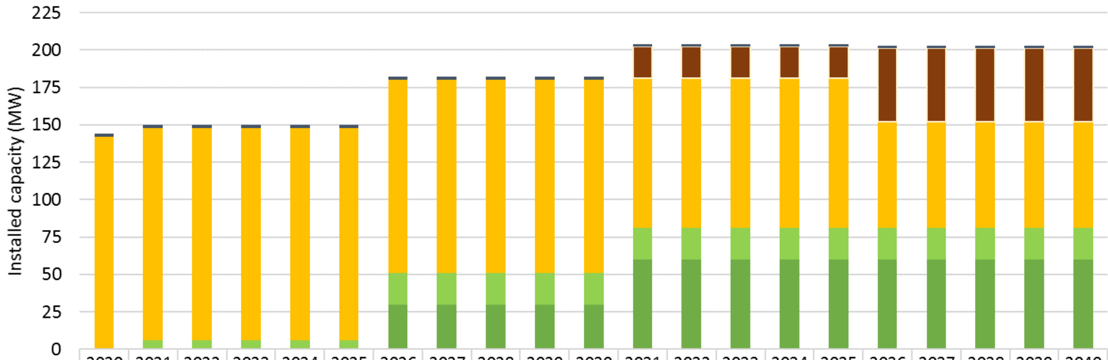
Table G-2: Summary of policy scenarios for the case where LNG is pursued

	Policy scenario	BELCO existing units	Conversion of BELCO units to natural gas	Fuel type for North Power Station	Renewables penetration constrained (bulk energy only)	Selection criteria for other future units
2A	LNG conversion	HFO (engines) & LFO (gas turbines) until 2024 LNG from 2025	Conversion of E5, E6, E7, E8, GT6, GT7, GT8 in 2025	HFO until 2024 LNG from 2025	No targets or constraints, but includes 6 MW at Finger (committed)	Candidates selected by increasing order of levelised cost, subject to maximum capacity limits
2B	LNG with Moderate renewables	HFO (engines) & LFO (gas turbines) until 2024 LNG from 2025	Conversion of E5, E6, E7, E8, GT6, GT7, GT8 in 2025	HFO until 2024 LNG from 2025	10% in 2022 15% by 2025 25% by 2030 35% by 2035	Candidates selected by increasing order of levelised cost, subject to maximum capacity limits
2C	LNG with High Renewables	HFO (engines) & LFO (gas turbines) until 2024 LNG from 2025	Conversion of E5, E6, E7, E8, GT6, GT7, GT8 in 2025	HFO until 2024 LNG from 2025	15% in 2022 20% by 2025 35% by 2030 50% by 2035	Candidates selected by increasing order of levelised cost, subject to maximum capacity limits
2D	LNG with Very High Renewables	HFO (engines) & LFO (gas turbines) until 2024 LNG from 2025	Conversion of E5, E6, E7, E8, GT5, GT7, GT8 in 2025	HFO until 2024 LNG from 2025	20% in 2022 25% by 2025 50% by 2030 75% by 2035	Candidates selected by increasing order of levelised cost, subject to maximum capacity limits

APPENDIX H: RESULTS FOR EACH POLICY SCENARIO

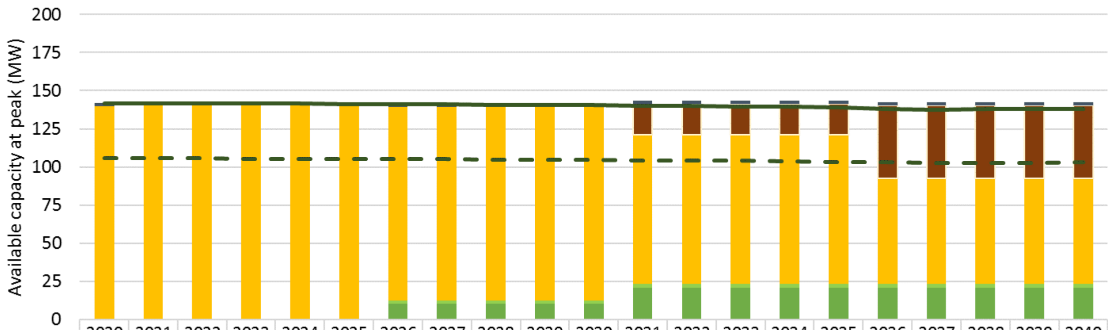
H.1. Scenario 1A: Business as usual

(a) Installed capacity



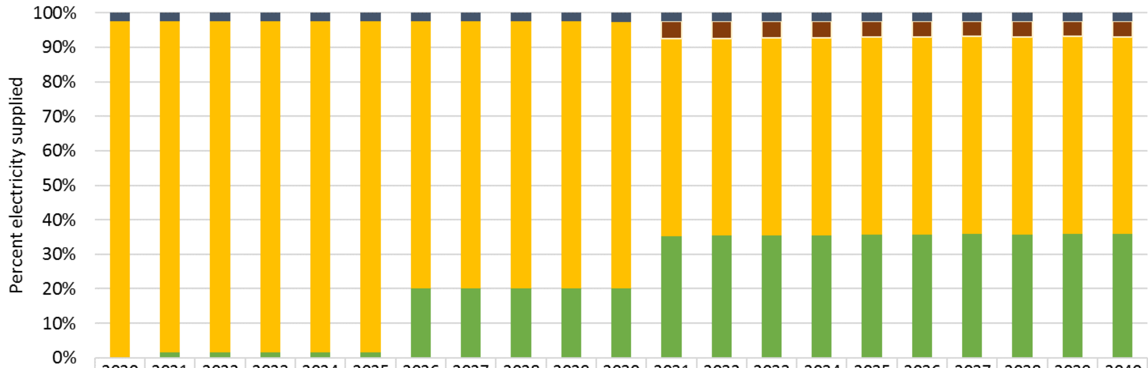
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LPG	0	0	0	0	0	0	0	0	0	0	0	21	21	21	21	21	49	49	49	49	49
LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO/LFO	142	142	142	142	142	142	129	129	129	129	129	100	100	100	100	100	71	71	71	71	71
BIOMASS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOLAR PV	0	6	6	6	6	6	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
OFFSHORE WIND	0	0	0	0	0	0	30	30	30	30	30	60	60	60	60	60	60	60	60	60	60

(b) Available capacity at peak



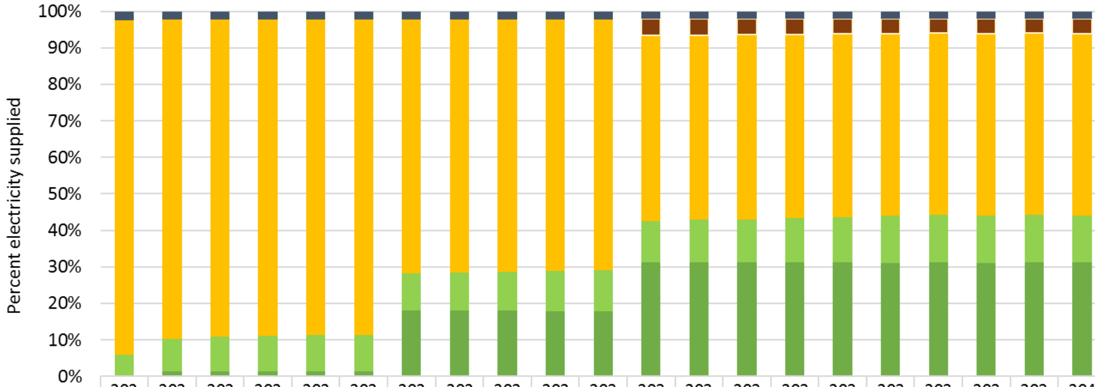
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.4	20.4	20.4	20.4	20.4	47.6	47.6	47.6	47.6	47.6
LNG	0.0	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	0.0
HFO/LFO	139.7	139.7	139.7	139.7	139.7	139.7	126.7	126.7	126.7	126.7	126.7	98.1	98.1	98.1	98.1	98.1	69.5	69.5	69.5	69.5	69.5
BIOMASS	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	0.0
SOLAR PV	0.0	0.6	0.6	0.6	0.6	0.6	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
OFFSHORE WIND	0.0	0.0	0.0	0.0	0.0	0.0	10.5	10.5	10.5	10.5	10.5	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Total demand	106	106	106	106	106	105	105	105	105	105	105	104	104	104	104	103	103	103	103	103	103
Peak + Margin	142	142	142	142	142	141	141	141	141	141	141	140	140	140	139	139	138	138	138	138	138

(c) Energy mix (bulk energy only)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	5%	5%	5%	5%	5%	4%	5%	4%	5%
LNG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HFO/LFO	97%	96%	96%	96%	96%	96%	77%	77%	77%	77%	77%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%
RENEWABLE	0%	1%	1%	1%	1%	1%	20%	20%	20%	20%	20%	35%	35%	35%	36%	36%	36%	36%	36%	36%	36%

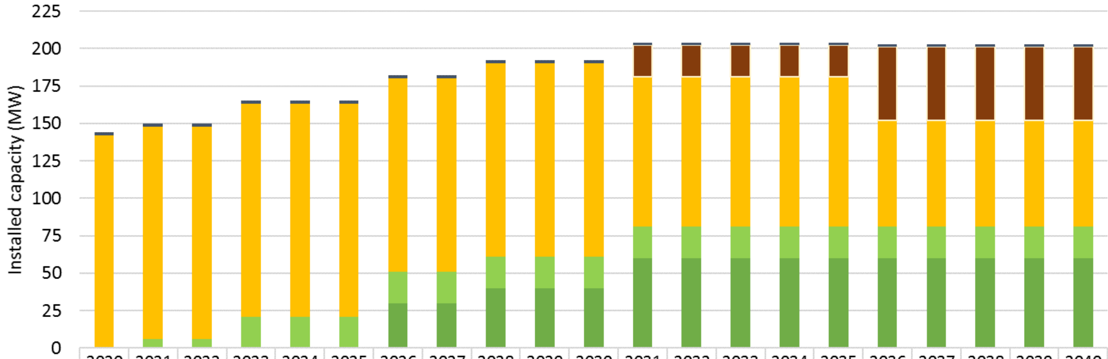
(d) Energy mix (bulk energy and distributed generation)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	4%	4%	4%	4%	4%	4%	4%	4%	4%
LNG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HFO/LFO	92%	87%	87%	87%	86%	86%	69%	69%	69%	69%	69%	51%	51%	50%	50%	50%	50%	50%	50%	50%	50%
OTHER RENEWABLE	6%	9%	10%	10%	10%	10%	10%	10%	11%	11%	11%	11%	12%	12%	12%	12%	13%	13%	13%	13%	13%
UTILITY SCALE RENEWABLE	0%	1%	1%	1%	1%	1%	18%	18%	18%	18%	18%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%

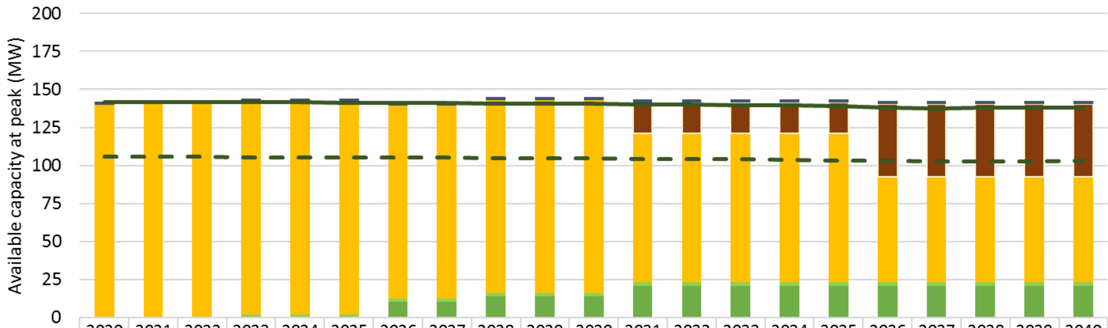
H.2. Scenario 1B: Moderate Renewables without LNG

(a) Installed capacity



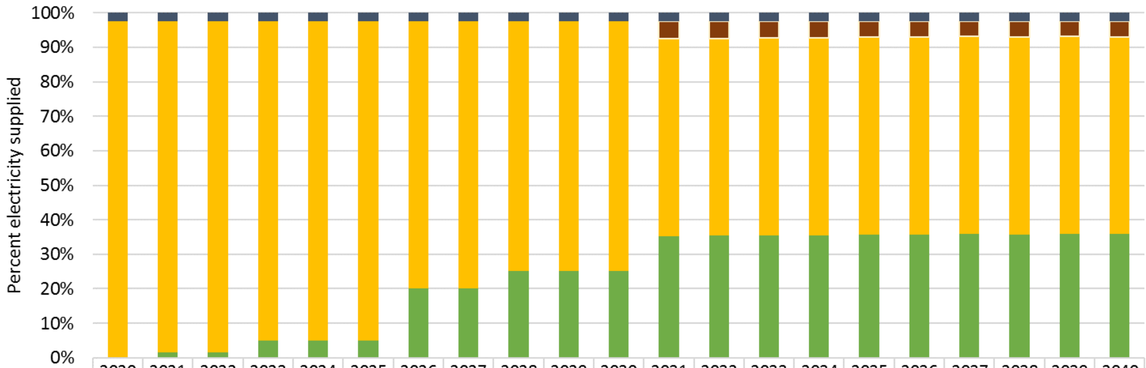
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LPG	0	0	0	0	0	0	0	0	0	0	0	21	21	21	21	21	49	49	49	49	49
LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO/LFO	142	142	142	142	142	142	129	129	129	129	129	100	100	100	100	100	71	71	71	71	71
BIOMASS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOLAR PV	0	6	6	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
OFFSHORE WIND	0	0	0	0	0	0	30	30	40	40	40	60	60	60	60	60	60	60	60	60	60

(b) Available capacity at peak



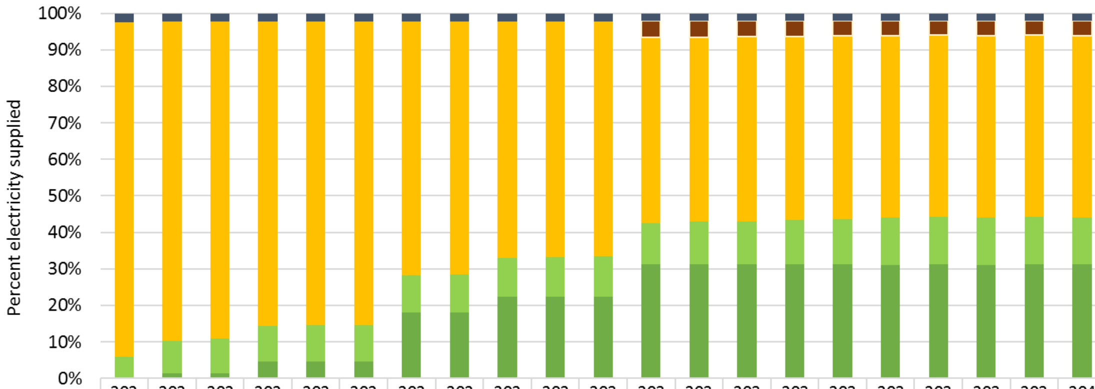
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.4	20.4	20.4	20.4	20.4	47.6	47.6	47.6	47.6	47.6
LNG	0.0	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	0.0
HFO/LFO	139.7	139.7	139.7	139.7	139.7	139.7	126.7	126.7	126.7	126.7	126.7	98.1	98.1	98.1	98.1	98.1	69.5	69.5	69.5	69.5	69.5
BIOMASS	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	0.0
SOLAR PV	0.0	0.6	0.6	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
OFFSHORE WIND	0.0	0.0	0.0	0.0	0.0	0.0	10.5	10.5	14.0	14.0	14.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Total demand	106	106	106	106	106	105	105	105	105	105	105	104	104	104	104	103	103	103	103	103	103
Peak + Margin	142	142	142	142	142	141	141	141	141	141	141	140	140	140	139	139	138	138	138	138	138

(c) Energy mix (bulk energy only)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	5%	5%	5%	5%	5%	4%	5%	4%	5%
LNG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HFO/LFO	97%	96%	96%	92%	92%	92%	77%	77%	72%	72%	72%	57%	57%	57%	57%	57%	57%	57%	57%	57%	57%
RENEWABLE	0%	1%	1%	5%	5%	5%	20%	20%	25%	25%	25%	35%	35%	35%	36%	36%	36%	36%	36%	36%	36%

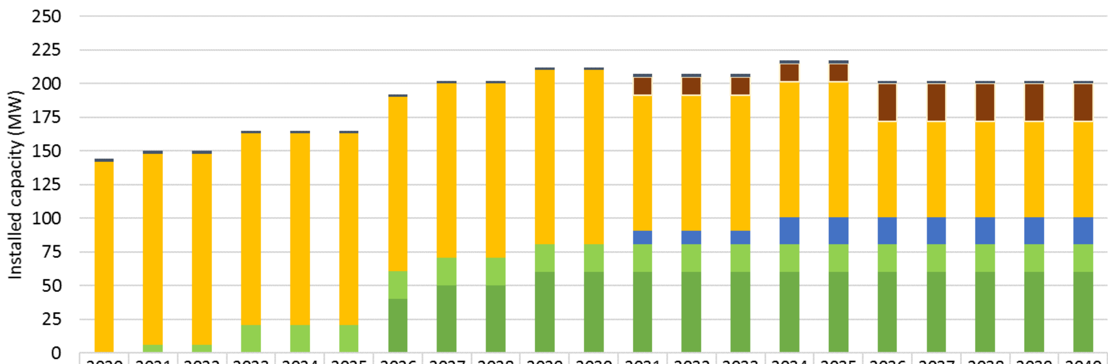
(d) Energy mix (bulk energy and distributed generation)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	4%	4%	4%	4%	4%	4%	4%	4%	4%
LNG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HFO/LFO	92%	87%	87%	83%	83%	83%	69%	69%	65%	64%	64%	51%	51%	50%	50%	50%	50%	50%	50%	50%	50%
OTHER RENEWABLE	6%	9%	10%	10%	10%	10%	10%	10%	11%	11%	11%	11%	12%	12%	12%	12%	13%	13%	13%	13%	13%
UTILITY SCALE RENEWABLE	0%	1%	1%	5%	5%	5%	18%	18%	22%	22%	22%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%

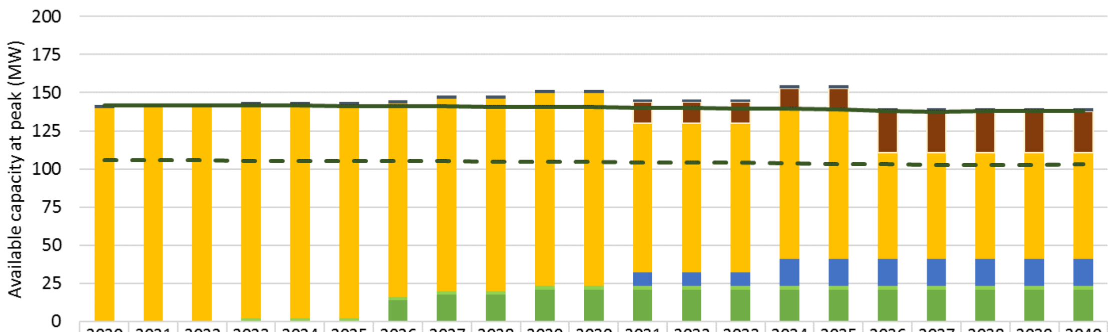
H.3. Scenario 1C: High Renewables without LNG

(a) Installed capacity



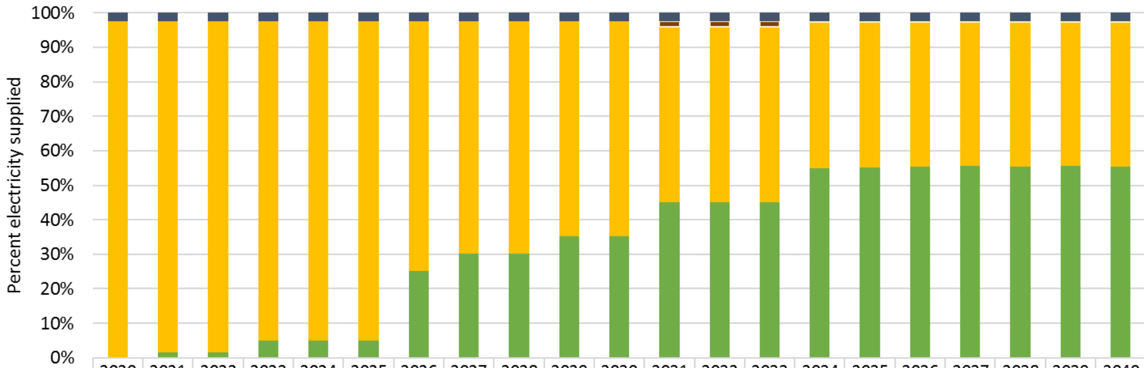
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LPG	0	0	0	0	0	0	0	0	0	0	0	14	14	14	14	14	28	28	28	28	28
LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO/LFO	142	142	142	142	142	142	129	129	129	129	129	100	100	100	100	100	71	71	71	71	71
BIOMASS	0	0	0	0	0	0	0	0	0	0	0	10	10	10	20	20	20	20	20	20	20
SOLAR PV	0	6	6	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
OFFSHORE WIND	0	0	0	0	0	0	40	50	50	60	60	60	60	60	60	60	60	60	60	60	60

(b) Available capacity at peak



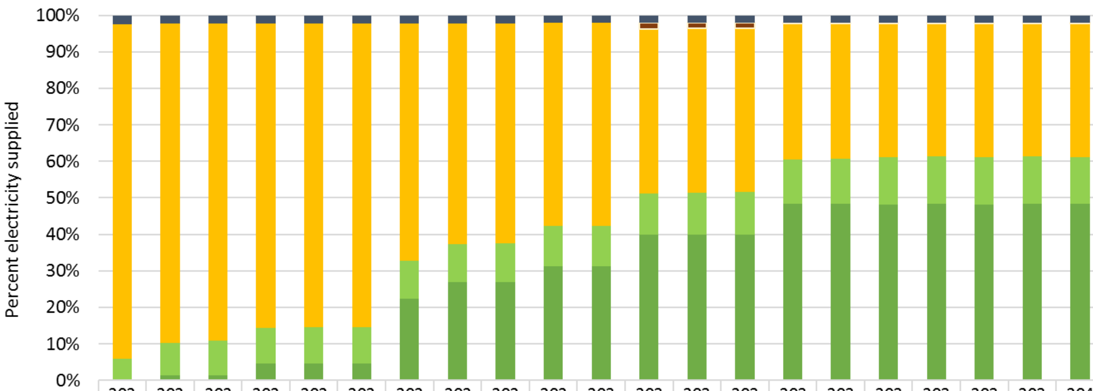
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.6	13.6	13.6	13.6	13.6	27.2	27.2	27.2	27.2	27.2
LNG	0.0	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	0.0
HFO/LFO	139.7	139.7	139.7	139.7	139.7	139.7	126.7	126.7	126.7	126.7	126.7	98.1	98.1	98.1	98.1	98.1	69.5	69.5	69.5	69.5	69.5
BIOMASS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	9.0	9.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
SOLAR PV	0.0	0.6	0.6	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
OFFSHORE WIND	0.0	0.0	0.0	0.0	0.0	0.0	14.0	17.5	17.5	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Total demand	106	106	106	106	106	105	105	105	105	105	105	104	104	104	104	103	103	103	103	103	103
Peak + Margin	142	142	142	142	142	141	141	141	141	141	141	140	140	140	139	139	138	138	138	138	138

(c) Energy mix (bulk energy only)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HFO/LFO	97%	96%	96%	92%	92%	92%	72%	67%	67%	62%	62%	51%	51%	51%	42%	42%	42%	42%	42%	42%	42%
RENEWABLE	0%	1%	1%	5%	5%	5%	25%	30%	30%	35%	35%	45%	45%	45%	55%	55%	55%	56%	55%	55%	55%

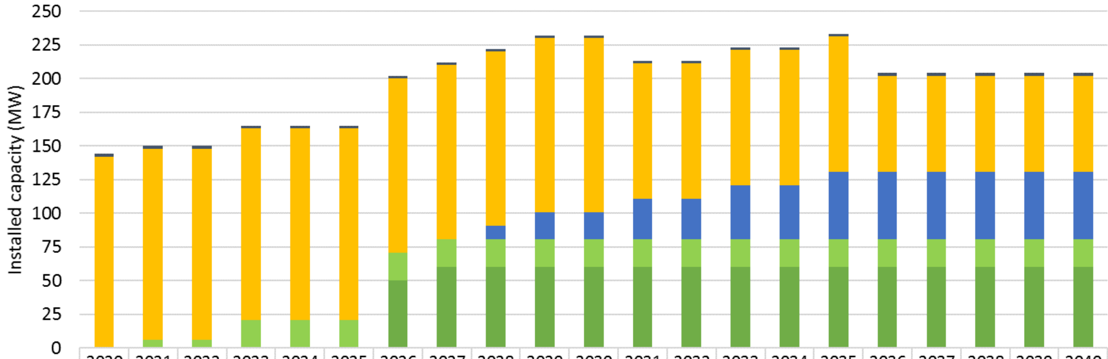
(d) Energy mix (bulk energy and distributed generation)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	1%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HFO/LFO	92%	87%	87%	83%	83%	83%	65%	60%	60%	56%	55%	45%	45%	45%	37%	37%	37%	36%	37%	36%	37%
OTHER RENEWABLE	6%	9%	10%	10%	10%	10%	10%	10%	11%	11%	11%	11%	12%	12%	12%	12%	13%	13%	13%	13%	13%
UTILITY SCALE RENEWABLE	0%	1%	1%	5%	5%	5%	22%	27%	27%	31%	31%	40%	40%	40%	48%	48%	48%	48%	48%	48%	48%

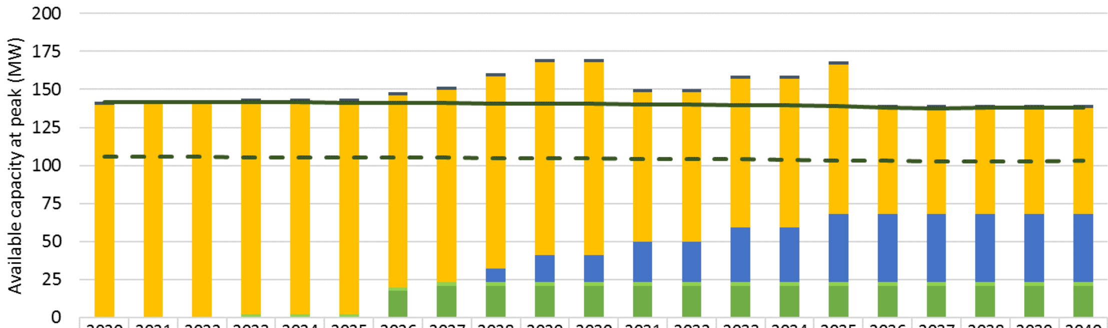
H.4. Scenario 1D: Very High Renewables without LNG

(a) Installed capacity



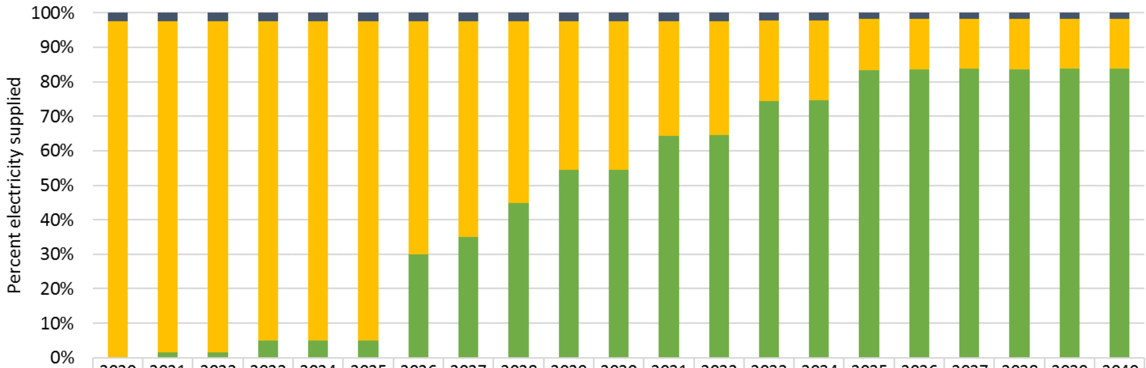
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LPG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO/LFO	142	142	142	142	142	142	129	129	129	129	129	100	100	100	100	100	71	71	71	71	71
BIOMASS	0	0	0	0	0	0	0	0	10	20	20	30	30	40	40	50	50	50	50	50	50
SOLAR PV	0	6	6	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
OFFSHORE WIND	0	0	0	0	0	0	50	60	60	60	60	60	60	60	60	60	60	60	60	60	60

(b) Available capacity at peak



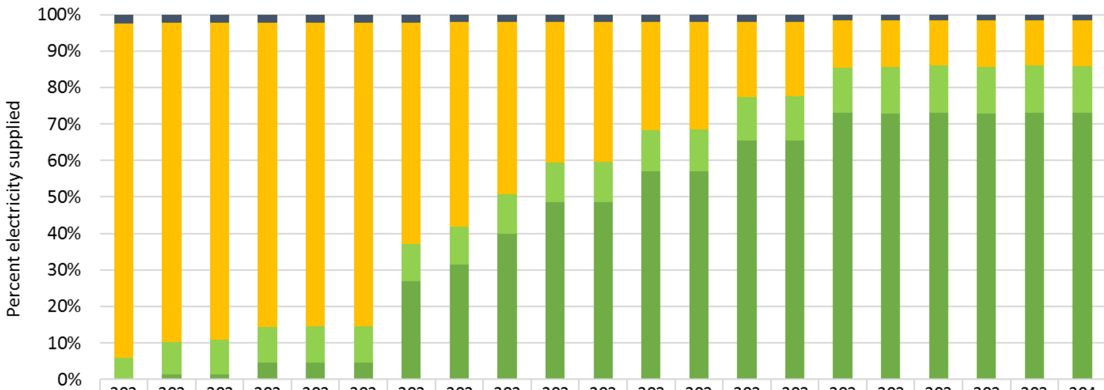
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LNG	0.0	0.0	0.0	0.0	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	0.0
HFO/LFO	139.7	139.7	139.7	139.7	139.7	139.7	126.7	126.7	126.7	126.7	126.7	98.1	98.1	98.1	98.1	98.1	69.5	69.5	69.5	69.5	69.5
BIOMASS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	18.0	18.0	27.0	27.0	36.0	36.0	45.0	45.0	45.0	45.0	45.0	45.0
SOLAR PV	0.0	0.6	0.6	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
OFFSHORE WIND	0.0	0.0	0.0	0.0	0.0	0.0	17.5	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Total demand	106	106	106	106	106	105	105	105	105	105	105	104	104	104	104	103	103	103	103	103	103
Peak + Margin	142	142	142	142	142	141	141	141	141	141	141	140	140	140	139	139	138	138	138	138	138

(c) Energy mix (bulk energy only)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HFO/LFO	97%	96%	96%	92%	92%	92%	68%	63%	53%	43%	43%	33%	33%	23%	23%	15%	15%	14%	15%	14%	14%
RENEWABLE	0%	1%	1%	5%	5%	5%	30%	35%	45%	55%	55%	64%	64%	74%	75%	83%	84%	84%	84%	84%	84%

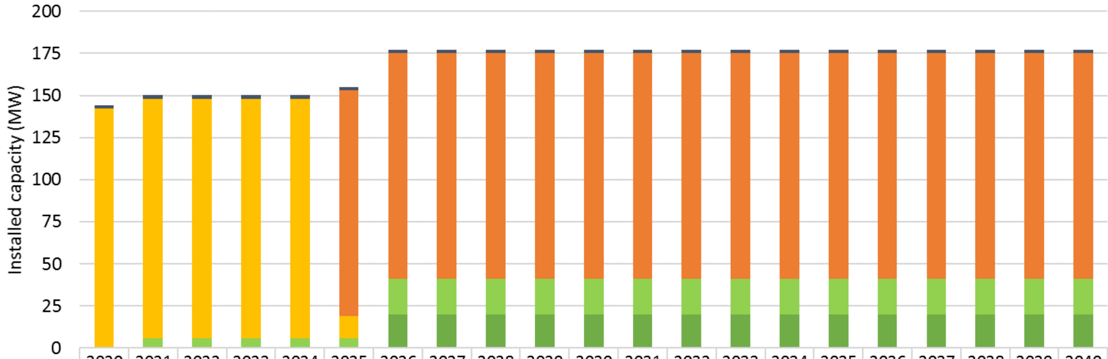
(d) Energy mix (bulk energy and distributed generation)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
HFO/LFO	92%	87%	87%	83%	83%	83%	61%	56%	47%	38%	38%	29%	29%	21%	20%	13%	13%	12%	13%	12%	13%
OTHER RENEWABLE	6%	9%	10%	10%	10%	10%	10%	10%	11%	11%	11%	11%	12%	12%	12%	12%	13%	13%	13%	13%	13%
UTILITY SCALE RENEWABLE	0%	1%	1%	5%	5%	5%	27%	31%	40%	49%	49%	57%	57%	66%	66%	73%	73%	73%	73%	73%	73%

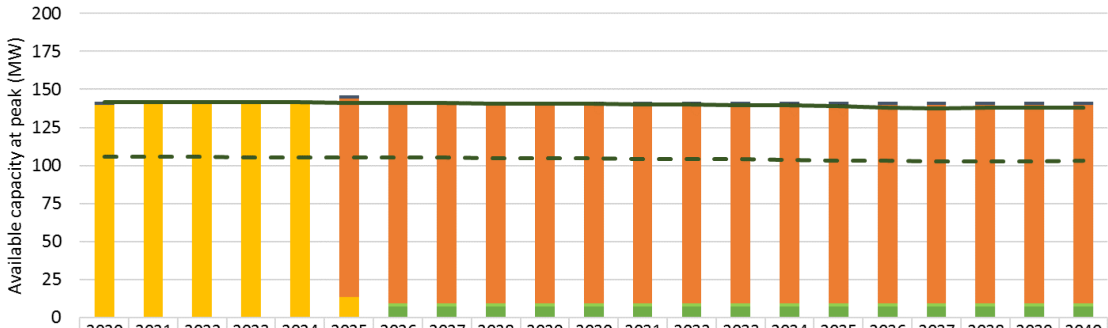
H.5. Scenario 2A: LNG Conversion without Renewables Targets

(a) Installed capacity



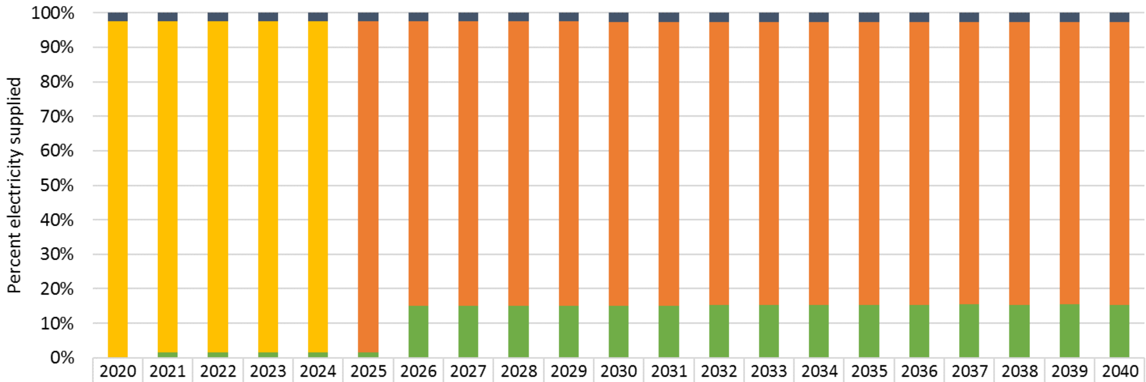
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LPG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	0	0	0	0	0	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
HFO/LFO	142	142	142	142	142	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BIOMASS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOLAR PV	0	6	6	6	6	6	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
OFFSHORE WIND	0	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20

(b) Available capacity at peak



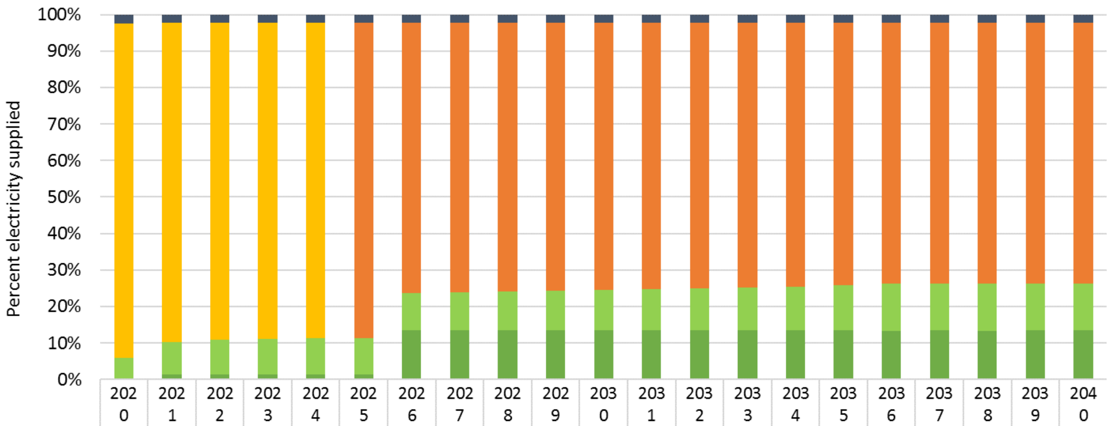
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LNG	0.0	0.0	0.0	0.0	0.0	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6
HFO/LFO	139.7	139.7	139.7	139.7	139.7	13.0	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
BIOMASS	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	0.0
SOLAR PV	0.0	0.6	0.6	0.6	0.6	0.6	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
OFFSHORE WIND	0.0	0.0	0.0	0.0	0.0	0.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Total demand	106	106	106	106	106	105	105	105	105	105	105	104	104	104	104	103	103	103	103	103	103
Peak + Margin	142	142	142	142	142	141	141	141	141	141	141	140	140	140	139	139	138	138	138	138	138

(c) Energy mix (bulk energy only)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	96%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%	82%
HFO/LFO	97%	96%	96%	96%	96%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
RENEWABLE	0%	1%	1%	1%	1%	1%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%

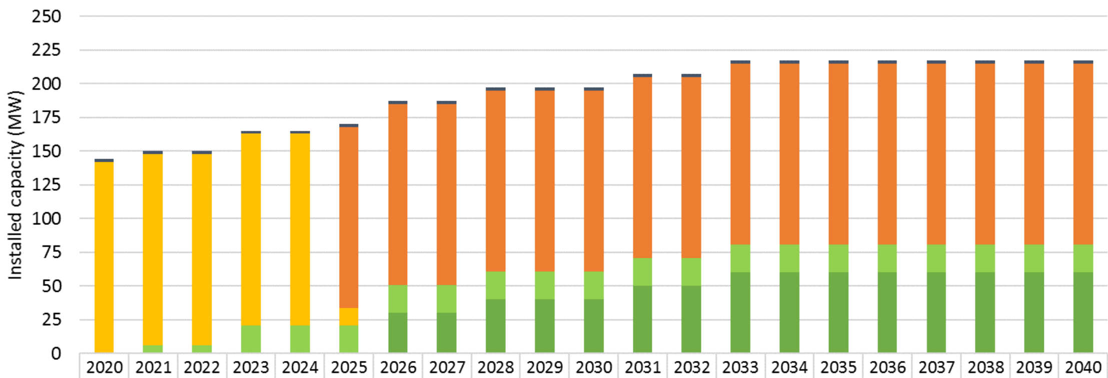
(d) Energy mix (bulk energy and distributed generation)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	86%	74%	74%	74%	73%	73%	73%	73%	72%	72%	72%	71%	71%	71%	71%	71%
HFO/LFO	92%	87%	87%	87%	86%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OTHER RENEWABLE	6%	9%	10%	10%	10%	10%	10%	10%	11%	11%	11%	11%	12%	12%	12%	12%	13%	13%	13%	13%	13%
UTILITY SCALE RENEWABLE	0%	1%	1%	1%	1%	1%	14%	14%	14%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

H.6. Scenario 2B: LNG Conversion with Moderate Renewables Targets

(a) Installed capacity

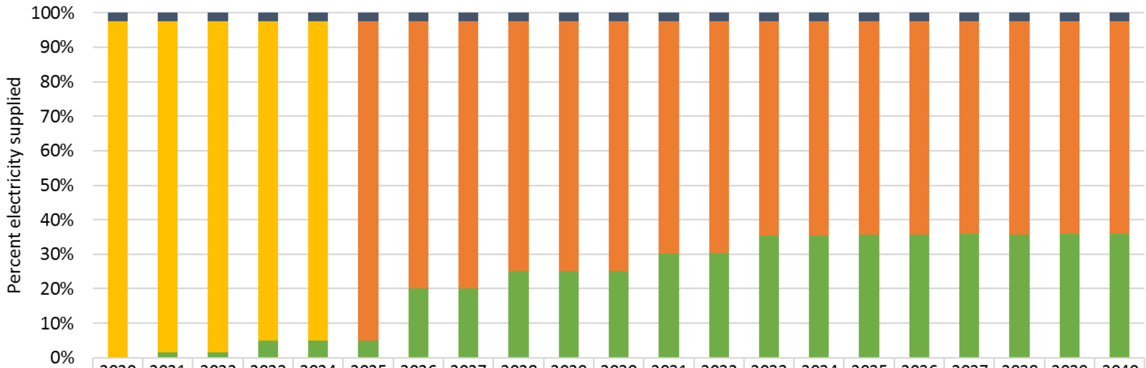


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LPG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	0	0	0	0	0	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
HFO/LFO	142	142	142	142	142	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BIOMASS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOLAR PV	0	6	6	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
OFFSHORE WIND	0	0	0	0	0	0	30	30	40	40	40	50	50	60	60	60	60	60	60	60	60

(b) Available capacity at peak

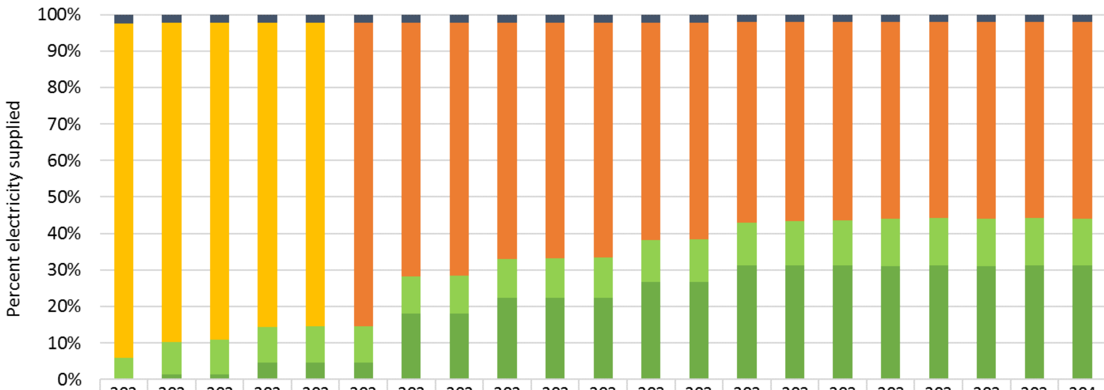
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LNG	0.0	0.0	0.0	0.0	0.0	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6
HFO/LFO	139.7	139.7	139.7	139.7	139.7	13.0	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
BIOMASS	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	0.0
SOLAR PV	0.0	0.6	0.6	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
OFFSHORE WIND	0.0	0.0	0.0	0.0	0.0	0.0	10.5	10.5	14.0	14.0	14.0	17.5	17.5	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Total demand	106	106	106	106	106	105	105	105	105	105	105	104	104	104	104	103	103	103	103	103	103
Peak + Margin	142	142	142	142	142	141	141	141	141	141	141	140	140	140	139	139	138	138	138	138	138

(c) Energy mix (bulk energy only)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	92%	77%	77%	72%	72%	72%	67%	67%	62%	62%	62%	62%	62%	62%	62%	62%
HFO/LFO	97%	96%	96%	92%	92%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
RENEWABLE	0%	1%	1%	5%	5%	5%	20%	20%	25%	25%	25%	30%	30%	35%	36%	36%	36%	36%	36%	36%	36%

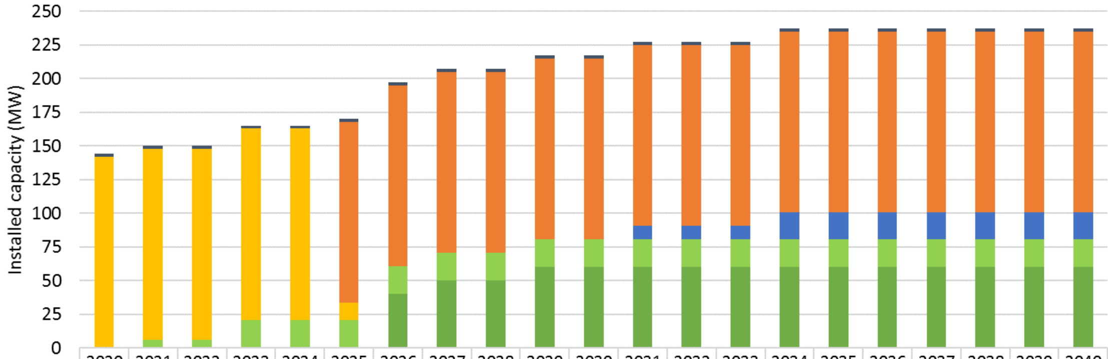
(d) Energy mix (bulk energy and distributed generation)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	83%	69%	69%	65%	64%	64%	60%	59%	55%	55%	54%	54%	54%	54%	54%	54%
HFO/LFO	92%	87%	87%	83%	83%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OTHER RENEWABLE	6%	9%	10%	10%	10%	10%	10%	10%	11%	11%	11%	11%	12%	12%	12%	12%	13%	13%	13%	13%	13%
UTILITY SCALE RENEWABLE	0%	1%	1%	5%	5%	5%	18%	18%	22%	22%	22%	27%	27%	31%	31%	31%	31%	31%	31%	31%	31%

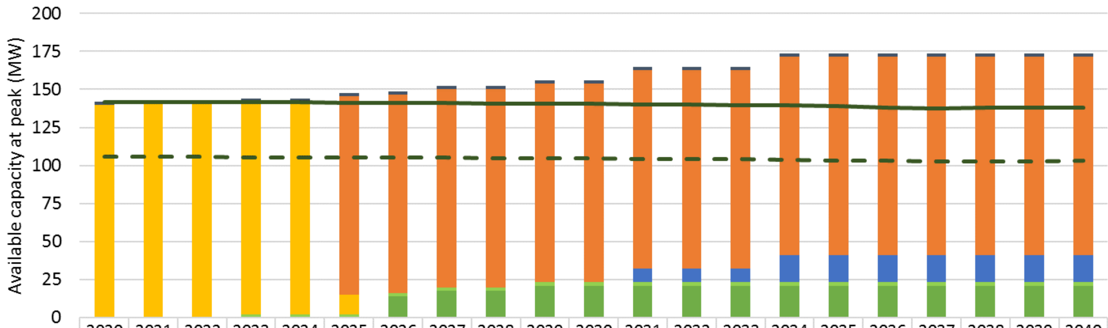
H.7. Scenario 2C: LNG Conversion with High Renewables Targets

(a) Installed capacity



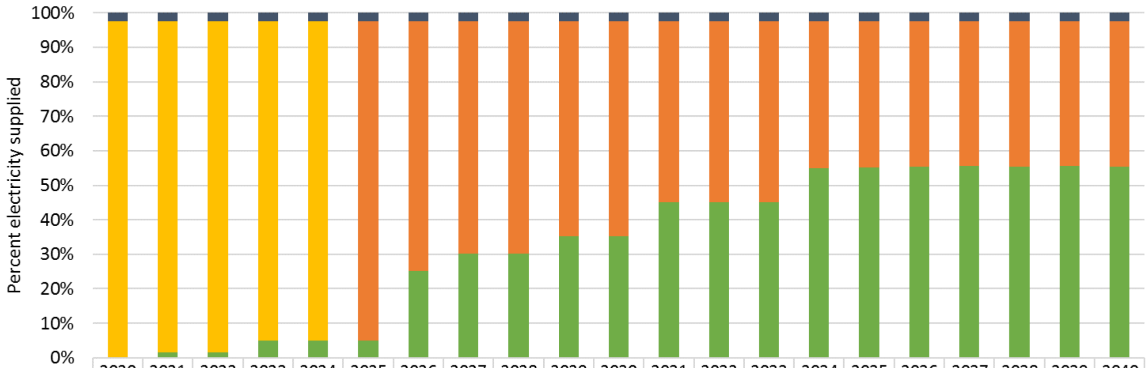
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LPG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	0	0	0	0	0	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
HFO/LFO	142	142	142	142	142	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BIOMASS	0	0	0	0	0	0	0	0	0	0	0	10	10	10	20	20	20	20	20	20	20
SOLAR PV	0	6	6	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
OFFSHORE WIND	0	0	0	0	0	0	40	50	50	60	60	60	60	60	60	60	60	60	60	60	60

(b) Available capacity at peak



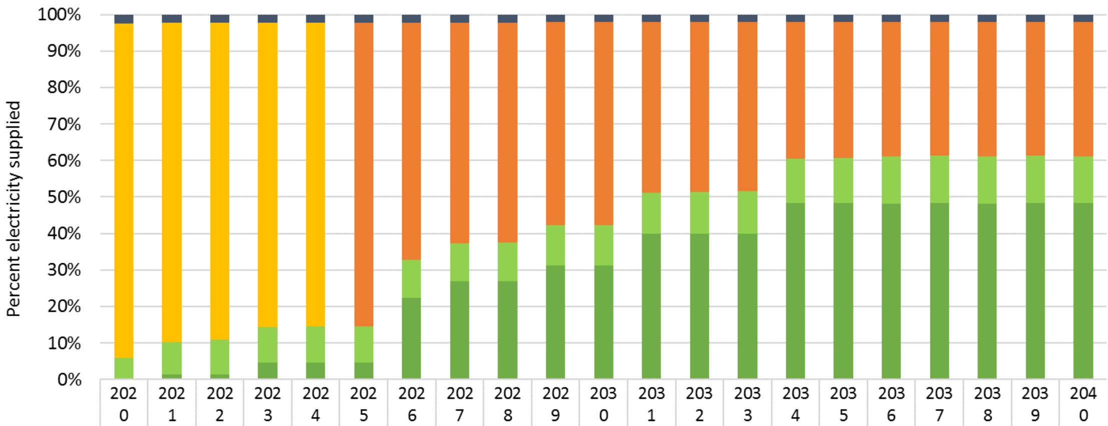
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LNG	0.0	0.0	0.0	0.0	0.0	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6
HFO/LFO	139.7	139.7	139.7	139.7	139.7	13.0	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
BIOMASS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	9.0	9.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
SOLAR PV	0.0	0.6	0.6	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
OFFSHORE WIND	0.0	0.0	0.0	0.0	0.0	0.0	14.0	17.5	17.5	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Total demand	106	106	106	106	106	105	105	105	105	105	105	104	104	104	104	103	103	103	103	103	103
Peak + Margin	142	142	142	142	142	141	141	141	141	141	141	140	140	140	139	139	138	138	138	138	138

(c) Energy mix (bulk energy only)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	3%	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	92%	72%	67%	67%	62%	62%	53%	53%	52%	43%	42%	42%	42%	42%	42%	42%
HFO/LFO	97%	96%	96%	92%	92%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
RENEWABLE	0%	1%	1%	5%	5%	5%	25%	30%	30%	35%	35%	45%	45%	45%	55%	55%	55%	56%	55%	55%	55%

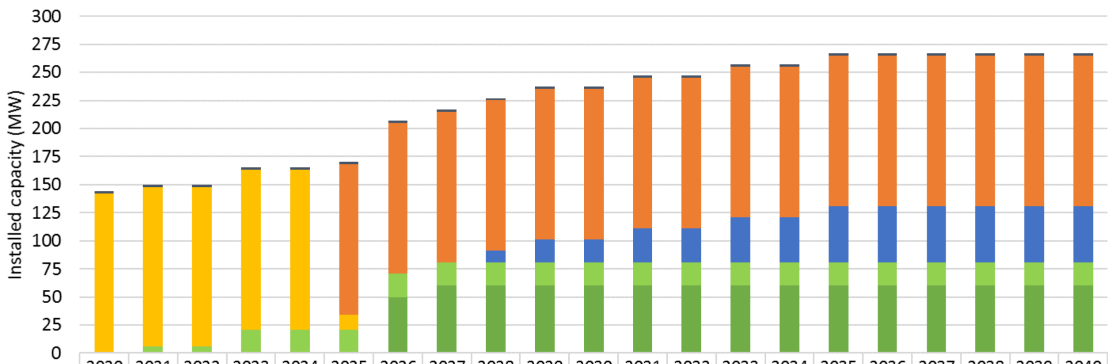
(d) Energy mix (bulk energy and distributed generation)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	83%	65%	60%	60%	56%	55%	47%	46%	46%	37%	37%	37%	37%	37%	37%	37%
HFO/LFO	92%	87%	87%	83%	83%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OTHER RENEWABLE	6%	9%	10%	10%	10%	10%	10%	10%	11%	11%	11%	11%	12%	12%	12%	12%	13%	13%	13%	13%	13%
UTILITY SCALE RENEWABLE	0%	1%	1%	5%	5%	5%	22%	27%	27%	31%	31%	40%	40%	40%	48%	48%	48%	48%	48%	48%	48%

H.8. Scenario 2D: LNG Conversion with Very High Renewables Targets

(a) Installed capacity

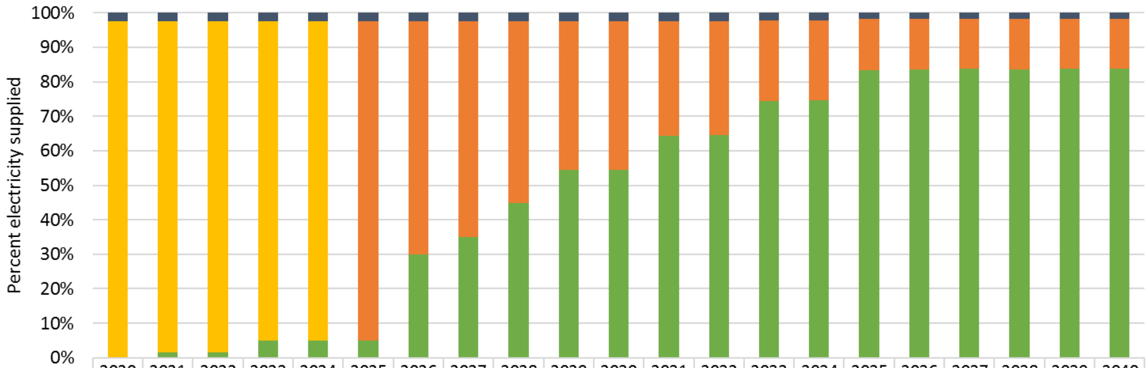


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
LPG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG	0	0	0	0	0	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
HFO/LFO	142	142	142	142	142	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BIOMASS	0	0	0	0	0	0	0	0	10	20	20	30	30	40	40	50	50	50	50	50	50
SOLAR PV	0	6	6	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
OFFSHORE WIND	0	0	0	0	0	0	50	60	60	60	60	60	60	60	60	60	60	60	60	60	60

(b) Available capacity at peak

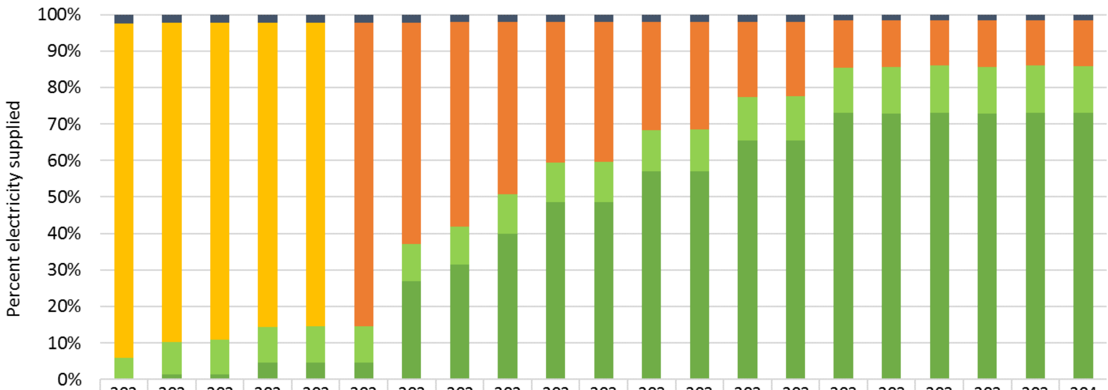
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LNG	0.0	0.0	0.0	0.0	0.0	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6	130.6
HFO/LFO	139.7	139.7	139.7	139.7	139.7	13.0	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
BIOMASS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	18.0	18.0	27.0	27.0	36.0	36.0	45.0	45.0	45.0	45.0	45.0	45.0
SOLAR PV	0.0	0.6	0.6	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
OFFSHORE WIND	0.0	0.0	0.0	0.0	0.0	0.0	17.5	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Total demand	106	106	106	106	106	105	105	105	105	105	105	104	104	104	104	103	103	103	103	103	103
Peak + Margin	142	142	142	142	142	141	141	141	141	141	141	140	140	140	139	139	138	138	138	138	138

(c) Energy mix (bulk energy only)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	3%	3%	3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	92%	68%	63%	53%	43%	43%	33%	33%	23%	23%	15%	15%	14%	15%	14%	14%
HFO/LFO	97%	96%	96%	92%	92%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
RENEWABLE	0%	1%	1%	5%	5%	5%	30%	35%	45%	55%	55%	64%	64%	74%	75%	83%	84%	84%	84%	84%	84%

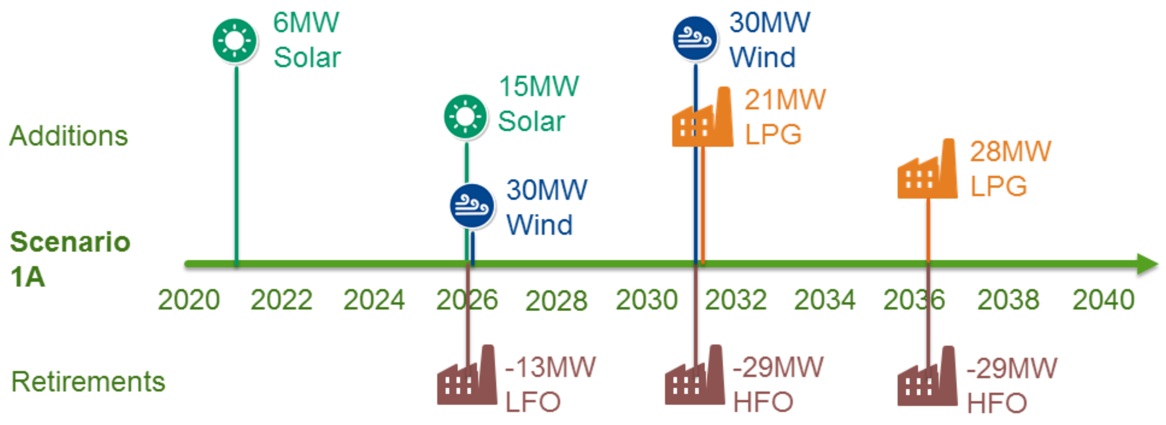
(d) Energy mix (bulk energy and distributed generation)

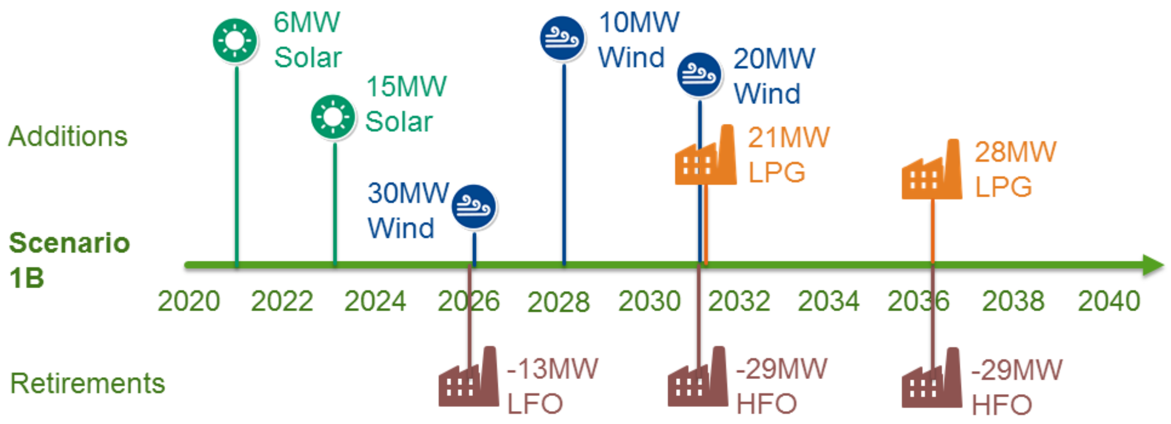


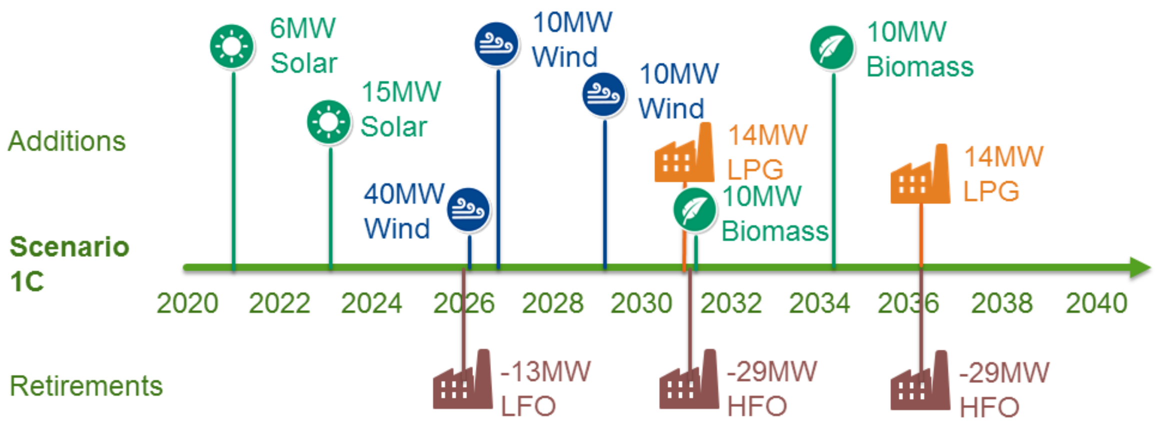
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OTHER	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LPG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LNG	0%	0%	0%	0%	0%	83%	61%	56%	47%	38%	38%	29%	29%	21%	20%	13%	13%	12%	13%	12%	13%
HFO/LFO	92%	87%	87%	83%	83%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OTHER RENEWABLE	6%	9%	10%	10%	10%	10%	10%	10%	11%	11%	11%	11%	12%	12%	12%	12%	13%	13%	13%	13%	13%
UTILITY SCALE RENEWABLE	0%	1%	1%	5%	5%	5%	27%	31%	40%	49%	49%	57%	57%	66%	66%	73%	73%	73%	73%	73%	73%

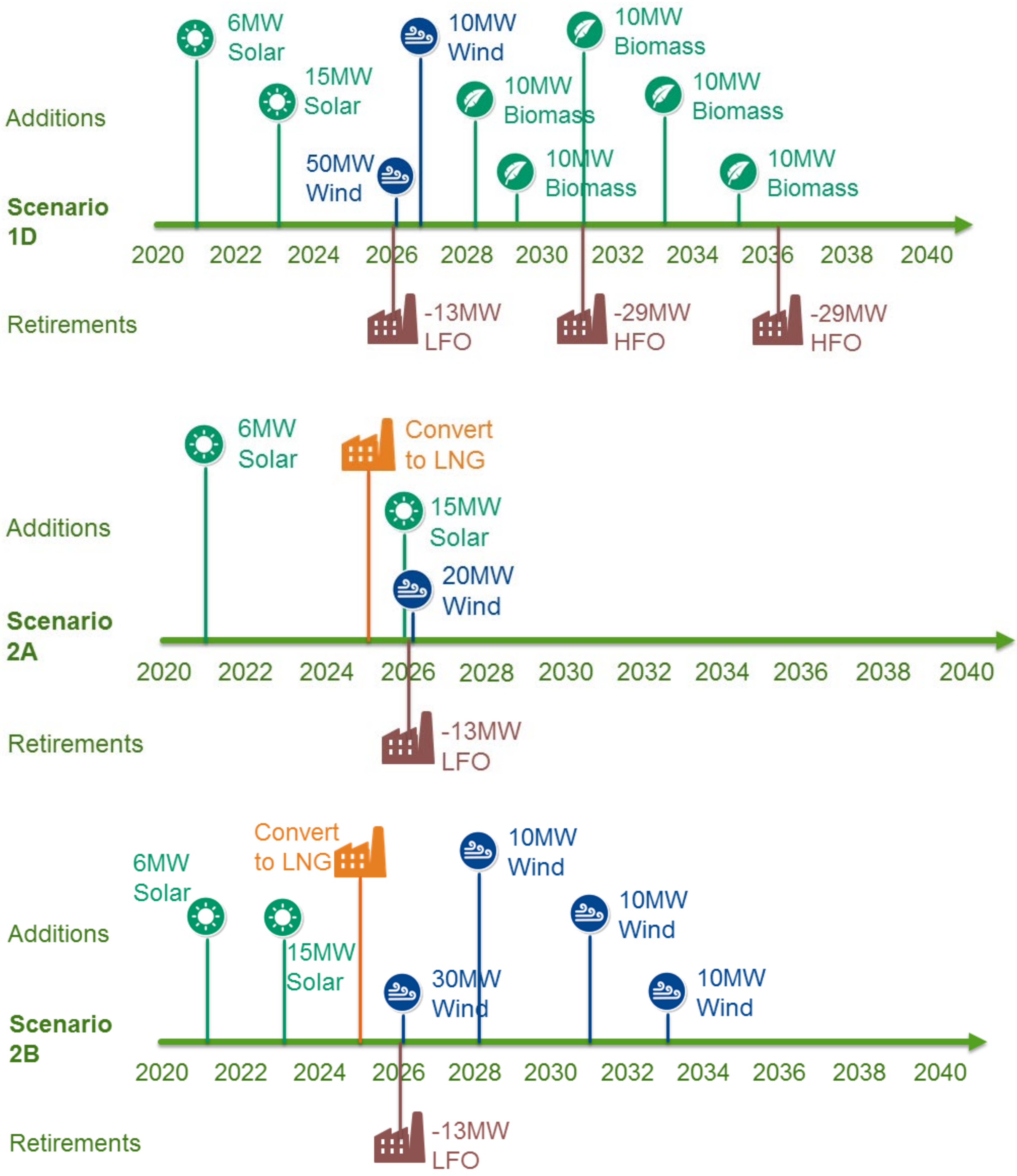
APPENDIX I: GENERATION PLAN TIMELINES FOR EACH SCENARIO

The generation plan timelines are summarised in the figures below and detailed in the tables that follow later in this appendix. The plans show the least cost approach to supplying enough electricity to meet demand and achieve the stated renewables targets in each year. In some cases, the model recommends installation of individual generators of the same type in different years, but within 2 to 3 years of each other. In practice, these units would probably be installed together in the first year to reduce construction costs.

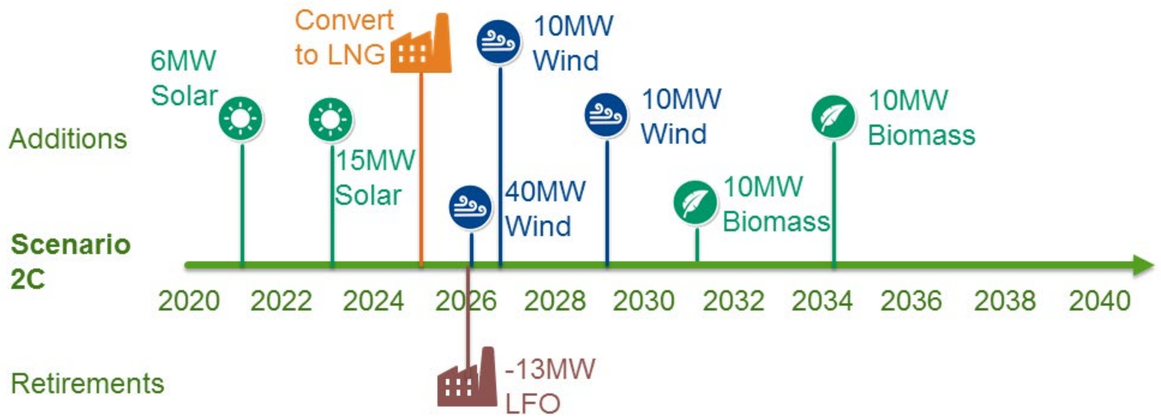


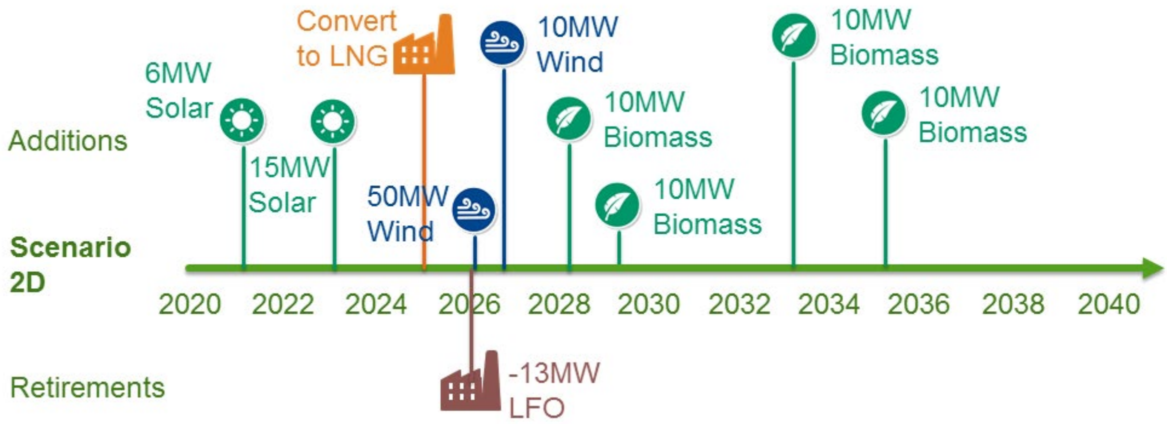






Additions
Scenario 1D
Retirements
6MW Solar
15MW Solar
50MW Wind
10MW Wind
10MW Biomass
10MW Biomass
10MW Biomass
10MW Biomass
10MW Biomass
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
-13MW LFO
-29MW HFO
-29MW HFO
Additions
Scenario 2A
Retirements
6MW Solar
Convert to LNG
15MW Solar
20MW Wind
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
-13MW LFO
Additions
Scenario 2B
Retirements
6MW Solar
Convert to LNG
15MW Solar
30MW Wind
10MW Wind
10MW Wind
10MW Wind
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
-13MW LFO


Convert
to LNG
10MW
Wind
6MW
Solar
10MW
Wind
10MW
Biomass
Additions
15MW
Solar
40MW
Wind
10MW
Biomass
Scenario
2C
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Retirements
-13MW
LFO


Convert
to LNG
10MW
Wind
10MW
Biomass
6MW
Solar
10MW
Biomass
10MW
Biomass
Additions
15MW
Solar
50MW
Wind
10MW
Biomass
Scenario
2D
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Retirements
-13MW
LFO

Policy Scenario 1A: Business as Usual											
	Capacity retirements			Capacity additions			Other Plants				
	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Installed Capacity (MW)	Available at Peak (MW)	Peak Demand net of EE & EV (MW)	Peak Demand + RM (MW)	Excess (MW)
2020							86.5	85.7	105.7	141.9	- 0.2
	E1 EPS	-12.2	-12.2								
	E2 EPS	-11.2	-11.2								
	E3 EPS	-10.1	-10.1								
	E4 EPS	-9.5	-9.5								
	D3 OPS	-7	-7								
	D8 OPS	-7	-7								
	D10 OPS	-7	-7								
	D14 OPS	-4.5	-4.5								
				NPS HFO	57.6	56.0					
2021							144.1	141.7	105.7	141.8	0.5
				Finger Solar	6	0.6					
2022							150.1	142.3	105.6	141.7	0.6
2023							150.1	142.3	105.5	141.6	0.7
2024							150.1	142.3	105.5	141.6	0.7
2025							150.1	142.3	105.3	141.3	1.0
2026							137.1	129.3	105.2	141.2	0.1
	GT5	-13	-13								
				New Solar PV - U1	3	0.3					
				New Solar PV - U2	3	0.3					
				New Solar PV - U3	3	0.3					
				New Solar PV - U4	3	0.3					
				New Solar PV - U5	3	0.3					
				Wind offshore - U1	10	3.5					
				Wind offshore - U2	10	3.5					
				Wind offshore - U3	10	3.5					
2027							182.1	141.3	105.0	141.0	0.3
2028							182.1	141.3	104.8	140.7	0.6
2029							182.1	141.3	104.7	140.6	0.7
2030							182.1	141.3	104.6	140.5	0.8
2031							153.1	112.7	104.4	140.3	3.3
	E5 EPS	-14.5	-14.3								
	E6 EPS	-14.5	-14.3								
				Wind offshore - U4	10	3.5					
				Wind offshore - U5	10	3.5					
				Wind offshore - U6	10	3.5					
				New Thermal LPG (MSD) - U1	7	6.8					
				New Thermal LPG (MSD) - U2	7	6.8					
				New Thermal LPG (MSD) - U3	7	6.8					
2032							204.1	143.6	104.2	140.0	3.6
2033							204.1	143.6	104.0	139.8	3.8
2034							204.1	143.6	103.6	139.4	4.2
2035							204.1	143.6	103.4	139.1	4.5
2036							175.1	115.0	103.1	138.2	4.0
	E7 EPS	-14.5	-14.3								
	E8 EPS	-14.5	-14.3								
				New Thermal LPG (MSD) - U4	7	6.8					
				New Thermal LPG (MSD) - U5	7	6.8					
				New Thermal LPG (MSD) - U6	7	6.8					
				New Thermal LPG (MSD) - U7	7	6.8					
2037							203.1	142.2	102.6	137.7	4.5
2038							203.1	142.2	102.8	137.9	4.4
2039							203.1	142.2	102.9	138.0	4.2
2040							203.1	142.2	103.1	138.2	4.1

Policy Scenario 1B: Moderate Renewables (no LNG)											
	Capacity retirements			**Capacity additions**			**Other Plants**				
	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Installed Capacity (MW)	Available at Peak (MW)	Peak Demand net of EE & EV (MW)	Peak Demand + RM (MW)	Excess (MW)
2020							86.5	85.7	105.7	141.9	- 0.2
	E1 EPS	-12.2	-12.2								
	E2 EPS	-11.2	-11.2								
	E3 EPS	-10.1	-10.1								
	E4 EPS	-9.5	-9.5								
	D3 OPS	-7	-7								
	D8 OPS	-7	-7								
	D10 OPS	-7	-7								
	D14 OPS	-4.5	-4.5								
				NPS HFO	57.6	56.0					
2021							144.1	141.7	105.7	141.8	0.5
				Finger Solar	6	0.6					
2022							150.1	142.3	105.6	141.7	0.6
2023							150.1	142.3	105.5	141.6	2.2
				New Solar PV - U1	3	0.3					
				New Solar PV - U2	3	0.3					
				New Solar PV - U3	3	0.3					
				New Solar PV - U4	3	0.3					
				New Solar PV - U5	3	0.3					
2024							165.1	143.8	105.5	141.6	2.2
2025							165.1	143.8	105.3	141.3	2.5
2026							152.1	130.8	105.2	141.2	0.1
	GT5	-13	-13								
				Wind offshore - U1	10	3.5					
				Wind offshore - U2	10	3.5					
				Wind offshore - U3	10	3.5					
2027							182.1	141.3	105.0	141.0	0.3
2028							182.1	141.3	104.8	140.7	4.1
				Wind offshore - U4	10	3.5					
2029							192.1	144.8	104.7	140.6	4.2
2030							192.1	144.8	104.6	140.5	4.3
2031							163.1	116.2	104.4	140.3	3.3
	E5 EPS	-14.5	-14.3								
	E6 EPS	-14.5	-14.3								
				Wind offshore - U5	10	3.5					
				Wind offshore - U6	10	3.5					
				New Thermal LPG (MSD) - U1	7	6.8					
				New Thermal LPG (MSD) - U2	7	6.8					
				New Thermal LPG (MSD) - U3	7	6.8					
2032							204.1	143.6	104.2	140.0	3.6
2033							204.1	143.6	104.0	139.8	3.8
2034							204.1	143.6	103.6	139.4	4.2
2035							204.1	143.6	103.4	139.1	4.5
2036							175.1	115.0	103.1	138.2	4.0
	E7 EPS	-14.5	-14.3								
	E8 EPS	-14.5	-14.3								
				New Thermal LPG (MSD) - U4	7	6.8					
				New Thermal LPG (MSD) - U5	7	6.8					
				New Thermal LPG (MSD) - U6	7	6.8					
				New Thermal LPG (MSD) - U7	7	6.8					
2037							203.1	142.2	102.6	137.7	4.5
2038							203.1	142.2	102.8	137.9	4.4
2039							203.1	142.2	102.9	138.0	4.2
2040							203.1	142.2	103.1	138.2	4.1

Policy Scenario 1C: High Renewables (no LNG)											
	Capacity retirements			Capacity additions			Other Plants				
	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Installed Capacity (MW)	Available at Peak (MW)	Peak Demand net of EE & EV (MW)	Peak Demand + RM (MW)	Excess (MW)
2020							86.5	85.7	105.7	141.9	- 0.2
	E1 EPS	-12.2	-12.2								
	E2 EPS	-11.2	-11.2								
	E3 EPS	-10.1	-10.1								
	E4 EPS	-9.5	-9.5								
	D3 OPS	-7	-7								
	D8 OPS	-7	-7								
	D10 OPS	-7	-7								
	D14 OPS	-4.5	-4.5								
				NPS HFO	57.6	56.0					
2021							144.1	141.7	105.7	141.8	0.5
				Finger Solar	6	0.6					
2022							150.1	142.3	105.6	141.7	0.6
2023							150.1	142.3	105.5	141.6	2.2
				New Solar PV - U1	3	0.3					
				New Solar PV - U2	3	0.3					
				New Solar PV - U3	3	0.3					
				New Solar PV - U4	3	0.3					
				New Solar PV - U5	3	0.3					
2024							165.1	143.8	105.5	141.6	2.2
2025							165.1	143.8	105.3	141.3	2.5
2026							152.1	130.8	105.2	141.2	3.6
	GT5	-13	-13								
				Wind offshore - U1	10	3.5					
				Wind offshore - U2	10	3.5					
				Wind offshore - U3	10	3.5					
				Wind offshore - U4	10	3.5					
2027							192.1	144.8	105.0	141.0	7.3
				Wind offshore - U5	10	3.5					
2028							202.1	148.3	104.8	140.7	7.6
2029							202.1	148.3	104.7	140.6	11.2
				Wind offshore - U6	10	3.5					
2030							212.1	151.8	104.6	140.5	11.3
2031							183.1	123.2	104.4	140.3	5.5
	E5 EPS	-14.5	-14.3								
	E6 EPS	-14.5	-14.3								
				Biomass - U1	10	9.0					
				New Thermal LPG (MSD) - U1	7	6.8					
				New Thermal LPG (MSD) - U2	7	6.8					
2032							207.1	145.8	104.2	140.0	5.8
2033							207.1	145.8	104.0	139.8	6.0
2034							207.1	145.8	103.6	139.4	15.4
				Biomass - U2	10	9.0					
2035							217.1	154.8	103.4	139.1	15.7
2036							188.1	126.2	103.1	138.2	1.6
	E7 EPS	-14.5	-14.3								
	E8 EPS	-14.5	-14.3								
				New Thermal LPG (MSD) - U3	7	6.8					
				New Thermal LPG (MSD) - U4	7	6.8					
2037							202.1	139.8	102.6	137.7	2.1
2038							202.1	139.8	102.8	137.9	2.0
2039							202.1	139.8	102.9	138.0	1.8
2040							202.1	139.8	103.1	138.2	1.6
2040							203.1	142.2	103.1	138.2	4.1

	Policy Scenario 1D: Very High Renewables (no LNG)										
	Capacity retirements			Capacity additions			Other Plants				
	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Installed Capacity (MW)	Available at Peak (MW)	Peak Demand net of EE & EV (MW)	Peak Demand + RM (MW)	Excess (MW)
2020							86.5	85.7	105.7	141.9	- 0.2
	E1 EPS	-12.2	-12.2								
	E2 EPS	-11.2	-11.2								
	E3 EPS	-10.1	-10.1								
	E4 EPS	-9.5	-9.5								
	D3 OPS	-7	-7								
	D8 OPS	-7	-7								
	D10 OPS	-7	-7								
	D14 OPS	-4.5	-4.5								
				NPS HFO	57.6	56.0					
2021							144.1	141.7	105.7	141.8	0.5
				Finger Solar	6	0.6					
2022							150.1	142.3	105.6	141.7	0.6
2023							150.1	142.3	105.5	141.6	2.2
				New Solar PV - U1	3	0.3					
				New Solar PV - U2	3	0.3					
				New Solar PV - U3	3	0.3					
				New Solar PV - U4	3	0.3					
				New Solar PV - U5	3	0.3					
2024							165.1	143.8	105.5	141.6	2.2
2025							165.1	143.8	105.3	141.3	2.5
2026							152.1	130.8	105.2	141.2	7.1
	GT5	-13	-13								
				Wind offshore - U1	10	3.5					
				Wind offshore - U2	10	3.5					
				Wind offshore - U3	10	3.5					
				Wind offshore - U4	10	3.5					
				Wind offshore - U5	10	3.5					
2027							202.1	148.3	105.0	141.0	10.8
				Wind offshore - U6	10	3.5					
2028							212.1	151.8	104.8	140.7	20.1
				Biomass - U1	10	9.0					
2029							222.1	160.8	104.7	140.6	29.2
				Biomass - U2	10	9.0					
2030							232.1	169.8	104.6	140.5	29.3
2031							203.1	141.2	104.4	140.3	9.9
	E5 EPS	-14.5	-14.3								
	E6 EPS	-14.5	-14.3								
				Biomass - U3	10	9.0					
2032							213.1	150.2	104.2	140.0	10.2
2033							213.1	150.2	104.0	139.8	19.4
				Biomass - U4	10	9.0					
2034							223.1	159.2	103.6	139.4	19.8
2035							223.1	159.2	103.4	139.1	29.1
				Biomass - U5	10	9.0					
2036							204.1	139.6	103.1	138.2	1.4
	E7 EPS	-14.5	-14.3								
	E8 EPS	-14.5	-14.3								
2037							204.1	139.6	102.6	137.7	1.9
2038							204.1	139.6	102.8	137.9	1.7
2039							204.1	139.6	102.9	138.0	1.6
2040							204.1	139.6	103.1	138.2	1.4

Policy Scenario 2A: LNG Conversion without RE targets

	Capacity retirements			Capacity additions			Other Plants				
	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Installed Capacity (MW)	Available at Peak (MW)	Peak Demand net of EE & EV (MW)	Peak Demand + RM (MW)	Excess (MW)
2020							86.5	85.7	105.7	141.9	- 0.2
	E1 EPS	-12.2	-12.2								
	E2 EPS	-11.2	-11.2								
	E3 EPS	-10.1	-10.1								
	E4 EPS	-9.5	-9.5								
	D3 OPS	-7	-7								
	D8 OPS	-7	-7								
	D10 OPS	-7	-7								
	D14 OPS	-4.5	-4.5								
				NPS HFO	57.6	56.0					
2021							144.1	141.7	105.7	141.8	0.5
				Finger Solar	6	0.6					
2022							150.1	142.3	105.6	141.7	0.6
2023							150.1	142.3	105.5	141.6	0.7
2024							150.1	142.3	105.5	141.6	0.7
2025							21.0	15.6	105.3	141.3	4.9
	E5 EPS	-14.5	-14.3								
	E6 EPS	-14.5	-14.3								
	E7 EPS	-14.5	-14.3								
	E8 EPS	-14.5	-14.3								
	GT6	-4.5	-4.5								
	GT7	-4.5	-4.5								
	GT8	-4.5	-4.5								
	NPS HFO	-57.6	-56								
				NPS LNG	62	60.2					
				E5 Refuel LNG	13.7	13.4					
				E6 Refuel LNG	13.7	13.4					
				E7 Refuel LNG	14.4	14.0					
				E8 Refuel LNG	14.4	14.0					
				GT6 Refuel LNG	5.3	5.2					
				GT7 Refuel LNG	5.3	5.2					
				GT8 Refuel LNG	5.3	5.2					
2026							142.1	133.2	105.2	141.2	0.5
	GT5	-13	-13								
				New Solar PV - U1	3	0.3					
				New Solar PV - U2	3	0.3					
				New Solar PV - U3	3	0.3					
				New Solar PV - U4	3	0.3					
				New Solar PV - U5	3	0.3					
				Wind offshore - U1	10	3.5					
				Wind offshore - U2	10	3.5					
2027							177.1	141.7	105.0	141.0	0.7
2028							177.1	141.7	104.8	140.7	1.0
2029							177.1	141.7	104.7	140.6	1.1
2030							177.1	141.7	104.6	140.5	1.2
2031							177.1	141.7	104.4	140.3	1.4
2032							177.1	141.7	104.2	140.0	1.7
2033							177.1	141.7	104.0	139.8	1.9
2034							177.1	141.7	103.6	139.4	2.3
2035							177.1	141.7	103.4	139.1	2.6
2036							177.1	141.7	103.1	138.2	3.5
2037							177.1	141.7	102.6	137.7	4.0
2038							177.1	141.7	102.8	137.9	3.8
2039							177.1	141.7	102.9	138.0	3.7
2040							177.1	141.7	103.1	138.2	3.5

Policy Scenario 2B: Moderate Renewables - With LNG											
	Capacity retirements			Capacity additions			Other Plants				
	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Installed Capacity (MW)	Available at Peak (MW)	Peak Demand net of EE & EV (MW)	Peak Demand + RM (MW)	Excess (MW)
2020							86.5	85.7	105.7	141.9	-0.2
	E1 EPS	-12.2	-12.2								
	E2 EPS	-11.2	-11.2								
	E3 EPS	-10.1	-10.1								
	E4 EPS	-9.5	-9.5								
	D3 OPS	-7	-7								
	D8 OPS	-7	-7								
	D10 OPS	-7	-7								
	D14 OPS	-4.5	-4.5								
				NPS HFO	57.6	56.0					
2021							144.1	141.7	105.7	141.8	0.5
				Finger Solar	6	0.6					
2022							150.1	142.3	105.6	141.7	0.6
2023							150.1	142.3	105.5	141.6	2.2
				New Solar PV - U1	3	0.3					
				New Solar PV - U2	3	0.3					
				New Solar PV - U3	3	0.3					
				New Solar PV - U4	3	0.3					
				New Solar PV - U5	3	0.3					
2024							165.1	143.8	105.5	141.6	2.2
2025							36.0	17.1	105.3	141.3	6.4
	E5 EPS	-14.5	-14.3								
	E6 EPS	-14.5	-14.3								
	E7 EPS	-14.5	-14.3								
	E8 EPS	-14.5	-14.3								
	GT6	-4.5	-4.5								
	GT7	-4.5	-4.5								
	GT8	-4.5	-4.5								
	NPS HFO	-57.6	-56								
				NPS LNG	62	60.2					
				E5 Refuel LNG	13.7	13.4					
				E6 Refuel LNG	13.7	13.4					
				E7 Refuel LNG	14.4	14.0					
				E8 Refuel LNG	14.4	14.0					
				GT6 Refuel LNG	5.3	5.2					
				GT7 Refuel LNG	5.3	5.2					
				GT8 Refuel LNG	5.3	5.2					
2026							157.1	134.7	105.2	141.2	4.0
	GT5	-13	-13								
				Wind offshore - U1	10	3.5					
				Wind offshore - U2	10	3.5					
				Wind offshore - U3	10	3.5					
2027							187.1	145.2	105.0	141.0	4.2
2028							187.1	145.2	104.8	140.7	8.0
				Wind offshore - U4	10	3.5					
2029							197.1	148.7	104.7	140.6	8.1
2030							197.1	148.7	104.6	140.5	8.2
2031							197.1	148.7	104.4	140.3	11.9
				Wind offshore - U5	10	3.5					
2032							207.1	152.2	104.2	140.0	12.2
2033							207.1	152.2	104.0	139.8	15.9
				Wind offshore - U6	10	3.5					
2034							217.1	155.7	103.6	139.4	16.3
2035							217.1	155.7	103.4	139.1	16.6
2036							217.1	155.7	103.1	138.2	17.5
2037							217.1	155.7	102.6	137.7	18.0
2038							217.1	155.7	102.8	137.9	17.8
2039							217.1	155.7	102.9	138.0	17.7
2040							217.1	155.7	103.1	138.2	17.5

Policy Scenario 2C: High Renewables - With LNG											
	Capacity retirements			**Capacity additions**			**Other Plants**				
	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Installed Capacity (MW)	Available at Peak (MW)	Peak Demand net of EE & EV (MW)	Peak Demand + RM (MW)	Excess (MW)
2020							86.5	85.7	105.7	141.9	- 0.2
	E1 EPS	-12.2	-12.2								
	E2 EPS	-11.2	-11.2								
	E3 EPS	-10.1	-10.1								
	E4 EPS	-9.5	-9.5								
	D3 OPS	-7	-7								
	D8 OPS	-7	-7								
	D10 OPS	-7	-7								
	D14 OPS	-4.5	-4.5								
				NPS HFO	57.6	56.0					
2021							144.1	141.7	105.7	141.8	0.5
				Finger Solar	6	0.6					
2022							150.1	142.3	105.6	141.7	0.6
2023							150.1	142.3	105.5	141.6	2.2
				New Solar PV - U1	3	0.3					
				New Solar PV - U2	3	0.3					
				New Solar PV - U3	3	0.3					
				New Solar PV - U4	3	0.3					
				New Solar PV - U5	3	0.3					
2024							165.1	143.8	105.5	141.6	2.2
2025							36.0	17.1	105.3	141.3	6.4
	E5 EPS	-14.5	-14.3								
	E6 EPS	-14.5	-14.3								
	E7 EPS	-14.5	-14.3								
	E8 EPS	-14.5	-14.3								
	GT6	-4.5	-4.5								
	GT7	-4.5	-4.5								
	GT8	-4.5	-4.5								
	NPS HFO	-57.6	-56								
				NPS LNG	62	60.2					
				E5 Refuel LNG	13.7	13.4					
				E6 Refuel LNG	13.7	13.4					
				E7 Refuel LNG	14.4	14.0					
				E8 Refuel LNG	14.4	14.0					
				GT6 Refuel LNG	5.3	5.2					
				GT7 Refuel LNG	5.3	5.2					
				GT8 Refuel LNG	5.3	5.2					
2026							157.1	134.7	105.2	141.2	7.5
	GT5	-13	-13								
				Wind offshore - U1	10	3.5					
				Wind offshore - U2	10	3.5					
				Wind offshore - U3	10	3.5					
				Wind offshore - U4	10	3.5					
2027							197.1	148.7	105.0	141.0	11.2
				Wind offshore - U5	10	3.5					
2028							207.1	152.2	104.8	140.7	11.5
2029							207.1	152.2	104.7	140.6	15.1
				Wind offshore - U6	10	3.5					
2030							217.1	155.7	104.6	140.5	15.2
2031							217.1	155.7	104.4	140.3	24.4
				Biomass - U1	10	9.0					
2032							227.1	164.7	104.2	140.0	24.7
2033							227.1	164.7	104.0	139.8	24.9
2034							227.1	164.7	103.6	139.4	34.3
				Biomass - U2	10	9.0					
2035							237.1	173.7	103.4	139.1	34.6
2036							237.1	173.7	103.1	138.2	35.5
2037							237.1	173.7	102.6	137.7	36.0
2038							237.1	173.7	102.8	137.9	35.8
2039							237.1	173.7	102.9	138.0	35.7
2040							237.1	173.7	103.1	138.2	35.5

Policy Scenario 2D: Very High Renewables - With LNG											
	Capacity retirements			Capacity additions			Other Plants				
	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Unit Name	Installed Capacity (MW)	Available at Peak (MW)	Installed Capacity (MW)	Available at Peak (MW)	Peak Demand net of EE & EV (MW)	Peak Demand + RM (MW)	Excess (MW)
2020							86.5	85.7	105.7	141.9	- 0.2
	E1 EPS	-12.2	-12.2								
	E2 EPS	-11.2	-11.2								
	E3 EPS	-10.1	-10.1								
	E4 EPS	-9.5	-9.5								
	D3 OPS	-7	-7								
	D8 OPS	-7	-7								
	D10 OPS	-7	-7								
	D14 OPS	-4.5	-4.5								
				NPS HFO	57.6	56.0					
2021							144.1	141.7	105.7	141.8	0.5
				Finger Solar	6	0.6					
2022							150.1	142.3	105.6	141.7	0.6
2023							150.1	142.3	105.5	141.6	2.2
				New Solar PV - U1	3	0.3					
				New Solar PV - U2	3	0.3					
				New Solar PV - U3	3	0.3					
				New Solar PV - U4	3	0.3					
				New Solar PV - U5	3	0.3					
2024							165.1	143.8	105.5	141.6	2.2
2025							36.0	17.1	105.3	141.3	6.4
	E5 EPS	-14.5	-14.3								
	E6 EPS	-14.5	-14.3								
	E7 EPS	-14.5	-14.3								
	E8 EPS	-14.5	-14.3								
	GT6	-4.5	-4.5								
	GT7	-4.5	-4.5								
	GT8	-4.5	-4.5								
	NPS HFO	-57.6	-56								
				NPS LNG	62	60.2					
				E5 Refuel LNG	13.7	13.4					
				E6 Refuel LNG	13.7	13.4					
				E7 Refuel LNG	14.4	14.0					
				E8 Refuel LNG	14.4	14.0					
				GT6 Refuel LNG	5.3	5.2					
				GT7 Refuel LNG	5.3	5.2					
				GT8 Refuel LNG	5.3	5.2					
2026							157.1	134.7	105.2	141.2	11.0
	GT5	-13	-13								
				Wind offshore - U1	10	3.5					
				Wind offshore - U2	10	3.5					
				Wind offshore - U3	10	3.5					
				Wind offshore - U4	10	3.5					
				Wind offshore - U5	10	3.5					
2027							207.1	152.2	105.0	141.0	14.7
				Wind offshore - U6	10	3.5					
2028							217.1	155.7	104.8	140.7	24.0
				Biomass - U1	10	9.0					
2029							227.1	164.7	104.7	140.6	33.1
				Biomass - U2	10	9.0					
2030							237.1	173.7	104.6	140.5	33.2
2031							237.1	173.7	104.4	140.3	42.4
				Biomass - U3	10	9.0					
2032							247.1	182.7	104.2	140.0	42.7
2033							247.1	182.7	104.0	139.8	51.9
				Biomass - U4	10	9.0					
2034							257.1	191.7	103.6	139.4	52.3
2035							257.1	191.7	103.4	139.1	61.6
				Biomass - U5	10	9.0					
2036							267.1	200.7	103.1	138.2	62.5
2037							267.1	200.7	102.6	137.7	63.0
2038							267.1	200.7	102.8	137.9	62.8
2039							267.1	200.7	102.9	138.0	62.7
2040							267.1	200.7	103.1	138.2	62.5

APPENDIX J: RESULTS FROM SENSITIVITY ANALYSIS

The first set of sensitivities investigated how the rankings of scenarios changed in response to changes in the economic assumptions and fuel prices.

Table gives the results from the sensitivities where the discount rate was varied. The base case input was 10%.

Table J-1: Results from the discount rate sensitivities (incl. carbon costs)

Sensitivity case input	Least cost scenario without LNG conversion (A)	Least cost scenario with LNG conversion (B)	(A-B) / B
5%	1D. Very High Renewables	2B. LNG with Moderate Renewables	9.5%
8%	1D. Very High Renewables	2B. LNG with Moderate Renewables	7.3%
12%	1D. Very High Renewables	2A. LNG Conversion without renewable target	5.0%

Table J-2 gives the results from the sensitivities where the HFO and LFO prices were varied in isolation. The base case price trend was based on the United States Energy Information Administration Annual Energy Outlook 2019[85] forecast (see details in Appendix D).

Table J-2: Results from the HFO and LFO price forecast sensitivities (incl. carbon costs)

Sensitivity case input	Least cost scenario without LNG conversion (A)	Least cost scenario with LNG conversion (B)	(A-B) / B
World Bank forecast[86]	1C. High Renewables	2B. LNG with Moderate Renewables	2.5%
Very low (EIA AEO - 50%)	1B. Moderate Renewables	2B. LNG with Moderate Renewables	-1.5%
Low (EIA AEO - 20%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	3.7%
High (EIA AEO + 20%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	8.2%
Very high (EIA AEO + 50%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	11.2%

[85]Available at URL: https://www.eia.gov/outlooks/aeo/excel/aeotab_12.xlsx.

[86] Available at URL: http://pubdocs.worldbank.org/en/598821555973008624/CMO-April-2019-Forecasts.pdf.

Table gives the results from the sensitivities where the LNG prices and infrastructure costs were varied in isolation. The base case price trend was based on the BP Annual Energy Outlook 2019[87] forecast (see details in Appendix D).

Table 21: Results from the LNG price forecast sensitivities (incl. carbon costs)

Sensitivity case input	Least cost scenario without LNG conversion (A)	Least cost scenario with LNG conversion (B)	(A-B) / B
Very low (-50%)	1D. Very High Renewables	2A. LNG Conversion without renewable target	24.2%
Low (-20%)	1D. Very High Renewables	2A. LNG Conversion without renewable target	11.7%
High (+20%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	1.0%
Very high (+50%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	-5.2%

Table gives the results from the sensitivities where the LPG prices and infrastructure costs were varied in isolation. The base case price trend was based on the BP Annual Energy Outlook 2019 forecast (see details in Appendix D).

Table J-4: Results from the LPG price forecast sensitivities (incl. carbon costs)

Sensitivity case input	Least cost scenario without LNG conversion (A)	Least cost scenario with LNG conversion (B)	(A-B) / B
Very low (-50%)	1B. Moderate Renewables	2B. LNG with Moderate Renewables	2.7%
Low (-20%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	6.0%
High (+20%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	6.0%
Very high (+50%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	6.0%

[87] Available at URL: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019.pdf.

Table gives the results from the sensitivities where the wood chip (biomass) prices were varied in isolation. The base case price trend was based on the Enviva-Albioma forecast in its Alternative Proposal (see details in Appendix D).

Table J-522: Results from the biomass price forecast sensitivities (incl. carbon costs)

Sensitivity case input	Least cost scenario without LNG conversion (A)	Least cost scenario with LNG conversion (B)	(A-B) / B
Low (-20%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	4.2%
High (+20%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	7.8%

Table gives the results from the sensitivities where the plant factors for renewable sources were varied in isolation.

Table J-6: Results from the renewable plant factor sensitivities (incl. carbon costs)

Sensitivity case input	Least cost scenario without LNG conversion (A)	Least cost scenario with LNG conversion (B)	(A-B) / B
Very low offshore wind plant factor (25%)	1D. Very High Renewables	2A. LNG Conversion without renewable target	8.3%
Low offshore wind plant factor (30%)	1D. Very High Renewables	2A. LNG Conversion without renewable target	6.9%
Low solar PV plant factor (15%)	1D. Very High Renewables	2B. LNG with Moderate Renewables	6.1%