# 2024 Resource Adequacy Plan

## Technical Conference #3: Scenarios and Sensitivities/ Modelling Approach and Considerations

October 16, 2024

newfoundland labrador hydro

# Safety Moment

# Experts Present Today

- **Robert Collett**, Vice President, Engineering & NLSO
- **Samantha Tobin**, Sr. Manager, Resource & Production Planning
- **David Goosney**, Team Lead, Long-Term Resource Planning
- **Samantha Smith,** Generation Performance Engineer
- **Phil DiDomenico**, Managing Consultant, Daymark (Virtual)
- **Kathy Kelly**, Vice President and Principal Consultant, Daymark (Virtual)

# Opening Statement

# Desired Conference Outcomes

Newfoundland and Labrador Hydro ("Hydro") aims to address parties issues and questions and provide adequate information in relation to the 2024 Resource Adequacy Plan to achieve consensus on the following topics:

i. Hydro's modelling approach;

ii. Assumptions underlying Hydro's modelling are appropriate;

iii. Hydro analyzed an appropriate range of scenarios and sensitivities; and

iv. Hydro has appropriately utilized the most conservative case of Scenario 4 to drive its recommended Minimum Investment Required Expansion Plan.

# Issues 5 and 6: Scenarios and Sensitivities/ Modelling Approach and Considerations

# Agenda

- Models
- Modelling Approach
  - Forced Outage Rates (“FORs”)
  - Capacity
  - Imports and Exports
- Scenarios
- Sensitivities
- Scenario 4

# Modelling Approach - Results

## 2024 Resource Adequacy Plan – Issues List:

- *NLH employed several models, including Vista Model to produce its hydroelectric generation forecasts to use in its Resource Planning Model, the Reliability Model to determine planning reserve margins, the Firm Energy Model to assess firm energy needs, the Resource Planning Model (i.e., the Expansion Model) to select resources, the Transmission Model to determine the investment on rates. Are the models sufficiently understood and has NLH provided sufficient data to support the reasonableness of assumptions and inputs used and the resulting outcomes?*

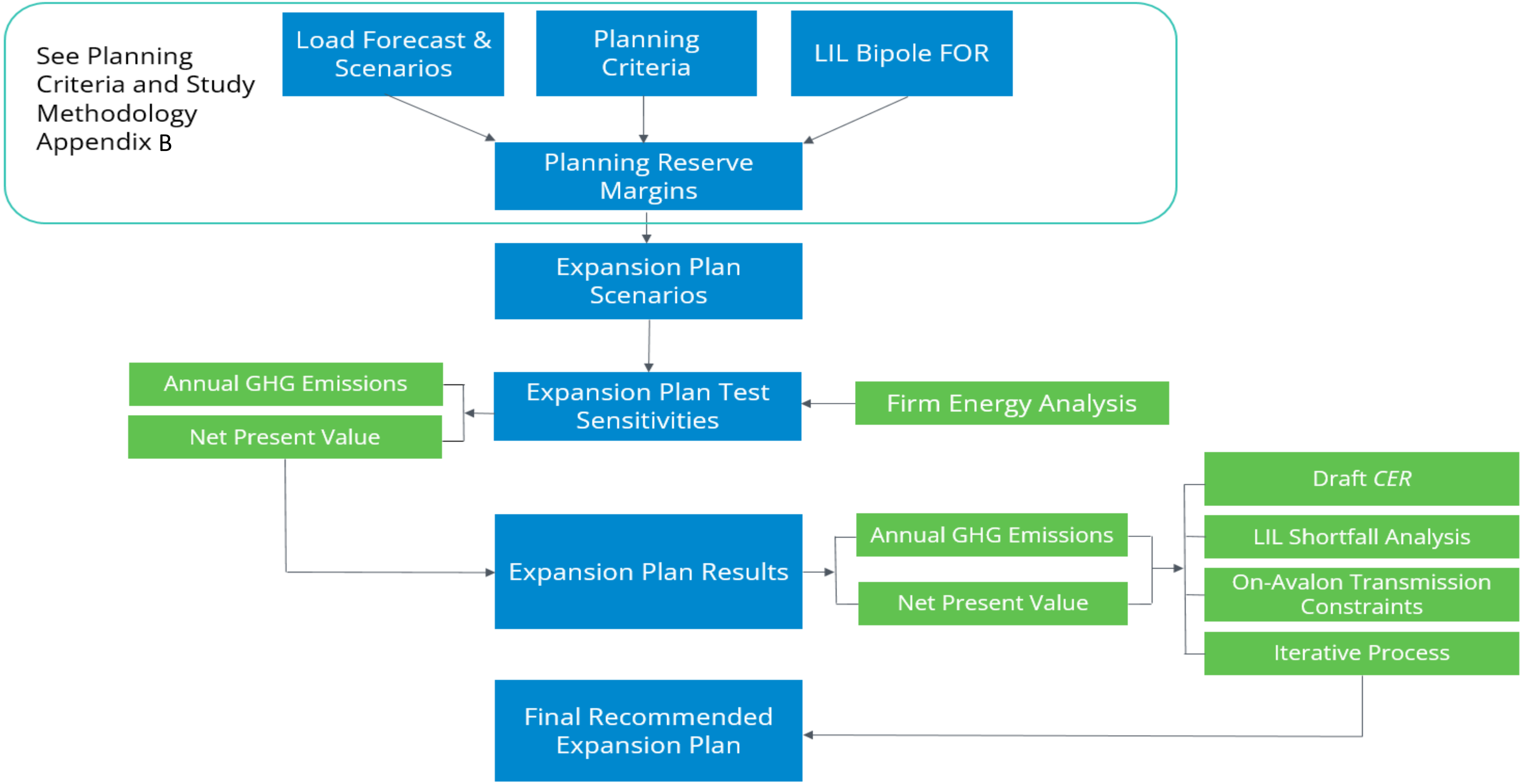
## Assessment of 2024 Resource Adequacy Plan:

- *Provide additional detail on modeling results, including energy deliveries over the LIL (#1).*
  - Energy deliveries over the Labrador-Island Link ("LIL") was addressed in Technical Conference #1. Additional details on the modelling is included in this presentation and modelling results to be discussed further in Technical Conference #4.
- *Perform additional model runs with a 0.1 LOLE standard (#3).*
  - Hydro will include an additional model run comparing a LIL equivalent forced outage rate ("EqFOR") of 1% with a planning criteria of 0.1 Loss of Load Expectation ("LOLE") for comparison purposes and inform the result in an request for information response.

# Resource Planning Criteria

- Hydro’s expansion plan analysis was driven by meeting three resource planning criteria:
  1. Probabilistic Capacity
     - The Island Interconnected System should have sufficient generating capacity to satisfy a loss of load hours (“LOLH”) expectation target of not more than 2.8 hours per year.
  2. Firm Energy Requirement
     - The Island Interconnected System should have sufficient generating capability to supply all its firm energy requirements with firm system capability.
  3. LIL-Shortfall Assessment
     - The Island Interconnected System should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL-shortfall event.

# Expansion Plan Development Process



# Description of Models Used

- Reliability Model (Plexos)
  - Purpose is to study reliability and loss of load events.
  - Used for setting reserve margin, shortfall analysis and near-term analysis.
  - Uses stochastic Monte Carlo analysis.
  - Key inputs are FORs, load forecasts, generator capacity and renewable generation curves.

- Hydraulic Model (Vista)
  - Optimized to study hydraulic generation.
  - Detailed models of reservoirs, inflows and generator curves.
  - Used to determine average and firm hydraulic generation, and plan hydraulic generation in the short and medium term.

# Description of Models Used

- Firm Energy Model (Excel)
  - Purpose is to determine the amount of generation required to meet firm energy criteria.
  - Compares forecasted load to available firm energy.
  - Determines the requirements for new energy builds.

- Production/Expansion Model (Plexos)
  - Purpose is to determine generation costs and least-cost expansion alternatives.
  - Used to develop expansion plans and production plans.
  - Key inputs are load forecasts, reserve margin, average generation, generation costs and market price forecasts.

# Description of Models Used

- Long-Term Financial Model
  - Used to determine the impact of the expansion plan investment on customer rates.
  - The projected rates associated with an expansion plan are used to determine the impact on forecasted load requirements.

- Transmission (PSSE)
  - Used to analyze constraints on the transmission system due to issues like thermal overloads and voltage limits.
  - Constraints are generally seen during LIL outages.
  - Used to determine options to mitigate transmission issues (line upgrades, synchronous condensers, line monitoring, etc.).

# Description of Models Used

- Plexos, PSSE and Vista are industry standard tools and are widely used by utilities across North America for resource planning
- The models were reviewed in-depth by the Board of Commissioner of Public Utilities previous consultant The Liberty Consulting Group in 2019.
- The modeling process was reviewed by Daymark as a part of each Reliability and Resource Adequacy filing.

# Modelling Approach

# Modelling Approach – Representative Year

**2024 Resource Adequacy Plan – Issues List:**

- *Is NLH selection a single representative year (2032) and application of the resulting planning reserve margins to the entire study period a reasonable approach?*

**Assessment of 2024 Resource Adequacy Plan:**

- *Provide further reasoning for the 2032 representative year being selected (#53).*

# Representative Year

- The reserve margin is one of the primary drivers of expansion.
  - The reserve margin drives expansion after the Bridging Period.
  - The representative year should be after the retirement of the Holyrood Thermal Generating Station ("Holyrood TGS"), Hardwoods and Stephenville Gas Turbines ("GTs").
  - The reserve margin is an accurate measure of reliability in the representative year.
    - As distance increases from a representative year, system conditions will increasingly change, which will lead to a change in the reserve margin.
  - The representative year should be close to the first expansion requirement.

# Modelling Approach – Electricity Rates

**2024 Resource Adequacy Plan – Issues List:**

- *For the Reference Case and Accelerated Decarbonization cases, NLH used a 14.7c/kWh customer rate, escalating at 2.25%/year, and for the Slow Decarbonization case, the same rate but escalated at 0.7%/year. Were these reasonable assumptions?*

# Electricity Rate Assumptions

- The rate assumptions used in the 2024 Resource Adequacy Plan included similar electricity rates as the finalized Government of Newfoundland and Labrador ("Government") rate mitigation plan.
  - Assumed rate mitigation for Muskrat Falls cost continues post 2030;
  - In addition to the 2.25% related to Government's publicized rate mitigation announcement, a 0.7% increase in Slow Decarbonization scenario was based on Newfoundland Power Inc.'s ("Newfoundland Power") historical average cost increases;
  - The 2.25% in Reference and Accelerated Decarbonization scenarios was based on Government's publicized rate mitigation announcement; and
  - The costs for the Minimum Investment Required Expansion Plan are not assumed to be mitigated.
    - If the cost associated with the Minimum Investment Required Expansion Plan were mitigated, the demand forecasted would increase.

# Electricity Rate Assumptions

- In Technical Conference #1, Hydro presented the 2024 Slow Decarbonization forecast, which includes:
  - The Government's final rate mitigation plan to 2030 and assumes rate mitigation continues post 2030;
  - Increases due to Newfoundland Power costs; and
  - The costs for the Minimum Investment Required Expansion Plan scenario as proposed in the 2024 Resource Adequacy Plan.
    - Bay d' Espoir ("BDE") Unit 8, 150 MW Combustion Turbine ("CT"), 400 MW of wind and a transmission upgrade from Soldier's Pond to Western Avalon.
- Electricity rates continue to have an impact on Domestic customer sales.
  - Decrease of 14 to 21 GWh in residential sales in the 2024 forecast.
  - Reference Case demand down by 22 MW by 2034.
  - Slow Decarbonization demand down by 9 MW by 2034.
- Hydro will continue to work with the Government on the post 2030 rate mitigation plan, providing necessary information to aid the Government in its decision-making process.

# Forced Outage Rates

# Modelling Approach – Forced Outage Rates

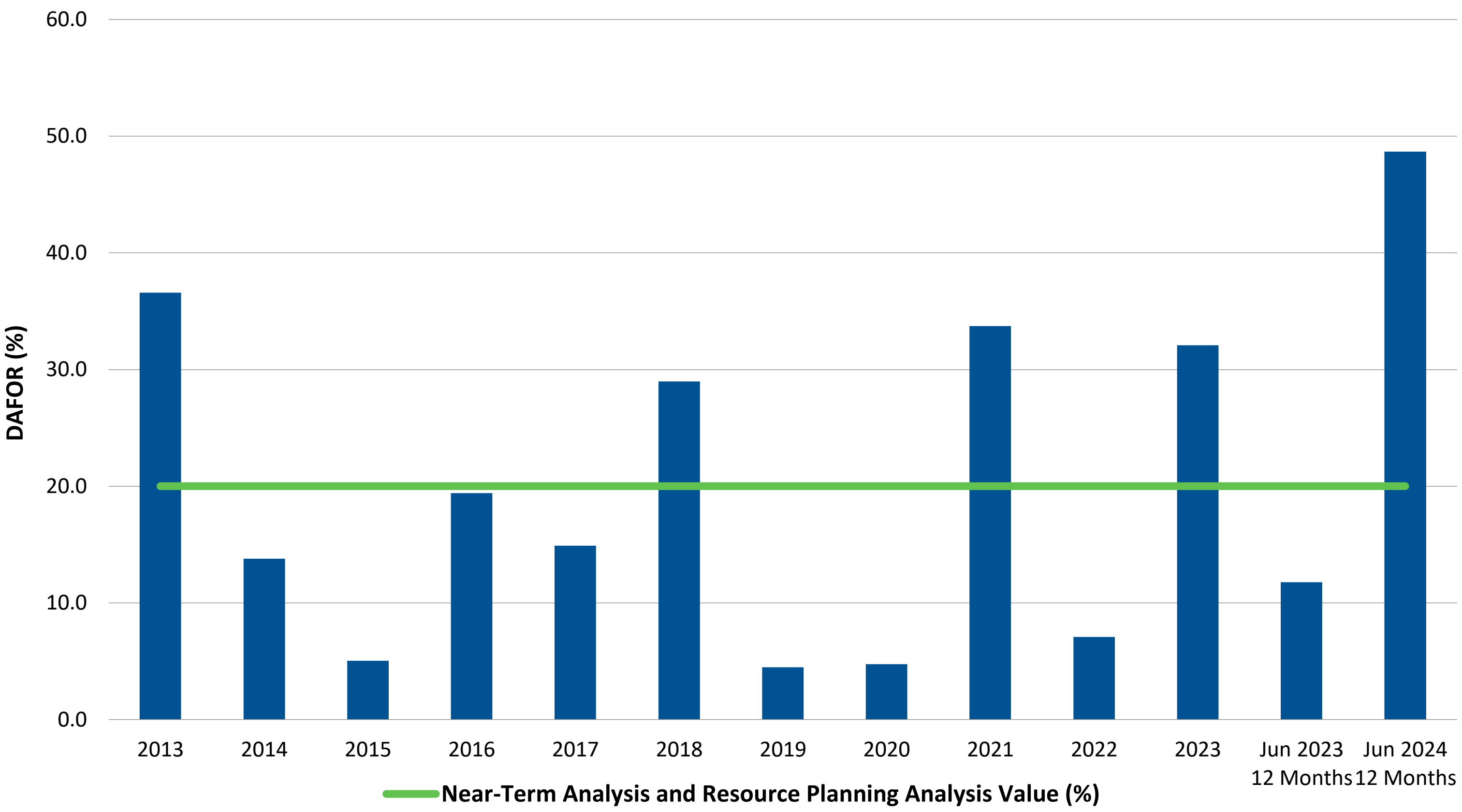
**2024 Resource Adequacy Plan – Issues List:**

*Regarding forced outage rates:*

- *For its existing thermal assets, NLH used a mix of historical derated adjusted forced outage rates ("DAFORs"), historical derated adjusted utilization forced outage probability ("DAUFOPs"), and equivalent forced outage rates ("EFORd") reported by NERC. Was this a reasonable approach, do historical data on NLH's assets support this approach of assumed forced outage rates?*
- *For Holyrood Thermal Generating Station, NLH proposed to use DAUFOP as the metric and a value of 20% in the base case and a sensitivity of 34% for "near-term planning." Is this a reasonable approach? And has NLH reasonably justified and explained the impact of the "near-term" sensitivity?*
- *For NLH's CTs, NLH used a mix of approaches here to derive the DAUFOP values for use in the "near—term analysis" and Resource Planning Model. Are these approaches and assumptions sufficiently explained, disclosed, and reasonable?*

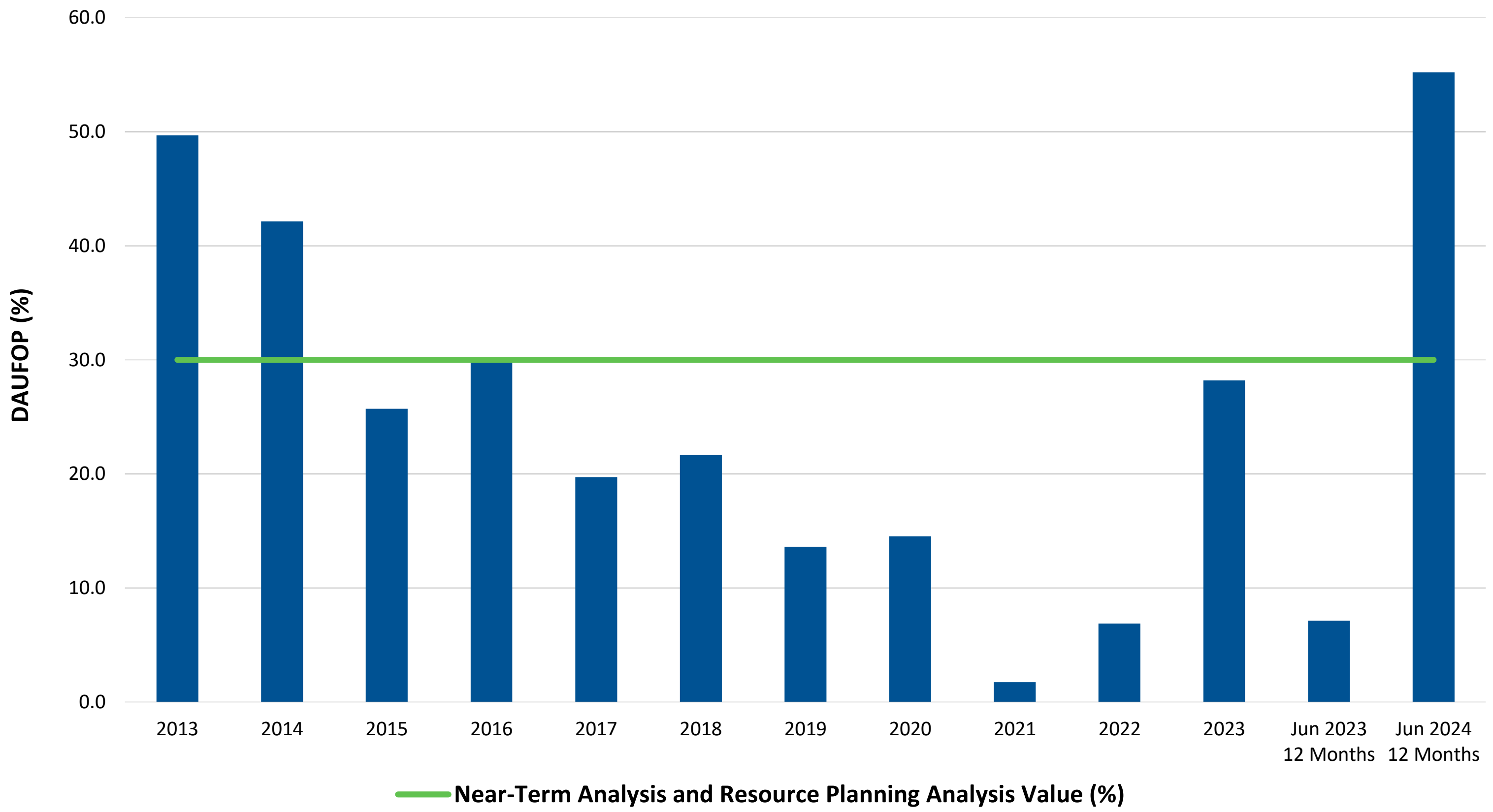
# Forced Outage Rates – Holyrood TGS

- **20% Base Case**
  - Reflects "average" performance over many years.
- **34% Sensitivity**
  - Winter 2021–2022 and Winter 2023–2024
  - Considers variability in Holyrood TGS FORs.



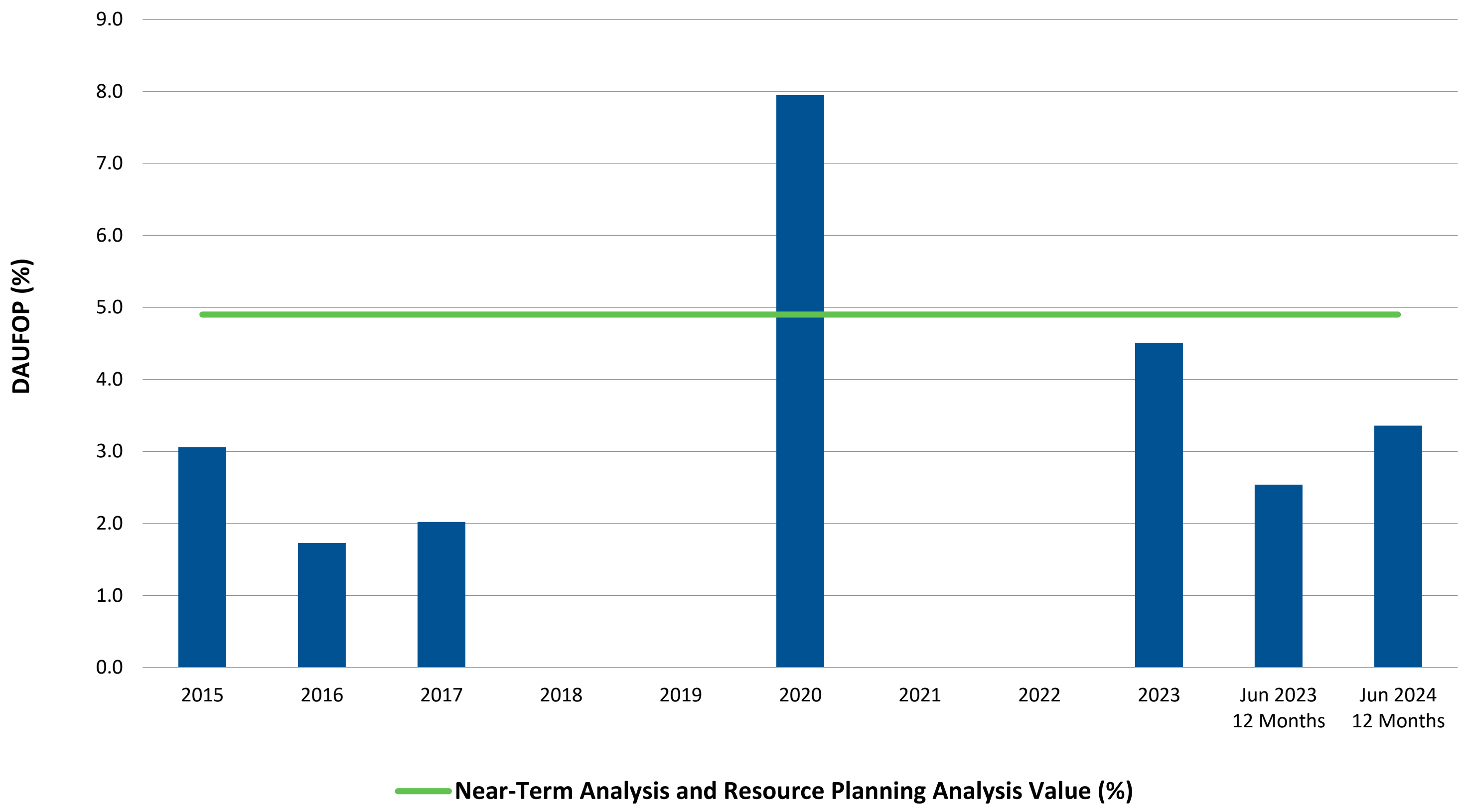
# Forced Outage Rates – Hardwoods & Stephenville GT's

- **DAUFOP value of 30%**
  - Based on historical data.
- Assumed retired in 2030.
- 2023–2024 impacted by Stephenville unit outage.



# Forced Outage Rates – Holyrood CT

- **DAUFOP of 4.90%**
- Need-based operation:
  - Yearly and seasonal variations.
- Scenario-based approach for establishing FOR.
  - Helps alleviate the variability year to year.
  - Assumes fixed operating profile.



# Modelling Approach – Forced Outage Rates

**2024 Resource Adequacy Plan – Issues List:**

*Regarding forced outage rates:*

- *For the LIL, NLH "calculated" an equivalent forced outage rate, which measures the percentage of time that the LIL bipole is unable to deliver its Maximum Continuous Rating (currently 700 MW but designed to be 900 MW) to the Island due to bipole forced outages, bipole derates, derates due to unplanned monopole outages, or derates due to overlapping monopole outages (effectively creating a bipole outage). This results in a 5% base case assumption. Was this a reasonable approach and supported by historical data observed so far support the assumptions (which is 2.34% based on a 700 MW rating and a 3.56% based on a 900 MW rating)? And how did NLH model outage of the LIL, e.g. was probabilistic outage used with different outage probability by season?*

# Forced Outage Rates – LIL

- The LIL was modelled with a range of FORs from 1% to 10%.
  - The calculated EqFOR of 2.79% @ 700 MW and 4.27% @ 900 MW falls within the modelled range.
  - As more operational data is available the modelled range should narrow.
- The LIL outages were modeled probabilistically using a Monte Carlo approach.
  - Outages were evenly distributed through the year with no seasonal variation.
  - There may be periods of the year where outages are more likely, but there is not enough data to determine a trend.

# Modelling Approach – Forced Outage Rates

**2024 Resource Adequacy Plan – Issues List:**

*Regarding forced outage rates:*

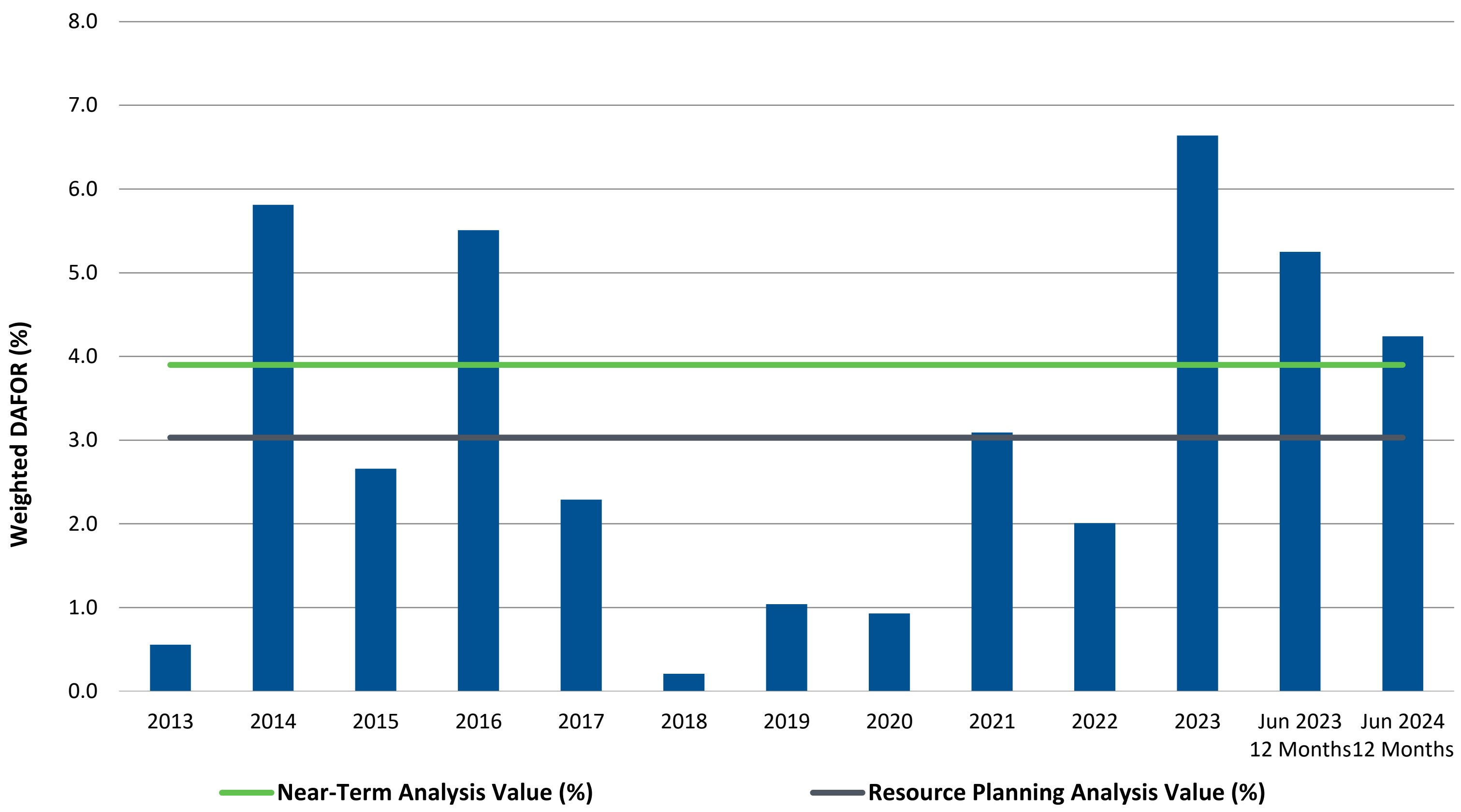
- *For its hydro units, NLH used a three-year capacity-weighted average DAFOR for the "near-term analysis," but a ten-year capacity-weighted average DAFOR for the Resource Planning Model. Was this reasonable, and is sufficient data provided to demonstrate the reasonableness of the assumptions?*
- *For the Muskrat Falls project, NLH used historical FORs observed to date for the near-term analysis, and for the Resource Planning Model, used FORs of the NLH-owned hydro resources. Were these reasonable assumptions?*
- *For third-party resources, NLH used industry data to determine DAFOR and DAUFOP, depending on the unit's generating characteristics, and for hydro resources, used industry averages. Were these reasonable?*

# Forced Outage Rates – On-Island Hydraulic Units

- Near-Term Analysis:
  - Based on the three-year average DAFOR.
  - Reflects current issues being experienced by the units.
    - Issues which would generally be resolved in the 1–3 year timeframe.
  - A year or two of high DAFOR can cause significant swings in this average.
- Long-Term Analysis:
  - Based on a ten-year average DAFOR.
  - Reflects how we maintain and invest in the units in the long term.
  - The longer timeframe provides more stability and would result in less annual variation.

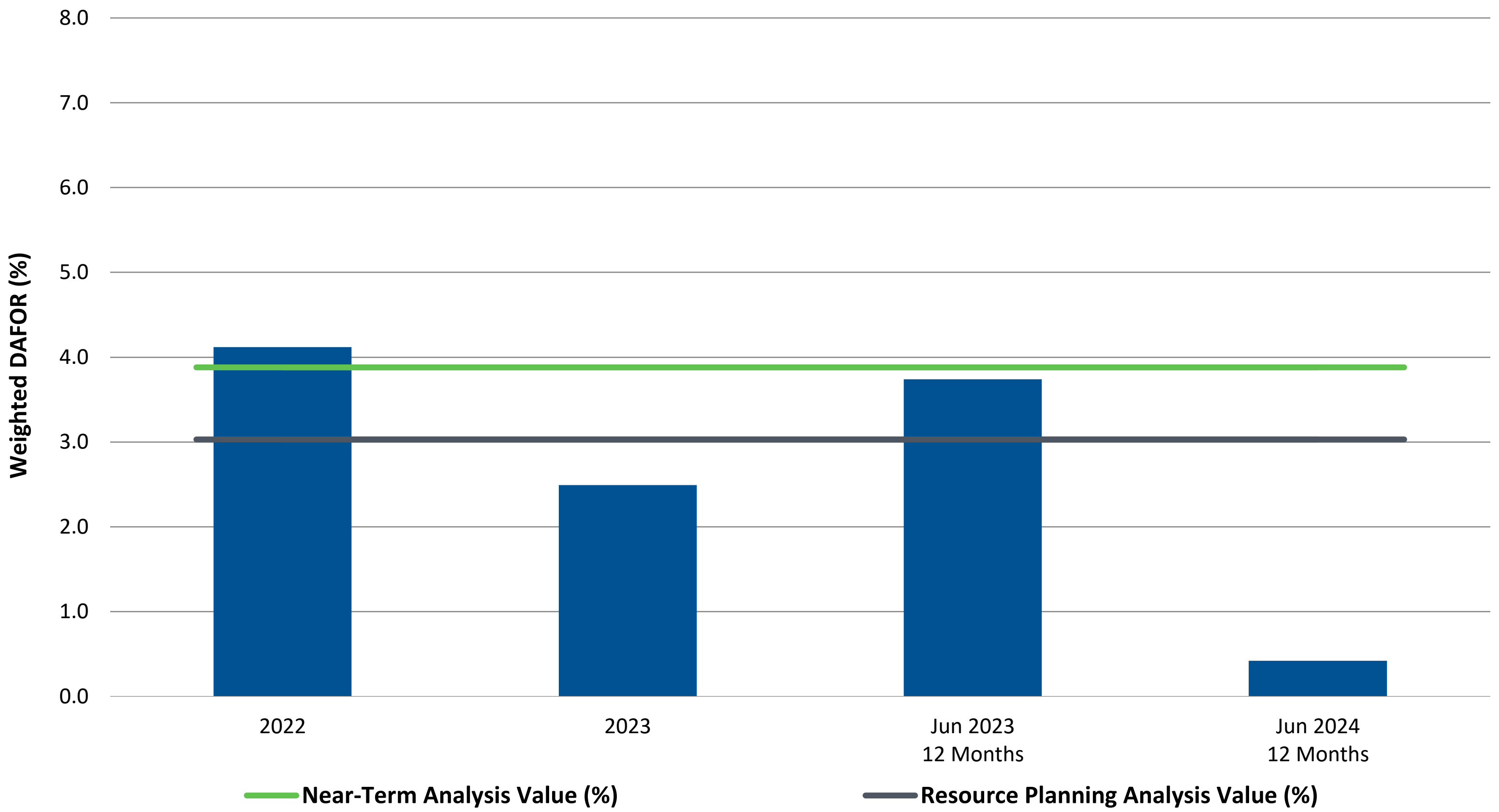
# Forced Outage Rates – Hydraulic Units

- Aging assets are not failing assets.
- Hydraulic units have a long life expectancy.
  - Activities such as refurbishment and replacement of major components extend the life.
- Hydro expects that the historical performance will continue in the long term.
  - Planned renewal and refurbishment work in long-term plans.



# Forced Outage Rates – Muskrat Falls

- **Near-Term Analysis:**
  - Muskrat Falls units relatively new.
    - Anticipated an increased DAFOR in the near term due to early failures.
      - Not reflected in the data to date.
- **Long-Term Analysis:**
  - Ten-year average DAFOR for Hydro Hydraulic.
    - Anticipate same level of maintenance and investment as the remainder of Hydro's fleet.
- Once Hydro has more operational data, the DAFOR calculation for Muskrat Falls Assets with our other Hydro units may be combined.



# Forced Outage Rates – Third Party Resources

- Industry averages are utilized for units that Hydro does not operate.
  - Generally higher than our assumptions (5.82% versus 3.03%).
  - Only represent a small portion of our system.
  - No large impact on reliability.

# Generation Assumptions

# Modelling Approach - Results

**2024 Resource Adequacy Plan – Issues List:**

- *NLH modeled some hydro units' firm capacity (e.g., BDE) at their full nameplate capacity, while others were modeled at lower firm capacity values due to seasonal restrictions (i.e., icing impacts). Run-of-river and small storage hydro units were modeled with daily energy limits that vary by month. Are these reasonable assumptions for these units?*
- *NLH modeled Muskrat Falls at its full capacity year-round, with daily energy profiles that are simulated and vary by month. Is this a reasonable approach?*

**Assessment of 2024 Resource Adequacy Plan:**

- *Provide the daily energy profiles simulated for use in the expansion and firm energy analysis models. (#47).*

# Hydro Restrictions

- Exploits winter capacity is restricted in the model because that system consistently experiences derates due to icing.
  - Other plants may experience icing events, but this is a rare occurrence.
- Most hydro units have large storage capacity and generation at these units would not be restricted in the short term.
  - Risk of long-term energy shortfall is managed by our firm energy criteria.

# Hydro Restrictions

- Units with small storage capacities are Muskrat Falls, Paradise River and Newfoundland Power’s hydro units.
  - Muskrat Falls is modelled stochastically, with one of 12 daily energy limits chosen randomly each year.
  - Paradise River and Newfoundland Power are modelled with one single daily profile.
  - Energy limitations have negligible effect on short-term reliability.
    - May have more effect as more energy limited resources are added to the system.
    - Will be studied as part of the Effective Load Carrying Capacity (“ELCC”) process.

# Hydro Restrictions – Daily Energy (GWh)

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Paradise River | 0.10 | 0.10 | 0.12 | 0.15 | 0.12 | 0.06 | 0.04 | 0.05 | 0.06 | 0.10 | 0.13 | 0.12 |
| NP Hydro – Avalon | 0.70 | 0.79 | 0.75 | 0.99 | 0.86 | 0.62 | 0.44 | 0.34 | 0.43 | 0.37 | 0.44 | 0.62 |
| NP Hydro - Off-Avalon | 0.29 | 0.37 | 0.46 | 0.56 | 0.66 | 0.52 | 0.49 | 0.37 | 0.34 | 0.34 | 0.38 | 0.34 |
| Rattle Brook | 0.02 | 0.02 | 0.02 | 0.05 | 0.08 | 0.05 | 0.03 | 0.03 | 0.04 | 0.05 | 0.06 | 0.04 |
| Muskrat Falls | 14.4 | 15.0 | 13.4 | 12.8 | 12.4 | 14.5 | 14.7 | 14.3 | 13.3 | 11.2 | 12.9 | 13.5 |

# Modelling Approach - Results

## 2024 Resource Adequacy Plan – Issues List:

- *Existing thermal generators, (except Holyrood diesel-fired units), were modeled as firm capacity equal to their full nameplate capacity. Is this a reasonable approach?*

# Firm Capacity – Thermal Assets

- Generally conventional generators are available at their rated capacity unless derated or on a planned or unplanned outage.
  - Holyrood diesels are limited by environmental regulations.
    - There are no other similar restrictions on thermal generators.
  - Derates and unplanned outages are captured by modelling the DAFOR/DAUFOP.
  - Planned outages are captured by modelling a maintenance schedule.

# Modelling Approach - Results

## 2024 Resource Adequacy Plan – Issues List:

- *Existing wind resources were modeled using 22% ELCCs, with separate wind profiles for the winter and non-winter seasons. Is this a reasonable set of assumptions?*
  - Wind ELCC assumptions were addressed in Technical Conference #2.

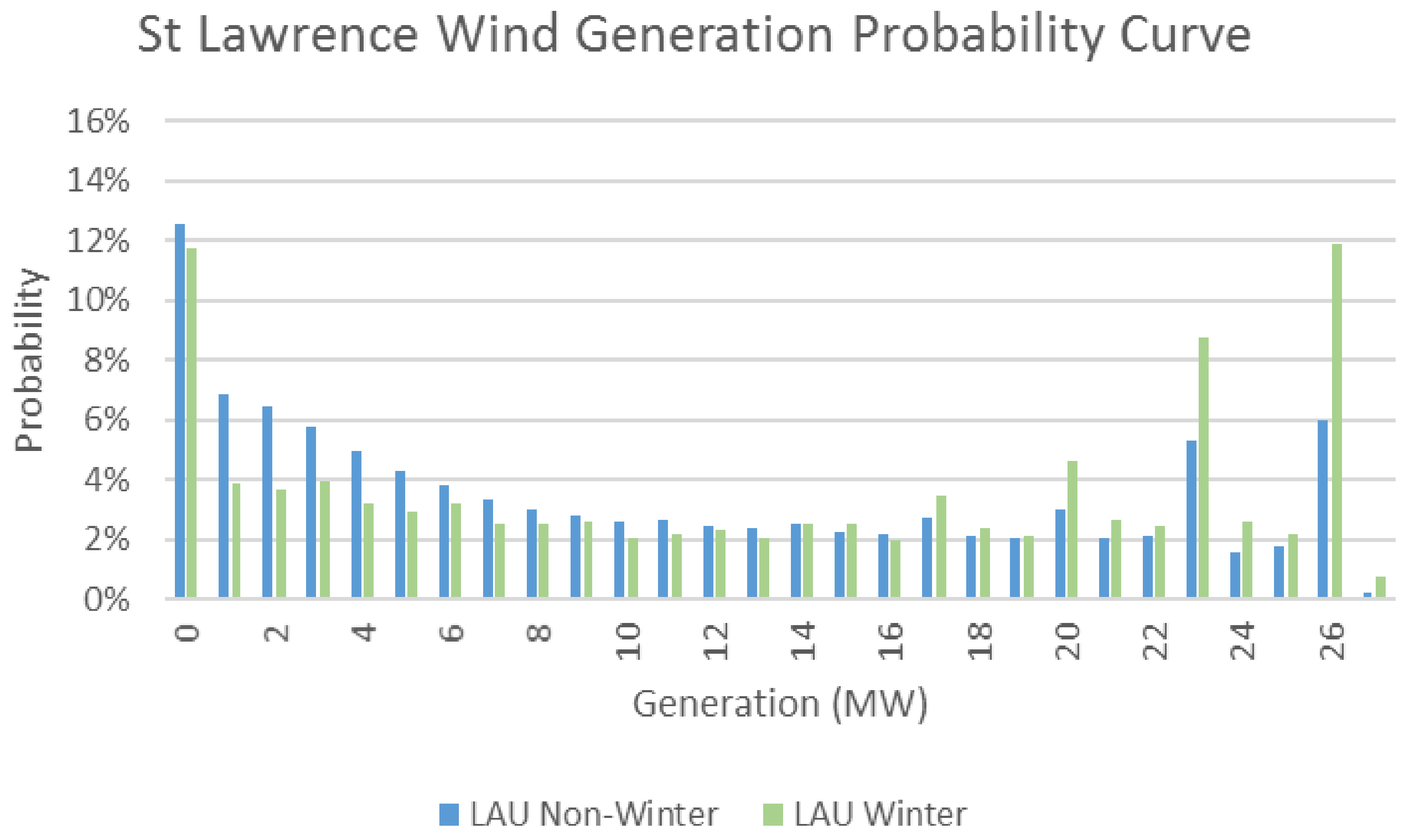
## Assessment of 2024 Resource Adequacy Plan:

- *Provide wind profiles and support to clarify seasonal variability in wind that was modeled (#46).*

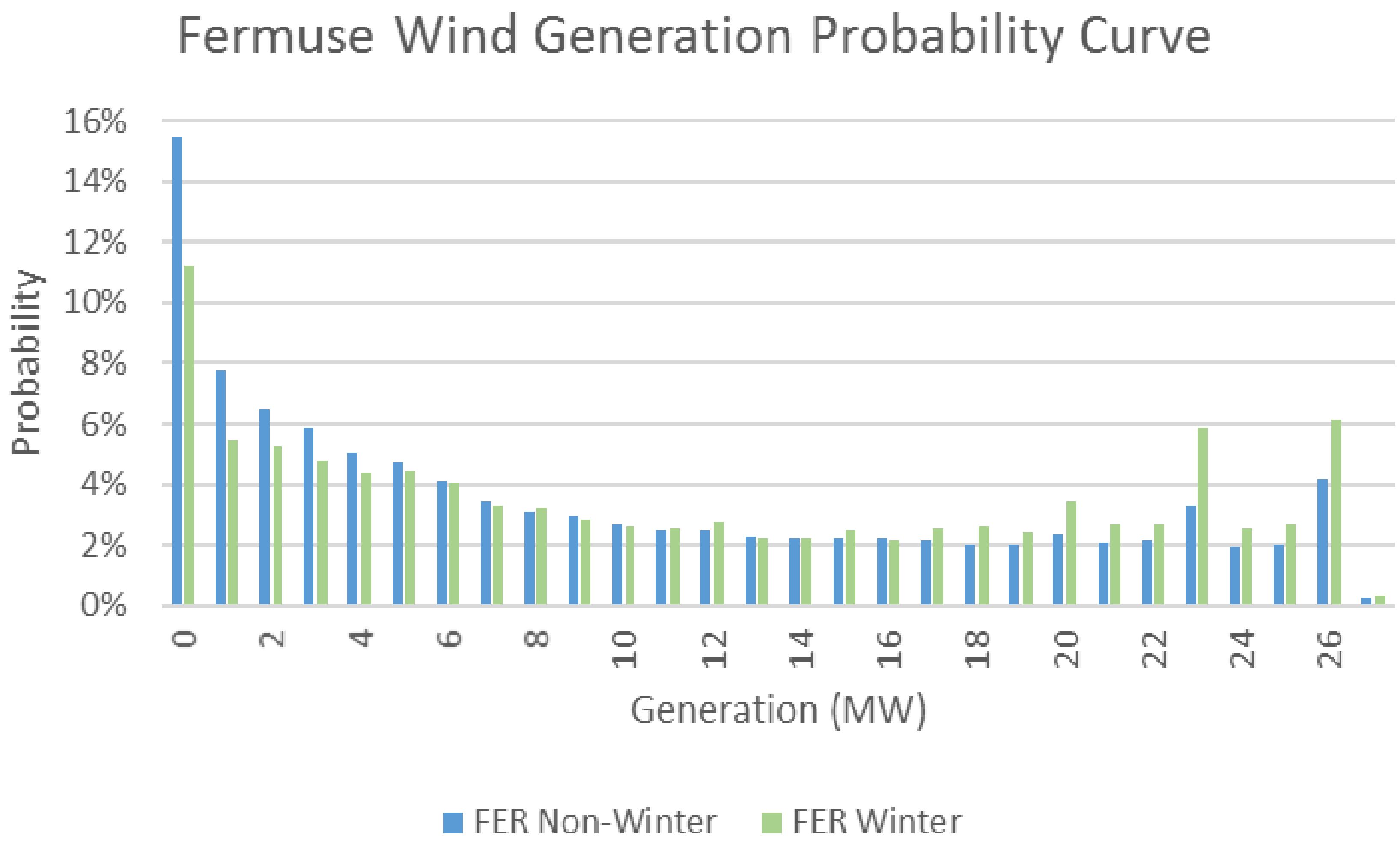
# Wind Assumptions

- Wind is modelled stochastically in the reliability model.
- Each hour is assigned a random generation according to the probability curves.
- Separate curves are used for winter and non-winter periods to capture increased generation in high-load periods.

# Wind Assumptions



# Wind Assumptions



# Modelling Approach - Results

## 2024 Resource Adequacy Plan – Issues List:

- *Is NLH's identified "Bridging Period" a reasonable approach, and if so, is the timeframe (2023-2030) supported? Should NLH consider a shorter Bridging Period and assess the cost impact of doing so (e.g., accelerating new capacity to 2029 (or earlier))?*
    - The Bridging Period, including consideration of a shorter Bridging Period was addressed in Technical Conference #2.

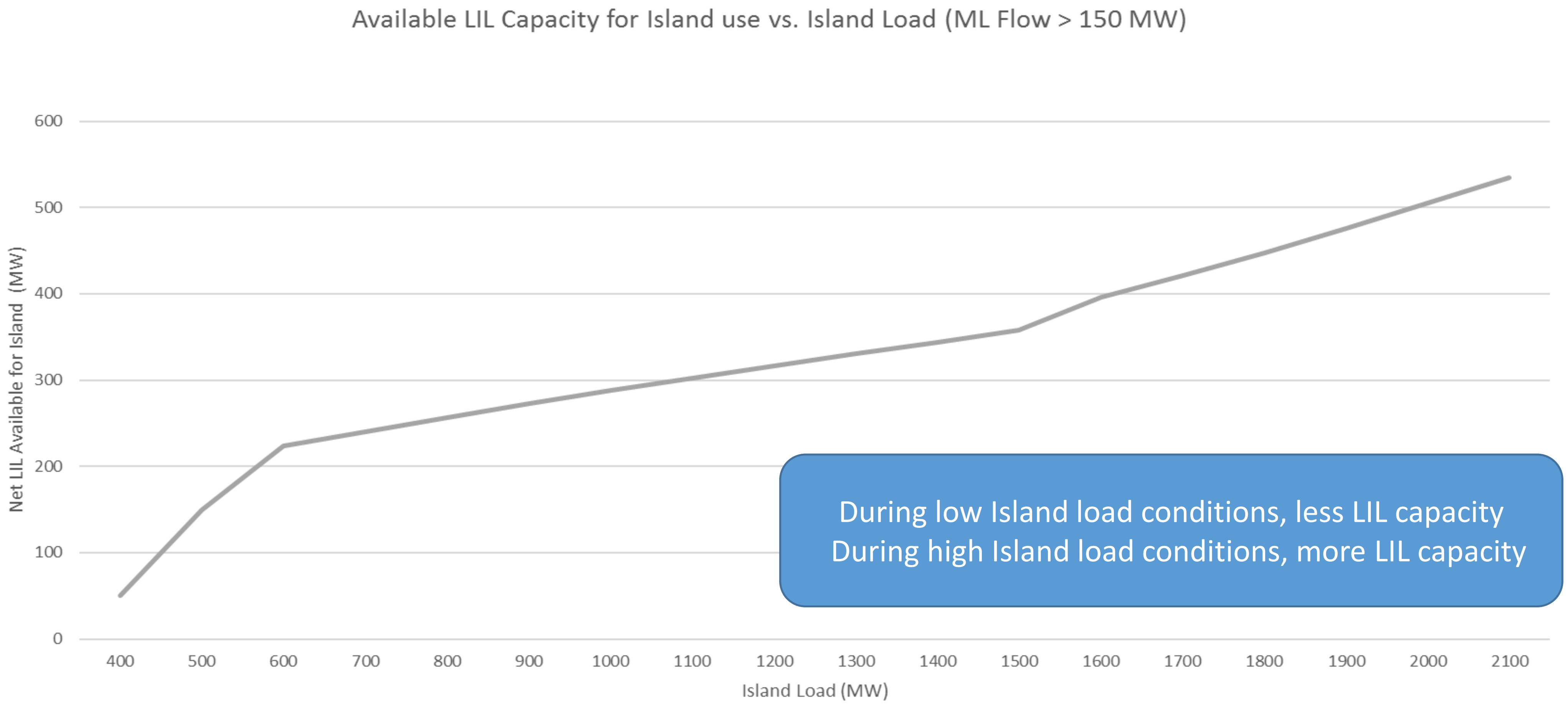
# Imports and Exports

# Modelling Approach – Maritime Link–LIL Relationship

## 2024 Resource Adequacy Plan – Issues List:

- *Regarding modeling of the LIL, NLH noted its dependency on the Maritime Link and stated that due to this relationship, NLH developed an hourly capacity profile for the LIL that serves as a constraint on the LIL and that is based on the hourly IIS load profile and the firm contractual export commitments over the Maritime Link. Has NLH provided sufficient data and information to assess this assumption? And is this a reasonable approach?*
  - The LIL–Maritime Link Relationship was addressed in Technical Conference #1.

# Maritime Link – LIL Relationship



# Modelling Approach – Import Potential

## 2024 Resource Adequacy Plan – Issues List:

- *Did NLH reasonably model potential imports, including imports from Nova Scotia, New Brunswick, and ISO New England? Was it reasonable to not consider any new potential long-term firm import contracts as a resource option?*
    - This was addressed in Technical Conference #1 (see slide 47).

# Import Potential

## Firm Import Potential: Transmission and Market Access

- The Island Interconnected System has access to three potential markets via the Maritime Link:
  1. Nova Scotia;
  2. New Brunswick; and
  3. New England.
- Firm transmission is still a constraint.
- Firm imports could be supplied from Nova Scotia, if available.
  - Hydro contacts Nova Scotia Power and New Brunswick Power annually to assess long-term firm energy potential and to date, both utilities confirm that acquiring a firm import contract during the winter period is not feasible in the near-term. Updates are provided in the annual Near-Term Reliability reports.

# Modelling Approach – Exports

**2024 Resource Adequacy Plan – Issues List:**

- *Has NLH reasonably modeled contractually-obligated and surplus exports to Nova Scotia and surplus energy through Quebec?*

**Assessment of 2024 Resource Adequacy Plan:**

- *Clarify that off-peak deliveries of energy to NSPI ("Supplemental Energy") were not modeled (#50).*
- *Explain how obligations under the Energy Access Agreement with Nova Scotia were modeled (#51).*
- *Provide additional detail about export arrangements (#52).*

# Exports – Reliability vs. Expansion Plan Models

## Reliability Model

- Firm capacity contracts modelled (currently only Nova Scotia Block).
  - Contingent on operation of the LIL.

## Expansion Model

- Québec
  - 240 MW export path through Québec.
- Nova Scotia
  - Nova Scotia Block – 154 MW On-Peak (firm)
  - Supplemental Block – 200 MW Winter Off-Peak until 2026
  - Energy Access Agreement – 900 GWh non-firm per year, based on a monthly peak/off-peak forecast.
  - Other non-firm market sales.

# Modeling Approach – Commercial Arrangements

## 2024 Resource Adequacy Plan – Issues List:

- *NLH indicates that it has "agreed to sell 1.7 TWh of energy banked in the Churchill River reservoir on behalf of Muskrat Falls." Have the details and implications of this transaction been sufficiently explained?*

## Assessment of 2024 Resource Adequacy Plan:

- *Provide additional status and details of the commercial arrangements with Hydro Quebec for energy or capacity from Muskrat Falls (#48).*

# Commercial Arrangements

- This occurred as a result of monetizing banked energy from the reservoir that could not have been used otherwise.
- There are no reliability, hydrological or cost implications impacting the 2024 Resource Adequacy Plan as we do not include this in our modelling assumptions.

# Firm Energy

# Modelling Approach – Firm Energy

**2024 Resource Adequacy Plan – Issues List:**

- *Has NLH conducted the firm energy modeling in a reasonable manner, including resource capacity factors, import and export potential, LIL availability, and LIS resource availability?*

**Assessment of 2024 Resource Adequacy Plan:**

- *Consider incorporating firm energy analysis process into the PLEXOS Model (#45).*
- *Provide detail regarding transmission losses assumptions and results, hydro spillage, and wind curtailments for its model runs (#49).*
- *Provide full results of Firm Energy Analysis and explain implications beyond 2034 (#54).*

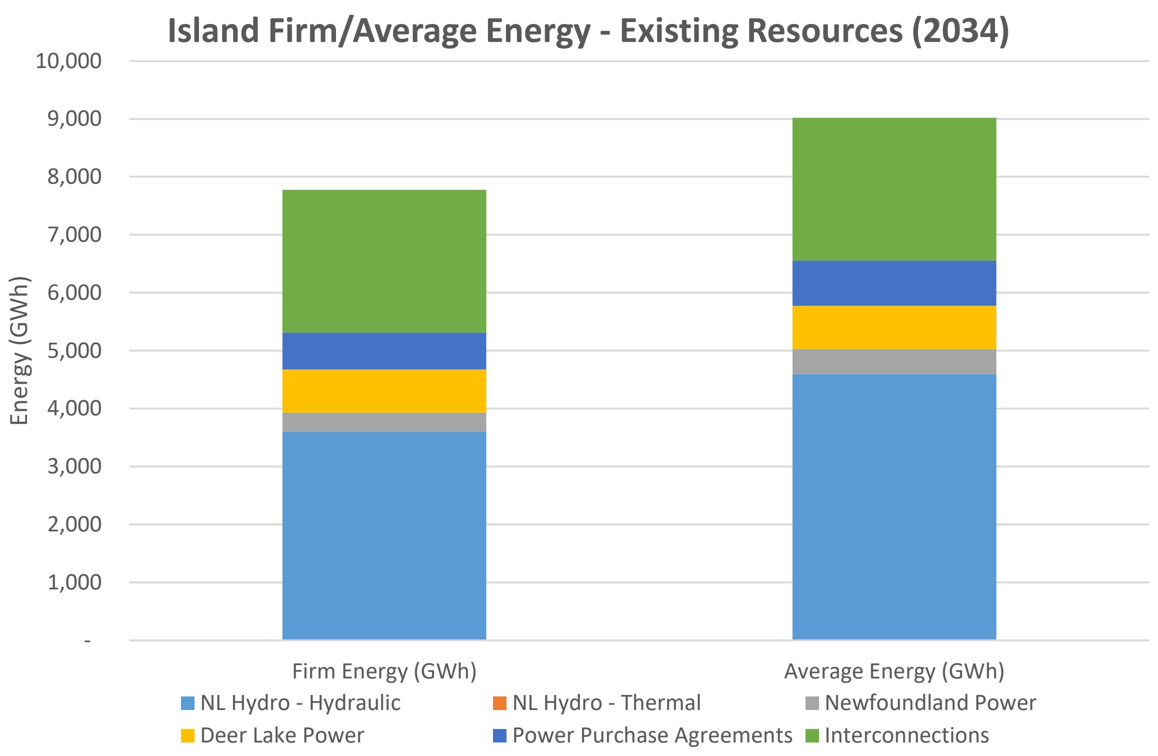
# Firm Energy Analysis

- Firm energy analysis is done outside of Plexos, but will be incorporated into the model in the future.
- Assumptions
  - Hydro-owned hydraulic generation is based on modelling in Vista and based on the driest three-year sequence.
  - Other hydraulic generation is based on historical minimum generation.
  - Other generation (wind, CBPP co-gen) based on historical averages. Holyrood is based on maximum generation minus outage rates and maintenance.
  - LIL is based on the LIL–Maritime Link relationship and the hourly Island Interconnected System load profile.
  - Other thermal and imports are not included
  - Losses are modelled as a fixed loss factor.
- Assumed that there is no spillage in a firm energy scenario.
- Wind curtailments will be studied as part of the ELCC study.

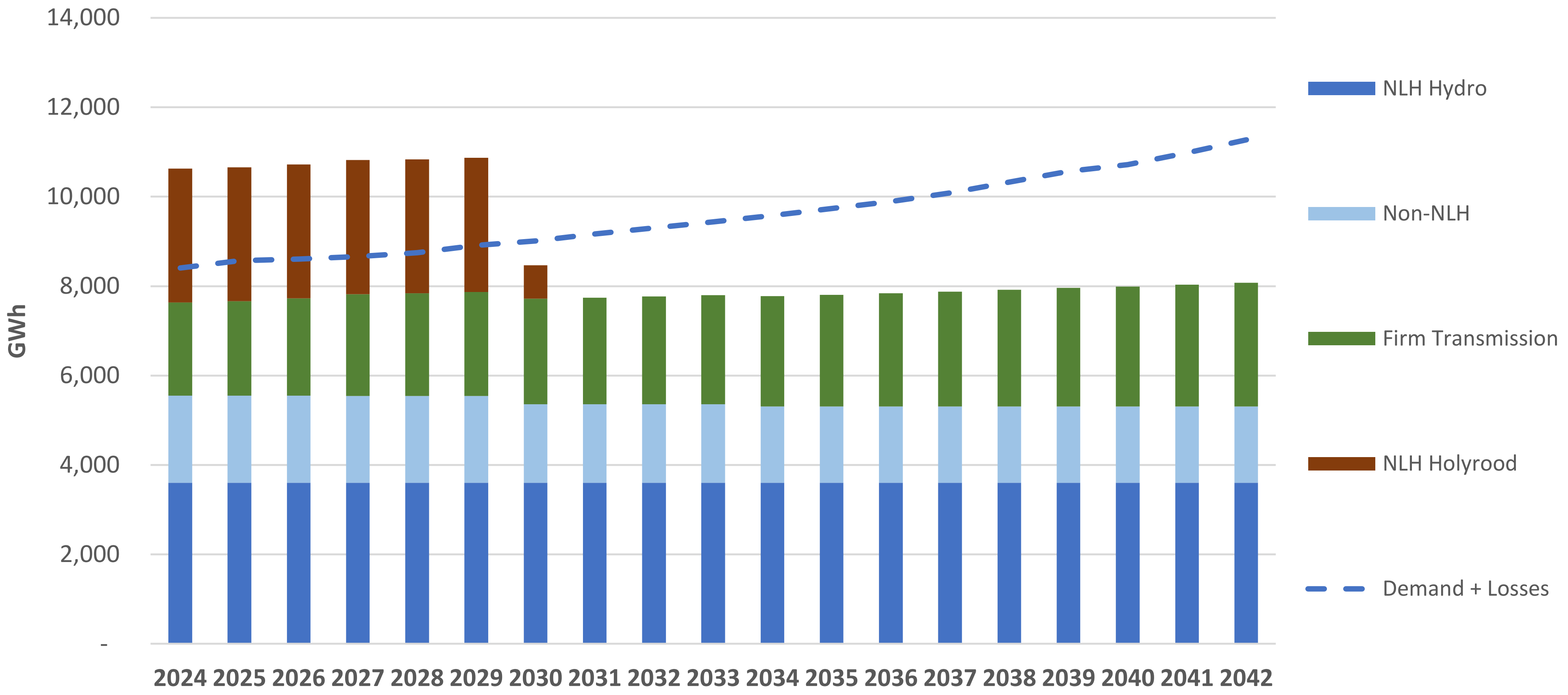
# Firm Energy Requirements

- Island Interconnected System firm and average energy from existing resources.

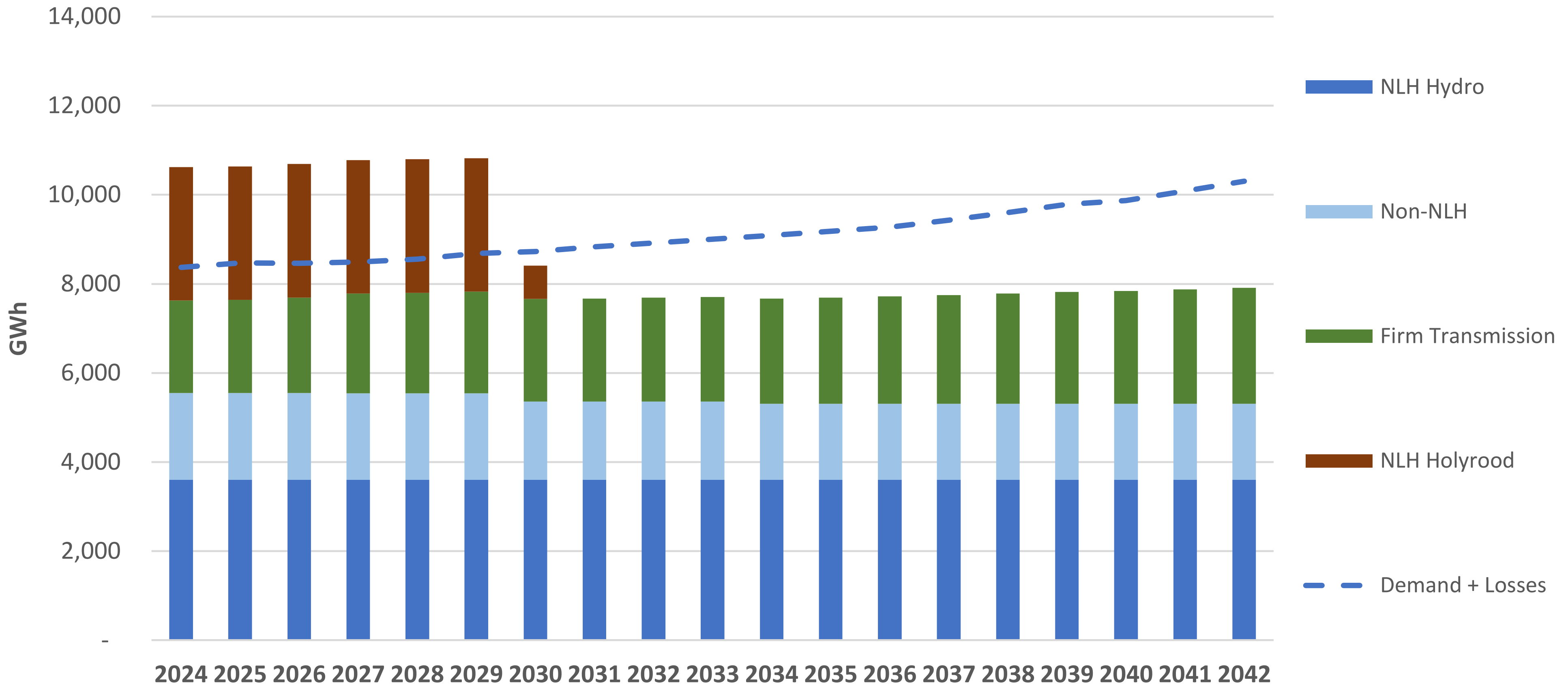
| | Firm Energy (GWh) | Average Energy (GWh) | Delta (GWh) |
|---|---|---|---|
| NL Hydro Hydraulic | 3,602 | 4,596 | 994 |
| NL Hydro Thermal | - | - | - |
| Newfoundland Power | 324 | 430 | 106 |
| Deer Lake Power | 750 | 750 | - |
| Power Purchase Agreements | 634 | 778 | 144 |
| LIL less Firm Maritime Link Exports | 2,464 | 2,464 | - |
| **Total Island Interconnected System** | **7,774** | **9,018** | **1,244** |



# Firm Energy Requirements – Reference Case to 2042



# Firm Energy Requirements – Slow Decarbonization to 2042

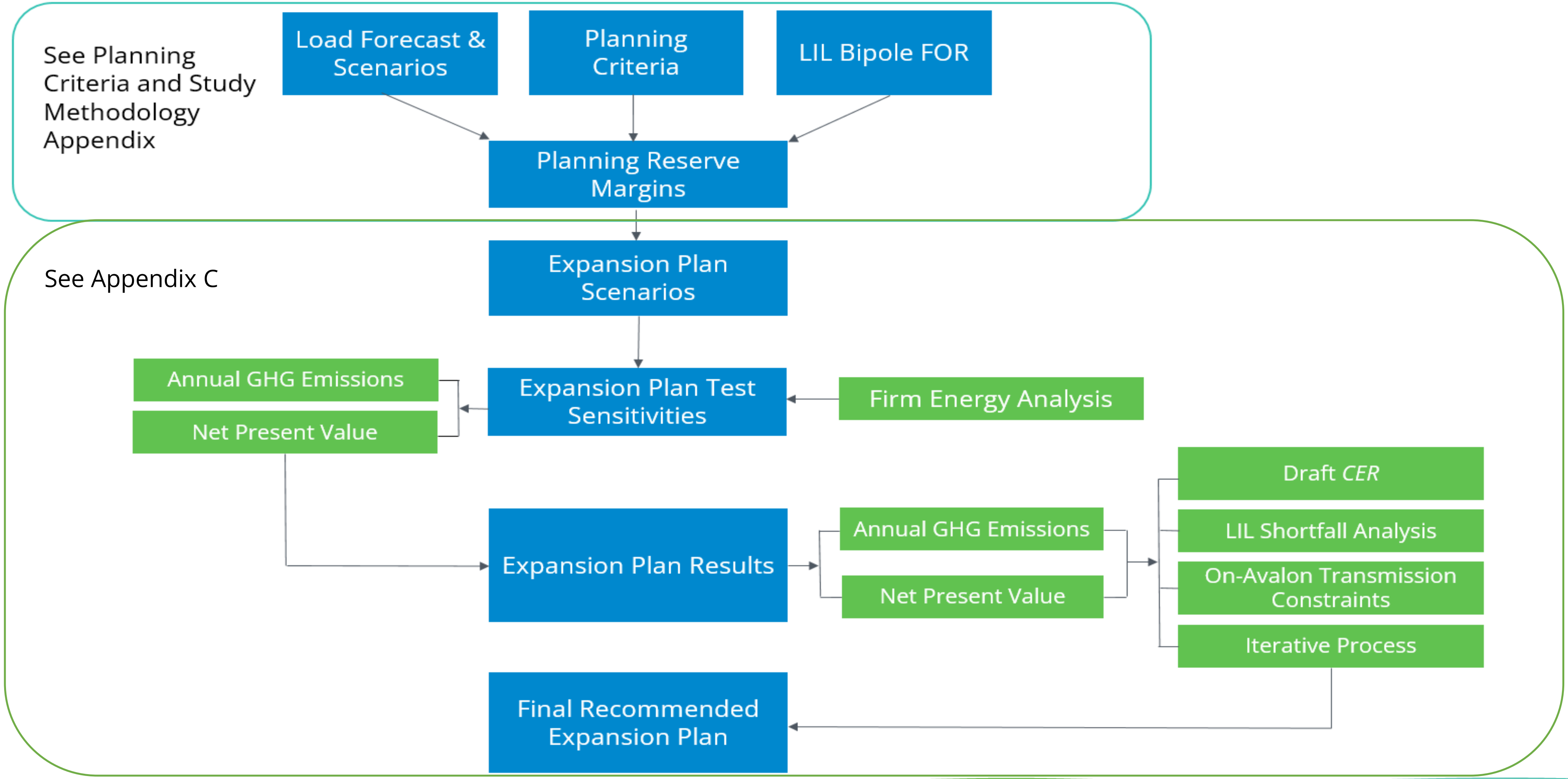


# Transmission Losses

- Transmission losses are modelled dynamically in Plexos using a simplified transmission system model.
  - Average Island Interconnected System losses are 3.6-4.4% (excluding LIL Losses).
  - LIL losses at 700 MW are 58 MW.
- Losses are modelled as quadratic equations developed from load flow analysis done by Transmission Planning.
- Captures changes in transmission line losses associated with outages.

# Scenarios

# Expansion Plan Development Process



# Expansion Plan Development Process

- The development process for the Expansion Plan was segmented into three steps:
  - Step 1: Development of Scenarios (Appendix C, Section 6.1)
    - Eight Expansion Plan scenarios that included variations of Island load forecast, LIL bipole EqFOR, and planning criteria.
  - Step 2: Development of Sensitivities (Appendix C, Section 6.2)
    - There were 11 sensitives identified to further test Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required) Expansion Plan scenarios.
    - The sensitivities considered parameters such as capital costs, fuel costs, limitations on certain resource options, variations in battery ELCC, etc.
  - Step 3: Further Analysis of Expansion Plans (Appendix C, Section 7.0)
    - Further analysis of the Expansion Plan was performed regarding the draft Clean Electricity Regulations, the LIL-shortfall analysis, On-Avalon transmission constraints, and an iteration between the rate, load forecast, and expansion plan requirements.

# Scenarios

## 2024 Resource Adequacy Plan – Issues List:

*Regarding NLH's eight Expansion Plan scenarios:*

- *Do the eight scenarios adequately cover a reasonable range of future scenarios for planning purposes?*

# Scenarios

- A total of eight scenarios were developed as the basis for the expansion plan analysis.
- Each scenario included variations of:
  - Island Interconnected System load forecast;
  - LIL bipole EqFOR and corresponding planning reserve margins; and
  - Planning criteria.
- The various combinations formed the basis from which comparisons could be made between scenarios.
  - For example, comparing the impacts between the load forecast scenarios, LIL bipole EqFOR, and capacity planning criteria.
  - Scenario 4 (Minimum Investment Required) represents the minimum commitment to capacity investment.

# Scenarios

| Scenario | Capacity Planning Criteria (LOLH) | LIL Bipole EqFOR (%) | Planning Reserve Margin (%) | Island Interconnected System Load Forecast |
|---|---|---|---|---|
| **1 (Reference Case)** | 2.8 | 5 | 25.8 | Reference |
| **2** | 2.8 | 5 | 25.8 | Accelerated Decarbonization |
| **3** | 2.8 | 5 | 25.8 | Slow Decarbonization |
| **4 (Minimum Investment Required)** | 2.8 | 1 | 17.1 | Slow Decarbonization |
| **5 (Maximum Investment Required)** | 2.8 | 10 | 29.1 | Accelerated Decarbonization |
| **6** | 2.8 | 1 | 17.1 | Accelerated Decarbonization |
| **7** | 0.1 LOLE | 5 | 35.1 | Slow Decarbonization |
| **8** | 2.8 | 100 | 35.0 | Reference |

# Scenarios

- Scenarios 1 (Reference Case), 2, and 3 were developed to directly compare the Island load forecast impacts on the Expansion Plan.
  - Capacity planning criteria, LIL bipole EqFOR, and therefore the calculated planning reserve margin remained constant.
  - Only the Island load forecasts varied between the Reference Case, Accelerated Decarbonization, and Slow Decarbonization load forecasts.

| Scenario | Capacity Planning Criteria (LOLH) | LIL Bipole EqFOR (%) | Planning Reserve Margin (%) | Island Interconnected System Load Forecast | Net Present Value ($ Billions)[1] |
|---|---|---|---|---|---|
| **1 (Reference Case)** | 2.8 | 5 | 25.8 | **Reference** | 5.8 |
| **2** | 2.8 | 5 | 25.8 | **Accelerated Decarbonization** | 8.9 |
| **3** | 2.8 | 5 | 25.8 | **Slow Decarbonization** | 4.1 |

[1] Net Present Value ("NPV") comparison based on expansion plan AEF sensitivities. Please refer to Appendix C, Section 6.3.2.

# Scenarios

- Scenarios 3 and 7 were developed to directly compare the capacity planning criteria of 2.8 LOLH versus the more stringent criteria of 0.1 LOLE and it's impact on the Expansion Plan.
  - The LIL bipole EqFOR remained the same, however the capacity planning criteria differed, resulting in different calculated planning reserve margins.

| Scenario | Capacity Planning Criteria (LOLH) | LIL Bipole EqFOR (%) | Planning Reserve Margin (%) | Island Interconnected System Load Forecast | NPV ($ Billions)[1] |
|---|---|---|---|---|---|
| **3** | **2.8** | 5 | 25.8 | Slow Decarbonization | 4.1 |
| **7** | **0.1 LOLE** | 5 | 35.1 | Slow Decarbonization | 6.4 |

[1] NPV Comparison based on expansion plan AEF sensitivities. Please refer to Appendix C, Section 6.3.2.

# Scenarios

- Scenarios 3 and 4 (Minimum Investment Required) were used to directly compare the impact of LIL Bipole EqFOR on the Expansion Plan.
    - The capacity planning criteria remained at 2.8 LOLH, however the LIL bipole EqFOR varied, resulting in different calculated planning reserve margins.
    - This was tested for LIL Bipole EqFOR of 1% and 5%.

| Scenario | Capacity Planning Criteria (LOLH) | LIL Bipole EqFOR (%) | Planning Reserve Margin (%) | Island Interconnected System Load Forecast | NPV ($ Billions)[1] |
|---|---|---|---|---|---|
| **3** | 2.8 | **5** | 25.8 | Slow Decarbonization | 4.1 |
| **4 (Minimum Investment Required)** | 2.8 | **1** | 17.1 | Slow Decarbonization | 2.8 |

[1] NPV Comparison based on expansion plan AEF sensitivities. Please refer to Appendix C, Section 6.3.2.

# Scenarios

- Scenarios 4 (Minimum Investment Required) and 6 were used to directly compare the impact of high load growth on the Expansion Plan, should reliability of the LIL be the best that can be reasonably anticipated.
  - The capacity planning criteria remained at 2.8 LOLH, the LIL bipole EqFOR, and therefore planning reserve margin remained the same.
  - Only the Island load forecasts varied between the Slow Decarbonization and Accelerated Decarbonization.

| Scenario | Capacity Planning Criteria (LOLH) | LIL Bipole EqFOR (%) | Planning Reserve Margin (%) | Island Interconnected System Load Forecast | NPV ($ Billions)[1] |
|---|---|---|---|---|---|
| **4 (Minimum Investment Required)** | 2.8 | 1 | 17.1 | **Slow Decarbonization** | 2.8 |
| **6** | 2.8 | 1 | 17.1 | **Accelerated Decarbonization** | 6.6 |

[1] NPV Comparison based on expansion plan AEF sensitivities. Please refer to Appendix C, Section 6.3.2.

# Scenarios

- Scenario 5 (Maximum Investment Required) represents the scenario requiring the maximum investment based on a low level of LIL reliability (10% LIL bipole EqFOR) and the highest load growth (Accelerated Decarbonization) reasonably anticipated on the Island Interconnected System.
  - This scenario is intended to bookend the Expansion Plan scenarios by identifying the Maximum Investment Required on the Island Interconnected System.

| Scenario | Capacity Planning Criteria (LOLH) | LIL Bipole EqFOR (%) | Planning Reserve Margin (%) | Island Interconnected System Load Forecast | NPV ($ Billions)[1] |
|---|---|---|---|---|---|
| **4 (Minimum Investment Required)** | 2.8 | **1** | 17.1 | **Slow Decarbonization** | 2.8 |
| **5 (Maximum Investment Required)** | 2.8 | **10** | 29.1 | **Accelerated Decarbonization** | 10.1 |

[1] NPV Comparison based on expansion plan AEF sensitivities. Please refer to Appendix C, Section 6.3.2.

# Scenarios

- Scenario 1 (Reference Case) represents the scenario requiring the expected investment on the system compared to Scenario 8 where the LIL does not provide any capacity benefit to the Island (i.e., an Energy-Only line) to determine the Expansion Plan and level of investment required.
  - The capacity planning criteria remained at 2.8 LOLH; however, the LIL bipole EqFOR varied, resulting in different calculated planning reserve margins.
  - This was assessed for LIL Bipole EqFOR of 5% and 100%.

| Scenario | Capacity Planning Criteria (LOLH) | LIL Bipole EqFOR (%) | Planning Reserve Margin (%) | Island Interconnected System Load Forecast | NPV ($ Billions)[1] |
|---|---|---|---|---|---|
| **1 (Reference Case)** | 2.8 | **5** | 25.8 | Reference | 5.8 |
| **8** | 2.8 | **100** | 35.0 | Reference | 8.2 |

[1] NPV Comparison based on expansion plan AEF sensitivities. Please refer to Appendix C, Section 6.3.2.

# Scenarios: Decarbonization Goals

**2024 Resource Adequacy Plan – Issues List:**

*Regarding NLH's eight Expansion Plan scenarios:*

- *Should full compliance with legislatively imposed decarbonization goals be a requirement of a Recommended Expansion Plan?*

# Scenarios: Decarbonization Goals

- The *Electrical Power Control Act* was recently modified to provide the ability for consideration of the environment. Legislation now reads:

3. (b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner…

> (iii) that would result in power being delivered to consumers in the province at the lowest possible cost, **in an environmentally responsible manner**, consistent with reliable service.

- In addition, the Government of Canada's draft Clean Electricity Regulations ("CER") are a key consideration in Hydro's evaluation of potential new sources of generation.

# Scenarios: Decarbonization Goals

- Hydro recognizes it’s goal of minimizing its environmental footprint by using less fossil fuel generation must be balanced with the goal of maintaining a reliable system at lowest possible cost.
- Scenario 4 (Minimum Investment Required) aligns with legislatively imposed decarbonization goals; however, they are not the driver.
- Scenario 4 (Minimum Investment Required) represents the least-cost resource options to meet reliability requirements.
    - This expansion plan aligns with the draft CER requirements, but was not modified to meet these requirements.
    - Hydro is confident that it will be able to comply with the draft CER, even with the addition of a 150 MW CT.
- Should Hydro convert the CT to burn renewable fuel in the future, the unit will have increased flexibility to generate more, should it be economical.
    - Conversion would not occur unless it was proven to be least-cost compared to burning diesel fuel.
- Hydro continues to monitor the progress of the draft CER, as well as all other provincial and federal energy policy developments.

# Sensitivities

# Sensitivities

**2024 Resource Adequacy Plan – Issues List:**

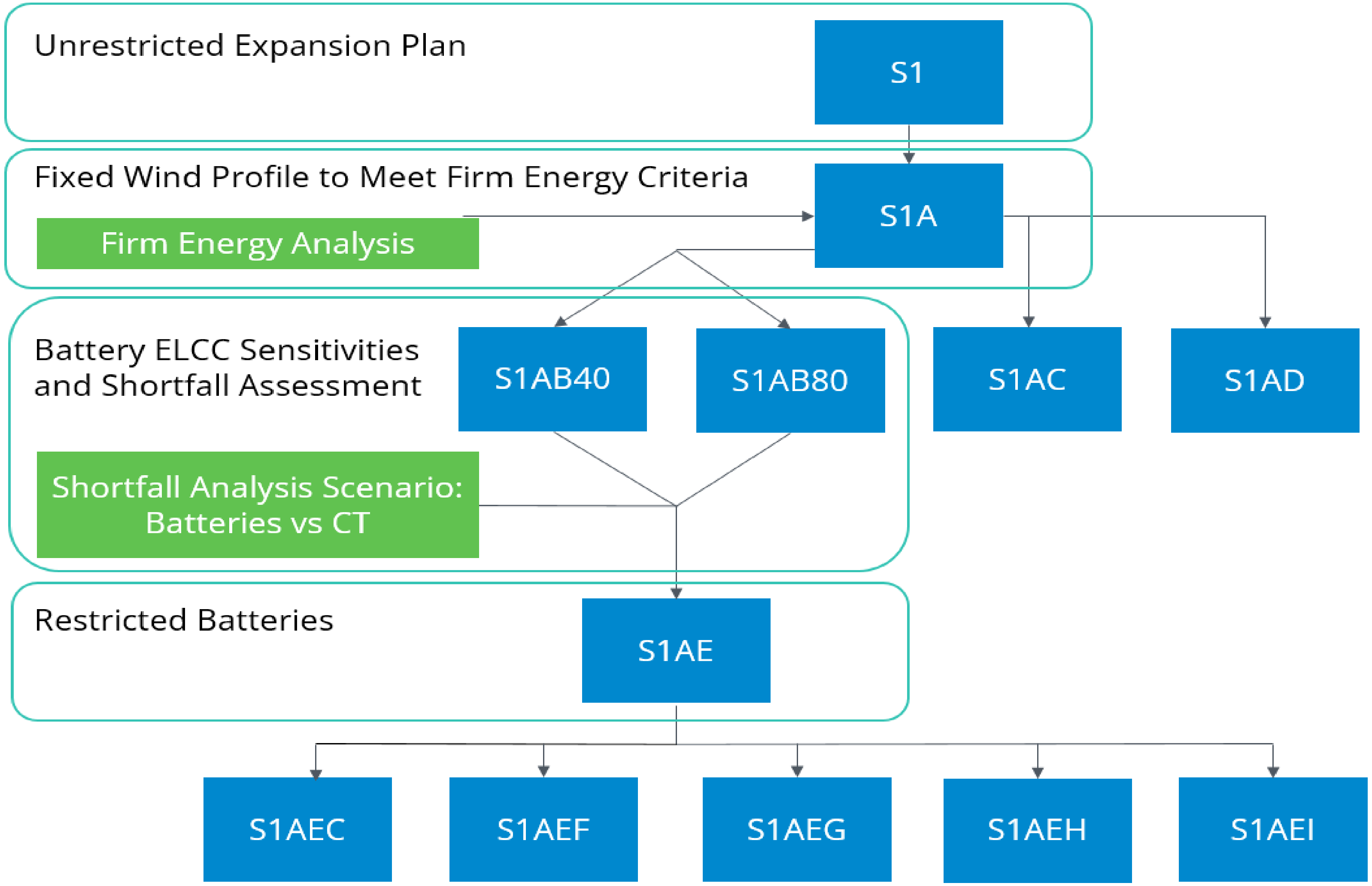
*Regarding NLH’s eleven Expansion Plan Sensitivities:*

- *Do the eleven scenarios adequately cover a reasonable range of futures for key variables for planning purposes?*

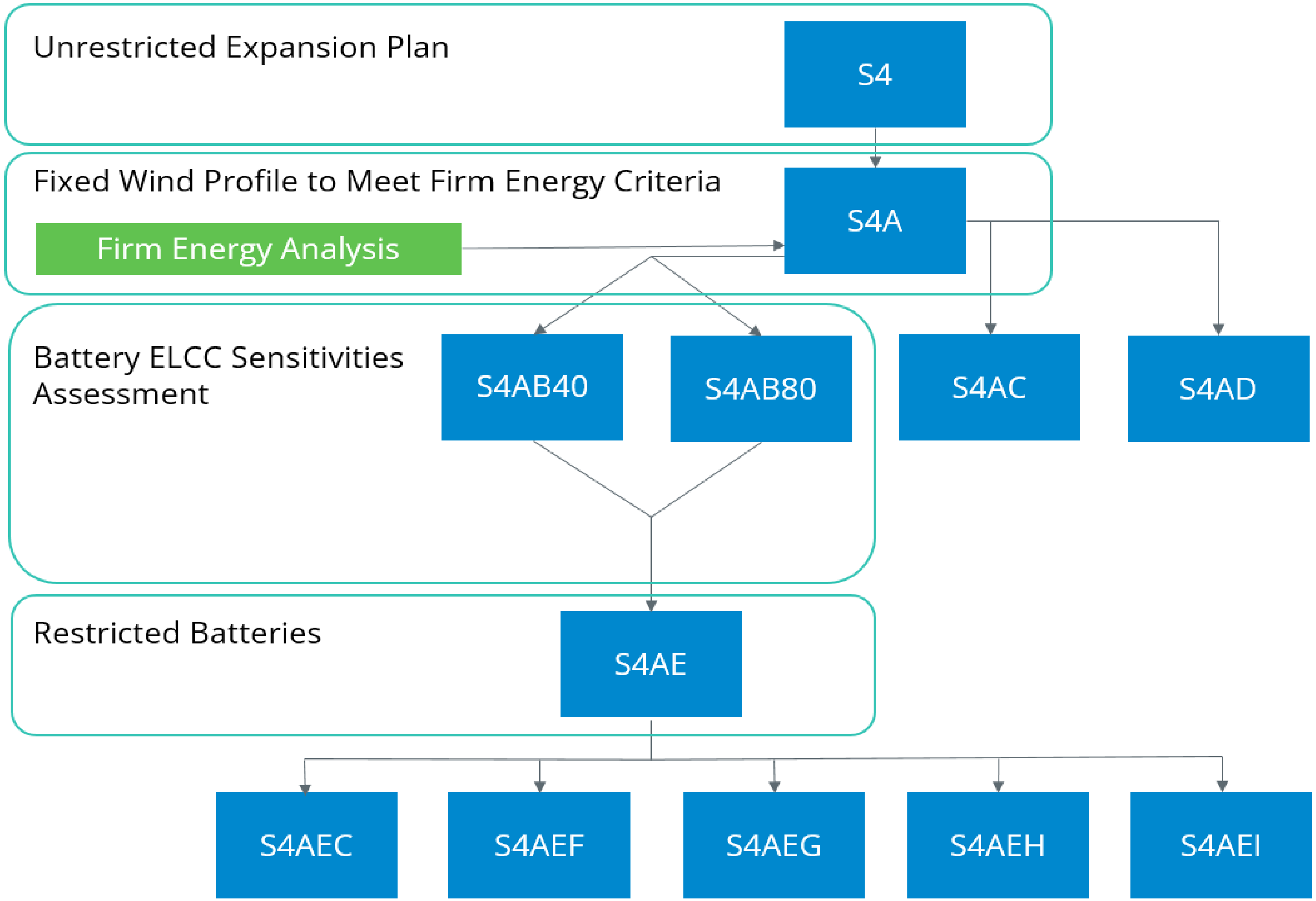
# Sensitivities

| | Sensitivity | Description |
|---|---|---|
| 1 | A | Fixed wind profile to meet firm energy criteria |
| 2 | AB40 | Same as Sensitivity A with an assumed battery ELCC of 40% |
| 3 | AB80 | Same as Sensitivity A with an assumed battery ELCC of 80% |
| 4 | AC | Same as Sensitivity A and removes forced CT fuel burn-off in consideration of the potential for contract negotiation and/or shelf life extension negating this requirement |
| 5 | AD | Same as Sensitivity A with the exception of increasing all Hydro capital costs by 50% in consideration of potential cost overruns |
| 6 | AE | Same as Sensitivity A and removes batteries as a resource option |
| 7 | AEC | A combination of Sensitivities A, AC, and AE to determine the impact of removing forced CT fuel burn-off in consideration of restricting batteries as a resource option |
| 8 | AEF | Same as Sensitivity AE with the additional restriction of limiting CT additions to 150 MW in consideration of current diesel fuel limitations on the Island |
| 9 | AEG | Same as Sensitivity AE with the exception of increasing CT fuel costs by 50% in consideration of potential future volatility in fuel costs |
| 10 | AEH | Same as Sensitivity AE with the exception of increasing CT capital costs by 50% in consideration of potential cost overruns |
| 11 | AEI | Same as Sensitivity AE with the addition of the potential Newfoundland Power 25 MW CTs in the years 2028, 2029, and 2030 |

# Sensitivities: Scenario 1 (Reference Case)



# Sensitivities: Scenario 4: (Minimum Investment Required)



# Sensitivities: Fixed Wind Profile

**2024 Resource Adequacy Plan – Issues List:**

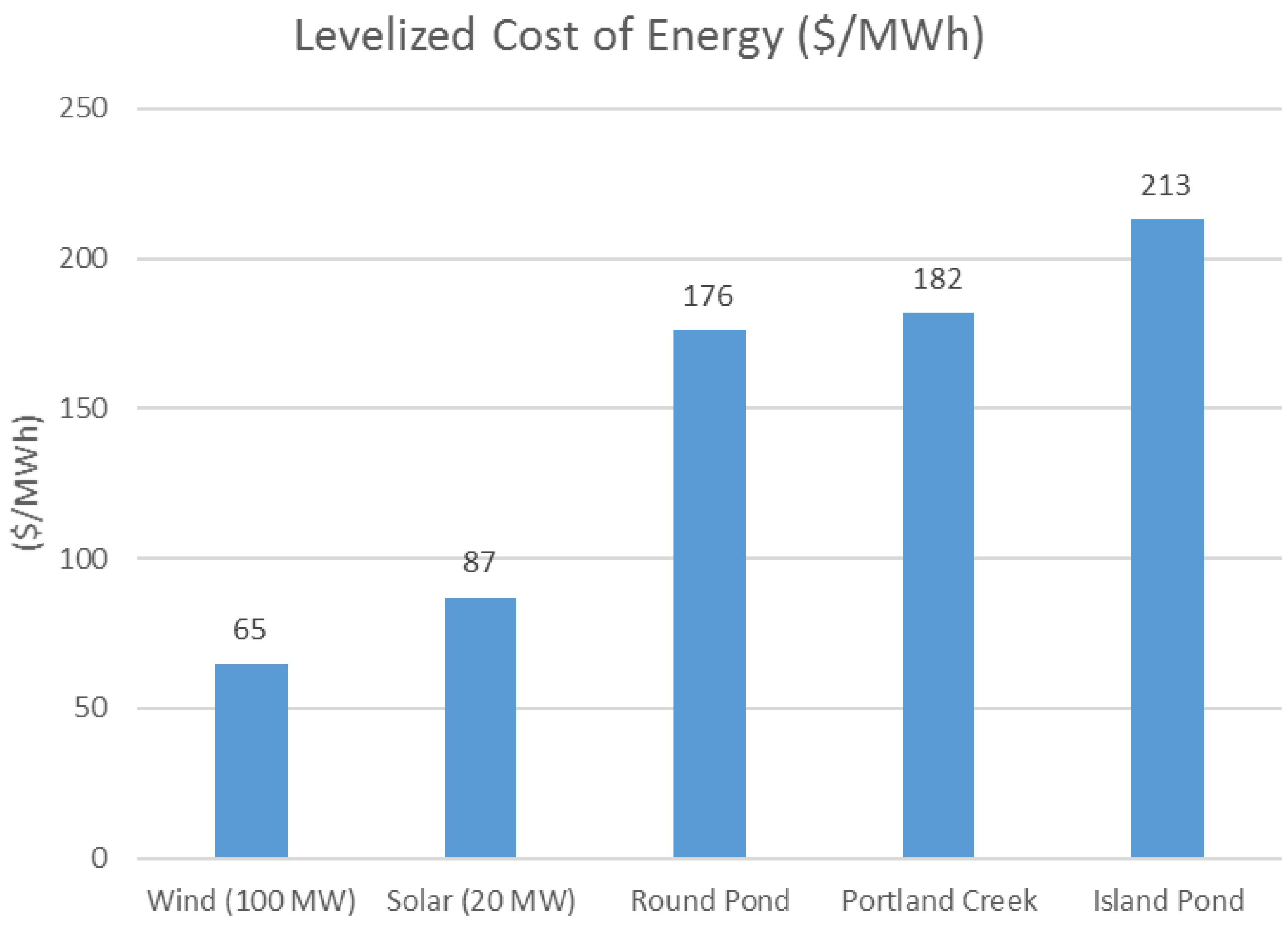
*Regarding NLH's eleven Expansion Plan Sensitivities:*

- *Sensitivity A forces the Expansion Model to include sufficient new wind resource to meet firm energy criteria and is carried through in every other scenario, other than the "unrestricted" scenario. Is it reasonable to select wind as the sole technology option to provide firm energy?*

**Assessment of 2024 Resource Adequacy Plan:**

- *Further explore and justify the forced inclusion of wind resources in all sensitivity designs (#43).*

# Sensitivities: Fixed Wind Profile



# Sensitivities: Fixed Wind Profile

- The first step in the expansion plan analysis was to run an unrestricted expansion plan where known constraints were ignored and the Expansion Model was enabled to determine the least-cost expansion plan.
  - This was done for Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required).
- The unrestricted run demonstrated that wind was the least-cost energy solution for each of these scenarios.
  - Other energy providing resource options included greenfield hydro (Island Pond, Round Pond, and Portland Creek) and solar; however, they were not selected by the model as least-cost energy options.

# Sensitivities: Fixed Wind Profile

- In the unrestricted expansion plan, while the Island Interconnected System capacity needs are met, does not meet the firm energy criteria requirement.
- Scenario 4A (Fixed Wind Profile) does meet the firm energy criteria requirement.
- The difference between each sensitivity is highlighted below for Scenario 4 (Minimum Investment Required).

| Scenario | Sensitivity | Resource | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|
| Scenario 4 | Unrestricted | Wind 100 MW | 0 | 1 | 2 | 3 | 3 |
| Scenario 4 | A (Fixed Wind) | Wind 100 MW | 1 | 4 | 4 | 4 | 4 |
| | | Delta | 1 | 3 | 2 | 1 | 1 |

# Sensitivities: Forced Fuel Burn-off

**2024 Resource Adequacy Plan – Issues List:**

*Regarding NLH's eleven Expansion Plan Sensitivities:*

- *Some sensitivities (e.g., AC), remove the baseline assumption that a new CT will be required to burn off ten days of fuel storage each year. Has NLH sufficiently explained the basis, costs, operational specifics, and alternatives for this assumption?*
  - The response to this question was covered during in Technical Conference #2.

**Assessment of 2024 Resource Adequacy Plan:**

- *Further review and justify the annual fuel burn-off assumption which provides the need for sensitivity AC (#44).*

# Sensitivities: Forced Fuel Burn-off

- Hydro’s assumption is based on fuel degradation and aligns with the Fuel Market Study provided by Hatch.
- Front-end engineering design (“FEED”) process will further explore alternatives to ten day burn-off assumption.
  - Also exploring contractual arrangements to avoid fuel burn-off.
- To be transparent in capturing appropriate costs associated with the CT, Hydro included the cost of having to burn the fuel annually.
- Should an alternate arrangement be found, this could result in a cost savings.
  - Expected generation is between 15–25 GWh annually, compared to 34 GWh in the ten day burn off scenario.

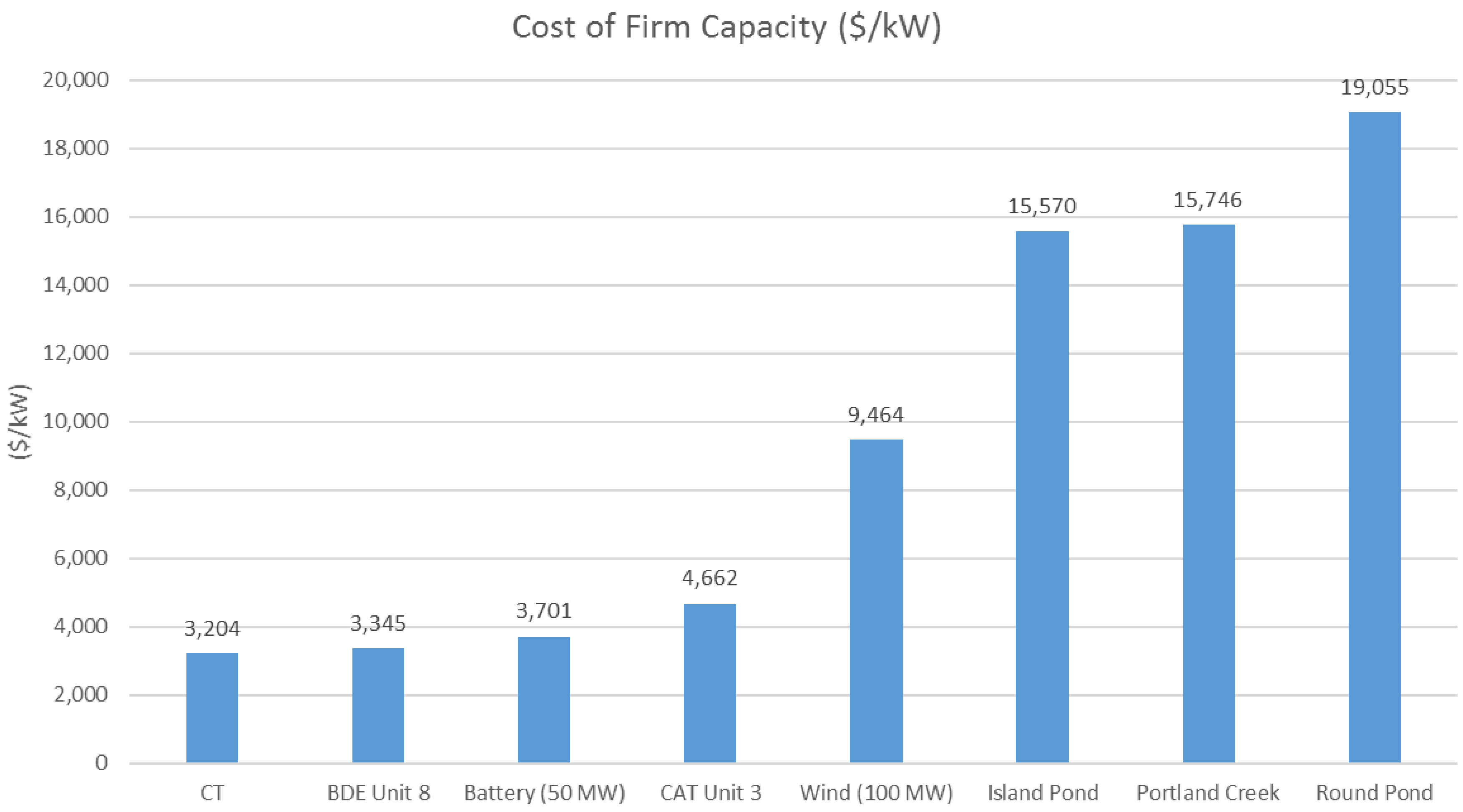
# Sensitivities: Cost Estimate Increases

**2024 Resource Adequacy Plan – Issues List:**

*Regarding NLH's eleven Expansion Plan Sensitivities:*

- *Is the assumption within Sensitivity AD that all hydro capital costs increase by 50% sufficient to do so?*
- *Should a scenario be completed that includes increases in both the capital cost and the fuel cost for a CT?*

# Sensitivities: Capital Cost of Firm Capacity



# Sensitivities: Cost Estimate Increases

- Costs included in the Resource Adequacy Plan are defined as AACE Class 5 estimate level, which is appropriate for screening level studies.
- Ongoing FEED activities will refine estimates to a AACE Class 3 level, which will be provided in the build application(s).
  - Hydro will rerun expansion model with the AACE Class 3 costs to support build application(s).
- An expansion plan was run (Sensitivity AD) that fixed the wind profile and increased the hydro capital costs by 50%.
  - Increasing the Hydro capital costs by 50% is enough to trigger the CT to be the least-cost capacity resource compared to BDE Unit 8.
  - Increasing the Hydro capital costs by more than 50% will not change this outcome.
  - Regardless of relative ranking, both capacity options are required in Minimum Investment Required Expansion Plan and the Reference Case.

# Sensitivities: Cost Estimate Increases

- A new sensitivity (Scenario 4AEGH) was completed that includes increases in both the capital cost and the fuel costs associated with a CT by 50%.
  - Scenario 4AEGH: Slow Decarbonization, fixed wind, no batteries, CT fuel costs +50% and CT capital costs +50%.
- There is no change to the expansion plan result when both the CT fuel costs and capital costs are increased.

| | Firm Capacity (MW) | Firm Energy (GWh) | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|
| BDE Unit 8 | 154.4 | 0 | | 1 | 1 | 1 | 1 |
| CT | 141.6 | 0 | | | | | 1 |
| Wind | 22 | 350 | 1 | 4 | 4 | 4 | 4 |
| Firm Capacity (MW) | | | 22 | 242 | 242 | 242 | 384 |
| Firm Energy (GWh) | | | 350 | 1400 | 1400 | 1400 | 1400 |

# Sensitivities: Limiting Resource Selections

**2024 Resource Adequacy Plan – Issues List:**

*Regarding NLH's eleven Expansion Plan Sensitivities:*

- *Some sensitivities limit the resources available to the Expansion Model, including sensitivities AE (which excludes BESS resources) and AEF (which limits CT additions to 150 MW or less). Are these important risks to consider and do the sensitivities reasonably capture those risks?*

# Sensitivities: Limiting Resource Selections

- Hydro modelled BESS at an ELCC of 40%, 60% and 80%, which is in line with the ELCC range assumed by industry.
  - At 40% ELCC, the model did not select batteries.
  - Batteries would have limited effectiveness in a shortfall situation but may be effective for capacities of up to 50 MW.
    - There would be limited energy to allow for recharging of the batteries, particularly at higher penetrations.
  - Eight-hour batteries would have minimal incremental benefit in a shortfall situation.
  - Batteries likely have a place in Hydro's generation fleet to meet the Reference Case, but require further study.

# Sensitivities: Limiting Resource Selections

- To meet Reference Case requirements, Hydro is committed to further study of battery ELCC to inform the next Resource Adequacy Plan.
- Hydro is planning to perform an ELCC study in 2025.
    - Will study BESS in conjunction with wind and solar.
    - Will demonstrate the relationship between:
        - Renewable penetration and ELCC.
        - Battery storage duration and ELCC.

# Sensitivities: Limiting Resource Selections

- Should fuel (renewable or otherwise) become more readily available, the implications for resource selection in the expansion model were analyzed.
  - All sensitivities prior to Scenario "AEF" did not restrict the number of CTs that could be constructed.
  - With information that is known today, it has been determined that fuel availability is limited to support only 150 MW of CTs.
- For Scenario 4 (Minimum Investment Required), when the model was not restricted, it only selected one 150 MW CT to be constructed during the period.
- Increasing the diversity of resource options on the electrical system is a mitigation strategy to Hydro's risk regarding fuel limitations.

# Sensitivities: Key Learnings

- For both scenarios tested, BDE Unit 8 is consistently being chosen by the model as the least-cost expansion option; however, CTs are cost-competitive to BDE Unit 8.
- When tested further, BDE Unit 8 remained the preferred expansion option if:
  - Fuel cost for CT increased by 50%.
  - The capital cost of the CT increased by 50%.
  - Both the CT fuel cost *and* the CT capital cost increased by 50%.
- When tested further, CT was the preferred expansion option if:
  - The forced annual burn-off was removed.
  - The capital cost of hydraulic expansion options increased by 50%.

# Scenario 4: Minimum Investment Required

# Scenario 4

**2024 Resource Adequacy Plan – Issues List:**

*Regarding NLH's eight Expansion Plan scenarios:*

- *Does Scenario 4 reasonably capture the most conservative case (i.e., the lowest forecasted capacity and energy needs) for use in the Recommended Expansion Plan?*

# Scenario 4

- Hydro's Scenario 4 (Minimum Investment Required Expansion Plan) is driven by meeting three resource planning criteria:
  1. Probabilistic Capacity
     - The Island Interconnected System should have sufficient generating capacity to satisfy a LOLH expectation target of not more than 2.8 hours per year.
  2. Firm Energy Requirement
     - The Island Interconnected System should have sufficient generating capability to supply all its firm energy requirements with firm system capability.
  3. LIL Shortfall Assessment
     - The Island Interconnected System should have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL-shortfall event.

# Probabilistic Capacity Criteria

- Determining the probabilistic capacity requirement involves calculating a planning reserve margin.
- Planning reserve margin key drivers include:
  - Planning Criteria; and
  - LIL Bipole EqFOR.
- Scenario 4 (Minimum Investment Required) inputs include:
  - Slow Decarbonization Load Forecast;
  - 2.8 LOLH Planning Criteria; and
  - LIL Bipole EqFOR of 1%.
- Resultant planning reserve margin of 17.1% (360 MW).

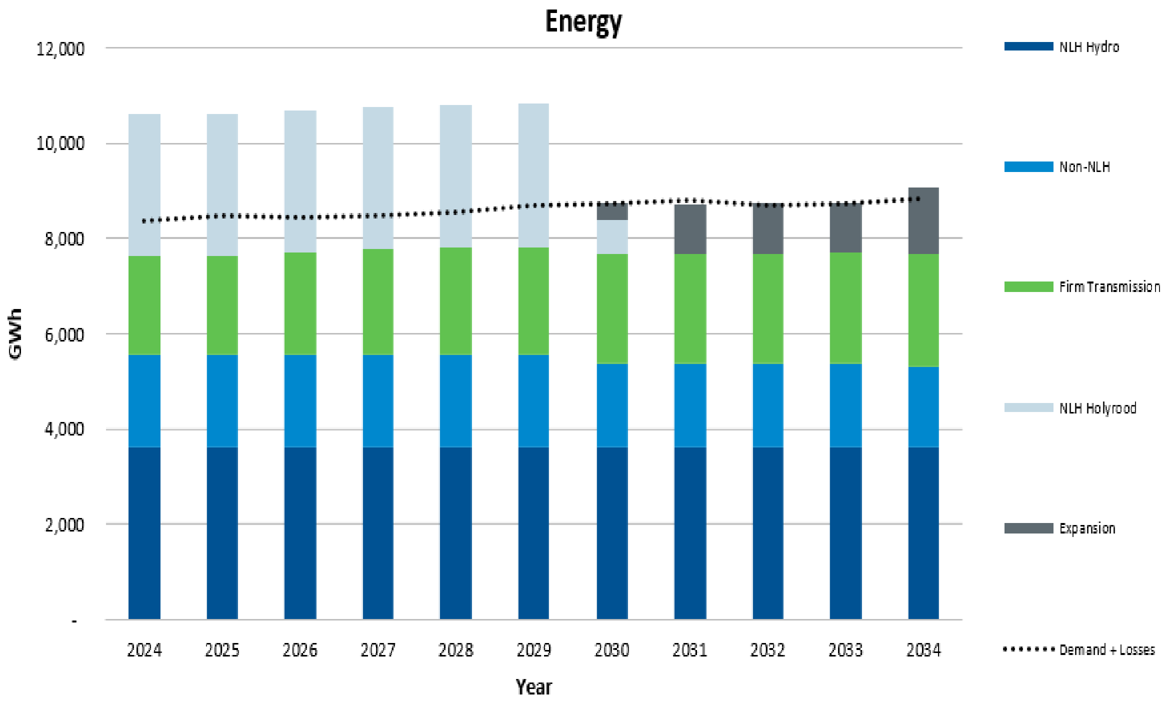
# Firm Energy Criteria

- The firm energy requirements are a function of Island load.
- Firm energy requirements to meet the Slow Decarbonization load forecast are 1.4 TWh by 2034.
- The table below compares the firm energy requirements against the three load forecast scenarios for 2034:

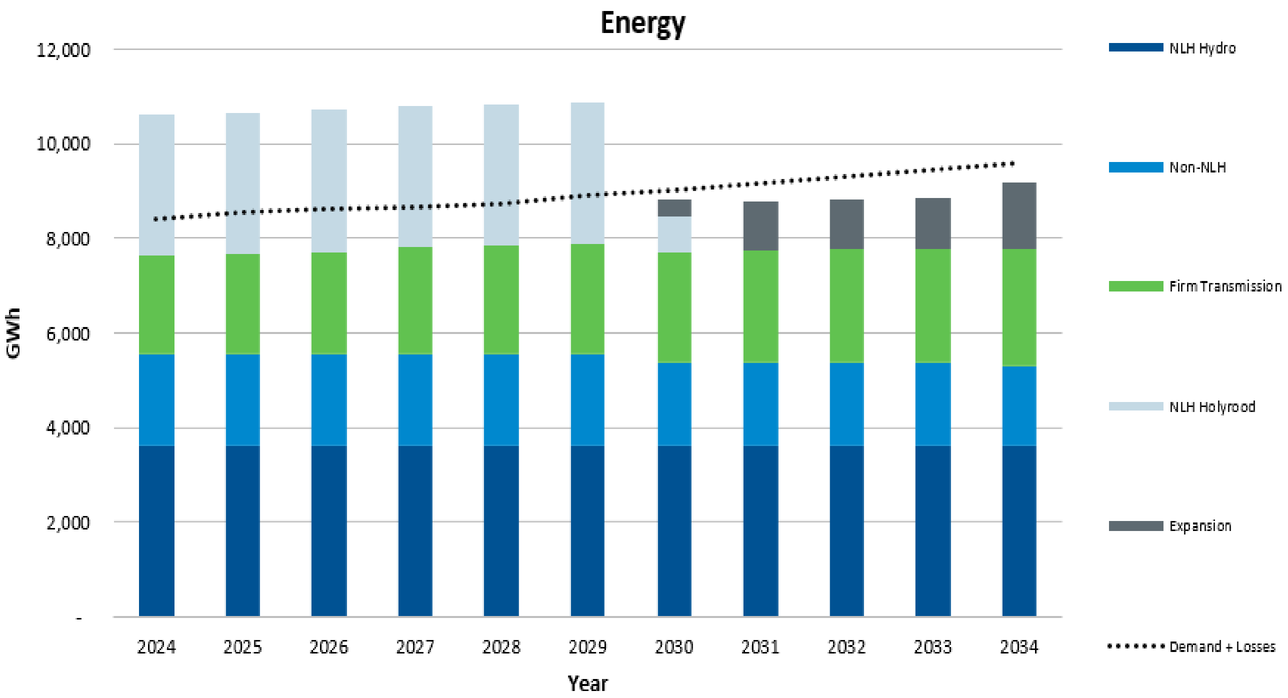
| Resource | Firm Energy (TWh) | Delta (TWh) |
|---|---|---|
| Slow Decarbonization | 1.40 | - |
| Reference Case | 1.75 | 0.35 |
| Accelerated Decarbonization | 2.45 | 1.05 |

# Scenario 4: Firm Energy Criteria

## Energy Load Resource Balance: Slow Decarbonization



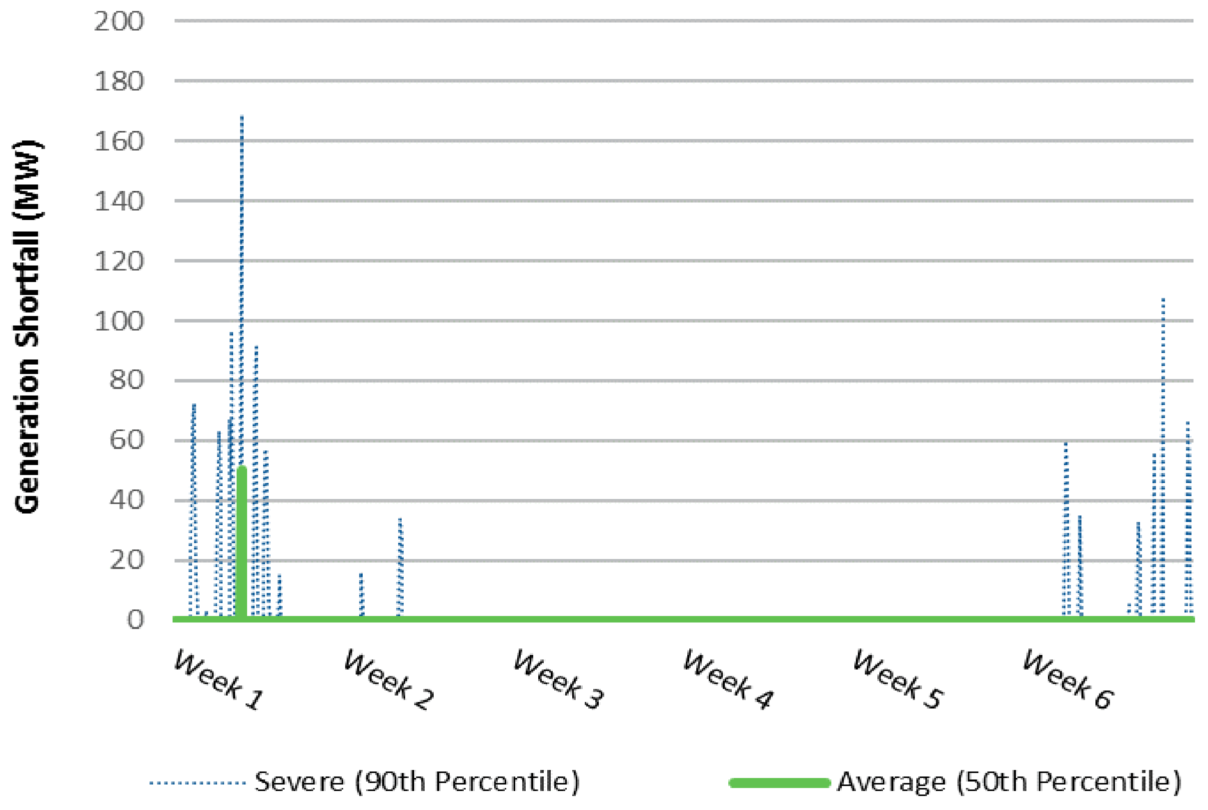

## Energy Load Resource Balance: Reference Case




- The firm energy requirements between the Slow Decarbonization and Reference Case load forecast is 350 GWh, or one 100 MW wind build.

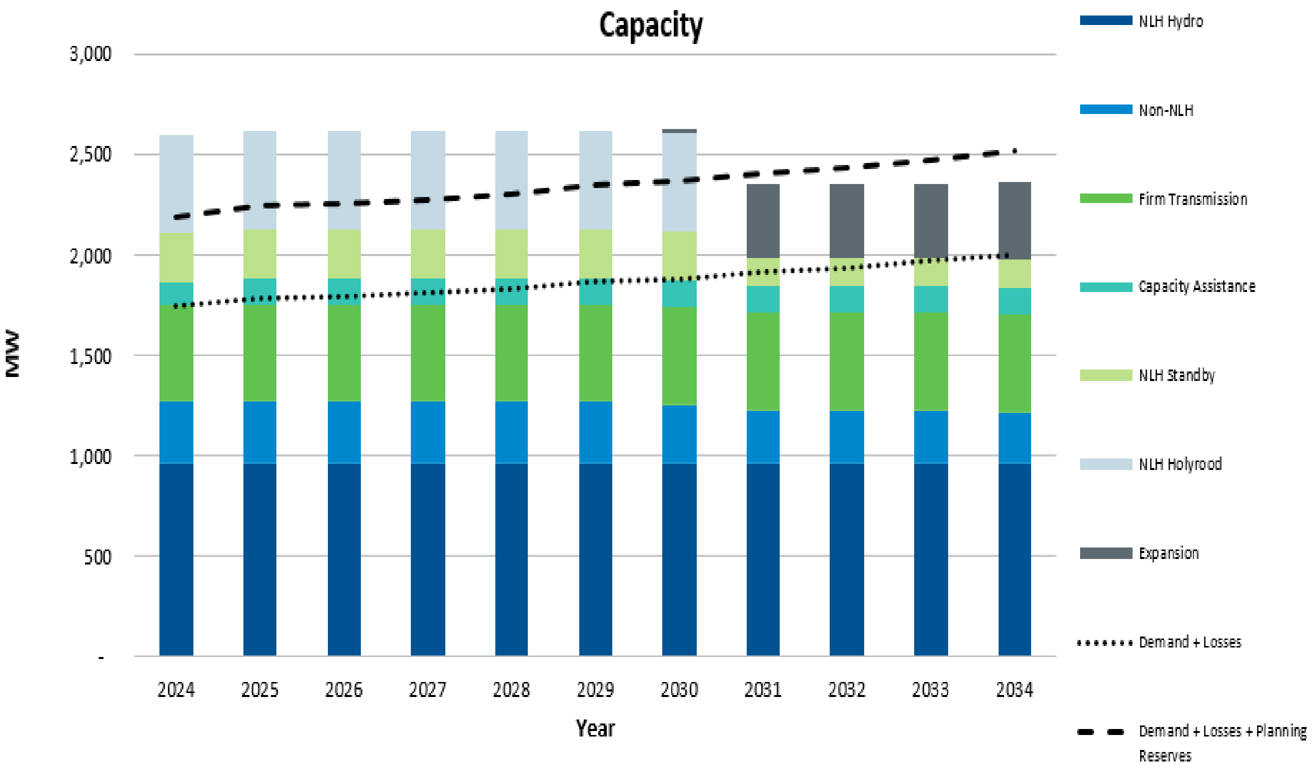
# LIL-Shortfall Assessment

- Hydro is planning to meet the average case (50th percentile) where a supply shortfall of 100 MW or higher is not experienced.
  - In the severe case, a supply shortfall of 100 MW or higher is expected only 0.2% of the time.



# Recommended Expansion Plan

- Capacity Load Resource Balance Plot: Scenario 1 (Reference Case) versus Scenario 4 (Minimum Investment Required) expansion plan.
- Table reflects the annual capacity, including the capacity from the resources identified in the Minimum Investment Required expansion plan, compared to the additional capacity needed to meet the Reference Case.

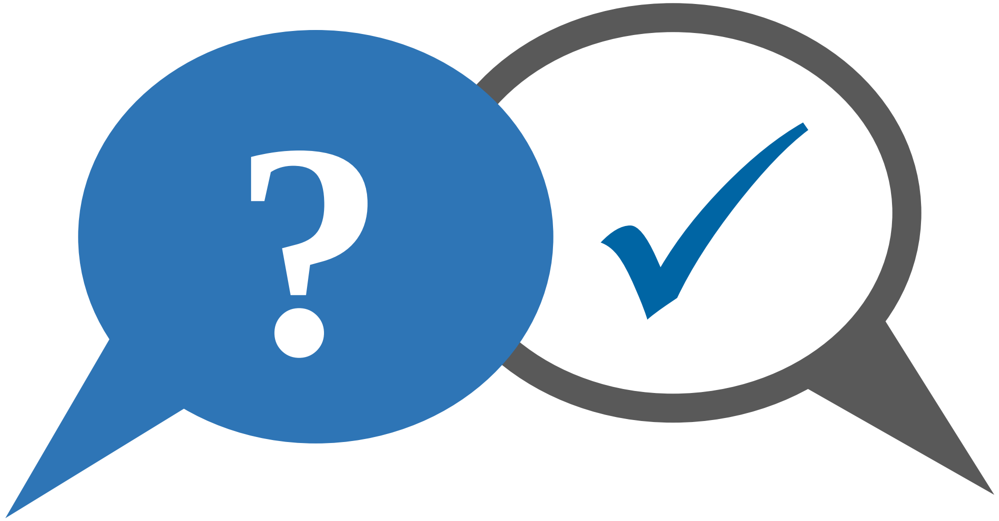



| | Capacity Required per Year (MW) | | | |
|---|---|---|---|---|
| **Scenario** | **2031** | **2032** | **2033** | **2034** |
| 4 (Minimum Investment Required) | 2,347 | 2,347 | 2,347 | 2,361 |
| 1 (Reference Case) | 2,408 | 2,437 | 2,475 | 2,515 |
| **Capacity Delta (MW)** | **-61** | **-90** | **-128** | **-154** |

# Issues 5 and 6: Hydro's Position

- Hydro endeavoured to ensure that sufficient data has been provided, outlining the reasonableness of assumptions and inputs.
- Hydro has outlined the expansion plan process, including the 8 expansion plan scenarios and 11 expansion plan sensitivities that were developed.
- The analysis of these scenarios and sensitivities helped Hydro define key learnings regarding both energy and capacity requirements during the study period that ultimately concluded with the recommendation of the Minimum Investment Required Expansion Plan.
- Hydro firmly believes that the Minimum Investment Required Expansion Plan represents the first step to meet the Island Interconnected System reliability needs.
- The underlying assumptions of the Minimum Investment Required Expansion Plan capture the most conservative case, and are appropriate as Hydro continues to plan to meet the requirements of the Reference Case Expansion Plan.

# Questions?



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