Prince Edward Island Resource Planning and Maritime Electric Capital Expenditures

Alternatives to MECL Integrated System Plans and Impact on MECL Capital Expenditures

Prepared for the PEI Regulatory and Appeals Commission

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AUTHORS

Bob Fagan
Shannon Liburd
Shelley Kwok

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

EXECUTIVE SUMMARY

Synapse Energy Economics reviewed Maritime Electric Company Ltd.'s (MECL) September 2020 Integrated System Plan (ISP) and completed an assessment of alternative system plans to the filed ISP. Synapse also reviewed MECL's 2022 Capital Budget Application and 2021 Supplemental Capital Budget Application, with a particular focus on the supply resource considerations in both applications.

Our resource analyses illustrate the importance of considering non-conventional, though commercially mature and economically attractive, alternatives to meeting systemwide peak and annual electric energy needs. MECL and Prince Edward Island as a whole depend considerably on import energy from New Brunswick. While that dependency will remain, and is beneficial to a large extent, there are clearly modifications to quantities and purchase timing that could reduce overall system costs to MECL (and potentially Summerside) ratepayers. Alternative ISPs will affect the pattern, amount, and type of MECL capital expenditure requirements.

MECL Integrated System Plan

MECL's ISP contains proposed resource plans that include a new combustion turbine (CT) at the Charlottetown Thermal Generating Station (CTGS) site, and proposed improvements to the transmission and distribution (T&D) system based primarily on equipment condition (age) and requirements arising from load growth projections. The supply resource plan suggests a new CT at the CTGS site, but MECL indicates that a full economic analysis of options has not yet been performed.

The ISP does not support battery resource installation as a capacity resource, seemingly based on economic concerns. However, MECL provides no comparative data or evidence, particularly to address recent rapid cost reductions in the utility battery energy storage industry.

The ISP also uses current (2018–2021) electricity efficiency and conservation plan (EE&C) inputs to inform its load forecast (along with reasonable considerations of electrification load additions). Newer electricity efficiency forecasts arising from the Dunsky potential study[1] and including projected effects from demand response will, or could, substantially reduce the PEI peak load growth trend reflected in the ISP.

These two factors—the load forecast (and underlying drivers) and the comparative economics of battery storage resources as on-Island capacity options—will affect the outcome of any updated ISP or the currently planned on-Island generating supply study. Medium- and longer-term needs for the T&D

[1] Dunsky, *Prince Edward Island Energy Efficiency Potential Study: A Comprehensive Assessment of Energy Efficiency and Demand Response Opportunities 2021-2030*, Volume I (Final Results) and Volume II (Appendices). Prepared for efficiencyPEI, April 2021.

system could also be affected by any reductions in the peak load trend seen in MECL's ISP due to updated EE&C plans.

Impact on Projected Capital Expenditures

The 2022 Capital Budget Application included plans for consideration of a new CT at the site of the retiring Charlottetown steam plant, separate from any Borden combustion turbine replacement need upon its retirement at the end the decade. The 2021 Supplemental Capital Budget Application contained a Long-Term Site Plan for the CTGS location that includes a provision for a new CT. The 2022 Capital Budget Application also calls for investment in T&D system assets, based on equipment and lifetime considerations, and also on planned levels of load growth. The largest near-term capital expenditure affected by our review of the ISP is the planning for a fourth CT (CT4) at CTGS.

Future capital expenditures for certain transmission needs driven by overall PEI peak load growth, and future distribution system needs premised on across-the-board feeder-level peak load increases, can potentially be deferred if or as the overall island-wide peak load growth is mitigated by both efficiency and demand response resources. To the extent that a portion of the battery resources we find to be optimal for installation on PEI over the next decade are strategically placed around the island as distributed battery storage, capital expenditure needs on T&D systems due to load growth may be reduced; however, the distributed resources themselves would become a different type of capital expenditure for which MECL will need to plan.

Alternative System Plans

Our analyses of alternative system plans, in comparison to MECL's September 2020 ISP, reveal the following:

1. The lowest cost plans contain increased levels of energy efficiency and peak load reduction through cost-effective electricity efficiency deployment, as represented by Prince Edward Island Energy Corporation's proposed update to its EE&C plan. That plan includes at least a rough doubling of the savings available from energy efficiency technologies.

    - Demand-side management (DSM) inclusive plans cost 16–18 percent less overall (net present value basis, 25-year period) regardless of whether or not the remaining resources are optimally procured.

2. Optimizing the resource choices available to MECL leads to modifying the mix of both capacity and energy resources required over the next 25 years, independent of the effect of lower load through DSM deployment.

    - Optimized plans cost 7–10 percent less overall (net present value basis, 25-year period) than unoptimized plans, across both base- and lower-load-level scenarios.

- On-Island installation of battery energy storage resources allows for both reduction in purchased capacity from New Brunswick Power (NB Power), and a reduction in the cost of import energy purchases by leveraging the time value of electricity. By 2030, the optimized cases see up to 160 MW of battery energy storage deployed on PEI, with deployments occurring annually beginning within the next few years.

- By 2030, MECL will likely see reductions in New Brunswick capacity purchases on the order of more than 50 MW, as battery installations and the impact of DSM load reductions are captured.

- Modeling shows that even though overall quantities of net purchased energy from New Brunswick remain similar between our base and optimized cases, the overall costs are considerably lower because MECL and PEI can avoid the highest price import energy by economically scheduling the charging and discharging of battery resources.

3. Capital expenditures for new generation resources on the island should likely focus first on battery rather than CT resources, especially as DSM program implementation helps to reduce (or slow any increase) of peak load on the island.

4. The modeled scenarios presume an increase of 30 MW of new wind energy in 2023, and 40 MW of new wind energy in 2025. Beyond those planned installations, the core optimized scenarios do not add any additional wind resources on PEI. That result is dependent on both the continuing existence of relatively low-cost energy from New Brunswick, and no new stringent requirement that PEI obtain much greater levels of electric energy from renewable resources. If either of those circumstances change, increasing the amount of wind energy on PEI is likely to be an optimal outcome. We see an increase in on-Island wind builds of up to 120 MW in our New Brunswick high energy price scenario, with additional wind coming online during the 2030 decade.

1. Introduction and Background

Prince Edward Island's electricity sector is dependent primarily on two sources of electric energy: on-Island wind resources and imports from New Brunswick's system. The latter includes specific purchases from the Point Lepreau nuclear facility and procurement from NB Power resources in aggregate (which in addition to the nuclear energy, consists of coal, oil, and gas-fired power stations; hydroelectric and wind resources; and imports from New England and Nova Scotia). Two new submarine cable installations in 2017 reinforced PEI's capability to reliably import energy from New Brunswick, supplementing the two existing cables which had been operating for over 40 years. While older on-Island fossil-fired generation serves as backup capacity, PEI obtains essentially all of its energy, and most of its day-to-day capacity requirements from those two primary energy sources.

PEI is in the process of increasing the use of heat pumps to provide supplementary or primary winter heating needs, and the presence of electric vehicles (EV) has begun to increase on the island.[2] Both of these end uses will increase the amount of electricity consumed, and they will potentially increase the winter peak load period capacity requirements on the island. Simultaneously, increased efficiency of electricity use continues, through market availability of higher efficiency products and through efficiencyPEI incentive offerings that support installation of more efficient products.

In combination, these two forces result in a net consumption trend for electricity that in recent years has been slightly increasing, but in future years could flatten, see a net decline, or maintain an increasing consumption trend, to some degree. How these two sets of driving factors play out will determine the overall electric resource needs for PEI. This analysis examines these trends, analyzes Maritime Electric Company Limited's (MECL) current planning environment, and contains cost and resource trajectory comparisons of alternative system plans that rely to a greater extent on island resources, and a lesser extent on New Brunswick imports, relative to MECL's 2020 Integrated System Plan (ISP).

1.1. Scope of Work

Synapse Energy Economics, Inc. (Synapse) was engaged by Carr, Stevenson & MacKay (CSM) and the Prince Edward Island Regulatory and Appeals Commission (IRAC) to examine alternatives to MECL's ISP as put forward in September of 2020.[3] Alternatives to MECL's filed ISP could have an impact on MECL's planned pattern of capital expenditures reflected in MECL's 2022 Capital Budget Application Filing (and related documents including the 2021 Supplemental Capital Budget Application filing) especially those

[2] MECL, ISP pages i and 5.

[3] MECL, Integrated System Plan, September 2020.

planned expenditures tied to projected increases in overall system peak load, and associated increases at individual distribution system feeder granularity.

The core tasks undertaken by Synapse included the following:

- Review of MECL's 2020 ISP, 2022 Capital Application Filing, and 2021 Supplemental Application for the CT3 building and CTGS 9/10 steam plant building demolition. Review of related documents as necessary (e.g., portions of the approved February 2021 Capital Application).

- Development of interrogatories directed to MECL and review of MECL's responses. While no technical conference or informal session with MECL has been held (as of the end of April, 2022), this remains an option to help reconcile any technical inconsistencies that may arise. The purpose of these data requests was to support ISP alternatives analyses.

- Analysis of ISP elements and development of alternative planning scenarios, including Synapse use of the EnCompass capacity expansion/production cost modeling tool to test resource needs and related economics.

    - We developed business-as-usual (BAU) and alternative scenarios and estimation of the net present value of revenue requirements (the portion associated with energy resource supplies) for these scenarios in the context of assessing the comparative value of MECL's ISP and alternative system plans. This part of our review and analysis focused on what an optimum generation/resource plan may look like, how it aligns with or diverges from MECL's ISP, and how that assessment could affect overall capital expenditure needs.

    - We used information available from the Prince Edward Island Energy Efficiency Potential Study (2021-2030) and efficiencyPEI program enhancements planned for 2022–2024 to help define reasonable alternative load scenarios.

    - We used the most recent estimates of renewable resource and battery resource costs as available from MECL or other PEI entities, and/or as available from the 2021 NREL Annual Technology Baseline dataset or similar resources.

- Analysis of the 2021 Supplemental Capital Application elements and the 2022 Capital Application, in the context of the ISP and alternative ISPs.

    - The focus of this task was to determine how the 2022 Capital Application, the Supplemental Capital Application (Charlottetown plant site) and planned capital expenditures for future years are aligned with the ISP.

    - This includes understanding how alternative system plans, especially those reflecting lower peak load and energy trajectories on MECL's system, could dictate a different pattern of planned expenditures, in particular reflecting deferment or elimination of expenditures based on peak load growth or energy growth indications that are lower than MECL's current ISP.

- This task also included review of the aspects of the Demand Asset Management Plan (DAMP) that are affected by projected peak load and energy demand on MECL's system.

1.2. Structure of Report

This report is structured as follows. After this introductory section, we summarize and discuss MECL's ISP, including its load forecast, capacity supply obligations, and identification of resource plan needs. We discuss how ISP assumptions can affect planned capital expenditures. We then describe our approach to modeling alternatives to the 2020 ISP filed by MECL. We next list the modeling inputs and assumptions used for our EnCompass modeling of ISP alternatives. We subsequently present results of the modeling of alternative integrated system plans. Lastly, we list our key findings and suggest prospective next steps and recommendations concerning the impact on capital spending requirements of alternatives to MECL's 2020 integrated system plan.

2. Maritime Electric 2020 Integrated System Plan and Capital Expenditures

2.1. Summary of MECL ISP

Maritime Electric's 2020 ISP examines near-term and longer-term system needs for transmission and distribution (T&D) infrastructure and identifies potential supply resource needs. MECL states that the context is to inform capital budget applications. While MECL also states that the plan does not "undertake a detailed examination of on-island energy sources,"[4] the plan nevertheless clearly recommends that MECL install peaking generation at the Charlottetown generation station (CTGS) site by 2024.[5] It emphasizes recent and emerging load growth trends from electrification of heating and

[4] ISP, page 5.

[5] "A minimum of 50 MW of additional generation should be installed in the Charlottetown area in 2024 to provide capacity, voltage, and operational support" (page i). "Install one medium-sized (50–75 MW) on-island dispatchable generator at the Charlottetown Plant site by 2024 in order to a) replace the capacity lost with the closure of the Charlottetown Thermal Generating Station [CTGS], and b) provide backup capability alongside Combustion Turbine #3" (page iii). "Additional on-Island generation must be in place by 2024, and should be located in Charlottetown as a backup for CT3, to allow increased maintenance activities on the 69 kV system, and to help offset West Royalty transformer overloading" (page 44).

transportation end uses,[6] contains a listing and discussion of generation supply options,[7] has minimal information on the role that utility-scale or customer-scale battery storage could play,[8] and references the current efficiencyPEI programs as informing its load forecast.[9] MECL briefly references the possibility for "Increase[d] Scale of Energy Efficiency and DSM Programming" and notes that efficiencyPEI rather than MECL is responsible for these programs;[10] but it does not consider such resources as "materially impact[ing] the need for more capacity."[11] MECL's proposed resource plan does not include any battery resource options; nor does it include the potential role than increased energy efficiency or demand response resources could play in determining overall supply needs going forward.[12]

MECL also responded to information requests from Synapse (specifically in reference to the ISP and the 2022 Capital Application). MECL's response to a clarification question from Roger King in the 2022 Capital Budget Application is also relevant to the ISP.[13] While MECL stated in the ISP that generation capacity was needed by 2024, MECL's threshold island-wide peak capacity of 355 MW (beyond which MECL claims a new CT will be necessary)[14] was not forecasted to be reached until 2028.[15]

Below is a summary of the ISP core components, and a discussion of the plan follows.

Load Forecast and Capacity Obligations

Load Forecast

MECL's ISP load forecast includes the impacts from the 2018–2021 DSM plan, but it does not account for any potential increased peak and energy savings contained in the proposed 2022–2025 EE&C plan.[16] MECL uses efficiencyPEI information on DSM to inform its forecast. MECL notes an increase in heating

6 ISP, page i and 13-15.

7 ISP, pages 35-43.

8 MECL includes minimal reference to battery supply for PEI, at pages ii, 38 and 40.

9 ISP, page 38 and response to Synapse IR-3.

10 ISP, page 38.

11 Id.

12 ISP, Generation Resource Adequacy, Section 7.5 Proposed Plan, pages 43-44.

13 September 23, 2021 MECL response to Roger King question IR-10, concerning the need for adding on-Island capacity and the costs and size for CT4. Notably, MECL states "Additional dispatchable on-Island backup generating capacity will need to be constructed and operational by 2028."

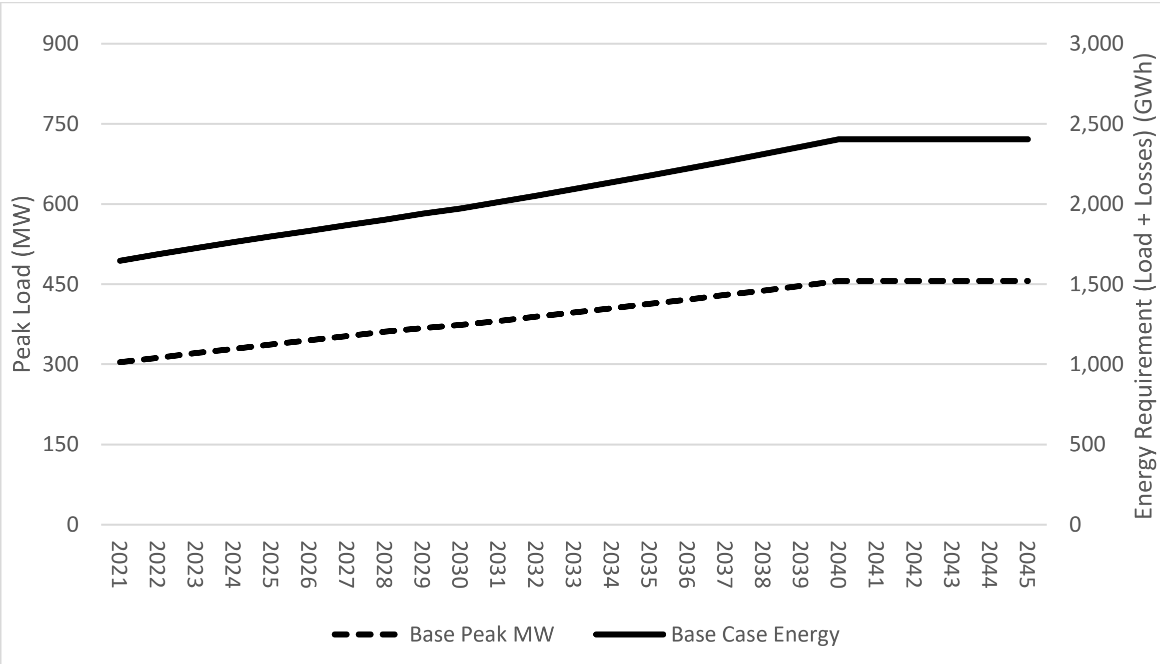
14 ISP, page 35; MECL response to Roger King IR-10, page 11, "Once the Island peak load increases beyond 355 MW, Maritime Electric will no longer be able to meet its security of supply planning obligations under an N minus 1 ("N-1") contingency protocol [loss of CT3 leads to supply of 300 (NB firm) +40 (Borden) +15 (Summerside diesel) = 355 MW]. Wind generation is not considered in security of supply planning as it is not dispatchable, and therefore cannot be counted on to be available in real time, if required."

15 ISP, Table 5, Energy and System Peak Forecast 2020-2030. 2027 Island winter peak = 353 MW; 2028 = 361 MW.

16 MECL Response to Synapse interrogatory IR-3 b and IR-3 c.

load (energy and peak demand) due to heat pump installation, and pending electric vehicle (EV) uptake on the horizon.[17] MECL's peak day load profile shows an evening peak period across a 4- to 5-hour window, with the highest peak from 5–7 PM.[18] Figure 1 below shows the island-wide forecast for MECL and Summerside load combined.

Figure 1. PEI load forecast, island-wide, annual energy and peak demand



Source and note: ISP Table 5, Table 12, Responses to Synapse interrogatories. Island-wide includes MECL and Summerside energy and peak demand. 2041–2045 flat growth projections from Synapse.

Capacity Obligations

MECL is obligated to have capacity resources to meet its peak load and an additional 15 percent reserve margin. These resources can be on-Island or off-Island. Off-Island resources must also have firm transmission reservations using NB Power's open access transmission tariff and must not exceed firm import capacity. To meet NB Power's requirements, the capacity and transmission must be secured for a full year in advance. On-Island wind resources can and do count towards meeting these obligations, although they are accredited at a fraction of their nameplate value to account for varying output patterns. For example, if MECL's peak load for the following year is projected to be 300 MW, a total of 345 MW of firm capacity from on-Island and purchased New Brunswick resources (imported over the submarine cables) is required. The on-Island resources would include the Borden (40 MW) and Charlottetown (50 MW) CTs, Summerside's diesel (15 MW), and the capacity value of the wind

[17] ISP, Table 4, page 15. Response to Synapse IR-4.

[18] ISP, Figure 3, page 13.

resources on PEI (16–20 percent of the nameplate value of purchased wind). The remaining requirement would be purchased as firm capacity from NB Power. New utility-controlled battery storage could be used to meet a portion of the overall capacity requirement.

The details of the NB Power Energy Purchase Agreement (EPA) would need to identify the counting convention for on-Island firm capacity. In the utility industry currently, 4-hour duration batteries are considered somewhat standard to serve as a "capacity resource" for resource adequacy purposes (i.e., 10 MW at 4-hours is a 40 MWh battery storage resource and counts as 10 MW of firm capacity). The intent of the capacity as firm "resource adequacy" capacity is not to carry the island on full loss of supply from New Brunswick, but to be able to regularly contribute to meeting daily peak load needs in winter. Thus, the 4-hour duration presumes availability during the 6PM–10PM window of winter peak. The rest of the day is available to charge the battery resource.

NB Power used 4-hour battery capacity as an option in its latest integrated resource plan (like MECL, NB Power asserts that batteries are too expensive, but notes future cost trends could support their deployment; from a technical perspective, NB Power does not exclude them as capacity resources).

Supply Resources

MECL's ISP describes and tabulates the existing resources on the island, explains its procurement of capacity and energy from New Brunswick, and includes a discussion on the circumstances of supply during loss of interconnection from New Brunswick.[19] MECL notes that "Maritime Electric has taken advantage of surplus generating capacity in New Brunswick by receiving lower NB capacity pricing to fulfill its short-term capacity requirements."[20]

Table 1 below lists the supply resources for PEI.

[19] ISP, pages 35-42.

[20] ISP page 24.

Table 1. PEI existing electricity supply sources, import capability, and new on-Island sources

Source	Nameplate Capacity, MW	Comment
Existing		
Charlottetown Generating Station (CTGS) 9&10	40	Retired, January 2022
Combustion Turbine (CT) 3	49	
Borden CT1 and CT2	40	Replacement in 2031
Summerside Diesel	15	
On-Island wind: MECL purchases	92.6	
On-Island wind: Other	111	Engie and Summerside
Solar	15	
Import		
Pt. Lepreau (MECL share)	29 (net)	
Existing (2021) and Forecast (2022–2025) NB capacity	120 / 170–195	
New Sources		
New planned wind	70 (2 sites)	
New combustion turbine	50-100	New CT4 at CTGS
New renewables (wind, solar)	varies	
New battery energy storage	varies	

Source: ISP, Table 7, page 18. Table 15, page 32. Synapse (other wind, solar, batteries).

Transmission and Distribution

The ISP includes a transmission section that describes the interconnecting facilities with New Brunswick, characterizes the transmission tariff used, broadly identifies transmission system needs, and offers a plan that includes a summary table of proposed solutions.[21] Those solutions are characterized as project needs based on load growth, equipment condition, or customer reliability enhancement.[22]

The ISP notes that "many of Maritime Electric's transmission lines will have spare thermal capacity well into the future," but also states generically that "the transmission system needs to expand" to meet MECL's projection of increasing energy and demand needs.[23] MECL does not explicitly recommend increasing the import capacity beyond the current firm capacity of 300 MW, but instead focuses on noting the importance of on-Island generation to meet capacity needs.

MECL's stated transmission needs include voltage and reactive power support, increased 138 kV capability in the west for reliability, and replacement and/or maintenance of existing 138 kV facilities.[24] MECL states that the 69 kV facilities on the island are generally in good condition. MECL states that its firm transmission capacity from New Brunswick to PEI is 300 MW.[25] MECL suggests that a third east-to-

[21] ISP, pages 44-56, including Table 23 "Transmission System Solutions."

[22] ISP, page 56.

[23] ISP, page ii, and page 46.

[24] ISP, pages 46-54.

[25] ISP page 25.

west 138 kV line is needed if the peak load goes beyond 350 MW.[26] MECL also notes that under certain loading conditions and transmission contingency (i.e., outage) situations, dispatchable capacity such as the use of CT3 is required to alleviate overloads.[27]

MECL's Distribution Asset Management Program (DAMP) describes conventional approaches to assessing and maintaining its distribution system assets. For the purposes of considering capital expenditures on distribution, we note that MECL's largest increase in distribution system asset management occurs with the PEI Broadband project and a transition to using smart meters. The portions of the DAMP directly tied to medium-term or longer-term load growth is represented in DAMP Section 6, *Distribution Planning*. All of MECL's projections for distribution system needs are predicated on the ISP's load growth projections.

MECL Identified Needs and Resource Plan

MECL identifies the following core needs and includes these suggested resources in its proposed resource plans.[28] MECL does note that it has not yet done an analysis of the best long-term supply solution, and it intends to conduct in 2022 an "On-Island Generating Capacity Study."[29]

- On-Island renewable energy supplies (wind and solar), and off-Island New Brunswick-sourced energy and capacity
- A new CT resource at the CTGS site, as a form of capacity supply
    - MECL states that additional on-Island generation "must be in place by 2024."
    - MECL states that it needs additional capacity in part to meet requirements under the NB-PEI interconnection agreement.[30]
    - MECL also states that it needs on-Island supply as backup for transmission and generation outages and constraints, in New Brunswick or on PEI, including the submarine cables.[31]
- Borden CT replacement when needed (currently slated for a 2031 retirement)—MECL suggests that consideration should be given to locate the Borden CT replacement near Sherbrooke substation.

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[26] ISP, page 47.

[27] ISP, pages 46-47.

[28] ISP, at pages 43-44 (supply), 55-57 (transmission), and 65-66 (distribution).

[29] ISP, page 5, 42.

[30] ISP, pages 23-26.

[31] ISP, pages 40-44.

- Various T&D line, substation, and ancillary supports (e.g., reactive power support): Table 23 of the plan[32] describes MECL's transmission system solutions. Various distribution system improvements— which are focused on line extensions, upgraded substation transformation, and other equipment, including distribution automation—are described in Section 9 of the ISP.[33]

2.2. Discussion

ISP Assumptions

Two ISP assumptions that resonate throughout the plan drive a number of the core identified resource needs. These should be vigorously examined by IRAC, since a materially significant portion of capital expenditure requirements (over the longer term, but also in the 2024–2026 period) depend on these assumptions:

1. the load forecast, which is current net of the electric energy efficiency estimates from the current (2018–2021) EE&C plan. This inclusion of the "older" existing EE&C plan savings results in a fairly steady increase of peak load over time. The proposed new EE&C plan has significantly greater projected peak and energy savings over time, which would reduce the net load forecast for the ISP; and
2. the assumption that a CT resource will be needed to "replace" the capacity of the retiring CTGS, even though the installation of the new submarine cables in 2017 dramatically increased the firm capacity import capability of PEI, far and above the size of the retiring CTGS units.

The reasonableness of relying on the existing EE&C plan savings assumption depends on the extent to which MECL (or the Commission) has confidence in the ultimate delivery of the level of savings in the new EE&C plan. From a technical and economic perspective, there is no reason to doubt the ability of the province to obtain the projected (higher) savings levels. Other jurisdictions in Canada (e.g., Nova Scotia) and New England and New York (with winter peaking areas, or at least sizable winter heating season DSM measures) easily meet performance levels at or above the projected performance of Prince Edward Island Energy Corporation's (PEIEC) EE&C plan filing. However, continuing evaluation and monitoring of those programs is required.

The need for a new CT4 at CTGS is not at all a reasonable assumption at this stage. MECL must do a full economic assessment of resource options that include on-Island utility-scale (or distributed) battery storage. MECL's one reference to an Alberta battery installation is insufficient evidence to reject the economic viability of battery resources as realistic, practical, and reliable resource options to pursue.

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[32] ISP page 56.

[33] ISP pages 65-66.

PEI is a potentially attractive option for battery installation at this time because of the synergies involved: a high level of renewable energy on the island, with relatively high output during winter periods; a need for on-Island capacity with ancillary service capabilities (batteries are ancillary service capable and have faster response times than conventional CTs); and clear site availability (CTGS) that can support a utility-scale installation at a good electrical location on the island. Battery storage is the buffer that time-shifts energy production to peak periods, and that allows for reduced high-price-period energy procurement from New Brunswick (and reduced capacity procurement need). The relative reliability of the submarine cable interconnection to New Brunswick (the 2018 mainland outage event notwithstanding) demands a careful assessment of the value of ongoing New Brunswick capacity procurement combined with high-value battery energy storage resource installation.

Based on our review at this time, which was focused on the effect the ISP has on capital requirements, the bulk of the remaining assumptions made by MECL (for example, replacement or upgrade of T&D assets) do not appear unreasonable, except to the extent that a new (lower) load forecast would lead to modifications in either (i) the timing or (ii) the ultimate need for expenditures that are more closely tied to load growth. This is likely to impact primarily the potential need for a new major 138 kV line (east-west). Over time, it would likely impact the pace of transformer upgrades required since some of those upgrades are predicated on individual feeder load increases, and some (such as major transmission-distribution transformers) are based on island-wide peak load increase trends.

As noted by MECL, "during this time of global energy transition and volatile energy pricing"[34] it is difficult to forecast future energy and capacity prices. This uncertainty impacts any modeling of system supply over long time-periods. MECL did not conduct a full integrated resource plan and thus did not have to forecast estimated prices and costs through a full planning horizon (which it will need to do in its On-Island Generation Capacity Study). Table 6 and Table 7 of MECL's responses to interrogatories[35] list projected capacity and energy pricing through 2040 for purchases from New Brunswick. When MECL does conduct the supply study, it will need to carefully vet, and preferably conduct numerous sensitivities, to ensure a robust result that accounts for possible higher future energy and capacity prices for New Brunswick imports. While our results point to clear economic benefits from battery resource installation instead of CT installation, we recommend that MECL conduct a thorough input assumption review and ensure a supply or capacity resource modeling analysis that tests various sensitivities to cover the uncertainty of energy (and capacity) pricing.

[34] Confidential response to Synapse IR-6g, October 22, 2021.

[35] Confidential Response to Synapse interrogatory IR-6 b through g, October 22, 2021.

2022 and 2021 Supplemental Capital Expenditures Application / ISP Impact

Based on a review of the 2022 Capital Budget Application[36] and the 2021 Supplemental Capital Budget Application, MECL's capital expenditures include the following projects that may be either unreasonable or unnecessary, or candidates for deferral:

- **2024 and 2025 proposed expenditures for CT4.** At this time, planning for a CT at CTGS is premature, and potentially unreasonable and unnecessary. Until MECL completes its on-Island supply study, it is not at all clear that a new CT is a priority for planned capacity expenditures rather than battery energy storage. The submarine cable installation in 2017 accomplished a major upgrade to allow use of New Brunswick capacity resources to meet PEI needs. Current costs of New Brunswick capacity are much lower than the costs of new CTs. Existing supply on PEI, including wind resources, fossil resources, and ongoing energy efficiency and demand response potential—along with consideration of battery energy storage (for energy price arbitrage)—could more economically provide for existing and incremental capacity needs and allow for incremental reductions to purchases from New Brunswick.

- **Longer-term 138 kV transmission**. This includes planned increases in transmission investment for 2027 and beyond, such as the third east-west line and potentially the 138 kV source at Lorne Valley. While Synapse has not conducted any independent assessments of the need for these specific projects, MECL has categorized them as load-growth dependent, based on the existing ISP load growth projection. MECL must revisit the need for these projects as a new EE&C plan is implemented, and update both its load forecast and its transmission planning assessment to account for potentially lower peak load growth than that assumed in the ISP.

- **Certain longer-term distribution investment**. Any longer-term (i.e., 2026 and beyond) needs for distribution system support or other transmission system support required due to load growth must be regularly monitored to reflect any updates to MECL's peak load forecast. MECL has not conducted any form of integrated distribution system planning, which could reveal value for distributed demand response and battery storage installation at the end-user level. These forms of potentially economic future resource installations could have a material effect on distribution system investment otherwise required to meet feeder-specific or island-wide peak load increases.

[36] We focused on review of resource planning related elements throughout the Application.

Charlottetown Thermal Generating Station Site

MECL's long-term site plan for the CTGS location is attached as Appendix A to its 2021 Supplemental Capital Budget Application.[37] The application contains five core elements with resource planning implications:

- removal of the existing steam plant building,
- construction of a new CT3 equipment building,
- consideration for a new CT (CT4),
- consideration for an eventual 138 kV substation, and
- room for eventual battery storage use.

We reviewed the Application with a focus on the core resource-planning-related elements contained in the long-term site plan.

Synapse agrees with MECL on four of the five elements under consideration for the CTGS site. Demolition of the existing steam plant site is reasonable at this time in large part because of the benefit of considering creating room for capacity resources that include battery energy storage, which at utility scale would require a site under MECL's control and of sufficient acreage. Planned future expansion of PEI's 138 kV backbone transmission system is a reasonable planned use for the location, especially if future increases in wind energy resources on the island lead to further need for 138 kV transmission system enhancement. Given the removal or demolition of the steam plant building, a new building to house the CT3 equipment is not unreasonable.[38]

Until a full on-Island capacity or supply study is completed however, it is not at all clear that the site should be planned at this time for installation of a new CT. The first, best incremental supply source for the CTGS site, based on our alternative ISP modeling, is more likely utility-scale battery energy storage. While Synapse did not analyze alternative locations for battery energy storage for PEI, and distributed battery resource options still need to be evaluated by MECL, the CTGS is an obvious and solid candidate site for utility-scale battery energy storage. This is due to its location close to the transmission system, its ownership by MECL, the potential for the 138 kV system to extend into the site, and the impending demolition of the old steam building, allowing for acreage for a battery resource installation.

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[37] MECL, *2021 Supplemental Capital Budget Application for Combustion Turbine 3 Equipment Building ("CT3 Equipment Building") and Demolition of the Existing Steam Plant Building at the Charlottetown Plant Site*, June 8, 2021.

[38] Synapse, *Planning for the Future at the CTGS Site: Report on the Proposal of Maritime Electric*, March 2019. We recommended removal of the steam plant building only after MECL demonstrated a long-term plan for the site that was justified based on "a more robust case for the cost-effectiveness of demolition over retention" (page ii). Consideration of battery energy storage resources, potentially other capacity resources, and transmission system expansion appears at this time to represent a reasonable set of resources for use of the site.

Battery Energy Storage as a Resource: Use and Application

Utility-scale or distributed battery energy storage systems are commercially mature, economically viable resources that can be used by a utility as a source of dispatchable, controllable capacity to support reliability through timely availability during system peaks. Battery energy storage systems provide energy during peak periods, and generally charge during either off-peak periods when energy prices or costs are low, and/or when variable output renewables resources (such as those purchased by MECL or Summerside) are generating power. They can effectively time-shift energy output, and shape or firm up variable output from wind resources on PEI.

Battery energy storage can also be a highly valuable ancillary service, able to respond instantaneously as a frequency responsive resource that can substitute for or complement regulating, frequency control, and reactive power provision otherwise secured from on-Island fossil resources. Storage can help to manage overall requirements and control of resources on PEI by functioning as a load-following resource during an "islanded" situation, or a full loss of supply from New Brunswick. They can perform the same function under normally operating conditions with a full or partial interconnection to New Brunswick.

Battery storage resources are sized according to power output (capacity, in MW) and in duration, usually as 2-hour or 4-hour resources but potentially as longer duration resources (at proportionately higher costs per MW). A 10 MW, 2-hour duration battery storage resource has an energy carrying capacity of 20 MWh. A 4-hour 10-MW resource has a capacity of 40 MWh.

Battery energy storage resource functionality and cost depends on its duration and the ratio of capacity capability to energy storage capability. Shorter-duration resources are more likely to be used for ancillary service provision, while longer duration resources are more likely to be used to time shift energy production. For consideration as a capacity resource that meets resource adequacy requirements, battery energy storage usually must demonstrate sufficient duration to cover capacity needs during peak periods, which can extend from 1 to as many as 6 hours in duration, depending on the region and circumstances involved.

In the United States, a 4-hour duration resource is usually considered sufficient to serve as a capacity or a "resource adequacy" resource, although this is a changing dynamic. Whether a region is summer peaking or winter peaking; the percentage of energy supplied by renewable resources; and supply output patterns (wind is different than solar) all influence the overall need for batteries to sustain output over 2 hours, 4 hours, or longer durations in order to be counted as a capacity resource.

MECL installation of battery resources on PEI will lead to a reduction in the amount of firm capacity MECL is required to purchase from NB Power, with the specific reduction potential dependent on NB Power's conventions for counting capacity from battery resources.[39] Battery resource installation is also

[39] A standard convention would have initial PEI battery resources with a 4-hour duration count at 100 percent of nameplate capacity; as battery resource capacity increased, this capacity credit for batteries would decrease, in a manner similar to the

a competitor to provision of peak power from CT resources. Battery storage of sufficient duration can fully substitute for on-Island peaking capacity to meet needs during normal winter peaking circumstances, when the PEI-NB interface is available at full capacity.

During times of partial availability of the NB-PEI interface, battery capability still provides dispatchable capacity and can at least partially substitute for on-Island peaking capacity, depending on the specific loading and loss-of-New Brunswick-supply duration circumstances involved. During times of full loss of mainland interconnection, a relatively rare occurrence, battery capacity can still provide dispatchable energy. However, its overall output could be limited based on the availability of on-Island resources to provide charging energy. During times of reduced interconnection capacity, battery energy capacity still provides its full rated output, but the duration and scale of interconnection capacity loss and the PEI loads during the event will affect the ultimate capability that the resource would provide in that circumstance.

In sum:

- Batteries can be used to store energy for longer time periods than 2, 4 or 6 hours, but at a greater cost for those extended durations. Whether or not longer duration battery storage is needed depends on the specific conditions concerning loss of supply from New Brunswick, including the duration of a loss of supply, the load on PEI, and the wind output level projected during the period of outage. Batteries can serve as an efficient load-following resource and thus can help to better utilize fluctuating wind resources on PEI during a time of loss of supply from New Brunswick.

- Battery storage is an acceptable form of backup supply, but the specific conventions for counting battery capacity MW as “firm” would need to be included in agreements with New Brunswick Power.

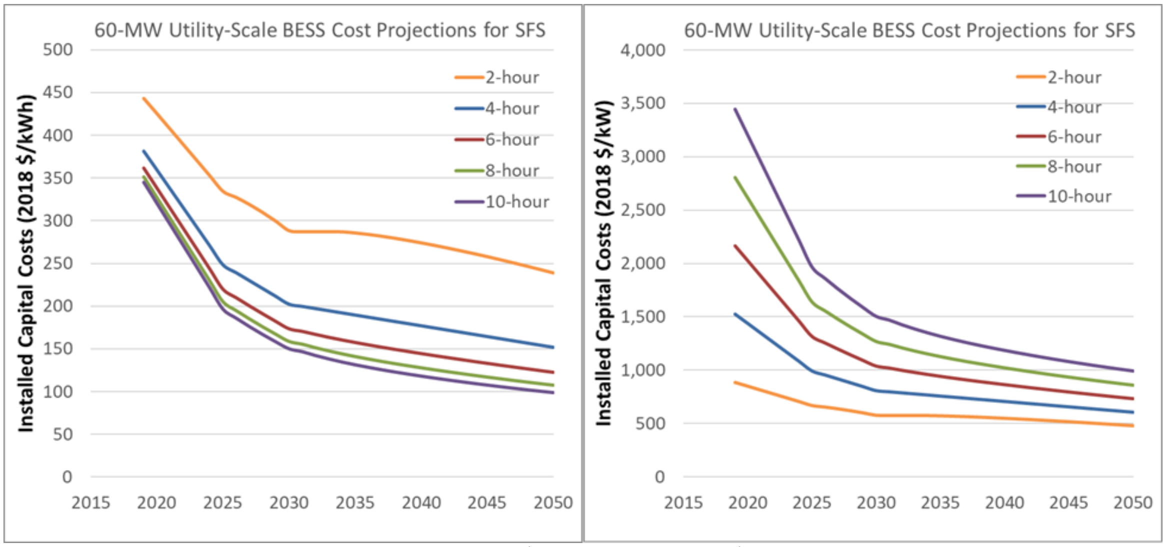
- Battery storage is a reliable capacity source. It has been used as a capacity resource in many jurisdictions worldwide. The extent to which it is reliable as a “backup” capacity resource on PEI depends on whether that is in reference to backup under the NB Power purchase agreement during “normal” times, when at least some supply interconnection is in place; or designed as backup for extended durations, if PEI wishes to design its system for long duration outages of the entire New Brunswick interconnection.

Battery storage costs have declined dramatically in the last decade. The utility industry has exponentially scaled its procurement and installation of battery resources over the past five years in large part (if not in total) because of the technological improvements and associated cost declines. Various data sources exist that show the trend of battery cost decline. Two credible sources are the U.S. National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) assessment of costs, which contains

way that capacity accreditation for wind power resources declines as the total penetration of wind power on PEI increases. See for example, MECL ISP, Figure 5 “Capacity Value of Wind Generation in PEI,” (page 21).

renewable energy and battery energy storage cost estimates; and Lazard. Figure 2 below shows an example of the cost trend from the NREL ATB.

Figure 2. Graphic from NREL ATB battery cost projection



Utility-scale BESS Moderate Scenario cost projections, on a $/kWh basis (left) and a $/kW basis (right)

Source: NREL ATB, https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage.

The most recent Lazard levelized cost of storage analysis[40] notes the following in its overview of use cases and underlying operational parameters and costs:

- The uses for battery energy storage include, in particular, utility-scale storage that serves as a dispatchable resource providing capacity, energy value, and ancillary service support: “Large-scale energy storage system designed for rapid start and precise following of dispatch signal. Variations in system discharge duration are designed to meet varying system needs (i.e., short-duration frequency regulation, longer-duration energy arbitrage (1) or capacity, etc.) – To better reflect current market trends, this report analyzes one-, two- and four-hour durations (2).”[41]
- Operational parameters for utility-scale battery storage, listed as generally ranging from 1 to 6 hours duration, 20-year lifetimes, and cycling once per day.[42]
- The costs of battery energy storage range from $181/kW-year to $322/kW-year (USD),[43] roughly equivalent to $231–$412/kW-year (CAD), or of the same magnitude as a

[40] *Lazard Levelized Cost of Storage*, Version 7.0. October 2021. https://www.lazard.com/media/451882/lazards-levelized-cost-of-storage-version-70-vf.pdf.

[41] Id., slide 3.

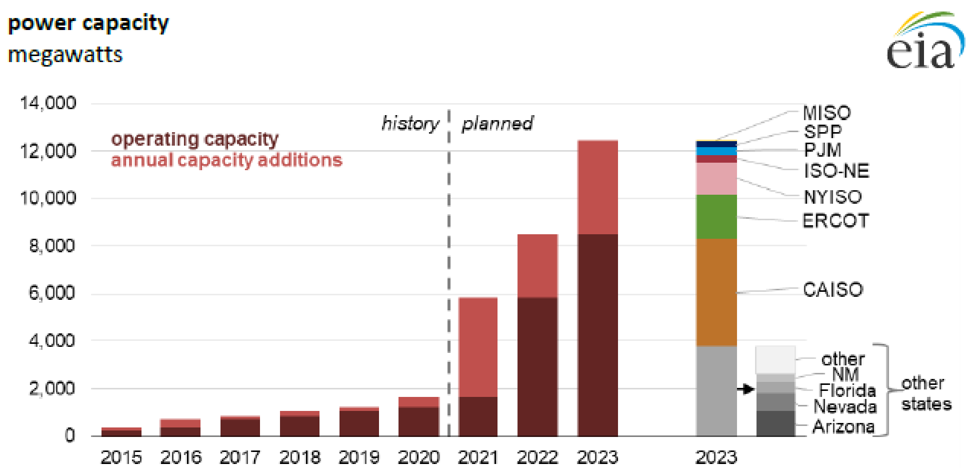
[42] Id., slide 4.

[43] Id., slide 5.

peaking capacity resource.[44] These are based on specific assumptions Lazard uses, which could vary on PEI depending on the financing and cost of capital assumptions applicable to MECL.[45]

The U.S. Energy Information Administration (EIA) recently posted a "Today in Energy" entry with a focus on the most recent information available on utility use of battery energy storage in the United States. At the end of 2021, the U.S. electric utility sector had 4,605 MW of battery energy storage installed, a notable increase to end-of-2019 levels of 1,022 MW of capacity. This demonstrates the particularly dramatic uptake the U.S. electric utility industry has very recently seen in battery storage installations, reflecting their use case, performance, and cost characteristics. The following graphic, from a U.S. EIA report from August 2021 shows the key historical trend and projected increases in battery energy storage capacity across the U.S. electric utility sector.

Figure 3. U.S. EIA graphic on historical and projected large-scale battery energy storage cumulative capacity in the United States



Source: U.S. Energy Information Administration, Dec 2020 Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*

Battery Energy Storage Examples

To demonstrate the overall trends seen in utility installation of battery energy storage, we cite four examples below. However, we note that there are many recent industry publications,[46] and a myriad of

[44] MECL estimated the cost of a new CT in 2024 at $90 million (50 MW), or roughly $1,800/kW. Assuming a capital recovery factor of 0.15, this would translate to approximately $270/kW-year.

[45] Id., slide 5, which notes "Here and throughout this presentation, unless otherwise indicated, analysis assumes a capital structure consisting of 20% debt at an 8% interest rate and 80% equity at a 12% cost of equity. Capital costs are composed of the storage module, balance-of-system and power conversion equipment, collectively referred to as the Energy Storage System ("ESS"), solar equipment (where applicable) and EPC. Augmentation costs are included as part of O&M expenses in this analysis and vary across use cases due to usage profiles and lifespans."

[46] U.S. National Renewable Energy Laboratory (NREL), U.S. Agency for International Development, *Energy Storage Decision Guide for Policymakers*, July 2021. https://www.nrel.gov/docs/fy21osti/78815.pdf. NREL, US AID, *Grid Scale Battery Storage,*

media reports[47] that indicate the increases in utility procurement and planning for battery energy storage resources. There are numerous recent industry sources and publications that describe in varying depth of detail the costs, benefits, capabilities, and roles that battery energy storage can play on a utility system. As noted in our recommendations, MECL's on-Island supply study should include the most recently available information on battery energy storage system performance and costs when examining the cost-effectiveness of different capacity supply options.

- **California – Moss Landing, Vistra Energy Storage Facility**. Two phases of a utility-scale battery energy storage facility initiated in 2018 are now complete and operational at the Moss Landing power plant site in California.[48] The first phase, 300 MW and 1,200 MWh, was operational in 2020. A second phase came online in 2021, increasing the total capacity to 400 MW and 1,600 MWh.

- **New England: Massachusetts and Maine Utility-Scale Battery Energy Storage**. Two large-scale battery energy storage projects were awarded capacity supply obligations in ISO NE's forward capacity market auction in early 2021.[49] The projects are currently under construction, for in-service operation in 2024. Plus Power is developing the Cranberry Point Energy Storage Facility in Carver, MA.[50] It is a 150 MW, 300 MWh facility that will be tied into the ISO NE transmission grid. A separate 175 MW, 350 MWh system called Crosstown Power is under development in Gorham, Maine, also for operation in 2024 and connection to ISO NE's transmission grid.[51]

Frequently Asked Questions, https://www.nrel.gov/docs/fy19osti/74426.pdf. NREL, 2021 Annual Technology Baseline, Utility-Scale Battery Storage, https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage.

[47] PV Magazine, *The Energy Storage Decade Has Arrived*, November 18, 2021. "The outlook estimated that 345 GW/999 GWh of new energy storage capacity will be added globally between 2021 and 2030." https://www.pv-magazine.com/2021/11/18/the-energy-storage-decade-has-arrived-says-bnef/. Bloomberg New Energy Finance, *Battery Pack Prices Fall to an Average of $132/MWh, but Rising Commodity Prices Start to Bite*, "Lithium-ion battery pack prices, which were above $1,200 per kilowatt-hour in 2010, have fallen 89% in real terms to $132/kWh in 2021." November 30, 2021. https://about.bnef.com/blog/battery-pack-prices-fall-to-an-average-of-132-kwh-but-rising-commodity-prices-start-to-bite/. Inside Climate News, *US Battery Storage Soared in 2021, Including Three Monster Projects*, March 31, 2022. https://insideclimatenews.org/news/31032022/inside-clean-energy-battery-storage/.

[48] Vistra Corp., *Vistra Completes Expansion of Battery Energy Storage System at its Flagship California Facility,* August 2021. "The 100-MW/400-MWh Phase II expansion is operating under a 10-year resource adequacy agreement with Pacific Gas and Electric Company (PG&E). The 300-MW/1,200-MWh Phase I project has a similar 20-year resource adequacy agreement with PG&E." https://investor.vistracorp.com/2021-08-19-Vistra-Completes-Expansion-of-Battery-Energy-Storage-System-at-its-Flagship-California-Facility.

[49] Utility Dive, *With Forward Capacity Auction Success, Batteries are Winning in New England.* September 28, 2021. https://www.utilitydive.com/news/with-forward-capacity-auction-success-batteries-are-winning-in-new-england/607282/.

[50] https://www.pluspower.com/home/cranberrypoint.

[51] https://www.crosstownenergystorage.com/.

- **Nova Scotia Smart Grid Pilot: Residential and Commercial/Industrial Batteries**. Nova Scotia Power has a Smart Grid battery storage pilot project underway.[52] This program includes the installation of residential and small commercial and industrial battery systems, which can be used to shave peak load at the feeder level.

- **Hawaiian Electric Utility and Distributed-Scale Battery Projects**. Hawaiian Electric is completing installation of a 185 MW, 565 MWh battery energy storage facility known as Kapolei Energy Storage.[53] This facility is intended to provide capacity after retirement of a large coal-fired station on Oahu and is slated for operation in 2022. Hawaiian Electric also has programs that support distributed battery installation across its service territories.[54] Its "battery bonus" programs pays for behind-the meter battery installations based on their discharge amounts during the peak evening hours.

Summary Comments: ISP and CTGS Site Plan

The following table summarizes the core areas of Synapse agreement or disagreement with MECL's ISP as presented in September 2020, as well as key elements of the Capital Applications:

Table 2. Summary comments: MECL Integrated System Plan issues

Issue	Agree/ Disagree	Comment
Load Forecast: Energy	Partially Agree	Increases in load from electrification are to be expected: We agree with MECL that continuing trends will add load. However, successful DSM programming will offset such additions to some extent. MECL and PEIEC must continually monitor performance and success of both energy efficiency and demand response (with and without enabling technologies) programs and then MECL must adjust input parameters to supply-side resource need forecasts accordingly.
Load Forecast: Peak Demand	Partially Agree	MECL notes the importance of managed charging for EV load increases and notes an increase in peak load from heating electrification. We agree broadly that electrification trends may build peak, but managed EV charging and energy efficiency and demand response (incentives, smart controls, time-of-use rates) can all impact peak increase trends. We model a lower peak increase trend than seen in the ISP.

[52] Smart Grid Nova Scotia Project, https://www.nspower.ca/cleanandgreen/innovation/smart-grid-nova-scotia/battery-pilot. Semi-Annual Report filed at the Nova Scotia Utility and Review Board, February 18, 2022. Matter 09985. https://uarb.novascotia.ca/fmi/webd/UARB15.

[53] https://www.kapoleienergystorage.com/.

[54] https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/battery-bonus.

Issue	Agree/ Disagree	Comment
Ability of DSM to Materially Affect Need	Disagree	ISP depends on 2018–2021 EE&C programmatic effects in making this claim (ISP, page 88). Successful EE&C at 2022–2025 levels have the potential to reduce peak load build by 2030 by more than 50 MW, per the Dunsky report. This compounding benefit of EE&C and demand response programs (which continues beyond 2030) if successfully secured can materially affect capacity resource need (CT, battery, or New Brunswick purchase).
Installation of CT4 at CTGS	Disagree	Immediate indications are that energy efficiency and demand response have potential to limit island peak load to materially less than 355 MW (threshold point) through 2030 and beyond, even with inclusion of electrification loading increases. CT need is not evident for 2028 (R. King response indication). There is no need to plan capital expenditure for a CT at this time, but capital expenditure planning for battery storage may be warranted. If Capacity Supply Study confirms value of initial battery energy storage resource installations, then the next ISP (2023–2025) is the right timeframe to continue systematic examination of need and options.
Location of Battery Storage at CTGS	Agree	CTGS is an ideal site for utility-scale battery storage on the order of tens of MW scale (or greater), although it is not the only site. Depending on scale, MECL substations (large, medium, or small sizes) at key locations could also be prime candidates for 1 MW or multi-MW installations.[55] Those other locations can help to potentially offset certain incremental, future transmission or distribution capital expenditure needs.
Timing, Use, Cost, and Viability: Battery Storage	Disagree	MECL must do a comprehensive economic assessment of battery storage value and cost using current data, including all benefits that accrue to battery storage (capacity, energy arbitrage and local wind storage capacity, ancillary service provision, resiliency under loss of New Brunswick supply circumstances –all of which reduce capacity amounts and related costs to procure from New Brunswick). Battery energy storage costs from the Alberta example (more than $2,000/kW for 2-hour duration) noted in ISP[56] are already outdated as cost trend declines have been dramatic throughout industry. MECL has not fully characterized the range of uses and value potential for batteries at utility scale on PEI.
Long-Term Site Plan: CTGS	Partial Agree	CTGS is an ideal site for utility-scale battery storage. A new CT is not necessary in a near-term plan at this time; while it is not unreasonable to reserve portions for possible CT use in the future, current focus should be to integrate first economic tranches of utility-scale battery storage at the site.

[55] For example, a 1 MW, multiple-hour-duration battery storage containment is seen in the industry to be at roughly the size of a shipping container. Battery storage in this form can be scaled as needed and in line with available areas for installation.

[56] ISP, page 38.

3. Modeling of Alternative System Plans

3.1. Modeling Approach—Alternative Integrated System Plans

Overview

MECL filed its current ISP in September 2020. In response to discovery questions from Synapse through the IRAC, MECL provided additional details on its input assumptions in October 2021. MECL noted that its ISP was not an integrated resource plan, as it concentrated on the T&D system impacts and was not a detailed examination of on-Island energy sources.[57] MECL states that the purpose of its ISP document "is to provide context for capital budget applications and an advance indication of major projects in addition to the annual capital budgets."[58]

Synapse's approach to developing alternative ISPs consists primarily of using the optimization functionality of the EnCompass production cost and capacity expansion modeling software to gauge the costs differences between resource plan scenarios, including a "base" scenario representative of MECL's ISP. The primary purpose of developing alternative system plans at this time is to inform the IRAC's consideration of MECL's capital application, and in particular any components that may be dependent upon the type or timing of resource installations that comprise part of MECL's ISP. The intent is to focus on modeling the full costs (capital and operating) of resources that could be substitutes, such as on-Island fossil or battery storage capacity versus incremental purchase of off-Island (New Brunswick system) capacity; off-Island energy versus incrementally greater amounts of on-Island wind or solar PV; or the effect of on-Island battery storage impacting the temporal pattern of purchases from New Brunswick.

The structure of the analysis does not require modeling the costs for those assets common to all resource plans (such as the procurement of a slice of nuclear energy from the Lepreau nuclear plant, or the cost of existing wind contracts between MECL and PEIEC). The purpose is to discern differences in the costs across plans that result from a different mix of new resource choices, rather than to determine a set of absolute costs that result from any given resource plan. The difference in the net present value of the revenue requirements associated with resource plans is a key metric used to assess the relative costs. This metric is calculated by taking the net present value of a stream of costs (2021–2045) consisting of operating and capital components for each resource plan.

Synapse developed a "base" system plan using MECL's ISP and responses to interrogatories as fundamental inputs, along with our Maritimes database of existing resources in the EnCompass modeling system. The base plan represents MECL's projection for future loads and anticipated resource purchases and on-Island capacity builds. It includes Summerside resources and loads. Synapse

[57] MECL, ISP, page 5.

[58] *Id*.

conducted production cost modeling of the base system plan scenario to determine a baseline of total production costs, and the costs for any new resource additions defined for the base plan. Synapse developed this plan to allow comparisons between it and alternative system plans that reflect an optimization of production and capital costs for new resources; and also to compare it to a plan that reflects lower loads through the implementation of greater levels of DSM than seen with the current EE&C plan. While the alternative system plans created are not exhaustive of all possibilities, they do indicate the extent of key economic tradeoffs that exist between purchasing energy and capacity from off-Island and building energy and/or capacity resources on-Island, and the effects of implementing DSM.

Synapse developed a "DSM Load Impacts" plan that presumes a lower level of energy requirement and a lower peak load trajectory, based on the effect of the proposed efficiencyPEI 2022/2023–2024/2025 plans and considering the foundational Dunsky potential study. The production costs for this plan were also modeled, along with the costs for the new resource additions for this lower load scenario.

The modeling included two primary optimization scenarios. In both of these scenarios, a capacity expansion optimization was run in EnCompass, coupled to a production cost run. These scenarios allow an optimal set of capacity and energy production resources to be determined by the model, which results in a least-cost resource plan given the loading inputs and the capital and operating costs of resource options. The primary resource options offered to the optimization process to provide energy and capacity to meet PEI island-wide load were CTs, energy storage batteries, utility-scale wind and solar PV, and energy and capacity purchases from New Brunswick.

<u>EfficiencyPEI Plans and Modeled Load Forecast</u>

MECL's ISP load forecast assumed energy efficiency impacts (both energy and peak demand) based on the current three-year EE&C Plan, for all future years of its ISP forecast.[59] As we illustrate below, the proposed new EE&C Plan contains a rough doubling of the annual energy and peak savings compared to the existing plan, with cumulative impacts leading to projected Island-wide energy and peak load trajectories that are significantly lower than those contained in MECL's ISP. This will substantially impact the requirements for any capital resources whose underlying needs were premised on continued peak or energy load growth. For this reason, we defined a "DSM Load Impacts" scenario to reflect outcomes under the proposed new EE&C plan.

On December 31, 2021, PEIEC filed and requested IRAC approval of its proposed 2022/2023–2024/2025 EE&C plan, which would be implemented by efficiencyPEI (ePEI). The EE&C Plan used Dunsky's efficiency potential study (included as Appendix F to the PEIEC filing) as its foundational document.[60] The plan would increase estimated energy and demand savings expected over the next three years compared to the current three-year EE&C Plan. The December filing indicated a rough doubling of both energy and

[59] MECL, response to Synapse interrogatory IR-3.

[60] PEIEC, application of PEI Energy Corporation for approval of the 2022/2023-2024/2025 EE&C Plan, page 3.

demand savings from the energy efficiency portion of the EE&C Plan, plus additional peak demand savings through demand response efforts.

MECL plans to include the forecast load reduction impact of any approved EE&C plan in its forecasts;[61] and thus in any updates to its ISP or the On-Island Generation Capacity Study.

Proposed EE&C Plan Savings

Table 3 below summarizes the energy and peak demand savings projected by the proposed EE&C Plan. We considered different levels of forecast peak and energy requirements for modeling "DSM Load Impact" levels of load on the Island, based on the proposed EE&C plan and also on the achievable potential indicated in the Dunsky potential study.

We separately modeled a single sensitivity that assumed EE&C plan effects (energy and peak demand reduction), plus additional demand response resource implementation that further limits peak load increases and allows for reductions to out-year purchases of New Brunswick capacity. In the demand response sensitivity, we assumed a ramp of additional peak load savings that reaches 31 MW by 2029 and remains flat thereafter. This reflects the EE&C plan data on the potential for demand response to reduce peak load.[62] The demand response resources include residential and commercial storage, direct load control, commercial and industrial interruptible load, and a dual-fuel program. We assumed increases continue through 2030, as per the capabilities reflected in the plan; and we held the effective demand response contribution fixed from 2030 through the end of the planning horizon.

[61] Response to Synapse IR-1 b), October 22, 2021.

[62] PEIEC, Electricity Efficiency and Conservation Plan, Appendix B, Demand Response Achievable Potential, page 4. December 2021.

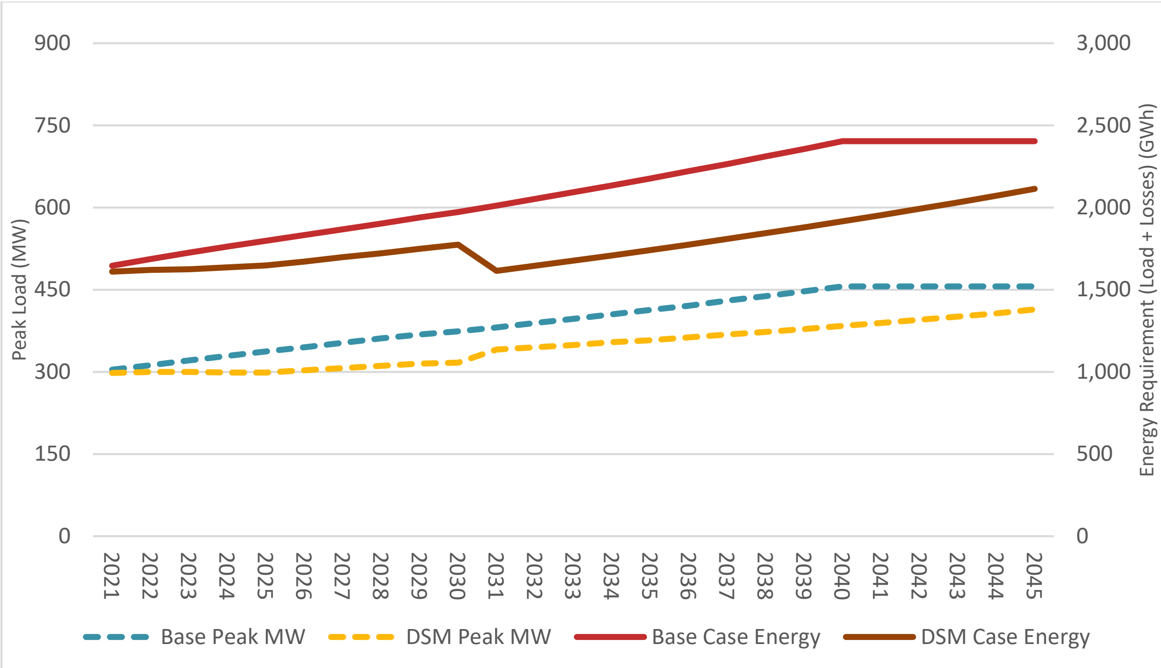
Table 3. Electricity Efficiency and Conservation Plan savings—proposed and projected to guide alternative system plan lower load scenario

			Annual		Cumulative from 2021 Baseline	
Calendar year	**EE&C Plan Year**	**EE&C Plan**	**Energy (GWh)**	**Peak reduction (MW)**	**Energy (GWh)**	**Peak reduction (MW)**
2021	21/22	Existing	Annual and cumulative amounts, and current level of spending, is less than one-half of proposed 2022/2023–2024/2025 plan.			
2022	22/23	Proposed	12.44	5.71	12.44	5.71
2023	23/24	Proposed	10.84	5.52	23.28	11.23
2024	24/25	Proposed	11.17	5.62	34.45	16.85
2025	25/26	Projected = to Extending Proposed Plan	11.17	5.62	45.62	22.47
2026	26/27		11.17	5.62	56.79	28.09
2027	27/28		11.17	5.62	67.96	33.71
2028	28/29		11.17	5.62	79.13	39.33
2029	29/30		11.17	5.62	90.30	44.95
2030	30/31		11.17	5.62	101.47	50.57

Source: Synapse tabulation, based on EE&C Plan, Appendix B, page 2.

The following Figure 4 shows the trajectory of energy and peak load we have assumed for the alternative system plan modeling. Generally, the DSM Load Impact plan shows a relative flattening of the trajectory over the first decade, but increases are still assumed for modeling purposes. The core alternative plans modeled do not necessarily reflect the fully achievable economic levels of energy efficiency.

Figure 4. Base and DSM Load Impact case—energy and peak load trajectory (island-wide)



Source: Synapse, based on MECL ISP load forecast ("Base"), and reductions to base levels from EE&C plan estimates.

<u>Past and Projected Performance of EE&C Plan and Implications for Resource Planning</u>

The 2022–2024 proposed EE&C Plan indicated reduced participation and overall savings performance from the current set of programs.[63] The proposed plan notes the "continuing engagement of the Advisory Group as well as annual program evaluations and a broad focus on continuous improvement"[64] of the EE&C plan.

In 2019, Synapse's recommendations concerning the 2018–2021 EE&C Plan included continuing with an Advisory Group process, conducting a potential study, and targeting peak load growth measures. The currently proposed plan builds off of the results of the completed potential study and reflects targeting of additional demand response for peak load reduction

The steps to be taken by efficiencyPEI should include not just increased funding for efficiency savings, but an increased level of marketing the benefits of the program to participants. EfficiencyPEI should also focus on Advisory Group recommendations to increase participation, which would include careful program incentive design across all measures.

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[63] PEIEC, 2022/23–2024/2 EE&C proposed plan, page 6.

[64] EE&C proposed plan, pages 4–5.

3.2. Modeling Scenarios and Input Assumptions

This section summarizes the base and alternative scenarios modeled and presents the input assumptions used for both capacity expansion and production cost aspects of the analysis.

Scenarios

To examine the cost and implications of alternative ISPs, Synapse modeled the following four core scenarios:

1. **Base**. Base load forecast, 2022 retirement of the CTGS, replacement of the Borden gas turbines in 2031, existing wind resources plus additional expansions of wind in 2023 (30 MW) and 2025 (40 MW). Energy and capacity procurement from New Brunswick.
2. **DSM Load Impact**. Same as Base scenario, except lower load (energy and peak) forecast trends, based on the effect of the increased level of DSM expected with updated EE&C plans.
3. **Optimized Base**. Using the same load forecast as the Base case and allowing capacity expansion optimization.
4. **Optimized DSM Load Impact**. Using the same load forecast as the DSM Load Impact case and allowing capacity expansion optimization.

The modeling results for two additional sensitivities are also included:

- Explicit representation of additional demand response resources, based on demand response potential included in the proposed EE&C Plan; and
- Increased cost of New Brunswick energy, relative to MECL's confidential trajectory of prices. This reflects, for example, any form of increased carbon dioxide emission pricing that might impact New Brunswick and increase the cost of energy for import to PEI.

Our recommendations for MECL for its On-Island Supply (or, capacity) Study includes analyzing a further sensitivity where the cost of capacity from New Brunswick is higher than the trajectory laid out in MECL's confidential responses to Synapse interrogatories on the ISP.

Input Assumptions

Table 4 below contains a summary of the core input assumptions used across the four scenarios analyzed.

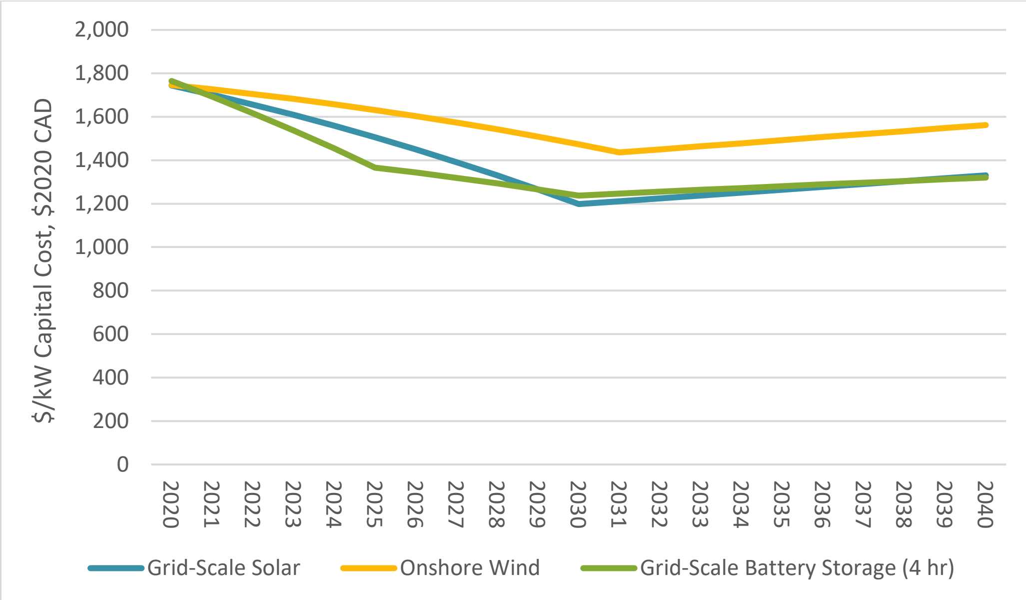
Table 4. Key input assumptions for modeled scenarios

Parameter	Base	DSM Load Impact	Optimized Base	Optimized DSM Load Impact
Peak Load	Island: 304 to 374 MW (2021–2030), increasing to 456 MW by 2040, flat thereafter	Island: 298 to 317 MW (2021–2030), increasing to 394 MW by 2040 and to 414 by 2045	Same as Base	Same as DSM Load Impact
Annual Energy	Island: 1,646 GWh increasing to 1,972 (2021–2030), increasing to 2,404 GWh by 2040, flat thereafter	Island: 1,610 GWh increasing to 1,775 (2021–2030), increasing to 1,917 GWh by 2040 and to 2,114 by 2045	Same as Base	Same as DSM Load Impact
Cost of New CT resources	$1,800/kW (2024) based on MECL estimate for the cost of a new 50 MW CT at CTGS ($90 million for a 50 MW CT). MECL estimate based on escalation of costs seen in 2015 application.			
Cost of New Brunswick import capacity*	Confidential—MECL.			
Cost/initial availability of battery storage capacity	4-hour battery storage in 2023 is $1,537/kW (nominal), declining in real terms by 3.4%/year (average) through 2030, then rising slowly by 0.6%/year through 2040. Available in 2023.			
Cost of New Brunswick import energy*	Confidential—MECL. Import prices as modeled presume hourly marginal price variation, roughly equal on average to MECL confidential average values for period through 2025.			
Cost/initial availability of capacity—new wind	New onshore wind in 2023 is $1,631/kW (nominal), declining in real terms by 1.7%/year (average) through 2030, then rising slowly by 0.9%/year through 2040. Available in 2024.			
Firm capacity credit—battery storage and wind	Capacity credit for wind resources is equal to 17–21%, based on penetration. Capacity credit for battery resources also based on penetration, ranges from ~50–90%.			
Transmission—Non-Firm Energy Import Limit	400 MW			
Transmission—Firm Capacity Import Limit** (Lepreau plus other New Brunswick import)	300 MW—up to 2039 310 MW (2040–2045) Assumed incremental firm increase allowed for last portion of planning horizon.			
Period of analysis	2021–2045 (25 Year)			

*Notes: *Response to Synapse interrogatories IR-6 b though IR-6 g. **Firm capacity import of 300 MW from MECL ISP (page ii), and MECL response to Clarification Question IR-10 from Roger King, September 23, 2021: "While there is a total of 560 MW of thermal interconnection capacity between New Brunswick and PEI via four submarine cables [two new at 180 MW each, and two older at 100 MW each], the NB-NS/PEI maximum firm interface transfer capacity is currently 300 MW." The response further notes in a footnote that "There are times when the NB system cannot provide the 300 MW and the PEI system is reliant on on-island generation to make up the difference." Synapse assumes this latter statement is in reference to resource capacity on the New Brunswick side of the cables, and not the cables themselves.*

Figure 5 below illustrates the pattern of declining real cost (through 2030) and then slightly increasing real cost for the key clean energy technologies (wind, solar PV, battery energy storage) serving as capacity and energy provision options for the optimized scenarios.

Figure 5. Real cost trajectories of clean energy technologies for EnCompass modeling



Appendix A contains a table of explicit capital and operating costs assumed for new generation supply, and operating costs for the existing assets in PEI where applicable.[65]

Other assumptions include the following:

- A pattern of import and export exchanges across New Brunswick boundaries with Nova Scotia and New England was the same for all scenarios. These patterns account for historical exchange patterns between New Brunswick and New England, and they account for projected changes to flow patterns between New Brunswick and Nova Scotia based upon Nova Scotia's recent integrated resource plan and changes to Nova Scotia policies concerning renewable energy percentage requirements and coal phase-out considerations.

- MECL estimates for longer term (2026 and beyond) capacity and energy costs are based on inflation. We used the MECL values for capacity costs. For energy, we presumed market-based hourly energy value reflecting New Brunswick's participation in the New England and Nova Scotia marketplaces.

- Synapse estimated DSM costs based on PEIEC's current proposed EE&C plan. We estimated a 25-year net present value cost based on the difference in energy requirements between the Base and DSM Load Impact cases and based on the per-unit costs for achieving energy requirement reductions from PEIEC's plan.

[65] The modeling used no estimates of capital cost or book value of existing assets on PEI, as all scenarios reflect the same amount of existing supply assets; thus, no differential costs are seen across the scenarios in respect of those costs.

- A sensitivity case assumed higher energy prices in New Brunswick. We assumed implementation of a form of carbon emission pricing that led to increases in the variable costs of operation for New Brunswick fossil resources that are part of the set of marginal electricity producing resources in the province. The purpose of the sensitivity was to determine if increased wind energy resources on PEI would be reasonable if New Brunswick energy import prices were substantially higher by the decade of the 2030s. The model results seen in the next section confirm this hypothesis.

3.3. Modeling Results

Summary results of modeling the base case and alternative integrated system plan scenarios are shown in the tables (Table 5 and Table 6) and figures (Figures 6-13) that follow. The section first shows alternative system plan resource trajectories for energy and capacity provision to meet PEI resource needs over the planning horizon (2021–2045). The results show alternative system plans that incorporate both energy efficiency improvements and incremental levels of battery energy storage resources (and some later period wind resources) relative to MECL's ISP, and related lower levels of capacity procurement from New Brunswick.

Figure 6 through Figure 13 show the projected energy and capacity resource provision for the Base load and DSM load level scenarios. We present Base and optimized scenarios (for each of two load levels analyzed) side-by-side to allow direct visual comparison. Figure 14 and Figure 15 that follow show the effect of the presence of battery energy storage resources on a winter day later in the planning horizon (2035). These graphs illustrate the key temporal leveraging of energy procurement that the battery systems enable. During the highest priced energy period (early morning and early evening peak periods in winter), batteries discharge to meet peak and avoid procurement of higher-priced energy; during lower load and lower energy pricing periods, the batteries recharge.

Figure 16 and Figure 17 show the results of the demand response case sensitivity, where additional demand response resources are presumed to be in place in PEI. Figure 18 and Figure 19 show the results of a sensitivity where energy prices in New Brunswick are assumed higher, leading to an optimal case that sees increases in wind and battery deployment on PEI during the 2030s.

Next, Table 5 and Table 6 present the net present value of modeled costs (including cost components) for the different scenarios. The costs modeled include operational costs (or, production costs) and the costs that would be incurred for new resource procurements. The costs explicitly include the costs of capacity and energy purchases from New Brunswick, required to meet most of PEI's load.

Scenarios with the same trajectory of peak and energy requirements can be directly compared to each other. The results seen in Table 5 and Table 6 demonstrate the lower costs associated with the optimized plans, which have different resource portfolios to meet load requirements. Those tables also illustrate that the total cost for plans with increased levels of energy efficiency are lower than the costs for Base scenarios, inclusive of the estimated costs for securing peak and energy consumption reduction through more efficient use of energy.

Resource Plan Results: Base and Alternative Integrated System Plans

Figure 6. Base case—energy resources (TWh), 2021–2045

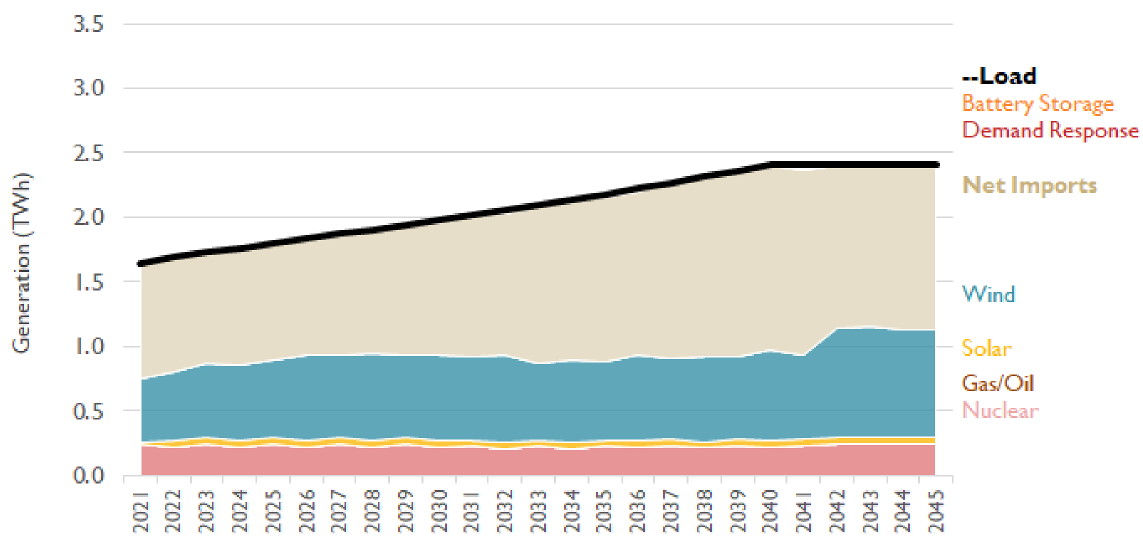
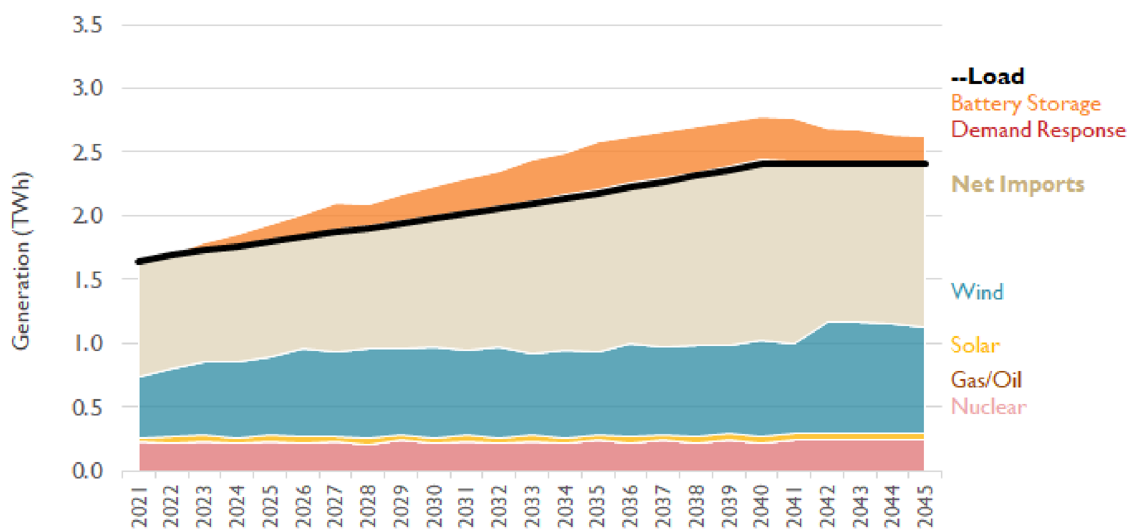


Figure 7. Optimized Base case—energy resources (TWh), 2021–2045



Note: Net annual import quantities are similar between base and optimized cases, but the timing and average cost of those imports differ, reflecting the energy arbitrage (temporal) value of battery storage. Battery storage energy represents the amount of stored energy and losses, sourced from other generation resources in the stack.

The figures above illustrate the following:

- Optimization leads to an increase in battery energy storage resources; this does not materially change the annual amount of energy resources used, but it allows for time-shifting of purchased energy to lower cost periods. The battery storage layer on the chart shows the magnitude of total PEI energy delivered through the battery system.

Figure 8. Base case—capacity resources, 2021–2045

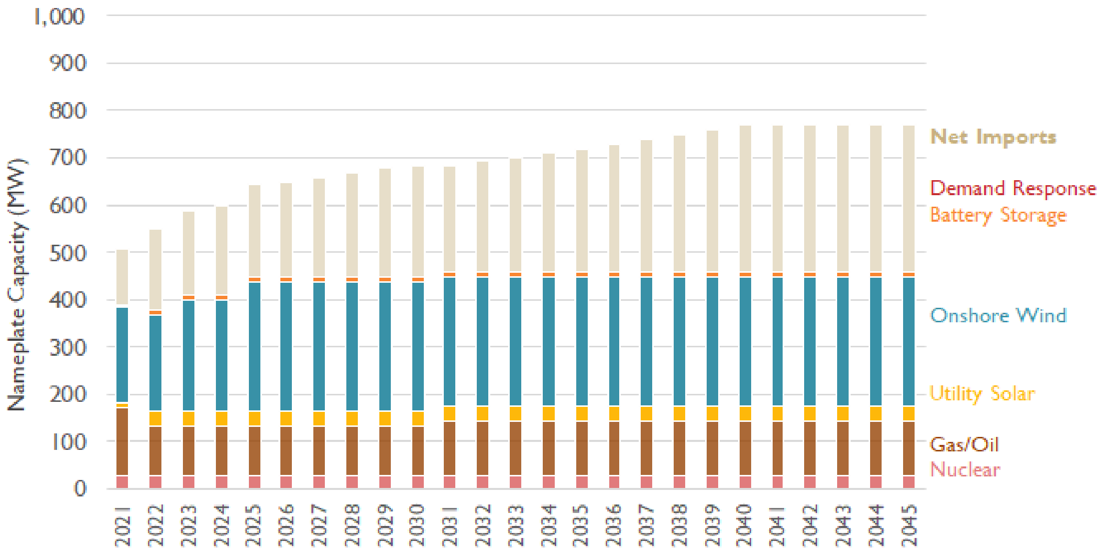
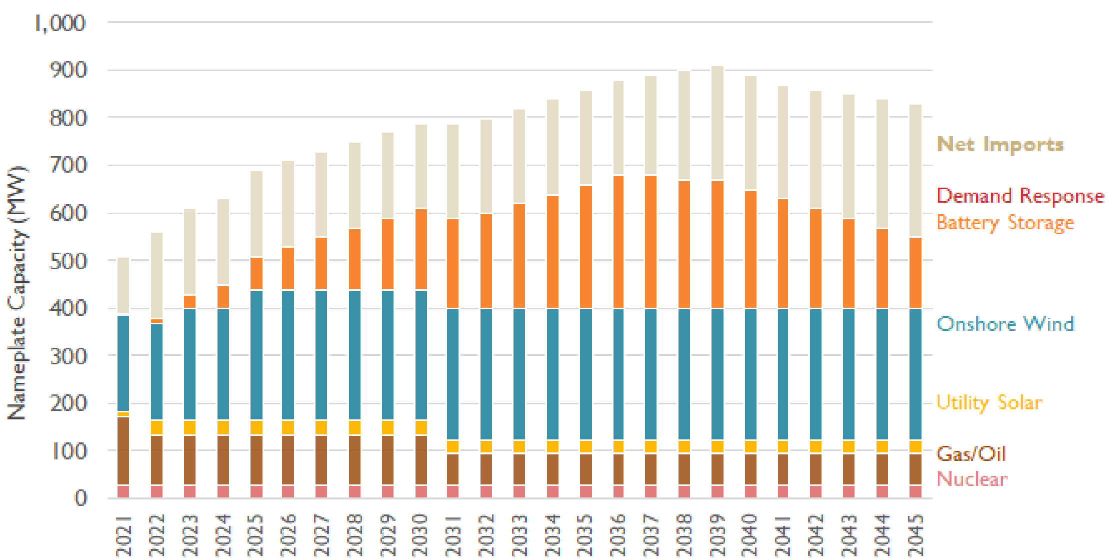


Figure 9. Optimized Base case—capacity resources, 2021–2045



The figures above illustrate the following:

- As noted with Figures 6 and 7, optimization leads to an increase in battery energy storage resources.
- A reduction in New Brunswick capacity import is seen in the optimized case; for example, by 2035 New Brunswick procurement is lower by 60 MW (260 vs. 200 MW).

Figure 10. DSM Load Impact case—energy resources (TWh), 2021–2045

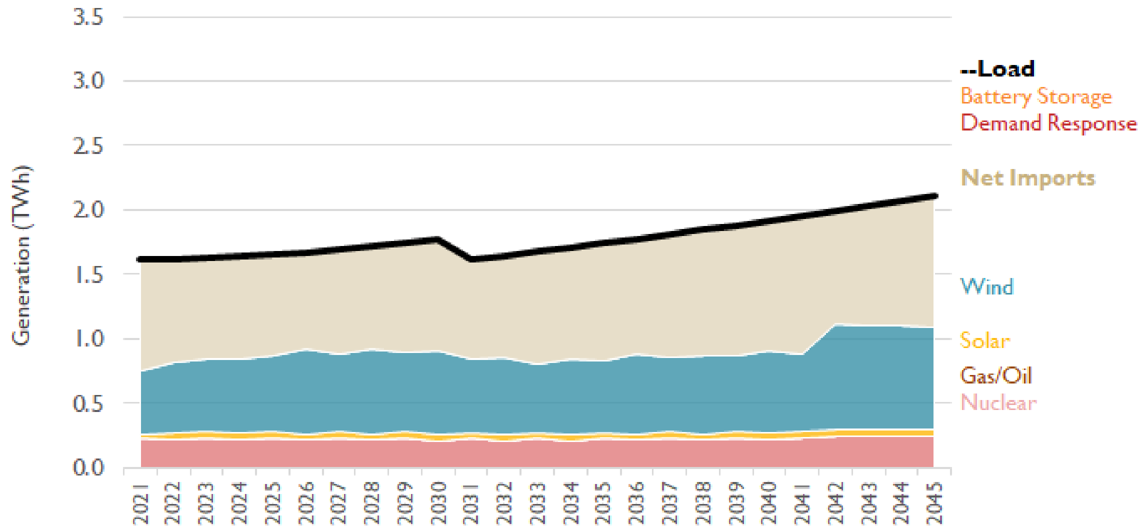
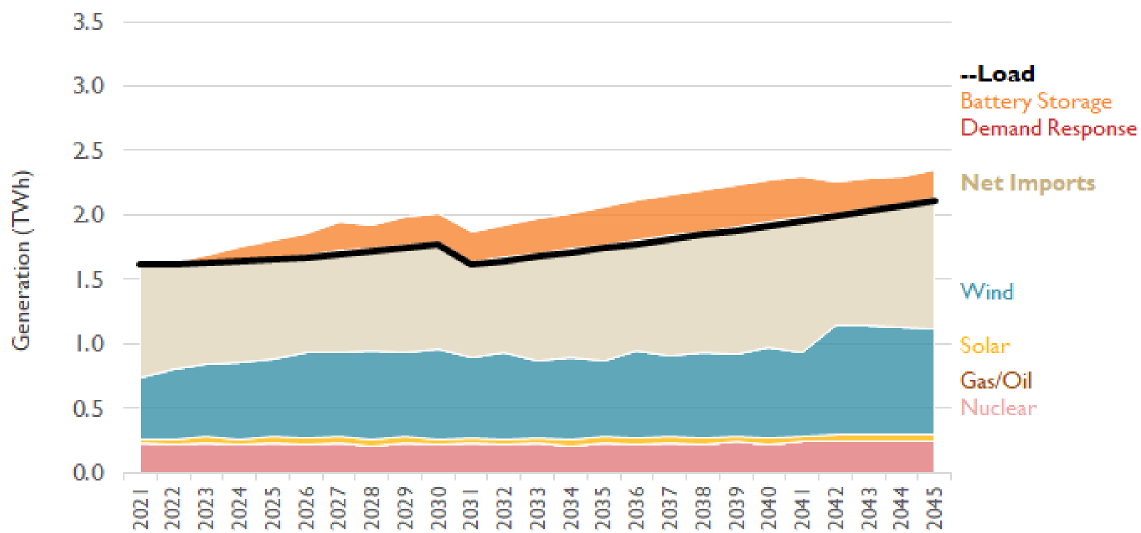


Figure 11. Optimized DSM Load Impact case—energy resources (TWh), 2021–2045



The figures above illustrate the following:

- As with the Base case, the lower load levels in the DSM case also result in an optimization that leads to an increase in battery energy storage resources. It allows for time-shifting of purchased energy to lower cost periods. The "battery storage" shows the magnitude of total PEI energy delivered through the battery system. The same pattern of additional increments of wind procurement in the later years, relative to the Base case, is seen in the Optimized DSM Load Impact case.

Figure 12. DSM Load Impact case—capacity resources, 2021–2045

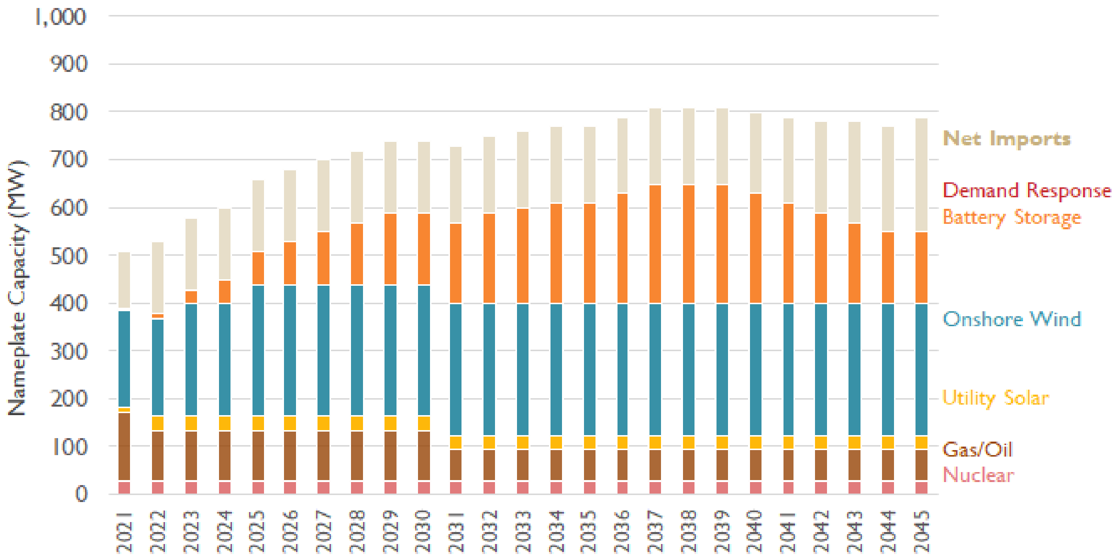
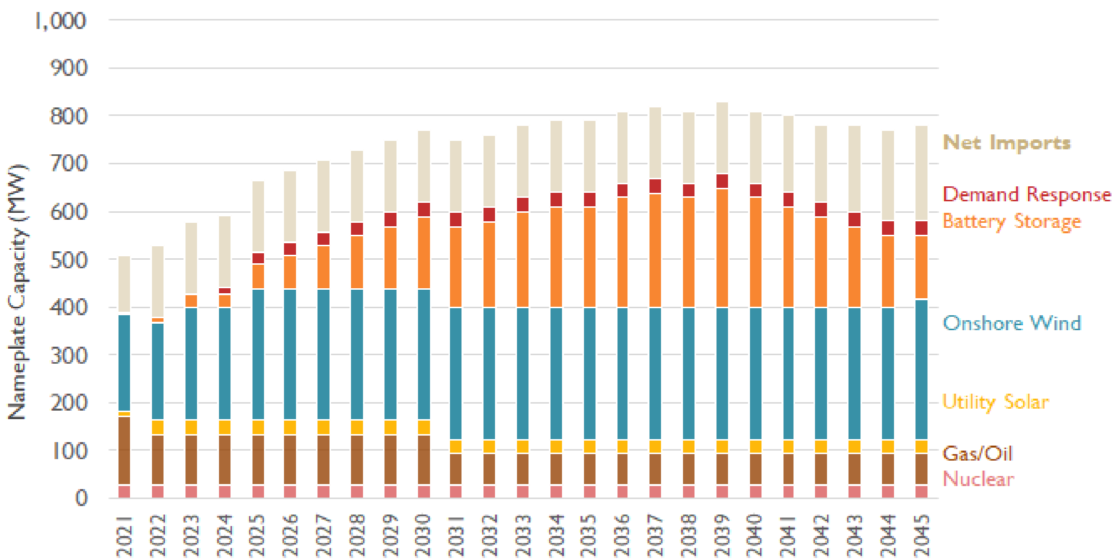


Figure 13. Optimized DSM Load Impact case—capacity resources, 2021–2045



The figures above illustrate the following:

- As noted with Figures 9 and 10, optimization leads to an increase in battery energy storage resources. In this case, the battery amounts reach a high of 231 MW by 2040.
- A reduction in New Brunswick capacity import is seen in the optimized case; by the end of the planning period, procurement is lower by 70 MW (240 vs. 310 MW).

Figure 14 and Figure 15 illustrate (based on the specific modeling output) what occurs on a winter day when the PEI system is more dependent on battery capacity to meet its needs. The greatest value comes from utilizing the battery to charge during times of less expensive energy (or greater wind output), and discharge during times of highest peak load or higher energy prices, which is usually during winter evenings, or early morning periods.

Figure 14. Battery charging and discharging pattern—Optimized Base case

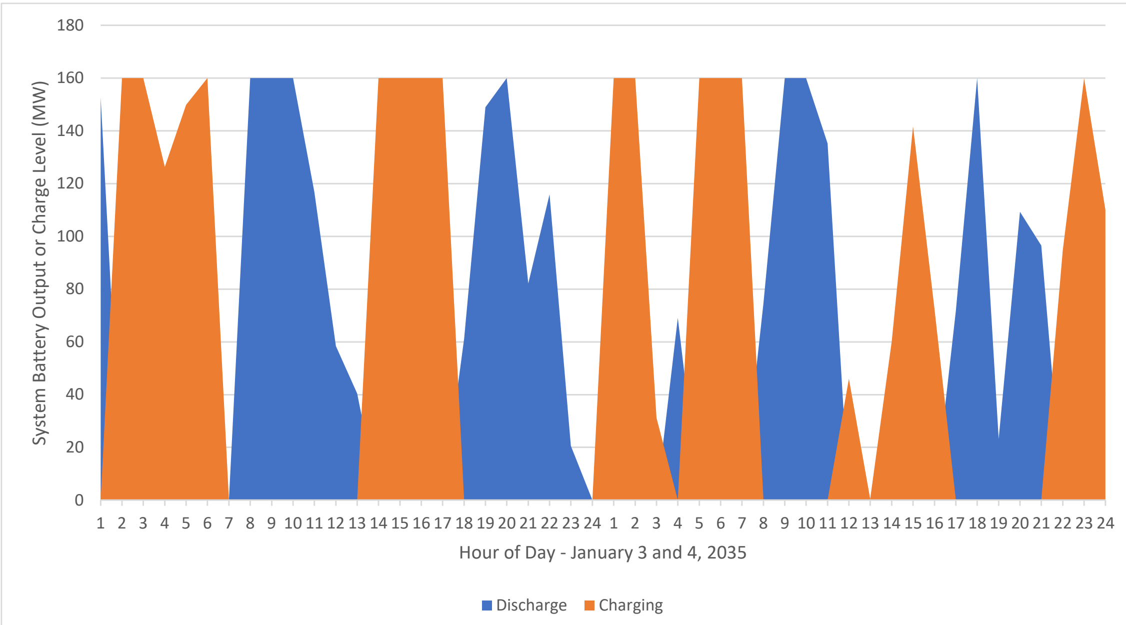
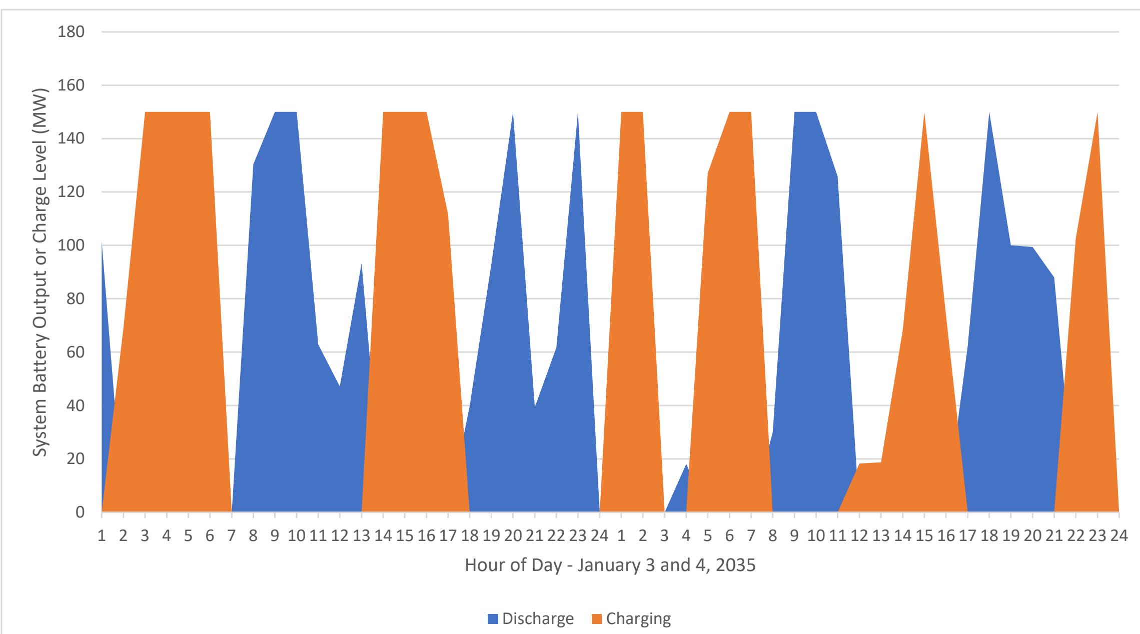


Figure 15. Battery charging and discharging pattern—Optimized DSM Load Impact case



The battery storage resources are available to support capacity needs during any interruption of supply from New Brunswick. However, the optimal sizing of the resources modeled here assumes a firm import capacity of 300 MW, which reflects the loss of at least one of the two newer submarine cables but not a full loss of interconnection. The PEI system could be optimized to ensure capacity availability during a full loss of supply, but numerous assumptions concerning the load conditions, the duration of supply loss, and wind output patterns (reflecting the season of the year, and the time of day of the supply interruption) would be required in order to gauge the level of on-Island capacity needed that would also reflect the presence of other island resources, wind or fossil-fired.

<u>Sensitivity Cases: Additional Demand Response Resources and Higher New Brunswick Energy Prices</u>

The following two sensitivity case results reflect (1) the effect of including larger levels of demand response in the projected resource plan, and (2) the impact on PEI's optimal supply if energy prices in New Brunswick were higher, due to applied carbon emission pricing.

Figure 16 and Figure 17 show the energy and nameplate capacity profile of the scenario that includes additional demand response capacity, illustrating minimal energy interaction (Figure 16) but showing (in Figure 17) that the demand response resource takes the place of imported New Brunswick capacity.

Figure 18 and Figure 19 highlight two changes that occur to the resource optimization if energy prices in New Brunswick were higher: first, Figure 18 shows an increase in PEI wind buildout during the decade of the 2030s, as wind is less expensive than imported energy; and second, Figure 19 demonstrates that battery buildout is higher in the case where New Brunswick energy prices are higher, as more wind would be in existence on PEI in this scenario. This is a reasonable result, as the model is optimizing a less expensive energy selection by taking advantage of lower cost wind resources on PEI, compared to New Brunswick energy imports.

Figure 16. Increased Demand Response case—energy resources (TWh), 2021–2045

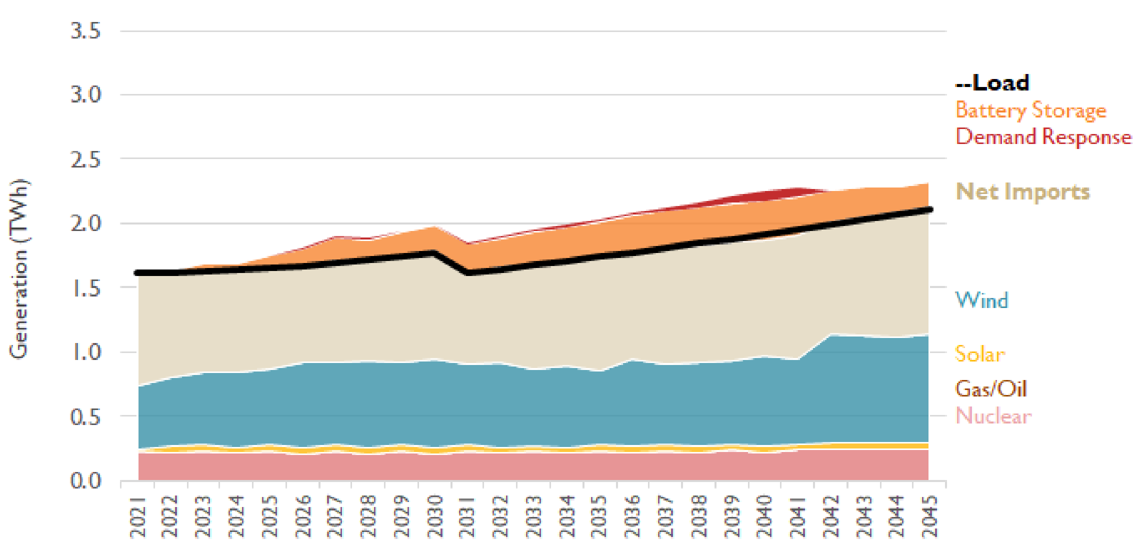


Figure 17. Increased Demand Response case—nameplate capacity, 2021–2045

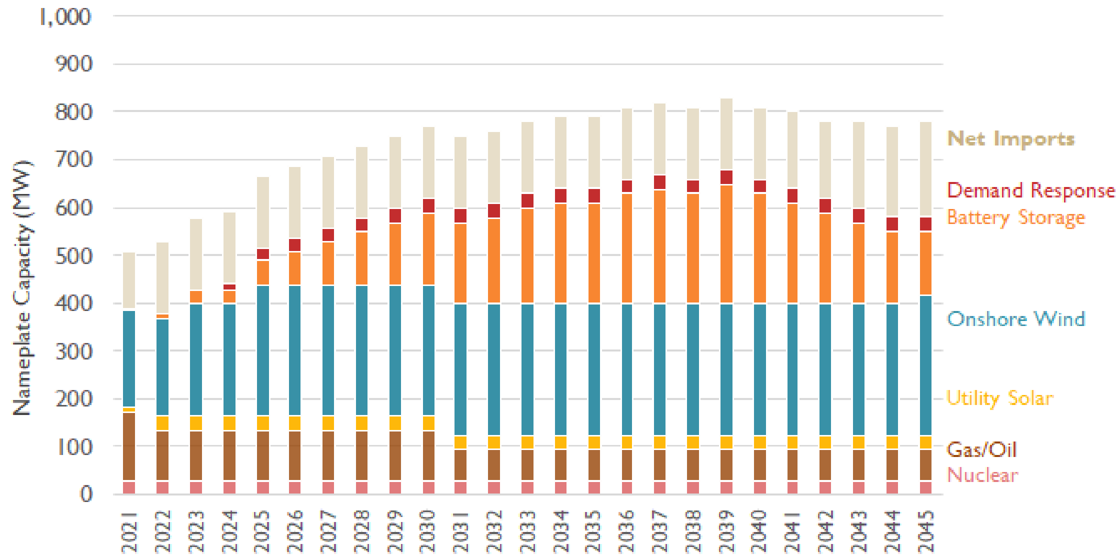


Figure 18. High New Brunswick Energy Price case—energy resources (TWh), 2021–2045

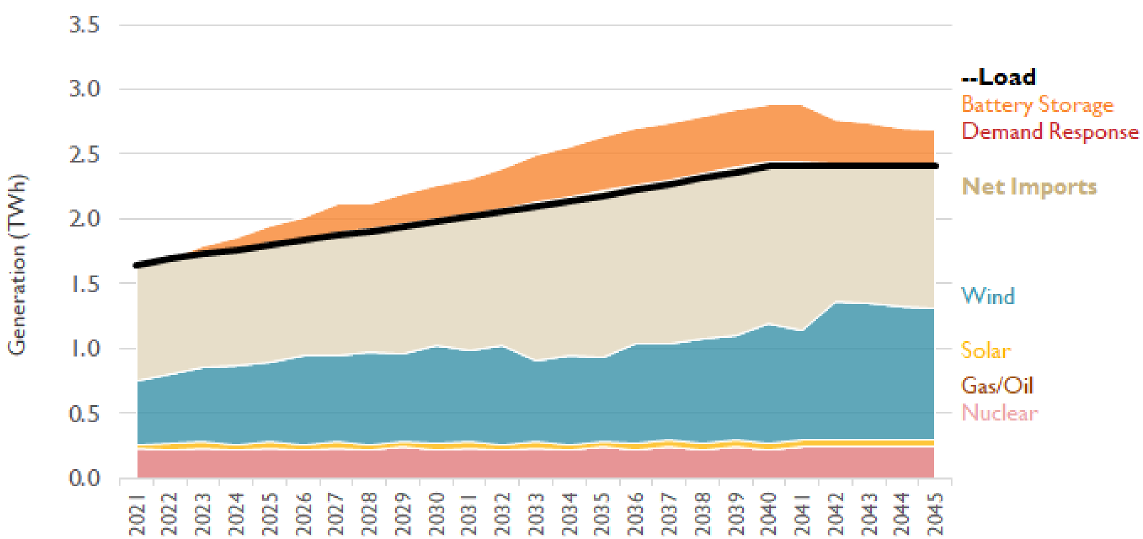
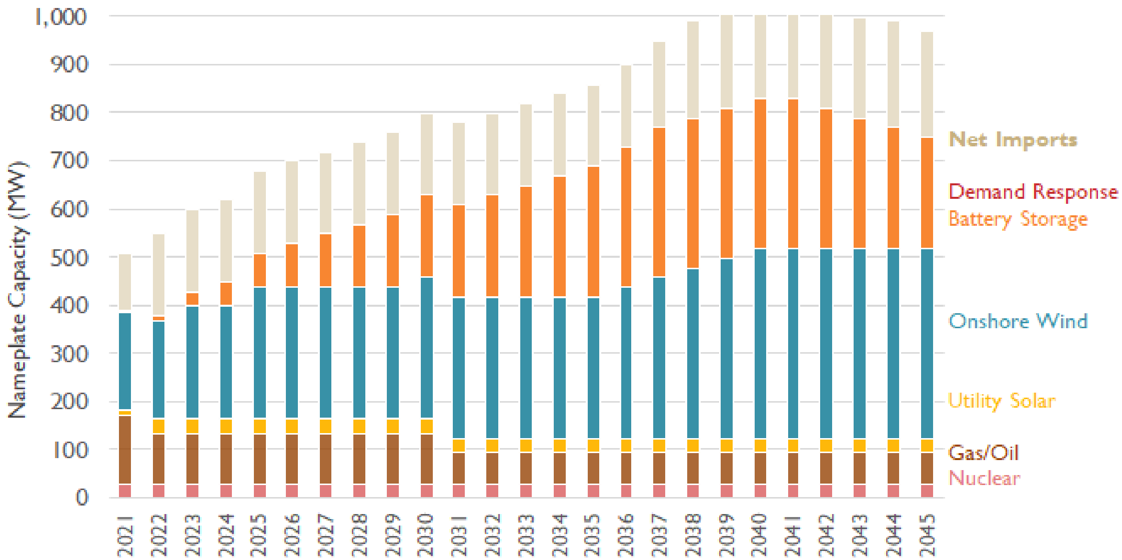


Figure 19. High New Brunswick Energy Price case—nameplate capacity, 2021–2045



- Additional increments of wind are procured in the later years, relative to the optimized case, due to higher energy costs for New Brunswick imports.

Net Present Value Differences: Base and Alternative Integrated System Plans

Table 5 and Table 6 below show that optimizing the resource selection over time leads to an increase in the use of battery storage resources to both provide capacity support and (critically) to allow economic arbitrage of energy value. This is the case at both higher and lower load levels, as would be expected. The Base load level scenarios show that optimizing the resource selection leads to a roughly 10 percent lower cost, when considering a 25-year planning horizon and using a discount rate of 6.85 percent. Purchased energy costs are lower (even though purchase quantities are similar; the timing of purchase is different) and capacity import purchases are reduced because the batteries serve a portion of the capacity requirement for PEI.

Table 5. 25-Year NPV costs base load levels, $ millions CAD

Cost Component	Base	Optimized	Difference, Optimized Case	Percentage Difference
Operating Costs (Fuel, O&M) Incl. Lepreau share	$386	$417	$31	7.9%
Energy Import Procurement - New Brunswick	$1,472	$1,091	-$381	-25.9%
Capacity Import Procurement - New Brunswick	$233	$196	-$38	-16.1%
DSM Costs	$0	$0	$0	
New Resource (Battery, Wind) Costs	$79	$246	$167	NA
Total	**$2,171**	**$1,950**	**-$221**	**-10.2%**

Note: NPV is computed in $2021 CAD, using a discount rate of 6.85 percent, tied to MECL's weighted average cost of capital.

Table 6. 25-Year NPV costs DSM load levels, $ millions CAD

Cost Component	DSM scenario	Optimized (DSM scenario)	Difference, Optimized Case	Percentage Difference
Operating Costs (Fuel, O&M) Incl. Lepreau share	$386	$424	$38	9.7%
Energy Import Procurement - New Brunswick	$1,059	$745	-$314	-29.7%
Capacity Import Procurement - New Brunswick	$232	$162	-$70	-30.2%
DSM Costs	$98	$98	$0	
New Resource (Battery, Wind) Costs	$0	$219	$219	NA
Total	$1,776	$1,647	-$128	-7.2%

Note: NPV is computed in $2021 CAD, using a discount rate of 6.85 percent, tied to MECL's weighted average cost of capital.

Comparing the costs for plans with and without DSM impacts shows that net present value costs are 16–18 percent lower for the plans with DSM impacts (and costs) included. This is seen by comparing the Base to the DSM scenario between Table 5 and Table 6, for either the unoptimized or the optimized (16 percent) cases.[66] It illustrates that even if DSM costs were considerably higher than estimated in the proposed EE&C plan, as long as those programs perform over the planning horizon ratepayers will be significantly better off than they would be in the case absent the programs.

4. Key Findings, Next Steps, and Recommendations

Our key findings are categorized into two areas: ISP review and modeling results, and the impact of ISP review on Capital Application elements.

4.1. Key Findings: ISP Modeling Results

- The total operating and capital costs of the DSM Load Impact scenario are less than those of the higher load scenario, inclusive of an estimate of costs for the DSM impacts based on the different energy and peak load inputs used in the modeling and based on PEIEC's projected DSM costs. This is aligned with both the Dunsky technical and achievable potential study, and the positive (>> 1.0) benefit/cost ratios seen in PEIEC's electricity efficiency and conservation plan filing of December 2021.

- Optimizing the selection of new resources over the 25-year planning horizon leads to a steady increase in the amount of battery storage capacity added to the Island system, compared to the Base case where new capacity required due to increasing peak load was procured almost solely from New Brunswick. This result holds for scenarios with base levels of load, and with load levels lowered due to the anticipated effect of more aggressive DSM implementation.

- The capital cost of new battery energy storage is higher on a per-kW basis than New Brunswick capacity procurement and is comparable to (or lower than) new CT costs. Optimized plan cases economically favor battery storage over CT builds. In addition to providing capacity, on-Island battery systems allow PEI to leverage the timing of required energy procurement from New Brunswick by discharging battery capacity during times of peak requirements, and/or higher New Brunswick energy price periods. This can be seen as either charging the battery systems from PEI wind energy (which has a very low, if not zero, marginal cost) or charging the batteries when New Brunswick energy costs are at their lowest. This attribute of battery energy storage systems is particularly important for PEI since it imports such a large fraction of its energy

[66] 18% = ($2,171-$1,776)/$2,171. 16% = ($1,950-$1,647)/$1,950

requirements, and any leveraging of the timing of such purchases allows for savings to accrue to ratepayers.

- In both optimized cases, the batteries discharge during peak periods of the day, and recharge during non-peak periods of the day.

- The value of batteries includes their ability to help regulate the system during normal periods, and also during any disconnection of supply from New Brunswick or during "islanded operation." The ISP notes that wind generation can be limited during islanded operations in part because of the need to use on-Island fossil resources to stabilize the variation in wind output. Battery storage acts as a buffer that can make islanded operations more efficient, as it can serve as the load-following resource without having to otherwise constrict remaining fossil operations during islanded conditions.[67]

4.2. Key Findings: Impact on Capital Application Elements

- The greatest impact seen from this modeling exercise is the clear indication that the combination of reduced system peak load due to DSM impacts, and the ability to provide on-Island capacity with battery energy storage systems allows for an immediate deferment, and potentially eventual elimination, of any need to replace the capacity from the retiring CTGS with a new CT. The corollary is a potential for capital expenditure requirements for battery energy storage systems in the very near term to support capacity needs and allow for the savings associated with energy arbitrage.

- A less demonstrable impact is likely for some portion of the proposed capital expenditures that are tied to the distribution system and transmission system needs influenced by system and local peak load increases. Widespread deployment of DSM measures in line with the proposed EE&C plan will reduce system peak, but the impact on local feeder peak loads could vary. Similarly, deployment of smart meters and potential reduction in peak loads from rate designs and/or direct load control can offset peak load increases otherwise expected from electrification. MECL and efficiencyPEI should coordinate deployment of energy efficiency and peak-load-shaving resources that arise from all future EE&C plans, and any demand response or distributed battery deployment. By doing so, they can target, at least initially, those feeders whose loads are more likely to lead to a need for upgrades due to thermal ratings exceedance on critical circuit elements.

[67] Section 7.4.5 of the ISP discusses "Energy Supply while Islanded," noting that disconnection of New Brunswick supply is "low risk but possible events could cause a lengthy interruption of mainland energy supply." The 2018 November outage was 7 hours, with a few additional hours required to "energize all available substations on PEI" (page 41).

4.3. Next Steps

- MECL's forthcoming study of the generation need issue should carefully consider and model the system taking the key ISP analysis findings into account. In particular, the ability for battery energy storage to arbitrage the timing of import purchases and more efficiently provide load-following capacity should be a lead element of the study. MECL should obtain the most recent data on battery energy storage cost and performance to ensure accurate economic analysis. Sensitivities that consider higher costs for New Brunswick energy and/or capacity should be part of the study's scenario analysis design.
- MECL should thoroughly explore ongoing demand response opportunities through enabling technologies as efficiencyPEI moves into its next three-year programming phase. With smart meter installation envisioned for the entire island and electrification of heating and transport end uses potentially adding peak load, peak-load-shaving opportunities through rate structures and direct load control (in addition to effects of electric end-use efficiency deployment) must be closely examined.
- MECL should directly incorporate analysis of the value of distributed battery resource solutions (in addition to the value of demand response resource deployment noted above) to reduce feeder peak loads into its ongoing distribution system capital expenditure analyses. MECL should consider a structured integrated distribution system planning approach to ensure that distribution system capital expenditures consider the role that demand response, distributed batteries, and the overall effects of increased electric efficiency can have in mitigating peak load increases from electrification.

4.4. Recommendations

- The On-Island Generating Study should expand to an On-Island Capacity Resource Study to directly allow for and consider battery energy storage as an incremental capacity resource that can be charged with existing wind energy and potentially New Brunswick grid energy during off-peak hours as economically dictated.
  - It is critical for MECL and its contractors to have up-to-date information on battery energy storage cost options, and to conduct sensitivities assuming higher capacity and energy procurement costs from NB Power for some years.
- MECL should continue to defer capital expenditure projection for a new on-Island CT but allow for earlier capital expenditure for battery energy storage capacity if its on-Island study finds best "first" on-Island capacity is initial utility-scale battery procurements.
- MECO should update its ISP to directly reflect a load forecast accounting for the new EE&C plan.
  - MECL should prioritize managed charging and smart meter / other DR control options for peak increase limitations as heat pump installations and the number of EVs on the Island increase.

- MECL should carefully revisit T&D expenditures that are dependent on projections of load growth to defer expenditures if / as peak load growth is mitigated to amounts lower than seen in the current ISP.

Appendix A. Capital and Operating Cost Assumptions and Nameplate Capacity Results

See separate attachment.

Appendix B. EnCompass Modeling Details

Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that allows for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including the following:

- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load shaping and shifting capabilities; production cost modeling
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis
- Long-term integrated resource planning, including capital project optimization and environmental compliance
- Market price forecasting for energy, ancillary services, capacity, and environmental Programs

EnCompass demonstrates flexibility in temporal representation:

- 8,760 hours/year, or reduced form (e.g., 2, 24-hour days/month—peak and offpeak—each month. 48 hours/month x 12 months)
- Often used in reduced form for capacity expansion, and 8760 form for production cost analysis

Input assumptions usually include the following:

- Market price forecasts (shadow pricing) for energy and ancillary services
- Relies on a database (National Database) that includes Maritimes (Nova Scotia, New Brunswick, PEI) loads and resources

Synapse used the Maritimes database in all modeling runs, focused on New Brunswick and PEI generating resources. New Brunswick is represented in detail as the source of import energy based on the marginal costs of generation in the province and considering its load requirement. The Nova Scotia and New England boundaries are represented with interchange flows based on historical patterns; and for Nova Scotia, anticipating changes to those patterns for the Nova Scotia–New Brunswick interface.