FINAL ARGUMENT OF THE PROTECT THE CHIGNECTO ISTHMUS COALITION

Matter EL-002-2025

Application by NB Power for Approval of the
Renewables Integration and Grid Security (RIGS) Capital Project
Pursuant to Section 107 of the Electricity Act

February 19, 2026

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1.0 Executive Summary

1.1 PCIC Position

The Protect the Chignecto Isthmus Coalition (PCIC) respectfully submits that NB Power's Application for approval of the Renewables Integration and Grid Security (RIGS) capital project should be denied.

The Application seeks the Board's approval for a 25-year, approximately $3.5 billion project to construct and operate a 400MW dual combustion turbine facility with synchronous condensers. This substantial capital commitment warrants rigorous scrutiny, comprehensive analysis, and clear evidence of prudence.

After extensive review of the evidence, interrogatory responses, and a week-long hearing, PCIC submits that NB Power has failed to meet its burden of establishing the prudence of this capital project. The evidentiary record reveals fundamental deficiencies in NB Power's application including: flawed resource adequacy assessment, inadequate consideration of alternatives, abandonment of its Integrated Resource Plan (IRP), and failure to demonstrate least cost solutions for NB Power customers.

1.2 Inadequacy of Evidence

This is not merely a case of debatable assumptions or competing expert opinions. Rather, NB Power has presented a series of disconnected documents cobbled together post-hoc, lacking the thorough, integrated analysis expected, and that legislation demands for a project of this magnitude.

From the outset, including the initial filings of evidence, there has been a fundamental lack of a comprehensive and coherent rationale for the RIGS project. It is apparent that NB Power never genuinely anticipated this project would require Board review; as a result, a collection of existing internal documents was rapidly assembled to support some semblance of a regulatory application.

The consequence has been that intervenors and the Board have been forced to navigate disjointed fragments of evidence, necessitating extensive information requests and responses in an attempt to bring critical documentation into the record, decipher key details, and strive to ascertain the truth. Although this process yielded additional information, the struggle continued throughout the week-long hearing, where NB Power staff offered meandering accounts of internal events and management discussions as further justification for RIGS approval.

1.3 The "No Study" Problem

As Mr. Logan of the Board correctly noted (Day 3 Transcript, p. 150, line 4), there is no study — "no three inches of paper" that drove NB Power to this point.

The entire $3.5 billion, 25-year investment is effectively justified by an 8-page document NBP 6.07 that is over two years old and has not been updated to reflect current conditions. The Board is left without a solid basis to assess prudence because the proper analysis and reporting has simply not been done.

PCIC submits that <u>if this level of evidence is sufficient</u> for NB Power to proceed with a 25-year, $3.5 billion project, it is no wonder that NB Power finds itself in financial difficulty and appears unable to avoid large capital project challenges.

1.4 The Test for Prudence

The goal of utility regulation is to impose on monopolies the discipline that competition imposes on competitive industries, thereby ensuring consumers pay only a fair, just, and reasonable amount for services received. As it relates to capital projects here, this goal is achieved by requiring NB Power to present sufficient evidence to establish that any project over $50 million is prudent.

According to Webster's online dictionary, prudence includes: the ability to govern and discipline oneself by the use of reason; sagacity or shrewdness in the management of affairs; skill and good judgment in the use of resources; caution or circumspection as to danger or risk.

Based on the definition of prudence and the objectives of Section 107 of the Electricity Act, the Board should not approve this capital project if NB Power's Application fails to demonstrate:

- Shrewd management
- Skill and good judgment in the use of resources
- Proper consideration of risks and benefits
- Delivery of the most economical service at the lowest cost to customers
- A failure to demonstrate the need based on Resource Adequacy

Failure on any of these points is sufficient to decline the application and PCIC submits the proposed RIGS project falls short on every point.

1.5 Key deficiencies

PCIC submits that NB Power has failed to discharge its burden of demonstrating the prudence of the RIGS capital project. The evidentiary record is characterized by:

- No comprehensive, integrated capital project study;

- A capacity decision driven by an outdated, 8-page document lacking comprehensive independent analysis;
- Alternatives structurally excluded from consideration by the Project Charter;
- A project not reflected in — or inconsistent with — NB Power's own approved IRP and Strategic Plan;
- Serious financial prudence concerns, including the absence of a tolling agreement analysis and the failure to respect NB Power's equity targets;
- A procurement process that foreclosed legitimate options before a proper analysis was completed.

PCIC respectfully submits that the appropriate path is to deny the Application and direct NB Power to conduct the rigorous, independent, and comprehensive analysis that this level of capital commitment demands — consistent with the IRP, with genuine consideration of alternatives coupled with demand response and demand-side management, and finally a procurement structure that properly protects ratepayers.

2.0 Electricity Act Section 107

2.1 Introduction and Standard of Review

To be helpful for the Board, we will first walk through the key elements of this Hearing in concordance with the Electricity Act, then this will be followed by in-depth arguments regarding the major topics.

This proceeding requires the Board to apply Section 107(11) of the *Electricity Act* and determine whether NB Power's RIGS project—and, specifically, NB Power's choice of a tolling agreement over an ownership model—is prudent and in the public interest.

A prudent utility manager, acting reasonably and with due regard to least-cost principles, equity objectives, statutory requirements, and approved planning, would not:

1. **Depart** from the approved Integrated Resource Plan ("IRP") without adequate justification;
2. **Select** a more expensive tolling structure over ownership;
3. **Overbuild** capacity not shown to be necessary under resource adequacy standards;
4. **Rush** on a compressed and unrealistic schedule that inflates costs; or
5. **Forego** basic governance disciplines, transparency, and its own Investment Governance framework.

2.2 Section 107(11)(a): Electricity Policy of the Government S.68

2.2.1 Section 68(a)(ii): Equity Target (20%)

The 20% equity target in Section 68(a)(ii) has been consistently reinforced in mandate letters from the shareholder and should have been central to NB Power's decisions. The undisputed evidence from NB Power and the public interveners' expert, Mr. Madsen (see NPB14.01 IR-4 at p. 13), establishes:

1. **The tolling agreement** negatively affects the equity target more than the ownership model.
2. **Reducing the project size** (e.g., from 400 MW to 200 MW) would facilitate progress toward the equity target.
3. **Not building new capacity**, as suggested by Mr. Palmero, would likewise materially improve progress toward the equity target.

NB Power chose the tolling structure on the basis of an initial schedule that was unrealistic and not achieved, despite the decision's hundreds of millions of dollars in net present value ("NPV") difference. On this basis alone, the Board should find that choosing a tolling agreement over an ownership model was not prudent, and not the decision of a reasonable manager given the importance of the 20% equity target. See Mr. Madsen's economic expert remarks in NPB 14.01 IR-4 on p. 13.

2.2.2 Section 68(b): Resource Adequacy and Efficiency

Section 68(b) enables Board-adopted codes and standards for resource adequacy through the use of reliability in the framing of the requirement.

Section 68(b)(i) requires the most efficient supply of electricity. Constructing rarely used, unneeded capacity inherently reduces efficiency and is inconsistent with prudent utility management.

Section 68(b)(iii) requires that, even where resource adequacy is considered, the result must be the lowest cost of service to customers. On the record before the Board, ownership is less expensive than tolling agreement no matter which party's NPV analysis is used and thus better aligns with Section 68(b)(iii).

2.2.3 Section 68(c): Rates as Low as Possible; Just and Reasonable Rates

Section 68(c) requires rates to be maintained as low as possible. Because the tolling agreement is more costly than the ownership model, it undermines this mandate.

Moreover, the Board must assess whether the rates in the tolling agreement are just and reasonable with the rigor of a rate proceeding. There is no evidence on the record substantiating the underlying costs in the tolling rate. To the contrary, the record shows the return on equity ("ROE") embedded in the tolling rate increased 3–4% between the first and second approvals by NB Power's Board of Directors after competition was dropped from the REOI process. See NBP 8.83C, NBP 8.85C, and NBP 8.14C. The Board should review these documents in detail. This concern is shared by Mr. Madsen. See NPB14.01 IR-6 at p. 19.

Conclusion under Section 68: The tolling decision undermines the equity objective, increases costs, reduces efficiency, and has not been justified to the "just and reasonable" standard. It is not prudent.

2.3 Section 107(11)(b): Approved Integrated Resource Plan S.100

2.3.1 Section 100(a): Load Forecast

NB Power's rejection of the approved IRP rests primarily on a revised load forecast. KPMG's internal audit (NBP 8.68 at p. 14) acknowledges that 2021–2022 population inputs understated actual population, affecting the forecast. While population is hard to forecast, actual population data should be updated annually.

However, the change in load forecast was not materially different enough to justify discarding the approved IRP. In NBP 8.35 at p. 73, NB Power's own graph compares the IRP's high load forecast with the NBP 6.07 Resource Adequacy Assessment forecast. Starting at 2028—the key date—the IRP's high forecast exceeds the Resource Adequacy forecast, yet the IRP does not show any new generation until 2030, and then only 100 MW, not 400 MW. By 2030, the IRP high load forecast remains substantially above the Resource Adequacy forecast; and by 2034, the updated load forecast never reaches the 3,300 MW shown for 2030 in the IRP scenario in which 100 MW is built.

This confirms there was no sound basis to deviate from the IRP's high-load scenarios: no capacity was needed until 2030, and then only ~100 MW. This is consistent with Mr. Palmero's evidence that NB Power may not need new capacity beyond 2030 and possibly beyond 2034. A reasonable manager would not discard the IRP on this record.

2.3.2 Section 100(b): Demand-Side Management (DSM)

For the past decade, NB Power's regulations and practice have emphasized DSM (reduce and shift) to defer new builds. The revised load forecast abandoned this ethos in a single stroke. DSM should have been NB Power's first tool. The April 17 SEOC meeting minutes reflect workshops and consultations that included numerous participants but not DSM experts. A reasonable manager would have deployed DSM first. A prudent manager would not have discarded the lowest cost and easiest to implement strategies for deferring new builds.

2.3.3 Section 100(e): Planning Horizon for Section 107 Applications

Section 100(e) supports extending the “three-year” plan to a ten-year horizon for applications under Section 107.

2.3.4 Section 100(f): Transparency of IRP Assumptions

Section 100(f) requires transparency for key assumptions. Many of NB Power’s assumptions have been challenged and are indefensible. PLEXOS can export all assumptions, aligning with the mandate letter’s “open by default” direction. The Board should order NB Power to provide all PLEXOS assumptions submitted to the government for IRP approval, as an appendix to the IRP.

2.3.5 Section 100(g): Stakeholder Consultation

NB Power typically solicits input before developing the IRP but does not release a draft IRP for public comment prior to filing with the Executive Council. The Board should order NB Power to publish a draft IRP for public comment and include those comments in the IRP.

2.3.6 Section 100(2): Least-Cost, Sustainability, Risk Management

RIGS is not least-cost or economic, and building unneeded fossil generation is inconsistent with net-zero goals. See NBP 8.82 at p. 87 (project risk register shortly before signing the tolling agreement). This project presents extraordinary risk; the Board should review the risk register carefully. A prudent manager would not choose a project that is not least-cost, not economic, is fossil-based and unnecessary for net-zero, and is extremely risky.

2.3.7 Section 100(3): Board-Directed IRP Content

Section 100(3) empowers the Board to require additional IRP content for Executive Council approval. Our conclusions will outline a series of recommendations for the 2026 IRP.

2.3.8 Section 100(4)(c): IRP Updates “At Any Time”

Section 100(4)(c) permits NB Power to submit an IRP for approval at any time (not merely at fixed three-year intervals). If NB Power wished to reflect the revised load forecast, it could and should have updated the IRP for shareholder approval. That did not occur. The Board should note: RIGS is not in the approved IRP—“the three-inch-thick document” referenced by Mr. Logan.

NBP 8.82 (April 17 SEOC minutes) at p. 8 identifies as a key risk:

“Revised estimate of shortfall (please see Appendix A – Resource Adequacy Report, 18-March-2024) not reflected in the IRP as filed with the EUB.”

NB Power knew from the outset that the IRP misalignment would be an issue, but proceeded anyway, effectively discarding a recently approved IRP. The April 17 minutes are the origin of RIGS and should be reviewed in detail. The minutes show that key decisions on scope, schedule, and cost were made via SEOC workshops and consultations **[REFERENCE ONLY]** Energy Control Center, Generation, Transmission Engineering, Enterprise PMO, Environment, First Nations, Legal, Corporate Evaluation, Corporate Planning, Strategic Partnerships, Corporate Communications, Corporate Affairs, Procurement, Risk & Treasury, and Business Transformation, **and there was consensus regarding:**

1. No plausible pathway other than combustion turbines—alternatives not considered.
2. An unrealistic deadline that materially increased costs and was not met.
3. Dual fuel was selected without cost discipline.
4. Renewable fuels were posited without substantiation.
5. Preference for one large, expensive project.
6. Site selection risks with inadequate notice to neighbors.
7. Adding synchronous condensers despite questionable need and no operational cost assessment.

These decisions proceeded without DSM experts present. The project rests on an 8-page report (Mr. Clark) produced four months after the new load forecast—prompted by forecast deficiencies arising from failure to account for actual population. This 8-page report remains the principal justification, never updated despite expert evidence that the underlying analyses were not being done annually.

Basic diligence questions were not asked or answered, including:

1. Where are the PLEXOS results showing combustion turbines are the only option?
2. Where are the PLEXOS outputs showing this is the least-cost solution?
3. What alternatives were assessed and compared?
4. Have we attempted to reduce the capacity (MW) requirement?

5. What steps have been taken to extend timelines via Demand response or DSM?
6. Can recently deployed smart meters be leveraged?
7. Is the schedule realistic, and is it reasonable to risk $220 million in NPV (April 17th meeting notes) with no guarantee of meeting that schedule?
8. Would the tolling agreement contain a lease that would go on the balance sheet?
9. Didn't the approved IRP contemplate public financing for all projects except renewables?
10. What will the EUB conclude about the lack of alternatives and least-cost?
11. What about future fossil fuel prices, U.S. supply risks, and future environmental regulation?
12. Why build fossil fuel capacity with net-zero goals outstanding?
13. Doesn't the IRP require shareholder approval for such a project?

There is no evidence that the shareholder approved this project; the shareholder may not have been aware until the first public media release. A reasonable manager does not proceed with a project of this magnitude without shareholder approval.

Regardless of NB Power's attempt to circumvent this review process, the NB Power Capital Project Charter (attached to the April 17 minutes at p. 11) confirms NB Power always treated RIGS as a capital project. Yet NB Power did not follow its Investment Governance Framework for capital projects. The Charter references Investment Rationale Documents (IRDs) as a gate, but no IRDs have been submitted in this proceeding. A billion-dollar investment without investment rationale evidence is not a prudent and reasonable practice.

The record also shows two missing SEOC meeting minutes between April 17 and October 8:

- **The April 17 minutes** (p. 9) say the project team would return to SEOC prior to issuing the public RFEOI (Gate 3), target June 25. There is no evidence Gate 3 occurred (no June minutes). This is critical because the REOI should have included both ownership and tolling options to enable proper comparative analysis. Limiting to tolling foreclosed ownership and excluded EPCs unwilling to own/operate. While November is the "official" ownership vs. tolling decision, the real decision was baked into an REOI that omitted ownership.
- **August 19, 2024:** The evaluation criteria were allegedly approved on this date, but no minutes exist. We have material concerns about the evaluations to be addressed in camera. We cannot describe them publicly but emphasize there are serious procurement issues. We further note that the redactions in the in-camera record appear to conceal not only commercially sensitive information, but also poor NB Power decisions. We request the Board review the redacted transcripts

to determine whether redactions were appropriate. The public deserves maximum transparency.

Finally, the Capital Project Charter states that, from day one, "[c]onsideration of other types of power generation to meet the 400 MW capacity deficit is out of scope." Alternatives were out of scope from inception. The only "alternatives" analysis appears newly created for this Application, not drawn from prior analytical work. A reasonable manager would not refuse to consider alternatives.

Mr. Clark admitted on cross-examination that updating PLEXOS with the new load forecast and pricing, and reviewing results, would take about a week—and he had four months before the SEOC meeting. Yet the least-cost analysis was not performed. All four resource adequacy experts agree the IRP process should have been used to identify and compare least-cost alternatives. Even where engineering judgment refines modeling results, deviations from least-cost must be reasoned and transparent. NB Power started with an unjustified engineering conclusion before least-cost was determined; to date, least-cost has never been established.

The absence of RIGS in the approved IRP should be considered a significant barrier to approval of NB Power's application, as there has been no shareholder approval.

2.4 Section 107(11)(c): Strategic, Financial, and Capital Plan S. 101(3)

Section 101(3) requires the three-year financial plan to be consistent with the latest approved IRP. NB Power has downplayed the IRP as merely "directional," but the Act is explicit: the three-year plan shall not be inconsistent with the approved IRP.

Notably, NB Power did not file the three-year plan with its original application, despite Section 107(11) requirements. It entered the record only during cross-examination via an undertaking PCIC requested. A reasonable manager files minimum statutorily required materials with an Application. The Board should order NB Power to produce an extended three-year plan (to 10 years) for all Section 107 supply-side applications, including sensitivities for all options and a "no-project" baseline.

Given the inconsistency with the IRP and lack of the supplemental analysis recommended in the E3 Report (Mr. Olson), this presents another barrier to approval.

2.5 Section 107(11)(e): Executive Council Directives S.69

Section 69(2) requires consideration of the most recent mandate letter. Once again, NB Power failed to submit the mandate letter and three-year plan with its application; both entered the record only through PCIC interrogatories and cross examination. The Board should assess whether NB Power complied with the mandate letter's expectations including:

1. Evidence-based decisions; open transparency - No.
2. Authentic engagement with New Brunswickers, communities, stakeholders, and experts - No.
3. Rebuild First Nations relationships through a nation-to-nation approach - No.
4. Balanced fiscal responsibility while enhancing essential services - No.
5. Proper consideration of a 25-year contract with a U.S. counterparty and potential for tariff disruptions and natural gas supply insecurity - No.
6. 20% equity target given due consideration (and whether RIGS pressures rates while hampering equity progress) - No.
7. Whether RIGS rates allow the corporation to absorb uncontrollable risks; whether risk premiums are extreme and unjust while leaving substantial residual risk - No.
8. Public leadership and transparency; making information more accessible - No.
9. Accurate financial statements; request an audit of existing PPAs to determine lease content - Order requested.
10. Duty to consult with First Nations - This has effectively been out-sourced to a U.S. company.
11. Procurement quality and price discipline - Not demonstrated.

These issues under the Act pose a significant barrier to a prudence finding in this Matter.

2.6 Section 107(11)(f): Policies Under S.142(1)(f) — Resource Adequacy

NB Power's application relies on a resource adequacy argument (not NPV, speculative exports, or generalized reliability & energy security). Yet two NPCC resource adequacy reports in the record show the Maritimes Area is compliant with the 0.1 LOLE days/year standard in 2028 without RIGS, and remains well below the standard into the foreseeable future:

- NB Power/NPCC-approved assessment: NBP 8.06 (results at p. 44). NB Power had this report before filing but did not file it because it shows RIGS is not required for adequacy.
- NPCC/NERC ProbA: "2025 NPCC Long Range Adequacy Overview | NERC Probabilistic Assessment (ProbA) | Final Report," in Brattle's rebuttal evidence, NBP 12.07 at p. 234. Conducted by NPCC using different software, yet similar results: adequacy is maintained without RIGS.

This is a fatal flaw of NB Power's Application. The Board adopts resource adequacy standards where NPCC is the compliance assessor. If NPCC is satisfied, the Board should be as well.

2.7 Section 107(11)(g): Other Relevant Factors

NB Power's discussions of speculative export sales, Point Lepreau reliability, and asserted RIGS benefits fall into the category of other relevant factors. Granted, they warrant less weight relative to the statutory criteria above. We also note that NB Power's testimony last week was not expert opinion and was largely comprised of unsupported opinions. NB Power offered no independent, detailed evaluation of: resource adequacy, RIGS economics, procurement, or portfolio selection; as these were conspicuously absent from the scope of work for NB Power experts.

The Board should focus on the pre-filed evidence: NB Power's written evidence; the 8-page stale report; an IRP that shows no need for RIGS; an outdated load forecast; and the tolling agreement itself. Much of the critical evidence entered via interveners' IRs; there was no second IR round to test NB Power's responses. We have identified the materials on record that deserve the highest weight through these final arguments and cross examination.

2.8 Conclusion Regarding the Act

On every Electricity Act Section 107(11) criterion, the record raises serious issues:

1. The tolling agreement is costlier than ownership and impairs equity progress (referring to Section 68).
2. The approved IRP was improperly discarded; least-cost was never established; DSM was sidelined; alternatives were out of scope from inception (Section 100).
3. The three-year plan is inconsistent with the IRP and was not filed until compelled (Section 101(3), Section 107(11)(c)).
4. Mandate letter expectations were not met, including transparency, stakeholder engagement, First Nations consultation, equity progress, and fiscal responsibility (Section 69(2), Section 107(11)(e)).
5. NPCC adequacy studies show no need for RIGS to meet LOLE (Section 107(11)(f)).
6. Other asserted benefits are speculative and warrant minimal weight (Section 107(11)(g)).

PCIC contends that it is easy to find that the project is not prudent. Conversely, to reach a finding of prudence, on this record, is a decision that is almost impossible to justify.

We will now turn to 6 key topics that warrant more detailed analysis, the first of which is resource adequacy…

3.0 Resource Adequacy

3.1 Resource Adequacy — The First Key Factor

3.1.1 What This Application Is (and Is Not) About

NB Power's application is premised on **resource adequacy**, not on NPV comparisons of alternatives. As clarified in the NPCC Directories' definitions, **resource adequacy is a subset of reliability**, and **reliability** comprises **adequacy** and **security** (NBP 8.39 at p. 21). Resource adequacy is a **probabilistic planning tool** that NB Power uses to determine its **20% planning reserve margin**—the standard used throughout the Maritimes (NB, NS, PEI, and Northern Maine), and the margin NB Power has historically applied (see NBP 6.07). It is **through this narrow lens of resource adequacy** that the Board must place substantial weight when assessing the prudence of NB Power's application.

Resource adequacy is measured by **Loss of Load Expectation (LOLE)** with a limit of **0.1 days/year**, applied to the **Maritimes Area as a whole**, not to NB Power in isolation.

The original application materials—the NBP 6.xx documents—**do not contain a LOLE study**. It was confirmed in IRs and on cross-examination that **neither** of the two calculations in NB Power's Resource Adequacy Assessment (NBP 6.07) is a LOLE probabilistic study, although the **planning 20% margin** (Table 1, left-hand side, NBP 6.07) is **derived from** a LOLE study performed by NB Power using PLEXOS.

Through the IR process and Rebuttle evidence, **two LOLE-based resource adequacy studies** entered the record. We submit these are the **proper foundation** for the Board's decision. The application really ought to have included NPV comparisons of alternatives, and the lack of economic consideration suggests this was not at all a concern of NB Power on behalf of rate-payers.

3.2 The Two Key LOLE Studies To Rely On

3.2.1 2025 Maritimes Area Comprehensive Review of Resource Adequacy

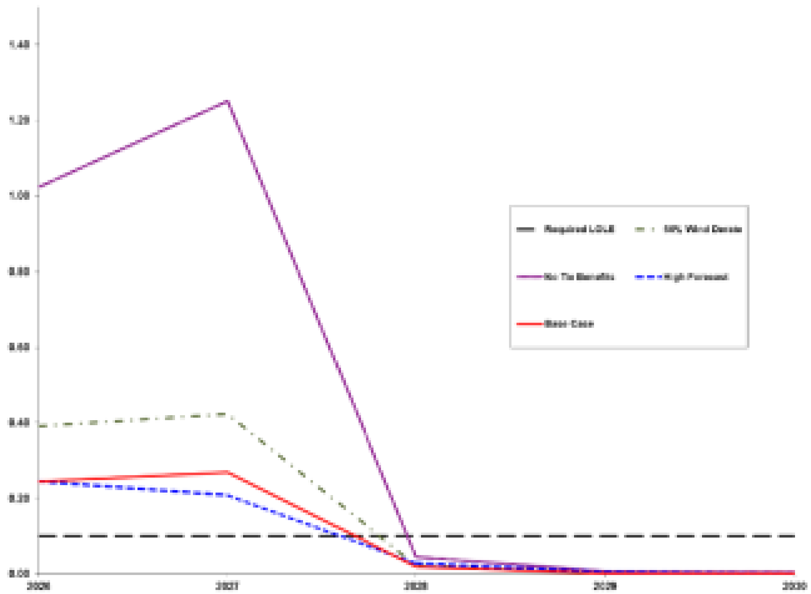
(NBP 8.06, p. 26 et seq.)

This study was primarily performed by NB Power, with support from Nova Scotia Power acting as the **Planning Coordinator** for the Maritimes Area. It is a **central piece of evidence** and should be afforded **significant weight**.

- **Timing and credibility:** The document is dated **October 2025**, i.e., **before** NB Power's pre-filed evidence deadline. NB Power **did not file it**, which raises a credibility concern (NBP 8.06 at p. 53).
- **Schedule reality:** It shows RIGS is **not online** by **Winter 2028**, but rather **Winter 2029**. This undermines the purported "urgency" that has driven **hundreds of millions of dollars** in additional costs to meet Winter 2028—costs that were **"all for nothing."**
- **Adequacy results:** The Maritimes **do not meet** LOLE criteria in **2026–2027**, but **easily meet** the standard in **2028 without RIGS**. Even using the **300 MW** No Interties sensitivity, the analysis shows **RIGS is not needed as far out as 2030**. LOLE (no tie benefits) on p. 43 is **0.045 days/year in 2028**, **0.008 days/year in 2029**, and **0.004 days/year in 2030**.

Capacity exports during a crunch. It emerged on cross that one reason the Maritimes are not compliant in 2026–2027 is that NB Power has **capacity export contracts** in ISO-NE. When Board Staff asked Mr. Cody directly whether NB Power is **selling capacity in a capacity crunch**, he answered: **"Yes, that's correct."** (Feb. 11, p. 61.) Mr. Pollock added that NB Power or its marketing affiliate would proceed with such commercial obligations **"if it's a net positive benefit for New Brunswickers."** If NB Power's **financial risk management policies** allow selling capacity that New Brunswickers need, **those policies warrant review**. The sales affect the **Maritimes LOLE**—not just New Brunswick's—raising the question why, if our **neighbors** are also in a crunch, the capacity was not sold **within the Maritimes** instead. See NBP 8.06 at pp. 52–53: removal of a **122 MW** sale after May and addition of a **177 MW** sale starting June in NB. Although the panel noted these contracts **"unwind"** and should not affect winter capacity, **there is no proof** on the evidentiary record; what **is** on record is that they **do** affect the Maritimes LOLE results.

Figure 4: LOLE Results – Base and All Sensitivity Cases



3.2.2 2025 NPCC Long Range Adequacy Overview | NERC Probabilistic Assessment

(ProbA) | Final Report (NBP 12.07 at p. 234)

This is a combined **NPCC/NERC** report (CP-8 Working Group) using **GE MARS software**, not NB Power's PLEXOS software. It was prepared by the **regulators themselves**, not NB Power. It **mirrors** the findings of the 2025 Maritimes Comprehensive Review: adequacy is satisfied **without RIGS**. We submit that if **NPCC and NERC**—the bodies responsible for adequacy compliance—show RIGS is **not** needed and there is **no urgent capacity shortfall**, the Board should **not be persuaded by threats of rolling black-outs**.

3.3 NB Power's Resource Adequacy Assessment

NBP 6.07 (p. 7) is an **8-page** document upon which NB Power's billion-dollar proposal relies. It should be afforded **zero weight since:**:

- It is **two years old** and **has never been updated**;

- It omits the **new, lower load forecast**; excludes the **additional 500 MW of wind** under signed PPAs; omits **new DSM programs**; and fails to reflect the change in **Belledune derating** from 375 MW back to **410 MW**;
- The status of **export contracts** is unclear; and
- Despite these deficiencies, NB Power still "stands by" the March 2024 report today.

The **recommendations** section is particularly problematic. It jumps from recommending **400 MW of capacity** to prescribing **combustion turbines**, relying on the IRP's **100 MW in 2030** as justification—yet the IRP (even under high load) **does not** show additional CTs **until Coleson Cove retires in 2040**. It also sketches a business plan for **export sales** if NB overbuilds, labels this **"extremely low risk"** and **"no regrets"**, and supplies **no substantiating evidence** in the body of the document. On Feb. 9, during cross examination, we showed NB Power itself treats export sales as among the **most significant risks** to RIGS (see NBP 6.82 at p. 87). When confronted with their own text, NB Power **would not admit** that their evidence said what it plainly stated.

The record indicates the **extra 200 MW** above the Load & Resource (L&R) Balance calculation was **always intended** for **short-term export sales**—a proposition laden with risk, dependent on **uncertain future value streams**, and requiring re-up **every 3 to 4 years**. Given rapid technology evolution, there is no assurance CTs will set capacity prices, nor that other jurisdictions will not favor **self-sufficiency**. If NB Power wants to build capacity **to serve export markets**, it must **make that case** - it has not - so the Board should give **very little weight** to speculative short-term export revenues.

There is **consensus among the three resource adequacy experts** in this hearing that portfolio selection should, at least as a **starting point**, be undertaken using **PLEXOS within the IRP process** (as the Act requires). Mr. Clark testified that **updating** the load forecast and pricing for CTs and batteries would take **about a week**; NB Power's supplemental responses to PCIC **confirm it was never done**.

3.4 Load & Resource Balance vs. Operational Requirement

The Board must decide whether to rely on the **Load & Resource Balance calculation** (the historical standard used by NB Power and others in the Maritimes) or on the **Operational Requirement** calculation (NBP 6.07, right-hand side). This is an **easy choice**: the correct approach is the **L&R Balance**.

We agree with **Mr. Palermo** that the **Operational Requirement** calculation is **inappropriate**. His expertise is substantial, he has **no skin in the game**, and he demonstrated professional candor by **acknowledging errors** during oral testimony. His opinion should carry **high weight**.

We also agree with **Mr. Olson**. His expert framework confirms **operational planning for resource adequacy is not the standard** and that NB Power effectively **skipped the planning stage** that belongs in the IRP. The Board should give his report **significant weight** and adopt its recommendations. We note one point of difference: in IRs and cross examination, Mr. Olson stated that a **notice of material change** should go to the **EUB Board**; we submit the **Electricity Act** requires notification to the Executive **Council**, because the Executive **Council** approves the IRP. There is **no evidence** the shareholder approved this project. No prudent manager would proceed without that approval.

By contrast, **Brattle's** evidence should receive **very little weight**. Brattle is the only expert advocating for the **Operational Requirement** approach. Its report largely **repeats NB Power's two-year-old analysis**, did not conduct **independent, detailed reliability modeling**, and **did not update** known assumptions (e.g., **500 MW of new wind**). We do think the Board should consider their proposal in **NBP 8.66**, as it demonstrates NB Powers scope control over their work, overriding what Brattle originally thought were NB Power's needs.

3.5 There is No Requirement for an Operational Calculation

Even if considered, the "Operational Requirement" calculation would have to **conform to NPCC Directory 1, Appendix F** to qualify as a "requirement." It does not. Operational calculations are **deterministic**. Yet both NB Power and Brattle **mix in probabilities** (e.g., treating unplanned outages as probabilistic). As established in cross examination, **unplanned outages are treated deterministically**, based on **historical averages**—not probabilistically. Directory 1, Appendix F states:

> "Estimate the amount of generating capacity which will be unavailable. This quantity should be based on **historical averages** for forced outages and deratings."

Brattle stated it was **retained to ensure procedures were followed**, yet its report **does not follow** Appendix F's **Procedure for Operational Planning Coordination – Attachment A**.

The most significant numerical flaw is the **reserve requirement**. The calculation uses **715 MW**, but if corrected to **318 MW**, it would be essentially right—and indeed **lower** than the L&R Balance. To be consistent with Appendix F, the Board should **adjust the calculation by approximately 400 MW**.

The **only NPCC-compliant operational calculations** in evidence are the **18-month** calculations in **NBP 8.22**. As Mr. Furey emphasized in cross with Mr. Palermo, if the Board gives any weight to operational planning, it should rely on **NBP 8.22**, not the non-compliant operational calculation in **NBP 6.07**.

On cross regarding the **715 MW** in NBP 6.07, we cited **NBP 8.22** and asked why 715 MW was used in the Resource Adequacy calculation while **318 MW** appears in NPCC reporting. NB Power could not answer and provided an **undertaking**—**NBP 14.03**—which is a **key document** for the Board's review.

NBP 14.03 explains how operating reserves are calculated:

10-min reserve 100% of the most significant supply capacity - MSSC (typically Point Lepreau, unless it is down) **plus 30-min reserve = 50% of SMSSC** (typically Belledune), **minus** Regulation & Load-Following requirements, **minus** PEI & Northern Maine contributions (load-ratio share), **minus** Nova Scotia reserve sharing, **minus** ISO-NE reserve sharing.

Neither Brattle nor NB Power discusses the **Regulation & Load-Following** or the **PEI/Northern Maine contributions**—**555 MW of reserves** omitted in NBP 6.07. This is a **major error** in both assessments.

3.6 The "Flashing Red" Narrative and Shift to "Energy Security"

Mr. Furey described **NBP 8.22** as a "flashing red" sign, walking through net-margin entries that appear in **red**, many in the **shoulder seasons**. But he did not explain why they're red, nor whether red entries correlate to **Lepreau being down**. We confirmed on cross that Mr. Palermo **did not have time** to assess those details..

NB Power's shift—from **resource adequacy** to **"energy security"**—is procedurally problematic. On **Motions Day**, when we requested **full-year data** (not just **January–February**), Mr. Furey argued the shoulder months were **irrelevant** because the application addressed **peak winter hours**. NB Power **cannot have it both ways**: having argued the other ten months are irrelevant, it cannot now pivot to **energy security in the shoulder seasons** while interveners lack the data to rebut. NB Power also focused on **net margin**, which already includes **unplanned outages**; we submit **gross margin** is more appropriate for the Board's consideration.

In our review of **NBP 6.22**, the red entries in shoulder seasons are, in all likelihood, because **Point Lepreau is down** (see Maint/Derate columns). In shoulder seasons, NB Power can and often does rely on **imports**. Shoulder seasons **should not** be a resource adequacy concern. Moreover, nearly all red entries are **~200 MW or less**, consistent with the **L&R Balance** approach.

Consistent with **NBP 8.06 at p. 35**, NB Power has numerous **operational procedures** (e.g., purchasing capacity from Québec or New England). NB Power **did so** as recently as **December 2025** from Hydro-Québec when **Lepreau was down**.

As to the claim that Lepreau drives unusually high reserves: when **Lepreau is down**, the **largest contingency changes**, and required operating reserves **drop**. See **NBP 6.22** (top of p. 8): the required operating reserve is **~102 MW**; the Main Derate column suggests **Lepreau was out**. NB Power's IR responses and **NBP 14.03** (bottom) confirm that when Lepreau is down, **ISO-NE transfer capability** increases from **400 MW to 500 MW**.

3.7 Regional Considerations and Portfolio Alternatives

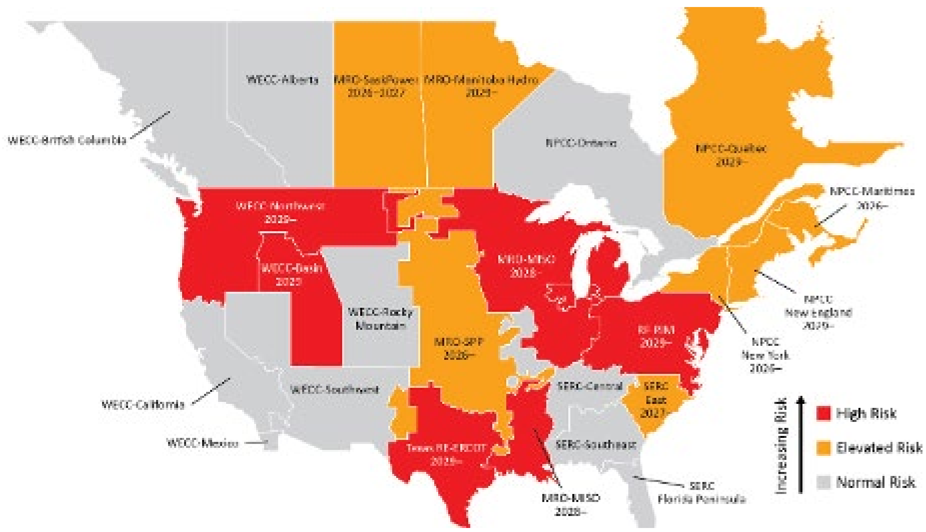
If the Board weighs broader **Maritimes** considerations, that weight should be **modest**. **Nova Scotia** needs **~600 MW** of CTs to phase out coal; **PEI** needs **~100 MW** of CTs. Rejecting RIGS would **free up turbines** for provinces that **actually need them**. Regionally, there may be a case for a **400–500 MW battery** in NB to bolster **regional energy security** and facilitate **low-cost renewable integration**. This is a preliminary concept; specifics would require study, but it is a **viable interprovincial strategy** that merits investigation.

3.8 Reliability Evidence in Rebuttal — Minimal Weight

NB Power's rebuttal pivots to **reliability** studies. Even if considered, they warrant **only small weight**, and NB Power's arguments are weak on the merits. The assessments show the Maritimes are **generally acceptable**, with some risk during **high load plus unplanned outages**. A brief transcript excerpt:

> **MR. LOGAN:** Is it normal to dip into that area once in a while… or almost never…?
> **MR. PALERMO:** It's rather general. It's **not uncommon**; some systems **almost never** have it happen, others **do**. Characterize it as **occasional**.

We urge the Board to review the reliability studies NB Power relies upon (see **NBP 12.07 at p. 6**). **[REFERENCE ONLY - MAP]**



This is **not** the "big red flashing sign" described in cross-examination. If anything, it suggests **caution** and points toward **battery storage**—not a justification for an **unaffordable rush** that led to an **incomplete application** and **skipped processes**. This is not the sort of chart that warrants proclamations mid-hearing that **"People are going to die."**

Moreover, because the studies are **Maritimes-wide**, the Board cannot determine which **sub-area** is at issue. We sought the **NS documents** through IRs and for our own evidence; NB Power **refused** and kept them off the record—even when almost entered through Mr. Marshall's evidence. NB Power **cannot argue it is an NB-specific problem** while **blocking** the evidence that would prove or disprove that premise. The available record suggests **PEI and Nova Scotia** have the **largest needs**. Brattle shows those provinces have **significantly**

more growth than NB, with NB the **lowest growth** among listed entities (see **NPB8.16 at p. 20**).

Further, **NBP 8.01 IR 1** shows NB Power has had **four** EEA alerts (one on Feb. **2**, 2023—not Feb. 4), while in **IR 16** Nova Scotia reported **49 capacity deficiency events**. NB Power has not been issuing rolling-blackout warnings on very cold days and, in fact, **“saved the day”** on the coldest day of the year.

3.9 Confidentiality and Export Sales

Existing and speculative export sales should receive very little weight in a decision regarding 400 MW of in-province capacity. PCIC contested the confidentiality claims on these contracts. NB Power called them “closely guarded secrets” but, because these contracts were not available for examination, they should carry minimal weight.

3.10 Is This for Lepreau Backup and Exports?

Point Lepreau’s reliability surfaced repeatedly. If NB Power’s real objective is **Lepreau backup** and **export sales**, that is **a different application**—with different scope, different issues, and likely different experts. If that is the case, NB Power should re-file accordingly. The present application simply concerns **resource adequacy**, and must be decided on that basis.

3.11 What, If Anything, Is Needed In-Province—and When

The Board must determine whether **400 MW** is required **in-province** to meet **resource adequacy**. If not, the project is **not prudent**. The Board may also consider whether **less** than 400 MW is needed, and **when**.

PCIC’s position is that NB Power **may require** some additional capacity **by 2030**, as the IRP identifies, in the range of **100–200 MW**. The record shows that at **~200 MW**, **batteries** have a **very high ELCC** and are **~25% less expensive** (using **2023** pricing). NB Power currently has an active **REOI for battery storage** and could have batteries **online by 2030**—though, with an updated L&R calculation, they **may not even be needed** then.

NB Power should **own** the batteries, with an **equity partnership with First Nations** and **NB Power low-cost debt** financing; NB Power should also seek **federal funding** that is available for batteries but not for combustion turbines to reduce impacts on ratepayers and play a part in building the clean energy grid of the future for Canada.

3.12 Conclusion on Resource Adequacy

PCIC submits that, according to the record, **400 MW of combustion turbines are not needed**. The application, falsely premised on this need for resource adequacy, is therefore **not prudent**.

4.0 The 2023 Cold Weather Event

4.1 Overview

NB Power relies on the February 3–5, 2023 cold weather event as further justification for the RIGS project. They have attempted to characterize this event as a **resource adequacy problem**, when the evidence clearly shows it was an **energy security and operational issue**, driven almost entirely by failures of fossil-fuel units — ironically combustion turbines.

NB Power claimed that this event proves that wind cannot be trusted and that reserve sharing agreements are “worthless pieces of paper” deserving zero weight. The factual record says otherwise:

1. **Combustion turbine failures** predominantly caused the hours of reserve deficiency,
2. **Reserve sharing agreements** were used successfully, and
3. **Wind power** prevented a loss-of-load event on February 3, 2023.

The evidence also shows that **battery storage** would have been more than capable of maintaining the required operating reserve margins throughout the event.

4.2 NB Power’s Rebuttal Evidence Misstates the Number of High-Load Hours

NB Power asserts in NBP 12.01 (p. 11) that NB Power's demand was equal to or above 3,000 MW for **41 hours** during the event. No basis has been provided for this number of hours.

A review of **NBP 9.13** (the spreadsheet of hourly system data) shows in Column C from **February 3 at 17:00** to **February 5 at 09:00** there were just **20 hours** above the 3,000MW level of NB demand.

Once again, NB Power has presented information that is **unsubstantiated**, which undermines the credibility of their evidence and oral testimony.

4.3 The Five Critical Hours When Batteries Would Have Prevented Shortfalls

More precisely, PCIC directs the Board to **Figure 3** in NBP 12.01 (p. 11) showing there were just **five hours from 19:00 on February 3 to 00:00 on February 4** during which NB Power's Operating Reserves fell below the required margins. Take note of the following:

These Operating Reserves:

- are **standby reserves**,
- do **not** represent energy delivered to the grid,
- and can be fully provided by grid-connected **battery storage**.

Evidence from Mr. Couture and from NB Power's IR responses to PCIC confirms:

1. **Batteries can be used as spinning reserves.**
2. **Batteries provide other advantages** such as virtual inertia, grid forming capabilities, black start capabilities, load regulation, arbitrage, depending on system conditions.
3. **Batteries do not need to discharge** their stored energy to meet requirements for spinning reserves.

A fully charged battery could have prevented negative reserve margins during all five critical hours — **without** even using stored energy.

The data also show:

- Before **February 3 at 17:00**, there were ample reserves to charge a battery.
- After **hour 20**, there were again ample reserves to recharge.

While such charging may rely on fossil generation during extreme conditions, this is entirely reasonable and far more economical than constructing a multi-hundred-million-dollar gas-fired plant.

4.4 Major Issues on Feb 3 Not Feb 4

It has been characterized as Feb 4th being the problematic day, but it was actually Feb 3rd that was the most critical time.

4.5 Timeline of the Event — Failure of CTs and Fossil Units, Not Renewables

This event began at **17:38** when Hydro-Québec experienced system security issues and reduced supply from **913 MW to 563 MW**.

The following sequence then occurred (NBP 9.12, pp. 6–9):

- **18:00** – Bayside derated to 250 MW (combustion turbine).
- **18:19** – HQ supply drops to **–38 MW**. This reduction is roughly equal to NB Power's **945 MW operating reserve**, lost within one hour.
- **18:54** – Millbank breaker cannot start due to cold (combustion turbine).
- **19:05** – Another Millbank unit unavailable (combustion turbine).
- **19:15** – Saint Rose combustion turbine fails to start.
- **19:50** – Another CT unavailable because staff were unsure whether it could be started remotely (later confirmed it could).
- **19:59** – Coleson Cove Unit 1 trips (330 MW).
- **20:00** – NB Power invokes ISO-NE and Nova Scotia reserve sharing; both succeed.
- **20:35** – MECL CTs are loaded so NB Power can curtail 50 MW — demonstrating our neighbors' reliability.
- **21:00** – NB Power purchases 165 MW of emergency energy from NS.

- **21:09** – NS confirms an additional 40 MW available.
- **21:22** – Saint Rose CT trips again.
- **21:26** – Additional derate at Coleson Cove.
- **21:30** – Additional emergency energy purchased from NS.
- **21:36** – HQ offers 200 MW emergency energy.
- **23:29** – Coleson Cove Unit 1 confirmed unavailable until Saturday.
- **23:40** – Bayside derated again.
- **23:43** – Additional derate at Coleson Cove.

Total fossil-related failures during the six critical hours: 12

Total fossil failures over the full event: 17

Using this three-day event to justify additional **combustion turbines** seems nonsensical.

4.6 Reserve Sharing Agreements Worked

Contrary to NB Power's testimony, the reserve sharing agreements:

- were invoked,
- they worked as intended,
- and they provided meaningful support that prevented a loss-of-load event.

Although they have been referred to as "worthless pieces of paper" the evidence says otherwise.

4.7 Wind Power Prevented a Loss of Load

During cross-examination PCIC directed the Board to the hourly system data (spreadsheet) in **NBP 9.13**, rows **2227 to 2234**, column **V** (wind power).

During the six critical hours:

- Wind generation was approximately equal to the **ELCC value** expected for 500 MW of wind.

- Without wind, NB Power would have **almost certainly** experienced a loss-of-load event.

Wind was a **key contributor** to system stability — not a liability. This fundamentally contradicts NB Power's assertions and raises serious questions about the credibility of their testimony.

4.8 Minor Equipment Issues Are Not a Basis for a Billion-Dollar Project

NBP 's weather report shows that most fossil-unit failures were due to:

- heat trace issues,
- building envelope issues,
- and even installing a **light bulb**.

These are operational and maintenance matters — not justification for a billion-dollar generation project.

4.9 System Data Show CTs Are Rarely Used and Imports Are Reliable

Again referring to the hourly system data in **NBP 9.13** combustion turbine activity in Column S shows NB Power's existing **500 MW** of combustion-turbine backup is **almost never used**. This implies that RIGS would simply be a **second, oversized backup generator**.

1. **The Québec Interface** in Column G shows that Québec supplied almost 1000 MW nearly all the time — except during the Feb. 3–5 window.
2. **ISO-NE Interface** data shows NB Power is almost always exporting, except in extreme cold, when it reliably imports from ISO-NE.
3. **Operating Reserves** data in Columns L, M, N shows that Reserve scarcity occurs only a few hours per year.

4.10 Year by Year Peak Day Evidence

A review of total loads on peak days in NBP 9.13 shows:

- **Jan 27, 2022 (8:00 AM):** Peak 3324 MW; **3 hours** above 3000 MW. Avg Jan–Feb: 2345 MW.
- **Feb 4, 2023 (9:00 AM):** Peak 3395 MW; **6 hours** above 3000 MW. Avg Jan–Feb: 2219 MW.
- **Feb 21, 2024 (7:00 AM):** Peak 2977 MW; **0 hours** above 3000 MW. Avg Jan–Feb: 2193 MW.
- **Jan 22, 2025 (8:00 AM):** Peak 3214 MW; **2 hours** above 3000 MW. Avg Jan–Feb: 2294 MW.

This demonstrates that:

- Peaks over 3000 MW occur only **a handful of hours per year**,
- The system's average winter load is well below 2300 MW, and
- **Batteries used as spinning reserves can easily replace RIGS** for these brief events.

4.11 Despite 15 Fossil Failures, the Lights Stayed On

Even with 15 supply-side failures, a 330 MW trip, reduced Hydro-Quebec imports, and extreme cold — **the lights stayed on**.

Far from proving the need for RIGS, this event shows a **robust** system capable of managing extreme conditions without a new 400 MW fossil plant.

4.12 Rolling Blackouts Are Less Harmful Than Common Storm Events

Even in the theoretical worst-case scenario, which did not occur, rolling blackouts are:

- controlled,
- temporary,
- rotated, and
- far less disruptive than events like the **2014 ice storm in Canada**, which destroyed distribution infrastructure.

This is not a justification for a billion-dollar capital project.

4.13 Conclusions Regarding the Cold Weather Event

The February 3 - 5, 2023 event demonstrates that:

- **Fossil units failed**, not renewables;
- **Reserve sharing** agreements worked;
- **Wind** prevented loss of load;
- **Batteries** would have solved reserve shortfalls; and
- The system is **resilient**, not resource-inadequate.

This event **does not** support the prudence of RIGS — it provides compelling evidence to the contrary.

5.0 Alternatives Not Considered

5.1 Starting On The Wrong Track

The Capital Project Charter makes it very clear that alternatives were explicitly excluded from scope since the very beginning. As shown in NBP 8.82, p. 11, NB Power pre-determined the outcome by defining the RIGS project so narrowly that no other options could be meaningfully assessed. This exclusion shaped the analytical process from that point forward.

5.2 RIGS Benchmark

During the hearing, a consistent and troubling pattern emerged: NB Power shifted its accounting stance and evaluation perspective when challenged. RIGS became the reference point, and all other options were measured *against RIGS*, rather than against the actual problem to be solved.

This benchmark shift is evident in Mr. Pollock's testimony regarding synchronous condensers (SCs). When confronted with the fact that SCs accounting for the cost of clutches were more expensive than simply replacing capacitors to meet requirements, Mr. Pollock responded that this was not an "apples to apples" comparison because SCs provide "other benefits." (Transcript, February 11, 2026, p. 56, line 4.)

In other words, having to concede that SCs were more expensive, NB Power shifted the analytical frame to the benefits of SCs within RIGS rather than acknowledge the cost reality. The problem should be the starting point — not the RIGS project

This hearing should be about the actual need or problem NB Power seeks to solve, including:

- The February 3–5, 2023 cold weather event,
- Forecasted loads,
- system capability, and
- least-cost ways to ensure reliability.

When viewed through this correct lens, it becomes clear that:

- Capacitors may be the least-cost solution,
- SCs may be unnecessary, and
- The RIGS project is not itself a “need,” but an assumed solution to which everything else was then compared.

This is not prudent planning.

5.3 Capacity Options

Before evaluating specific options, it is necessary to address the serious flaws in NB Power’s approach to assessing alternatives.

5.3.1 Limited Use of PLEXOS

PLEXOS is one of NB Power’s most powerful analytical tools and is accepted by regulators all over the world and is even approved by NPCC. It has been used for major decisions, including small modular reactors. The exchange beginning at page 178 of the February 9 transcript highlights PLEXOS’s value for major resource decisions. (Transcript, February 9, 2026, p. 178, line 4 and lines 18–24.)

Yet NB Power did not use PLEXOS to perform a full optimization analysis, even though optimization is precisely what PLEXOS is designed for.

Instead, as confirmed by Mr. Clark:

- PLEXOS was used only for delta analysis for fossil fuel reductions at Colson Cove,
- NB Power did not use it to identify the optimal generation portfolio,

- the model is simple to run, and
- NB Power did not re-run it as new data (like falling battery costs) became available.
  (Transcript, February 9, 2026, p. 180, line 4.)

NB Power admitted it continued to rely on the high-level IRP analysis (Transcript, p. 180, line 16), despite the fact that the IRP itself did not identify any need for 400 MW of new capacity in 2028.

The decision was locked in before analysis

Mr. Clark's testimony strongly suggests the PLEXOS optimization was not performed because NB Power had already decided on RIGS.

This failure is unacceptable.

For a 25-year, $3.5-billion project, a prudent utility would:

- fully utilize PLEXOS,
- update it continuously with new cost data,
- evaluate multiple options and combinations, and
- use the tool right up to the moment of signing any binding agreement.

NB Power did not. That alone raises serious doubt as to the prudence of the decision.

5.3.2 Intermittent Renewable Options

NB Power has already signed contracts for 500 MW of wind, which is not included in the Resource Adequacy Assessment.

There is substantial potential for additional wind and solar, and the ELCC of wind remains strong up to approximately 1000 MW of total wind capacity.

Renewables should have been fully integrated into any least-cost analysis, but NB Power did not do so.

5.3.3 Battery Storage

One of the most shocking revelations in this hearing is NB Power's lack of understanding of modern battery technology.

NB Power does not understand the capabilities of batteries.

During cross-examination (Transcript, February 11, 2026, pp. 74–76):

- Mr. Pollock stated that a 4-hour battery can only support a peak event for four hours.
- At line 18, Mr. Coady agreed, saying a battery only provides a “four-hour kick at the can.”

This is factually incorrect.

Mr. Couture testified that:

- there are 4-hour, 12-hour, 24-hour, and even 100-hour battery technologies commercially available today, and
- a 4-hour 400 MW battery can operate:
    - at 200 MW for 8 hours, or
    - at 100 MW for 16 hours.
    - Or even ramping over time

Multiple batteries can be sequenced to meet long-duration needs.

The combined evidence shows that:

- NB Power lacks expertise in battery technology,
- NB Power did not understand what a modern battery can do,
- NB Power likely drafted the REOI for batteries incorrectly,
- NB Power did not consider battery solutions seriously, and
- NB Power is not capable of performing proper comparative battery analysis without expert support.

One of the many significant findings in this hearing is that:
NB Power defaulted to the technology it understood — gas turbines — not the technology that is least-cost or most appropriate. PCIC submits that NB Power needs a battery expert and must redo its evaluation.

5.3.4 Demand Response Programs

Demand response is one of the most promising and least-cost tools available — yet NB Power treated it as an afterthought.

NB Power ignored 70–75 MW of available ELCC

As identified in the exchange between Ms. Northrup and Mr. Clark
(Transcript, February 9, 2026, p. 63; NBP 8.31 (CCNB), IR Response p. 4):

- NB Power identified 285 MW of demand response potential by 2030,
- with an ELCC of 100–105 MW,
- 70–75 MW of which is not accounted for.

This is nearly 20% of the supposed 400 MW need, yet NB Power calls it a “future initiative.”

Residential demand response — never attempted

NB Power’s efforts have focused on industrial customers. The residential sector — which is larger and more flexible — has:

- no program,
- no pilot study,
- no strategy,
- not even a basic phone-based voluntary load-reduction notification system.

A simple free smartphone app could provide meaningful peak shaving almost immediately. Customers can remotely adjust:

- heat pumps,
- EV charging,
- water heaters,
- major appliances.

This would cost almost nothing and reduce peak demand during the most expensive hours. NB Power simply did not try.

Demand response is:

- cheap,
- fast,
- proven,
- measurable, and
- extremely flexible.

And yet NB Power’s analysis effectively ignored it.

5.3.5 Combination of Alternatives

NB Power not only failed to evaluate individual alternatives, but also failed to evaluate combinations of:

- wind,
- battery storage,
- demand response,
- capacitors or SCs,
- Imports, and
- DSM measures.

At page 68, line 6 (Feb. 9 transcript), NB Power admits that combinations were not properly evaluated. Their repeated statement that “NB Power is pursuing lots of things at the same time” is not the same as:

- conducting formal system modelling,
- assessing combinations in PLEXOS,
- performing financial comparisons, and
- presenting comprehensive analysis to the Board.

At page 69, lines 15–19, NB Power admitted that they did not try to implement “seven or eight small things.” They chose one solution and pursued only that.

PCIC submits that neither stand-alone alternative nor combined alternatives received serious, evidence-based evaluation.

5.4 Conclusion Regarding Alternatives Not Considered

The evidence shows that:

1. **The Tolling Agreement restricts NB Power’s ability to change output except in 30-minute increments**, precluding fast-start responsiveness.
2. **The TA Appendix A—not the GCA—**prevails in the event of conflict, and Appendix A does not require fast-start or ancillary-service capability.
3. Any additions or corrections to scope require **mutual agreement**, leaving NB Power in a weakened commercial position.
4. **There is no evidence** on the record supporting NB Power’s assurances that these services will be contractually required or enforceable.

Given the magnitude of the RIGS project and the importance of fast-start capability to NB Power’s stated rationale, this omission is **not a minor clerical issue**—it is a material failure in contractual diligence.

The Board should review the contractual record closely and assess **the legal implications** of the Appendix A priority clause. If NB Power cannot demonstrate that the necessary ancillary-service obligations are contractually secured, the Board should treat this as **another example of imprudence** on the part of NB Power's management with respect to the RIGS project.

6.0 Perceived Operational Benefits

6.1 Fast-Starting Combustion Turbines?

6.1.1 Contract-Limiting Plant Scheduling

On the morning of **Tuesday, February 10**, PCIC cross-examined NB Power regarding the fast-start capabilities of the proposed RIGS combustion turbines and the ancillary services they would be able to provide, including: **regulation**, **load following**, **automatic generation control**, **10-minute reserve**, **10-minute spinning reserve**, and **30-minute reserve** services.

During that examination, PCIC turned to the Tolling Agreement (NBP 6.18), specifically **page 124**, which states:

> *"Buyer may adjust such Scheduling Instructions during any Scheduling Period until thirty (30) minutes before the start of the Hour of delivery."*

This language raises a critical issue. If NB Power may only adjust RIGS's output in **30-minute increments**, then the facility cannot be considered "fast-start" in any meaningful sense. A generator that cannot respond within 10 minutes, or even within 30 minutes, cannot provide the **10-minute reserves**, **regulation**, or **load-following** services that NB Power represented would support renewable integration and system reliability. In other words, the contractual language itself appears to preclude the very ancillary services NB Power claims RIGS will provide.

When confronted with this inconsistency, NB Power assured interveners that all required fast-start and ancillary-service capabilities would be enforced through the **Generator Connection Agreement (GCA)**, and that there would be "no way" for ProEnergy to avoid providing these services once connected.

However, upon reviewing the Generator Connection Agreement incorporated within the Tolling Agreement, PCIC identified the following clause on **page 63**:

> *"In the case of deviations in the technical requirements of the OATT Generation Connection Agreement and the scope as described in this Appendix A and its attachments, the Appendix A and its attachments shall take precedence and the Parties may adjust the scope via mutual agreement on a Buyer-requested change."*

This clause undermines NB Power's assurances for three reasons…

6.1.2 Appendix A Takes Precedence Over the GCA

The technical requirements that NB Power said would "guarantee" fast-start and ancillary-service capability are **not controlling**. If Appendix A is silent or inconsistent with the GCA's requirements, **Appendix A prevails**.

6.1.3 Appendix A Does Not Include The Fast-start Or Ancillary-Service Obligations NB Power Promised

PCIC's review of Appendix A reveals **no explicit inclusion** of:

- regulation capability
- load-following obligations
- automatic generator control
- 10-minute spinning reserve
- 10-minute non-spinning reserve
- 30-minute reserve obligations
- fast-start performance criteria

Nothing in Appendix A requires ProEnergy to provide these services - contrary to NB Power's testimony.

6.1.4 Changes Require Mutual Agreement, Giving ProEnergy Bargaining Power

The clause expressly states that scope adjustments require **mutual agreement** between the parties.

This gives ProEnergy a **contractual advantage**:

- NB Power cannot unilaterally impose ancillary-service obligations later;
- ProEnergy can demand compensation or refuse changes entirely; and
- NB Power has no evidence that ProEnergy is obligated to accept such modifications.

Thus, NB Power's statements that there is "no way" ProEnergy can avoid providing the services are at least **unsupported by the contract**.

6.2 Benefit of Centre Village Location

Centre Village is only a convenient site for RIGS, not for local residents who were never consulted before NB Power signed the contract with ProEnergy. PCIC submits that this project does not have social licence, something NB Power representatives have said is important for the relationship it wants to have with communities across the province.

The dual site criteria involving the intersection of power and gas lines for RIGS is not a requirement for batteries, thus opening up a much greater range of suitable sites in the province for NB Power to deploy battery technology.

6.3 Synchronous Condensers

During cross-examination, PCIC and NB Power discussed NB Power's claim that the **nine existing capacitors** would be effectively replaced by the **synchronous condensers (SCs)** included in the RIGS project. NB Power asserted that this substitution resulted in cost savings.

6.3.2 NB Power's Claimed $12 Million "Savings" Is Incorrect

Mr. Pollock testified that the normal replacement cost for the nine capacitors would be approximately **$15 million**, based on a **Class 5 estimate**, and that replacing them with synchronous condensers as part of RIGS produced a supposed savings of **approximately $12 million** (i.e., $15M – $3.4M).
(Transcript, February 11, 2026, p. 54, line 10.)

However, earlier evidence from **CCNB** confirmed that the **clutches** required for the RIGS synchronous condensers cost **$14 million**. Importantly, Mr. Pollock acknowledged that this $14 million cost **was not included** in NB Power's calculations of the claimed RIGS "savings."

When the clutch cost is properly included, the economics reverse:

- **Claimed savings:** $11.6 million
- **Actual additional cost once clutches are included:** $14M – $11.6M = **$2.4 million more expensive**

PCIC submits that **the synchronous condensers do not provide savings**, and in fact are **more costly** than simple capacitor replacement.

6.3.3 NB Power Failed to Account for Operating Costs—Which Are Substantial

More importantly, NB Power **failed to include the significant ongoing operating costs** associated with synchronous condensers. Capacitors, by contrast, have **effectively zero operating cost**.

PCIC requests that the Board review **NBP 8.77C**, which details the operating costs associated with the synchronous condensers. These costs are substantial, yet NB Power's economic comparison **ignores them entirely**.

During cross-examination, NB Power further admitted that it must **pay for the power required to operate the synchronous condensers in synchronous-condenser mode**, a cost **not reflected in NBP 8.77C**. Thus, the true operating costs are **much higher** than even the already-material figures disclosed.

PCIC also directs the Board to the responses provided by **Mr. Palermo** in **PI4.01 IR-01**, which further reinforce concerns regarding the economic and operational implications of synchronous condensers.

6.3.4 NB Power's Claimed Inertia Benefit Is Not Supported by the Evidence

NB Power asserted that one of the primary benefits of installing synchronous condensers is that they provide **inertia**. However, during cross-examination, it was shown from NB Powers own documents that the system **does not require inertia in the short, medium, or long term**. While synchronous condensers may provide certain electrical characteristics superior to capacitors, the evidence demonstrates that **the existing capacitors are sufficient** for system needs.

This undercuts NB Power's justification for choosing synchronous condensers over less expensive alternatives.

6.3.5 NB Power Did Not Study Whether Batteries Could Avoid the Need for Certain Transmission Investments

PCIC also questioned NB Power regarding the possibility that **battery storage** could reduce or eliminate the need to build a transmission line that supposedly becomes unnecessary if RIGS is constructed. NB Power responded only that **"maybe"** batteries could provide this value, and admitted that **no study was conducted**.

This omission is inconsistent with prudent planning and contradicts NB Power's obligations to consider least-cost alternatives, especially given:

- the high **Effective Load Carrying Capability (ELCC)** of batteries established in evidence;
- the substantial decline in battery costs; and
- the potential for batteries to provide both inertia-like grid support and transmission-deferral benefits.

A prudent manager would not incur significant capital expenditures without assessing whether **batteries**, already under evaluation in NB Power's own REOI process, could defer or avoid such costs.

6.3.6 Environmental Benefits

Benefits of RIGS are only framed in relation to other NB Power fossil fuel resources. Proper framing of environmental benefits would have comparisons of alternatives to meet the system needs, and batteries would have clear advantages as they do not emit GHGs, other air, water, or land pollutants, and do not require large volumes of water to operate.

There are issues with the site regarding air, water, and land resources that are reviewed by environmental assessments separately from this Hearing, but even with environmental approvals these will still represent risks for the RIGS project.

7.0 Procurement of New Generation Capacity

7.1 Ownership versus Tolling Agreement Considerations

7.1.1 Construction and Ownership Risk

The cost NB Power has subjected ratepayers to to mitigate these risks is not justifiable. It is in the range of hundreds of millions of dollars and doesn't mitigate any of the serious risks like fossil fuel volatility, risk of increased environmental rules like carbon taxes. An EPC contract mitigates almost all of the same risks at a much lower cost. In an ownership model the utility only pays for the risk if it materializes. The tolling agreement you pay the premium even if the risk never materializes.

7.2 Procurement Process and Outcome

In-Camera

8.0 Governance Process

8.1 Executive Oversight - April 3 SEOC Documents

The foundational document underpinning the 400MW capacity determination — the April 3 Strategic Energy Options Committee (SEOC) materials — amounts to little more than a shopping list compiled from consultations and workshops. While NB Power consulted broadly, it appears to have consulted everyone except the demand-side management team, and conducted zero analytical modeling to support the capacity decision.

The decision to select 400MW was never realistic from a needs-based perspective, and the ratepayers of New Brunswick have paid a substantial premium as a result. Critically, the in-service date is still not guaranteed despite the costs already incurred.

NB Power's own Integrated Resource Plan (IRP) demonstrates that no new capacity is required until 2030. PCIC aligns with the IRP's conclusions and submits that the appropriate near-term solution is 100 to 200 MW of battery storage — a targeted, cost-effective, and technically appropriate response to the identified grid reliability needs.

The RIGS project, as proposed, is not consistent with the Government approved IRP. Furthermore, the project is inconsistent with NB Power's 3 year Strategic Plan. This internal contradiction — between the IRP, the Strategic Plan, and the RIGS Application — has never been satisfactorily explained or reconciled in the evidentiary record.

Alternatives were explicitly designated as out of scope within the Project Charter, meaning that demand-side management and other cost-effective alternatives were structurally excluded from consideration. This is not fact-based decision making. It is decision-based evidence-making — arriving at a predetermined conclusion and then assembling justification after the fact.

The RIGS project, as structured, represents a significant financial risk to New Brunswick ratepayers. PCIC characterizes this project in the following terms for the Board's consideration:

- A $3.5 billion, 25-year commitment justified primarily by an 8-page, out-of-date internal document with no independent analysis.
- An extremely expensive, over-specified solution — analogous to purchasing a heavily modified, dual-fuel heavy-duty vehicle with an expensive extended warranty, when what was needed was an economical, fit-for-purpose electric vehicle. The evidence suggests NB Power could not overcome its institutional "range anxiety" with respect to battery and renewable solutions.
- A project extended warranty (the tolling agreement structure) that does not cover the major risks ratepayers face.
- A financing structure that goes well beyond NB Power's means, with no apparent regard for the 20% equity target or the long-term financial health of the utility.

PCIC also notes with serious concern that NB Power is selling capacity to the United States market at a time when it has declared a capacity crunch at home. When directly asked, Mr. Coady confirmed this to be the case. This raises profound questions about NB Power's capacity planning, its priorities, and whether the RIGS project is being sized and structured to serve New Brunswick ratepayers or external commercial interests.

A further fundamental deficiency in NB Power's process concerns the ownership versus tolling agreement decision. This threshold question — whether NB Power should own the asset outright or enter into a tolling arrangement — should have been resolved as a gate decision before the Request for Expressions of Interest (REOI) was issued, and shareholder approval should have been requested. .

Instead, the REOI was structured in a manner that effectively foreclosed the tolling agreement option by not soliciting EPC (Engineering, Procurement and Construction) ownership bids. The REOI should have explicitly invited proposals for both ownership and tolling structures so that NB Power could conduct a genuine, comparative analysis of the options before committing to a procurement path. The failure to do so represents a structural process deficiency that cannot be remedied at this stage.

8.2 NB Power Board of Directors Approval

We find it concerning that this project had to be approved twice because the contract had changed so much. That the Board was required to revisit its approval suggests the project's scope, cost, or terms evolved materially after the initial decision was made. While it is not unusual for complex infrastructure projects to undergo some degree of change during development, the extent of the changes here raises questions about the adequacy of the initial due diligence and project planning. The Board should have had a sufficiently complete and stable picture of the project before granting its first approval. Requiring a second approval to ratify substantially different terms undermines confidence in the oversight process and suggests that the project may not have been ready for Board consideration when it was first presented.

8.3 Lease Treatment, Balance Sheet Impacts, and the Equity Target

8.3.1 NB Power Should Have Determined Lease Treatment Before the REOI

One of the most significant issues in this proceeding is NB Power's failure to properly assess whether the RIGS tolling agreement would be treated as a lease under applicable accounting standards. NB Power initially believed the project would not appear on its balance sheet and categorized it in the "#1 Transformer" bucket — meaning it assumed the project would be treated as an off-balance-sheet arrangement.

This assumption was incorrect, and NB Power failed to confirm the accounting treatment before structuring and releasing its Request for Expressions of Interest (REOI).

Before issuing the REOI, NB Power had a duty to determine whether the tolling agreement:

- would likely be considered a lease,
- would appear on NB Power's balance sheet, and
- would therefore not help NB Power progress toward its legislated 20% equity target.

This analysis was never done. Instead, NB Power proceeded under the false assumption that a tolling agreement would avoid balance sheet recognition. In fact, the correct accounting treatment — that the tolling agreement is a lease — undermines the very equity objective NB Power is required to pursue.

Once NB Power learned, or reasonably should have learned, that the tolling agreement would be treated as a lease, a prudent manager would have halted the project immediately.

8.3.2 NB Power Should Have Shifted to an EPC/Ownership Model When Lease Treatment Became Clear

Upon realizing that the tolling agreement would be recognized as a lease, NB Power should have promptly:

1. Stopped all advancement of the tolling model,
2. Entered negotiations with ProEnergy for an EPC contract, and
3. Proceeded under the ownership model,
4. For which Pro Energy already had a quote.

This corrective action would have been required not only because of the equity target, but because:

- The NPV of the tolling agreement is significantly worse than the ownership option, and
- The tolling structure imposes hundreds of millions of dollars in additional costs.

A prudent manager would have switched to the ownership model immediately upon learning the tolling agreement would not achieve its intended accounting effect.

NB Power did not.

8.3.3 NB Power Lacks the Expertise Required for These Accounting and Structural Decisions

This situation should raise serious red flags for the Board.

NB Power's inability to determine the basic accounting treatment of a major financial instrument demonstrates a lack of internal expertise in:

- financial structuring,
- lease accounting,
- risk analysis, and
- capital-market considerations.

The concern is amplified by the fact that NB Power is also signing Power Purchase Agreements (PPAs) for renewables in which NB Power retains control over output. Such control is a key factor that would trigger lease accounting, meaning:

- These PPAs will very likely also be treated as leases, and
- The resulting lease liability may be larger than the debt that would have been required under an ownership model.

This means NB Power's financing choices not only fail to support progress toward the 20% equity target - they may actually exacerbate NB Power's financial position.

8.3.4 Expert Evidence on Why Debt Financing Would Improve Cash Flow

On Friday, Mr. Madsen provided critical evidence to the Board explaining that:

- taking on debt increases cash flow because utilities typically do not fully repay principal, especially during periods of high capital investment,
- this increased cash flow reduces the need for additional borrowing on other projects, and
- public financing (debt-financed ownership) can therefore strengthen NB Power's equity ratio and financial position.

His testimony underscores the imprudence of NB Power's choice:

- Ownership improves cash flow and equity position;
- Tolling worsens cash flow and equity position.

Yet NB Power chose the tolling model - even after learning it would be treated as a lease.

8.3.5 Public vs. Private Financing Must Be Examined in the Next IRP

Given the severity of these issues, PCIC submits that public vs. private financing must be rigorously analyzed in the next Integrated Resource Plan. This analysis must include:

- how public versus private financing affects least-cost outcomes,
- impacts on electricity rates,
- effects on the 20% equity target, and
- the financial consequences of lease treatment vs. debt treatment.

A utility that repeatedly selects structures that worsen its equity position, worsen NPV, and reduce financial flexibility cannot be said to be acting prudently.

8.3.6 Tolling Agreement Not Capital in Governance Process
NB Power did not follow its own investment governance process and has not provided any investment rational documentation to support this project. It states that the SEOC committee is a suitable replacement. The SEOC has missing meeting minutes from critical decisions on the REOI and Evaluation criteria. The SEOC accepted at face value the results of consultations and workshop wish lists without any supporting documentation and analysis and not even basic questions being asked. The board will need to consider if the SEOC committee was a suitable replacement of the Investment Governance Process. We argue that it is not.

9.0 Conclusion and Relief Sought

Mr. Chair and Members of the Board:

PCIC submits that NB Power has not met its burden under Section 107. The application rests on an 8-page, outdated internal memorandum, a procurement path that excluded ownership options before analysis, non-compliant operational calculations, and a tolling structure that is costlier in terms of NPV, treatable as a lease, and a barrier to reaching the 20% equity target. The only LOLE studies put properly before the Board - NBP 8.06 and NBP 12.07 p. show that the Maritimes meets adequacy in 2028 without RIGS. The approved IRP shows no need for capacity until ~2030, and even then only ~100 MW, not 400 MW.

Alternatives and DSM were structurally excluded; PLEXOS optimization was never run—despite all four resource adequacy experts saying it should have been used, and NB Power's scope for Brattle's prevented an independent expert portfolio evaluation. The February 2023 event demonstrates the system's resilience, the value of wind, reserve-sharing, and that battery spinning reserves would have addressed the minimal shortfall hours - without discharging.

The procurement process and NB Power governance also suffered from significant issues. NB Power has not demonstrated prudence on the record and the appropriate outcome is to **deny** the application.

PCIC is requesting the following (22) **Orders from the Board…[READ EACH BULLET NUMBER INTO THE RECORD]**

9.1 Disposition of Application

1. **Deny** NB Power's Application for approval of the RIGS capital project under s.107 of the *Electricity Act*.

9.2 IRP Directions (Section 100)

2. For the **2026 IRP**, order NB Power to include the following items A-F as appendices:

   (A) An **independent public vs. private financing report** (for all capital projects including renewables) that analyzes impacts on least-cost objectives, customer rates, and the 20% equity target.

   (B) An **external audit** of the IRP's **assumptions and methodologies**.

   (C) PLEXOS exports and **input assumptions** consistent with the "open by default" policy to ensure transparency.

   (D) A **No-SMR sensitivity** analysis with a **quantified** cost delta versus SMR; the 2023 IRP's "no-SMR" scenario lacked the cost difference—this must be disclosed in the next IRP.

   (E) Provide a best estimate baseline for the IRP and not just "High" and "Low" load sensitivities.

   (F) Publish a draft IRP for public comment and **include** public comments in the IRP submitted to the Executive Council. The public should be able to comment at the first and last part of the process.

3. **Extend the three-year plan to 10 years** for any s.107 supply-side application, with full **option sensitivities** and a "**no-project" baseline**.

4. Require NB Power to **use PLEXOS optimization** (not delta-only runs) for portfolio evaluation, **update inputs** regularly (battery prices, new wind and DSM, load), and **document deviations** from modeled least-cost portfolios.

5. **Retain an expert statistician/economist** to review econometric models, the confidence intervals for load forecasts (P10 and P90 estimates), and other statistical analysis use for load forecasting and IRP development.

9.3 Alternatives, DSM, and Batteries

5. Direct a comprehensive alternatives analysis that:
   • accurately and precisely defines the capacity problem (magnitude, duration, frequency, and seasonality);
   • fully evaluates battery storage (4-, 8-, 12-, 24- and 100-hour technologies; ELCC; spinning reserves without discharge; and stacked grid services);
   • evaluates combinations (batteries + demand response + imports/reserve sharing + capacitors/SCs + DSM).

6. Retain a battery expert to specify capabilities, stacked services, and repair the battery REOI scope (durations, control, interconnection, performance metrics).

7. Immediately implement low-cost residential demand response, beginning with an opt-in smartphone notification program enabling voluntary curtailment/shifting during peak periods (e.g., remote adjustment by customers of EV charging, heat pumps, water heating, major appliances).

8. Quantify and include the 70–75 MW DR ELCC not yet reflected in the load/resource position; develop and file a plan to capture the broader 285 MW DR potential by 2030.

9. Evaluate 100–200 MW of batteries for in-province needs by ~2030 (ownership model with First Nations equity, NB Power low-cost debt, and pursuit of federal funding).

10. Evaluate 400–500 MW of batteries as an interprovincial project to enhance regional energy security and enable low-cost renewables integration.

9.4 Procurement Structure; Ownership vs Tolling

11. Correct procurement process defects since there are issues with the REOI process, and using the RFP process before proponent selection would serve ratepayers better.

9.5 Accounting, Finance, Equity Target

12. **Order an audit of existing PPAs** to determine whether NB Power's control over output triggers **lease accounting**; require NB Power to **file** the resulting **balance-sheet impacts** and equity implications.

13. **Order NB Power** to demonstrate compliance with the **Investment Governance Framework**, including filing **Investment Rationale Documents (IRDs)** for capital projects.

14. **Review and require filing** of NB Power's **financial risk management** policies addressing **capacity sales to external markets** during asserted domestic capacity crunches; the Board may order policy amendments to preclude such conflicts.

9.6 Evidence Weighting and Findings

15. **Give zero weight** to **NBP 6.07** (the 8-page RA document) because it is outdated, not updated for the lower load forecast, excludes **500 MW** of new wind, omits **DSM**, and does not reflect updated derates; export status is unclear.

16. **Afford significant weight** to **NBP 8.06** and **NBP 12.07 p. 234 (NPCC/NERC ProbA)** showing that **LOLE is met without RIGS** in 2028 and thereafter.

17. **Adopt the Load & Resource Balance** method (the historical standard), give **high weight** to the evidence of **Mr. Palermo** and **Mr. Olson**, and **limited weight** to **Brattle** (whose scope NB Power limited and whose methods did not update assumptions or perform independent modelling or follow basic procedures).

9.7 Financial Plan; Filing Requirements

18. **Order production of a 10-year version** of the **three-year plan** for any s.107 supply-side application, including **option sensitivities** and a **no-project baseline**.

9.8 Rules of Procedure and Transparency

19. **Define "Restricted Confidential" precisely and narrowly.** Amend the Rules to:
    • clearly define criteria for **restricted confidential** treatment;
    • require a **line-by-line redaction justification chart**;
    • adopt a presumption of **maximum public disclosure** consistent with commercial sensitivity; and
    • require parties to consider **partial disclosure** (summaries/tables) where full disclosure is not possible.

20. **Enhance guidance for unrepresented intervenors.**
    • designate a limited-scope **procedural liaison / duty counsel** for **procedural questions** (not legal advice);
    • hold an early **case-management conference** to address logistics, objections, confidentiality, IR drafting, and evidence format.

21. **Codify minimum evidentiary foundations for s.107 capital applications.** Require that filings include, at minimum:
    • a **comprehensive needs assessment** anchored in LOLE and IRP consistency;
    • a **PLEXOS optimization** run (not delta-only) with full transparency of assumptions and exports;
    • a documented **alternatives assessment** (batteries, DR/DSM, imports, capacitors/SCs), including **combinations of these solutions**;
    • a **DSM plan** with near-term, low-cost residential measures;
    • demonstration of **least-cost portfolio** and clear explanation for any deviation;
    • confirmation of **alignment with the approved IRP** and **three-year/ten-year plans**.

    • adherence to NB Powers' Investment Governance Framework

Respectfully submitted this 19th day of February, 2026.