NEW BRUNSWICK
ENERGY & UTILITIES BOARD

COMMISSION DE L'ÉNERGIE ET DES SERVICES PUBLICS
NOUVEAU-BRUNSWICK

REASONS FOR DECISION

IN THE MATTER OF an application by New Brunswick Power Corporation pursuant to subsection 103(1) of the *Electricity Act*, S.N.B. 2013, c. 7 for approval of the schedules of the rates for the 2026/27 fiscal year and other approvals.

(Matter No. EL-003-2025)

August 26, 2026

IN THE MATTER OF an application by New Brunswick Power Corporation pursuant to subsection 103(1) of the *Electricity Act*, S.N.B. 2013, c. 7 for approval of the schedules of the rates for the 2026/27 fiscal year and other approvals. (Matter No EL-003-2025)

APPLICATION:	October 1, 2025
PUBLIC HEARING:	March 9 to 20, 2026
DECISION:	April 1, 2026
ORDER:	April 13, 2026

NEW BRUNSWICK ENERGY AND UTILITIES BOARD:

Chairperson	Christopher J. Stewart
Member	Heather Black
Member	Michael Pickup

PARTICIPANTS:

New Brunswick Power Corporation	John Furey
New Brunswick Coalition of Persons with Disabilities	Shelley Petit
Saint John Human Development Council	Randy Hatfield
Solar NB Solaire	Michael Bourque
Utilities Municipal	Ryan Burgoyne

PUBLIC INTERVENER: J.M. Alain Chiasson

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1 Introduction and summary conclusions

[1] The *Electricity Act* (the "Act") requires NB Power to apply to the Board for approval of the rates it proposes to charge customers for its services.

[2] NB Power is asking the Board to approve a 4.75 percent rate increase for the fiscal year ending March 31, 2027, to be applied uniformly, meaning that customers in all rate classes would see the same percentage increase. NB Power says it needs to increase rates to address aging infrastructure, higher demand for electricity, climate change impacts, and a government-mandated transition to net-zero, all while facing serious financial challenges and awaiting the results of a comprehensive review of the utility. NB Power is also asking the Board to approve a higher wind balancing charge, higher fees for its Customer Energy Solutions products and services, a new AMI Opt-Out fee, a new optional Net-Zero Rate, new rate designs and rates related to electric vehicle charging, and other rates, charges and proposals.

[3] The Board has determined that a rate increase of 4.29 percent applied uniformly across all rate classes, exclusive of the statutory rate rider, is just and reasonable. This is lower than NB Power's proposed increase of 4.75 percent because the Board has reduced NB Power's budget, known as the revenue requirement, by approximately $7.0 million to reflect:

1. NB Power's updated forecast related to ERP upgrade project spending;
2. reasonable vacancy credit assumptions for forecasting Labour and Benefits expense;
3. reasonable Depreciation and Amortization expense forecast that excludes depreciation related to the Point Lepreau Nuclear Generating Station generator rewind project; and
4. a reasonable revenue forecast associated with the Net-Zero Rate and AMI Opt-Out fee.

[4] Subject to these adjustments, NB Power has demonstrated that its proposed revenue requirement is reasonable. The Board approves NB Power's proposal to apply the rate increase uniformly to be more affordable for residential customers but does not possess the jurisdiction to establish a rate relief program. Other rate design measures, rates, and charges are also approved.

[5] The Board denies NB Power's request to recover its revenue shortfall through a rate rider.

2 Overview

[6] The Board's primary obligation in this proceeding is to fix just and reasonable rates for its fiscal year ending March 31, 2027, referred to as Fiscal Year 2027 or the test year. The *Electricity Act* requires the Board to base its decision on the revenue requirement of NB Power.

[7] NB Power develops its revenue requirement using a modelling program called PROMOD to simulate the operation and generation costs and revenues the utility needs to serve in-province and export load at the lowest cost to in-province customers. Key assumptions within the PROMOD model include generation station outages and other performance metrics, and commodity prices for fuel sources and purchased power. NB Power deducts its forecast export sales revenue and other revenues to determine the total revenue requirement it proposes to collect from ratepayers, then calculates rates by allocating that total revenue requirement among rate classes following a Board-approved cost allocation methodology.

[8] NB Power proposed a larger revenue requirement for Fiscal Year 2027 because it is planning for additional investment in vegetation management, more spending on demand-side management programs, strengthened cybersecurity measures, services to support improved generation station reliability, union and wage adjustments, costs associated with the ERP upgrade, and new positions to address increased workloads.

[9] The Board applies the law and regulatory principles to the evidence to determine whether it would be just and reasonable for NB Power to recover its proposed revenue requirement from ratepayers through rates. If not, the Board fixes higher or lower rates that are just and reasonable. Subsection 103(7) of the Act lists several factors the Board must consider when fixing just and reasonable rates based on NB Power's revenue requirement. These factors are referred to collectively as the "mandatory statutory factors".

[10] One mandatory statutory factor is the government's policy for NB Power expressed in section 68 of the Act. The policy sets an expectation that the utility will be managed and operated in a way that, among other things, provides safe and reliable service resulting in the lowest cost of service for in-province customers. According to the same policy, rates should allow NB Power to reduce the percentage of debt in its capital structure with a goal of reaching 20 percent equity while, to the extent practicable, remaining low and stable. NB Power's goal of reaching 20 equity is referred to as the "equity goal".

[11] Other mandatory statutory factors include the Directive issued to NB Power by the Minister of Energy on April 8, 2025, NB Power's most recent Three-Year Financial Plan for

Fiscal Years 2027 to 2029 and its 2023 Integrated Resource Plan, all of which were filed as evidence in this proceeding. Relevant legal requirements such as those related to demand side management, energy efficiency and renewable energy are also mandatory statutory factors.

[12] Subsection 103(8) of the Act allows the Board to consider any other factors the Board considers relevant. In Matter 541, the Board concluded that the statutory variance accounts established under section 117.4 of the Act were one such factor. Separate from this rate-setting process, section 117.4 requires variances between actual energy supply costs and electricity sales and those in the revenue requirement to be tracked and reimbursed to or repaid by customers through a rate rider mechanism. Since the actual results are compared against NB Power's approved revenue requirement, overestimating or underestimating the revenue requirement directly impacts these regulatory variance account balances and the statutory rate rider. These Reasons refer to these accounts as the "statutory variance accounts" to distinguish them from the other regulatory accounts permitted under 117.5 of the Act.

3 The hearing, public participation and Board transparency

[13] Appendix A lists the parties to this proceeding and describes each witness. NB Power, the Saint John Human Development Council, and the Public Intervener made witnesses available for cross-examination during the public hearing.

[14] Before the public hearing, the Board heard presentations from members of the public who participated in a public session held virtually. The Board also received 15 letters of comment. NB Power representatives observed the public session. Submissions from the public provide important context for the public hearing and the Board's deliberations but are not treated as evidence under the Board's *Rules of Procedure* because they are not subject to interrogatory inquiries and cross-examination. The Board appreciates the efforts of those who made submissions or presentations.

[15] Documents related to this proceeding are published on the Board's website, including almost 1,000 pieces of evidence, transcripts, other filed documents, letters of comment, and the Board's orders and decisions.

4 The issues

[16] Issues related to the revenue requirement:

1. Did NB Power calculate its Fuel and Purchased Power expense forecast using reasonable assumptions (Section 5.1)?

2. Is the Operations, Maintenance and Administration expense forecast reasonable, despite being $123.9 million higher than last year and considering NB Power has spent more than approved in the past (Section 5.2)?

3. Should rates be based on a revenue requirement that includes, on an interim or final basis, Depreciation and Amortization expense associated with an asset repair project that the Board has not yet determined is prudent? Should NB Power make depreciation adjustments that would reduce the revenue requirement (Section 5.3)?

4. Is it reasonable for NB Power to forecast minimal Net Earnings, considering its objective to achieve its equity goal (Section 5.4)?

5. Does the proposed revenue requirement reasonably account for all forecast revenue (Section 5.5)?

[17] Issues related to rates and rate design:

1. Is it just and reasonable for the percentage rate increase to be applied uniformly to all customers to make rates more affordable for Residential customers? What else have NB Power and the Board done to support vulnerable NB Power customers? What else could be done to support them (Section 7.1)?

2. Are the proposed changes to the wind balancing charge, Customer Energy Solutions Portfolio prices, eCharge Network usage fees and interruptible and surplus rates just and reasonable based on cost, strategic and/or policy considerations and the Board's rate design principles (Sections 7.2, 7.3, 7.7 and 7.9)?

3. Are the proposed new AMI Opt-Out fee, optional Net-Zero Rate and public EV charging station operation rates just and reasonable based on cost, strategic and/or policy considerations and the Board's rate design principles (Sections 7.4, 7.6 and 7.8)?

[18] Other Issues:

1. Should the Board allow NB Power to implement a rate rider to recover the revenue shortfall it incurred between April 1 and April 14, 2026 (Section 10)?

2. See Sections 6, 7.5, 8 and 9 for other issues.

5 A revenue requirement of $2.7333 billion is reasonable

[19] NB Power requests approval of a total revenue requirement of $2.7403 billion for Fiscal Year 2027. To fix just and reasonable rates, the Board adjusts the revenue requirement as shown in the table below.

	Fiscal Year 2027 (in millions $)		
Revenue Requirement Component	Submitted	Adjustments	Approved
Fuel and Purchased Power	$1,195.3	-	$1,195.3
Operations, Maintenance and Administration	770.6	(13.0)	757.6
Depreciation and Amortization	460.0	(5.0)	455.0
Taxes	49.5	-	49.5
Finance Costs and other Income	259.1	(0.1)	259.0
Net Change in Regulatory Balances	(0.4)	11.2	10.8
Rate Rider Adjustment Factor	(57.9)	-	(57.9)
Net Earnings	64.0	-	64.0
Total Revenue Requirement	$2,740.3	($7.0)	$2,733.3

[20] The Board concludes that the adjusted revenue requirement gives NB Power a reasonable opportunity to recover its prudently incurred costs and earn a reasonable return in the form of Net Earnings. Each component of the revenue requirement is evaluated in more detail below.

5.1 Fuel and Purchased Power Expense is reasonable

[21] NB Power's application includes a Fuel and Purchased Power expense forecast, an in-province revenue forecast, and an out-of-province sales and gross margin forecast, all derived from production modelling results based on June 2, 2025, commodity prices and other inputs ("Q1 PROMOD Results"). Forecasts derived from the Q1 PROMOD Results indicate that NB Power's in-province Fuel and Purchased Power costs will be $1,195.3 million in Fiscal Year 2027, $82.2 million lower than last year's approved Fuel and Purchased Power expense.

[22] The Board's review of these forecasts included considering the evidentiary value of the Q1 PROMOD Results compared to more recent production modelling results and the performance assumptions underlying NB Power's forecast replacement energy costs

related to generation station outages. For the reasons below, the Board concludes that the Fuel and Purchased Power expense forecast of $1,195.3 million shown in paragraph [19] is reasonable. The Board relies on the Q1 PROMOD Results and concludes that the Fuel and Purchased Power expense component of the revenue requirement reflects reasonable generation performance assumptions.

5.1.1 The Board relies on the Q1 PROMOD Results

[23] The Board ordered NB Power to update its forecast evidence using production modelling results based on January 2026 commodity prices and other updated inputs (Q3 PROMOD Update), having determined in Matter 541 that requiring updated forecast evidence for revenue requirement components flowing through the statutory variance accounts would reduce forecast error and minimize the net statutory variance accounts balance. The Board scheduled the Q3 PROMOD Update to be filed several weeks before the public hearing.

[24] If the Board relies on the Q3 PROMOD Update instead of the Q1 PROMOD Results, the test year revenue requirement will be $1.9 million lower than NB Power is proposing. The Q3 PROMOD Update indicates a $14.6 million deterioration in forecast in-province Gross Margin and a $16.5 million improvement in forecast export Gross Margin over the test year compared to the forecast based on the Q1 PROMOD Results.

[25] The Board finds that relying on the Q3 PROMOD Update would not materially reduce test year forecast error and does not have a material, known or certain impact on the revenue requirement. While the forecast improvement in the export margin relates primarily to known and certain export sales, the forecast deterioration in the in-province margin relates to higher electricity market prices that may change. No other available updated evidence favours relying on the Q3 PROMOD Update in these circumstances. The Board, therefore, relies on the Q1 PROMOD Results as the basis for the revenue requirement.

5.1.2 Generation station performance assumptions are reasonable

[26] When a generation station is not operating, NB Power must plan to replace that energy. Replacement energy costs are a significant component of NB Power’s Fuel and Purchased Power expense forecast.

[27] The Board evaluates NB Power’s forecast replacement energy costs by examining the generation station performance assumptions on which the Fuel and Purchased Power expense forecast is based. Generating station performance assumptions should reflect realistic estimates of planned and unplanned generation station outages because unduly

optimistic forecasts erode NB Power's Net Earnings and add to the statutory variance accounts balance to be paid by ratepayers.

[28] PLNGS performance is a key determinant of NB Power's replacement energy costs. NB Power assumes a 63.4 percent capacity factor PLNGS, composed of a 119-day planned maintenance outage and a six percent forced outage rate. For the reasons below, the Board concludes that this assumption is reasonable.

[29] The 2026 Outage Plan describes large motor work with the stated aim of improving station reliability. The plan is consistent with the Three-Year Plan, which identifies sustained performance improvement at PLNGS as a critical strategic objective for NB Power that will benefit ratepayers by stabilizing fuel and purchased power costs and enhancing energy security. This and other evidence show the 2026 Outage Plan is reasonable. No intervener challenged the critical nature of improving PLNGS performance or the assumptions. There is no evidence indicating that any of the work is unwarranted or that the work planning is unreasonable.

[30] The 119-day outage schedule includes 34 contingency days, a 40 percent contingency rate. In Matter 552, the Board accepted a 40 percent contingency rate as representing reasonable improvement over the historical average contingency rate of almost 60 percent. At that time, the Board expected contingency rates to continue declining as reliability work scheduled for 2024 and 2025 began to show sustainable benefits and NB Power developed more precise planning expertise. Instead, the historical average contingency rate has persisted at 57 percent because NB Power extended planned outages in 2024 and 2025 after discovering a critical issue affecting the generator stator bars. NB Power has since acknowledged operational and leadership gaps at the station that have prevented NB Power from achieving the expected planning expertise. These events demonstrate that the Board's previous expectation is unrealistic for the test year. The Board concludes that the risk to ratepayers of underestimating the contingency outweighs the risk of unused contingency, most of which would be reimbursed to ratepayers through the rate rider mechanism. Therefore, the Board accepts the budgeted contingency as reasonable for Fiscal Year 2027.

[31] The Board concludes that NB Power's forecast six percent forced outage rate is reasonable. Compared to a 5-year historical average of 8.8 percent and the approved seven percent approved for the previous year, and considering historical year-to-year volatility, NB Power's forecast represents reasonable incremental improvement resulting from completing the 2026 outage work and earlier improvement work.

[32] Regarding conventional generating stations, NB Power plans two outages of the Bayside Generating Station, a Unit #2 outage and a full plant outage of the Coleson Cove Generating Station, and outages of the Mactaquac Generating Station. NB Power's evidence supports the reasonableness of these plans, as well as the reasonableness of the estimated six percent forced outage rate for the Bayside Generating Station and nine percent forced outage rate for the Belledune Generating Station.

5.2 Operations, Maintenance and Administration expense is reduced

[33] Operations, Maintenance and Administration ("OM&A") expense represents more than one-quarter of NB Power's revenue requirement. NB Power budgets $770.6 million in OM&A Expense for Fiscal Year 2027, an increase of $123.9 million from last year's approved revenue requirement. NB Power divides OM&A expenditures into two categories: "base OM&A costs" required to run the day-to-day activities of the utility, and "initiative OM&A costs" that are outside of daily operations, finite in duration, and expended to improve performance or solve a problem. NB Power applies its investment governance framework to prioritize and budget OM&A initiatives. This is the same work planning and resource allocation process NB Power uses for its capital project spending.

[34] NB Power identified support services for the Point Lepreau Nuclear Generating Station, the ERP upgrade, vegetation management and intensified DSM activities as being among the primary drivers of its higher OM&A budget, as well as union and wage increases. Interveners challenged NB Power's plan for recovering the costs associated with PLNGS support services and the proposed Labour and Benefits expense forecast, continuous improvement credit and vegetation management expense forecast. The Public Intervener also advocated for an overall OM&A reduction.

[35] Each of these issues is examined below. As shown in the table in paragraph [19], the Board reduces the OM&A expense forecast by $13 million for the reasons in Section 5.2.1 and Section 5.2.3.2, $11.1 million of which is offset by a corresponding increase in Net Change in Regulatory Balances and a decrease in Finance Costs and Other Income.

5.2.1 ERP upgrade initiative spending is reasonable

[36] NB Power's Enterprise Resource Planning ("ERP") system manages the lifecycle of tangible and intangible assets and supports and enables NB Power's operations. NB Power's current ERP platform, SAP, runs the utility's billing and financial systems, external financial reporting, internal controls, corporate information, customer data, procurement and inventory management, and work management systems at all of NB Power's operational facilities. In Matter 552, the Board found that NB Power's current ERP platform has reached the end of its life and needs to be upgraded. The Board approved

$29.1 million for ERP upgrade activities planned for Fiscal Years 2025 and 2026 and established a regulatory account to defer recovery of NB Power's prudently incurred upgrade costs until the ERP upgrade is complete.

[37] NB Power now seeks approval to spend $28.7 million in Fiscal 2027 on ERP upgrade activities and to add $1,097,800 to the ERP upgrade deferral account. For the following reasons, the Board approves these requests.

[38] NB Power applies its investment governance framework to evaluate strategic spending initiatives like the ERP upgrade. As part of this process for the ERP upgrade, NB Power's Board of Directors has approved an investment rationale document prepared by NB Power with the participation of Deloitte Canada. The investment rationale document describes the objectives of the ERP upgrade, estimates the costs and resources required, establishes a project schedule and evaluates its expected benefits. NB Power has also established a governance structure composed of three executive sponsors, a steering committee, and a program delivery team, to manage the ERP upgrade.

[39] This and other evidence disclose NB Power's intention to complete the planning phase of the ERP upgrade and commence the execution phase in Fiscal Year 2027 by procuring a system implementer/integrator and conducting detailed design activities. The sequence and timing of these activities differ from the plans laid out in the preliminary investment rationale document the Board reviewed in Matter 552, which contemplated completing the upgrade by 2027 and addressing data cleanup and the core ERP before replacing the human resources tool.

[40] Since then, NB Power has completed the Business Suite on Hana technical upgrade and planning for data cleanup, acquired licences to support the initiation phase of the project, and completed the ERP Upgrade Plan Development known as "Phase 0" that resulted in a project schedule, budget, and risk assessment in the form of an investment rationale document. One of the outcomes of this work is a licensing agreement for extended support from the software vendor, SAP, to carry NB Power through its upgrade transition. This agreement mitigates the operational risks NB Power faced due to the pending obsolescence of its existing SAP system.

[41] NB Power now plans to complete the upgrade by September 2028 and replace the human resources tool before proceeding with the core ERP. The investment rationale document and other evidence show that the activities planned for Fiscal Year 2027 and the related forecast spending is reasonable. Extending the completion date is reasonable because NB Power has mitigated the risks associated with the obsolescence of its current ERP system by obtaining extended support from SAP. Replacing the human resources tool is

reasonable because NB Power's current tool is nearing end of life and would not integrate into the ERP as easily as would an SAP tool. Replacing the human resources tool before proceeding with the core ERP allows human resources data to support core ERP processes and functionality. NB Power's decision to defer data cleanup activities in favour of focusing on Phase 0 activities was made in consultation with Deloitte. These activities and other planned activities are budgeted and scheduled in the investment rationale document.

[42] The evidence also outlines the SAP accessibility standards, features, and design that will be incorporated into the ERP upgrade. In response to concerns raised by Ms. Petit about the potential for overspending due to delays in accounting for accessibility requirements related to the upgraded system, NB Power confirmed that its system implementor/integrator will be required to have expertise in accessibility requirements.

[43] For these reasons, the Board approves the forecast spending for Fiscal Year 2027. The Board adjusts the revenue requirement to reflect NB Power's updated forecast by reducing the OM&A expense forecast by $11.0 million, increasing the Net Change in Regulatory Balances by $11.2 million, and reducing Finance Costs and Other Income by $0.1 million.

[44] In Matter 552, the Board established a regulatory account to defer recovery of NB Power's prudently incurred ERP upgrade costs from ratepayers until the project is complete. To mitigate risks related to cost overruns and premature spending commitments to which ERP projects are particularly susceptible, the Board restricted future additions to the deferral account to approved expenses actually incurred.

[45] NB Power reports having spent $1,074,301 of the $29.1 million approved in Matter 552 in Fiscal Year 2025. NB Power spent less than forecast because the utility delayed plan development activities pending Board approval, refined the project estimate, and deferred data cleanup work to focus on plan development.

[46] The Board approves adding $1,097,800 to the ERP upgrade deferral account, representing the $1,074,301 NB Power spent in the Fiscal Year ended 2025 for the ERP upgrade plus interest.

[47] The Board confirms that NB Power has complied with the direction to file a progress report on the ERP upgrade no later than June 30 of each year, beginning in 2025. The Board accepts the project schedule, budget and risk assessment reflected in the Investment Rationale Document filed in this proceeding as the baseline for future annual progress reports.

5.2.2 Laurentis Agreement spending is reasonable

[48] NB Power has entered into a support services agreement with Laurentis Energy Partners, an affiliate of Ontario Power Generation, to help NB Power improve PLNGS performance and sustain that improvement over time. The agreement contributes $25.8 million to forecast OM&A expenses in the test year and is expected to cost $98.4 million over its three-year term.

[49] The evidence supports Mr. Furey's submission that the support services agreement is a prudent investment for NB Power. PLNGS performance issues pose a significant risk to NB Power's financial health. PLNGS is a cost-effective source of generation when it is operating, but replacing this energy during outages is expensive. The evidence shows replacement energy costs range between $1 million and $4 million every day PLNGS is out of service and could exceed that range if forced outages were to occur in cold winter weather. Achieving sustained performance improvement at PLNGS is a critical strategic objective for NB Power that will benefit ratepayers by stabilizing fuel and purchased power costs and enhancing energy security. Mr. Murphy acknowledged that NB Power has been unable to achieve high levels of sustained performance at PLNGS, despite attempting to do so for many years. He pointed to operational and leadership gaps at the station that must be closed to accelerate NB Power's ability to deploy its capital investments in PLNGS performance improvement effectively.

[50] The support services agreement is intended to close identified operational and leadership gaps by improving operational oversight and addressing key areas including operational leadership, capital design and upgrade, and outage execution. Ontario Power Generation has extensive experience with CANDU technology and is familiar with PLNGS operations. These factors, together with the Key Performance Indicator and Performance Fee Framework outlined in Exhibit NBP9.62, give NB Power a reasonable chance of achieving the support services agreement's objectives, including reducing the frequency and duration of outages. Given that preventing a single forced outage can avoid tens of millions of dollars in replacement energy costs, the long-term benefits to ratepayers of achieving the objectives of the support services agreement will far exceed its cost. Further, the evidence shows Laurentis was the only available option within a very limited pool of qualified service providers. For these reasons, the Board concludes the investment is prudent.

[51] Mr. Madsen did not oppose NB Power's decision to enter into the support services agreement but recommended permitting recovery of the associated costs only if NB Power achieves the intended performance objectives. Having concluded that NB Power's decision to enter into the support services agreement is prudent, the Board has no basis

for making the recovery of the associated costs contingent on a future outcome as Mr. Madsen proposes.

5.2.3 Labour and Benefits expense is reduced to account for a higher vacancy credit

[52] Labour and Benefits expense represents the direct and indirect labour expense for all NB Power employees. It includes bargaining and non-bargaining wages, the employer portion of benefits and statutory remittances, and overtime costs. NB Power forecasts $513.1 million in Labour and Benefits expense for Fiscal Year 2027, an increase of $80.1 million from the approved budget for Fiscal Year 2026. After allocations to capital, Labour and Benefits expense represents 67 percent of NB Power's OM&A budget for Fiscal Year 2027. For the reasons below and in Section 5.2.7, the budget is reasonable.

5.2.3.1 Wages and new positions are reasonable

[53] More than 90 percent of NB Power employees are unionized. Budgeted wage increases for unionized employees comply with the wage mandate letters or exceptions approved by the Lieutenant-Governor in Council. Of the forecast increase, $27.1 million is associated with negotiated collective agreements to realign unionized wage rates with inflation, as well as merit increases, acting or lead hand pay. Another $23.4 million is associated with increased overtime. NB Power's pre-filed evidence demonstrates these increases are reasonable. For the reasons in Section 5.2.7, the Board does not rely on the evidence led by the Public Intervener on this issue.

[54] NB Power proposes to add 215 positions, accounting for $23.7 million of the increase. The Board concludes this increase is reasonable because NB Power faces workload increases, legislated obligations, and operational risks that cannot be mitigated through the reassignment of employees from their day-to-day tasks to new tasks or other temporary measures. Utilities Municipal challenged the need for new positions, alleging a lack of supporting evidence and an internal NB Power prohibition against increasing the budget. The Public Intervener made similar submissions relying on broad conclusions Mr. Madsen reached in his pre-filed testimony that labour costs are not tracked and have not been shown to be reasonable. Neither argument is persuasive.

[55] NB Power's leadership team issued a memorandum on May 16, 2025, informing cost centre owners of a new budgeting process. The stated purpose of the new process was to create consistency, improve efficiency, avoid rework, and prioritize spending. The memorandum included the following language:

> Fiscal 2026/27 OM&A will not be more than $684 million. It is expected that budgeting for Fiscal 2026/27 will remain in line with the Q0 Forecast for Fiscal 2025/26 and that each cost centre maintains their current position complement.

> Any increases in OM&A costs must be offset by reductions elsewhere. Increases in labour will only be accepted if it impacts the following Priority Investment areas:
>
> 1. Financial Sustainability
> 2. SAIDI/SAIFI scores
> 3. Incremental improvement in conventional generation reliability
> 4. PLNGS Sustained Performance
> 5. Energy Efficiency
> 6. Customer Demand
> 7. ERP Program
> 8. Capital Areas: MLAP, Grid Modernization, AMI ADMS, Large Transmission Projects
> 9. Renewable Integration and Grid Security (RIGS)

[56] Based on this language, Mr. Burgoyne contended that NB Power leadership prohibited adding the new positions without offsetting the cost. As the budget has increased due to new positions, Mr. Burgoyne asked the Board to conclude that NB Power contravened the instructions of its own leadership.

[57] The Board finds the memorandum did not prohibit adding the new positions without offsetting the cost. Mr. Murphy explained that the memorandum was issued to a broad audience of approximately one hundred employees and was intended to convey prioritization and restraint and to make the budget process more efficient. Considered in the context of the evidence reviewed in paragraphs [58] and [59], the memorandum is consistent with Mr. Furey's characterization as a screening and prioritization mechanism to ensure proposed increases were justified in terms of NB Power's priorities and to make the budget process more efficient. The timing of the Support Services Agreement between NB Power and Laurentis Energy Partners (Section 5.2.2) also supports this finding. The Board agrees with Mr. Furey that Mr. Burgoyne's interpretation of the memorandum as imposing an upper limit on OM&A would require concluding that NB Power's leadership did not contemplate the support services agreement expenses despite an express reference to prioritizing "PLNGS Sustained Performance" or that they expected to find another $25.7 million in offsetting cost reductions in the context of an existing continuous improvement savings target of $28.6 million. Neither conclusion is reasonable.

[58] NB Power's evidence demonstrates a business need for the new positions. 91 new positions support the Mactaquac Life Achievement Project and 53 others are associated with other capital or initiative work, including the ERP upgrade, the expansion of the Transmission vegetation management program, and other Transmission and Distribution capital projects. The need for these positions is evaluated within NB Power's investment governance process and most of the cost, representing approximately half of the $23.7

million requested for new positions, does not impact the revenue requirement because it is charged to capital. The Lieutenant-Governor in Council may approve the Mactaquac Life Achievement Project, in which case the project is deemed to be prudent and the recovery by NB Power of the associated costs and expenses in rates is deemed to be just and reasonable. The Board reviews the need for the ERP upgrade and vegetation management work elsewhere in Section 5.2 and has previously determined the prudence of other Transmission capital projects. Another three positions associated with new nuclear work will be funded by third parties. 24 new positions are required to meet audit and regulatory requirements, for succession planning, to manage higher customer contact volumes, and support plans to increase productivity and reduce labour costs over time through new technology. 14 other new positions are required to allow NB Power to meet legislated energy efficiency targets or are funded by third parties to achieve other policy objectives. Nine new positions being added to improve the cost-effectiveness of existing work by insourcing Hired Services and reducing overtime. 21 new positions are required to address baseload requirements in several business areas.

[59] NB Power's witnesses repeated and expanded on pre-filed evidence describing how it budgets for these new labour needs. Mr. Murphy described a "top-down and bottom-up" process commencing with corporate high-level direction that prompts the preparation of manager-level budgets representing each department's workload for the upcoming year, then proceeds through a "non-linear" series of consolidations, discussions and reviews up through the organization. Ms. Hachey outlined NB Power's approach to assessing labour needs for the test year beyond typical baseload work. Her testimony shows the labour planning process involves considering the most cost-effective way to meet new work requirements through regular discussions with cost centre owners, supervisors, managers, directors and executive members who are familiar with work requirements and priorities. Mr. Justin Urquhart outlined the budget schedule, which shows multiple reviews with senior management and executives throughout the budgeting process. Ms. Hachey testified to the "pointed" and "challenging" nature of those discussions and the role her team plays in reviewing vacant positions and overall headcount. Mr. Murphy, Ms. Moore and Ms. Hachey confirmed that NB Power does not systematically record every discussion or its outcome and Mr. Justin Urquhart confirmed that NB Power leadership denied 226 valid new position requests to "stretch every penny".

[60] For these reasons and the reasons in Section 5.2.7, the Board concludes NB Power has established a need for the new positions through an assessment process of which individual justifications are only one part. In this context, it would not be reasonable to expect the prioritization and cost management exercise to be conducted entirely within

each cost centre and documented in the individual position justifications. It would also not be reasonable to expect NB Power to have generated a complete written account of its work assessing labour needs throughout the budget process.

5.2.3.2 The Board increases the proposed vacancy credit

[61] NB Power includes a vacancy savings factor of $4.8 million in its Labour and Benefits expense forecast to recognize that it generates savings when budgeted positions are vacant. To calculate this vacancy credit, NB Power assumed five percent of positions will be vacant at any time during the year and incremental costs incurred to backfill vacancies will reduce those savings by two-thirds. The vacancy credit reduces the labour budget by $5.8 million when associated benefit costs are considered.

[62] NB Power recently refined its vacancy credit calculation to use the average monthly vacancy rate as an input instead of the vacancy rate on March 31. The evidence does not support the five percent vacancy rate on which the vacancy credit calculation is based.

[63] A reasonable vacancy rate assumption considers historical vacancy rates. The average vacancy rate has exceeded five percent since at least Fiscal Year 2021 and exceeded seven percent in two of the last three fiscal years. Ms. Hachey testified that the average vacancy rate for Fiscal Year 2026 was 5.77 percent as of the week of March 9, 2026, down from 5.9 percent the previous October. Based on this evidence and considering NB Power's view that, historically, vacancy rates based on average monthly calculations have been comparable to those based on vacancies as of March 31, the Board concludes that a five percent vacancy rate assumption no longer reasonably reflects NB Power's historical and test year vacancies.

[64] A reasonable vacancy rate assumption accounts for circumstances that may affect the vacancy rate in the test year. NB Power expects more new positions in the test year than were expected in Fiscal Year 2025 when, according to Ms. Hachey, an unusually large influx of new positions increased the average vacancy rate to seven percent. On the other hand, Ms. Hachey testified that her department will strive to fill the new vacancies quickly to achieve a five percent vacancy rate and Ms. Moore spoke to the business motivation to support those efforts, thereby enabling planned work to be completed without using more costly overtime or hired services. Considering these circumstances, the Board concludes the three-year average vacancy rate is a reasonable input for the test year vacancy credit calculation because it reasonably reflects the high number of new positions for the test year amid a growing workload and insourcing while accounting for NB Power's efforts to fill those positions efficiently.

[65] The evidence supports a benefit rate assumption of 22 percent. NB Power used a 20 percent average benefit rate assumption for the vacancy rate calculation. Mr. Drillen's testimony describing a fluctuating assumption based on benefits usage by employees is consistent with the statement in NB Power's pre-filed evidence describing the benefit rate calculation as a function of benefit costs. However, NB Power states in its pre-filed evidence that those benefit costs represent approximately 22 percent of regular and term labour costs and not 20 percent.

[66] For these reasons, the Board reduces the Labour and Benefits expense forecast by $2,071,282 to reflect a vacancy credit calculated using a vacancy rate equal to 6.69 percent, being the three-year historical average of year-end vacancy rates, and a 22 percent benefit rate assumption. As NB Power anticipates continued growth in work requirements, the Board directs NB Power to apply these assumptions in its vacancy credit calculation in the next general rate application.

[67] In Matter 552, the Board directed NB Power to complete a backfill data capture initiative and incorporate the results into this application. The Board accepts NB Power's evidence that data challenges and a lack of connection between its human resource systems and budgeting system prevented the utility from capturing and reporting on the specific costs of vacancies and backfilling in this application.

5.2.4 Continuous improvement credit is reasonable

[68] NB Power includes a $28.6 million continuous improvement credit in its proposed revenue requirement, representing the sustainable savings the utility expects to generate during the test year.

[69] With the Board's approval, NB Power has included a $27.5 million continuous improvement credit in its revenue requirement each year since first targeting $27.5 million in sustainable savings in Fiscal Year 2024. The Directive directs NB Power to increase its target by four percent to $28.6 million in Fiscal Year 2027. $26.1 million of the credit represents costs NB Power eliminated from previous budgets and expects to sustain in the test year. The remaining $2.5 million represents the utility's commitment to eliminate additional costs from its budget in Fiscal Year 2027 through one-time cost avoidance and cost management activities.

[70] A $28.6 million continuous improvement credit is a reasonable estimate of achievable continuous improvement savings in the test year, despite being composed mostly of sustained savings. Sustained improvement is good for NB Power and its customers. Over $118 million in customer benefits have been generated since Fiscal Year 2024 without any requirement for the credit to be composed of only new savings. The Board acknowledges

NB Power's increasing efforts to proactively identify, implement, and execute sustainable improvements in all areas of the business.

[71] Further, embedding an unrealistic credit in the revenue requirement risks impairing rather than enabling NB Power's ability to achieve its Net Earnings forecast, contrary to the expectations in section 68 of the Act and the Directive. At the same time, the Board encourages the utility to make all reasonable efforts to achieve additional savings to meet and improve upon its approved Net Earnings forecast and to otherwise improve productivity and avoid costs.

[72] The Board agrees with NB Power's submission that it is timely and reasonable to establish a new baseline target for continuous improvement savings. Approximately 45 percent of the forecast test year savings have been sustained since Fiscal Year 2024. For its next general rate application, the Board orders NB Power to include in its continuous improvement credit forecast for Fiscal Year 2028 new savings and sustained savings originating no earlier than April 1, 2024. As NB Power expects ERP-enabled improvements beginning in Fiscal Year 2029, the Board directs NB Power to file, as part of its next general rate application, a proposal for resetting the baseline for the continuous improvement credit and establishing a reasonable rolling, multi-year period for sustaining savings in the credit.

[73] The Board expects NB Power to comply with the direction given in paragraph 25 of the decision dated November 8, 2024, in Matter 552 to account for the Continuous Improvement credit and similar future credits in its budgets in a way that shows the revenue requirement and variance accounts benefits.

5.2.5 Vegetation management expense is reasonable

[74] NB Power forecasts $5.1 million more in the test year for vegetation management work than the Board approved for Fiscal Year 2026. NB Power intends to charge another $300,000 to capital.

[75] Vegetation management enables reliable service. NB Power recently achieved a second quartile vegetation-related reliability ranking relative to other utilities, after several years of performing below industry standards. NB Power's stated objective for the test year is to maintain that service level by "staying on top of" vegetation management. Its plans include hiring four forestry technicians or utility arborists in the test year to widen the transmission right-of-way as part of an expanded transmission vegetation program.

[76] The higher budget and transmission vegetation program expansion do not indicate excessive spending. NB Power has shown that its current distribution cycle times are too

long, the cost of each kilometre of vegetation management work has increased, and tree growth rates are accelerating. This evidence was uncontested. Other evidence filed by NB Power shows the right-of-way widening work will address a known cause of reliability issues, cannot be performed by current staff, and will be pursued only if the program expansion business case is approved. Based on this evidence and Mr. Landry's testimony that regaining lost ground after falling behind takes more time and money than maintaining the current vegetation management levels, the Board finds that NB Power has budgeted to maintain current service levels and address known material reliability risks.

[77] To the extent that NB Power has overestimated the budget, the Board concludes that the risks of NB Power exceeding current moderate service levels are outweighed by the risk associated with NB Power falling behind in its vegetation management program.

[78] For these reasons, the Board concludes the budget is reasonable

5.2.6 Energy Efficiency and Demand Side Management expense is reasonable

[79] Demand-side management ("DSM") seeks to modify electricity demand by encouraging customers to use energy more efficiently and change their pattern of usage.

[80] NB Power forecasts spending $55.8 million on DSM programs for the test year, $46.2 million of which is offset by adjustments to the DSM regulatory deferral account. The growth of $9.1 million compared to last year is driven by an increase in the commercial demand response Peak Rebate program targets to address winter capacity deficiencies and increased spending on energy efficiency programs to achieve legislated energy reduction targets and meet other policy objectives. NB Power's budget is part of a larger $168.4 investment in demand-side resources across New Brunswick, including funding from the Government of New Brunswick and the Government of Canada. NB Power has filed extensive evidence demonstrating how this funding in its DSM programs will reduce CO_2e emissions by 57,964 tonnes and deliver benefits several times greater than the cost, including $356 million in customer bill savings and electric system and economic benefits equal to $517 million.

[81] To evaluate the proposed revenue requirement, the Board's primary focus is on NB Power's forecast spending of $55.8 million in the test year within the context of the larger investment and its broad policy benefits. For the reasons below, the Board concludes that the proposed spending is reasonable.

[82] In support of its budget, NB Power filed a three-year DSM Plan and related plans, manuals, evaluations and analyses with detailed information on program participants,

expenditures, energy and peak demand savings, and cost-effectiveness of NB Power's DSM investments. The DSM Plan features several enhancements reflecting its mandate to deliver energy efficiency programs to all sectors and fuels to achieve broad policy objectives with government funding support. These enhancements include serving equity-deserving groups, adding benefit cost analysis tools to capture participant benefits and to assess how DSM programs align with government policy objectives, and improving program delivery.

[83] Based on the evidence filed in this proceeding, the testimony of Mr. Leopkey, and the legislated energy efficiency targets, the Board concludes that the $55.8 million test year budget is reasonable.

[84] The Board confirms that NB Power has complied with the directions given in paragraph 24 of the decision dated November 8, 2024, in Matter 552 to improve transparency regarding the costs and benefits of its demand-side management and energy efficiency programs and acknowledges that renewable measures have been removed from the DSM Plan.

5.2.7 Other OM&A expense items not explicitly addressed are reasonable

[85] The Board is satisfied that NB Power has met its burden of proof concerning OM&A expense subcategories and divisions listed in Tables 3.2.1 and 3.2.4 of Exhibit NBP1.03 but not explicitly addressed. The Board concludes that the proposed revenue requirement related to these forecast costs is reasonable.

[86] The Public Intervener contended that NB Power's OM&A budget is not reasonable because it is based on a continuation of historical overspending by the utility that has not been explained to the Board. Over the past six fiscal years, NB Power has spent 4.3 percent more on OM&A than the Board has approved. The Public Intervener based his submissions on Mr. Madsen's opinion that this spending demonstrates poor cost control and should be addressed by reducing the revenue requirement. Mr. Burgoyne relied on the same evidence in support of his request for the Board to force NB Power to curb its OM&A spending.

[87] The Board agrees with Mr. Furey's characterization of Mr. Madsen's analysis as superficial. Mr. Madsen did not substantiate his statement that most utilities control OM&A spending to within 1 or 2 percent. His analysis did not engage with NB Power's extensive pre-filed evidence and oral testimony that established PLNGS performance issues and storm-related events as the cause of over 40 percent of that spending variance, nor did he rebut Mr. Justin Urquhart's testimony describing the absence of discretionary

"nice-to-have" items or budgetary padding in NB Power's budget and the limited ability to offset those kinds of increases.

[88] For these reasons, the Board makes no adjustments to NB Power's proposed OM&A expense except those referred to in Sections 5.2.1 and 5.2.3.

5.3 Depreciation and Amortization expense is reduced to exclude the PLNGS project

[89] NB Power's budgeted Depreciation and Amortization expense of $460.0 million for Fiscal Year 2027 is $59.1 million higher than last year's budget due to recent and upcoming capital investments.

[90] In support of its proposed Depreciation and Amortization Expense forecast, NB Power filed studies authored by Larry Kennedy, who assessed the regulated life estimates related to NB Power's transmission and distribution assets and certain generation assets, all as of March 31, 2024. The Board reviewed a similar study of NB Power's other generation assets in Matter 552. The studies concluded that NB Power's depreciation lives accurately reflect the consumption of average service life of its regulated assets and set out recommended average service lives and life span dates.

[91] Based on these studies, Mr. Kennedy's testimony and the other evidence filed by NB Power, the Board accepts NB Power's proposed Depreciation and Amortization expense forecast as reasonable, except as it pertains to the Point Lepreau Nuclear Generating Station generator rewind project. This issue and others are examined below. As shown in paragraph [19], the Board reduces the Depreciation and Amortization expense forecast by $5 million for the reasons in Section 5.3.1.

5.3.1 Depreciation related to the PLNGS project is disallowed

[92] NB Power's Depreciation and Amortization expense forecast includes $5 million related to the Point Lepreau Nuclear Generating Station generator rewind project. The Board has not yet determined whether the project was prudent. If the project is not prudent, allowing NB Power to recover the related depreciation expense from ratepayers would not be just and reasonable. For the reasons below, the Board reduces the revenue requirement Depreciation and Amortization expense forecast by $5 million.

[93] Major capital projects like the generator rewind project must be pre-approved by the Board pursuant to section 107 of *Electricity Act*. Subject to certain exceptions, section 107 prohibits NB Power from spending more than 10 percent of the projected capital cost of a major capital project before the Board is satisfied as to its prudence. One such exception is subsection 107(4), which allows the Board to approve a completed project with retroactive effect if the expenditures were necessary.

[94] NB Power applied for retroactive approval of the generator rewind project under subsection 107(4) after the project was completed and the generator came back into service. That matter was scheduled to be heard in June 2026. NB Power seeks to recover the associated depreciation expense before the matter is heard because applicable accounting standards do not permit deferral of depreciation for assets once they are placed in service. Mr. Furey suggested the Board could include the $5 million in depreciation expense in the revenue requirement on an interim basis and direct NB Power to rebate the amount to customers should the Board later conclude the project was not prudent.

[95] The Board is not satisfied that it is advisable to exercise its discretion to make such an interim order. Subsection 107(4) is intended to give retroactive effect to the approval of the project, not the denial of approval. Further, as the Board stated in its motion ruling delivered on March 9, 2026, interim rates must be just and reasonable based on the available evidence. NB Power has not established whether or how the accounting limitations will cause financial hardship or that the regulatory timing was out of the utility's control.

[96] For these reasons, the Board reduces the proposed Depreciation and Amortization expense forecast by $5 million relating to the generator rewind project as the Board has not yet satisfied itself as to the prudence of the project.

5.3.2 The Board will not require NB Power to make other depreciation adjustments

[97] For the reasons below, the Board will not adopt Mr. Madsen's recommendations to apply the Average Life Group procedure, accelerate the refund of the accumulated depreciation variance, or revise the average service lives for certain accounts.

[98] NB Power has applied the Equal Life Group (ELG) procedure combined with the straight-line method and remaining life technique to depreciate its transmission and distribution assets. The ELG procedure has been approved by the Board for NB Power since 2008 based on periodic depreciation studies and has been reviewed and accepted by NB Power's external auditors. Mr. Madsen recommended NB Power transition from the ELG procedure to the Average Life Group (ALG) procedure. He expects this change would reduce Depreciation and Amortization expense by $35.7 million in the test year. NB Power opposed this recommendation on the basis that Mr. Madsen has not demonstrated that the ELG procedure is unreasonable or that the ALG procedure is more precise. NB Power also submitted that Mr. Madsen has overstated the revenue requirement impact of changing to the ALG procedure. NB Power offered the expert testimony of Mr. Kennedy in support of its opposition. For the following reasons, the Board will not require NB Power to transition to the ALG procedure.

[99] The ELG and ALG procedures are both considered to produce reasonable estimates of depreciation expense and both result in the same total depreciation recovery over the life of the assets. The procedures differ with respect to timing: ALG assumes assets retire at their average service life while ELG explicitly recognizes that assets may retire at any point during their service lives and implicitly accounts for early retirements and associated derecognition effects. Because of this timing difference, the ELG procedure recovers more depreciation earlier in the life of the assets than does the ALG procedure. The reverse is also true.

[100] Depreciation adjustment is not an appropriate tool to reduce the revenue requirement for rate mitigation purposes. To accept Mr. Madsen's recommendation, then, the Board must be convinced that using the ELG procedure no longer results in a reasonable reflection of NB Power's asset retirement behaviour. Mr. Madsen alleged that the ELG procedure "routinely and consistently results in an over-recovery of depreciation expense", characterizing this as a difference between the theory and practice of the ELG procedure. He clarified on cross-examination that his allegation pertained only to a scenario in which asset lives are extending, and that "over-recovery" refers to too much depreciation being recovered earlier in the life of the assets.

[101] There is no evidentiary basis for making the change Mr. Madsen recommended. What he described is merely one side of the mathematical consequences of accounting for the possibility of early retirements within the ELG procedure and not doing so within the ALG procedure. Further, Mr. Kennedy's rebuttal testimony demonstrated that Mr. Madsen's assertion regarding lengthening asset lives is based on unsubstantiated assumptions. Finally, based on NB Power's rebuttal evidence and the testimony of Ms. Hicks-Gesner, the Board finds that Mr. Madsen's calculated difference between the two procedures does not reflect the impact of retirement losses for distribution assets amounting to $24.9 million, and that adopting the ALG procedure would require NB Power to establish a process to forecast those losses. For these reasons and based on Mr. Kennedy's testimony, the Board concludes that the ELG procedure reasonably reflects NB Power's asset retirements.

[102] Mr. Madsen also raised concern about the $205.3 million difference between the depreciation NB Power has expensed in relation to its distribution and transmission assets and the depreciation that would have been expensed had the current estimates been in place throughout the lives of those assets. Mr. Madsen recommended accelerating that process and implementing a $25 million refund in the test year if NB Power retains the ELG procedure.

[103] NB Power asked the Board to reject Mr. Madsen's recommendation. NB Power relied on the evidence of Mr. Kennedy, who described depreciation as an estimate that may change over time based on depreciation studies in which estimated asset lives are altered. He testified that the resulting differences between calculated and book reserve are not errors or overcollections; they are calculations of the amount of true-up required to be made over the remaining life of the asset group using a Remaining Life depreciation calculation. Mr. Madsen acknowledged the difference could be recovered over the expected remaining life of the assets but recommended accelerating a portion of the recovery to ensure customers "benefit from a portion of the refund during the period of heightened rate increases." He noted that the Alberta Utilities Commission has implemented measures of this nature where there is an extraordinary need to address rate pressures for customers.

[104] The Board rejected a similar recommendation made by Mr. Madsen in Matter 552 because depreciation adjustment is not an appropriate tool to reduce the revenue requirement for rate mitigation purposes. In its Matter 552 decision, the Board noted that some of the variance, then $187 million, had since been refunded to ratepayers through the normal operation of NB Power's accounting policies and, to the extent the difference endures, the remainder will be refunded throughout the remaining lives. The Board left open the possibility of considering a future recommendation for a refund if the then-upcoming depreciation studies indicate it is justified.

[105] The authorities Mr. Madsen cited in support of his testimony caution against making these kinds of adjustments without careful analysis. Page 189 of *Public Utility Depreciation Practices*, published by the National Association of Regulatory Utility Commissioners, instructs depreciation professionals to avoid making accelerated adjustments without careful analysis of the causes of the differences between past and current depreciation estimates. Page 76 of *Depreciation Systems* by Frank K. Wolf and W. Chester Fitch describes additional factors that should inform the depreciation professional's recommendation as including account characteristics, estimates of future events, volatility, and depreciation policies. The Board has no analytical basis for finding a clear case of an "over-contribution of depreciation".

[106] The Board also finds Mr. Madsen's calculation of accumulated depreciation variance does not recognize the $24.9 million loss on retirement account related to distribution assets.

[107] The Board accepts the evidence of Mr. Kennedy and, for these reasons, will not adjust the Depreciation and Amortization expense forecast as Mr. Madsen proposed.

[108] Mr. Madsen also recommended different average service lives for several accounts which, in his view, provide a better estimate of depreciation expense. Average service lives and survivor curves are key determinants of depreciation expense. Curve selection involves the exercise of expert judgment. The depreciation studies review how Concentric selected curves to estimate average service lives for the assets with the largest level of investment.

[109] In most cases, Mr. Madsen's recommendation is based on his opinion that his selected curves have a better mathematical and statistical fit to the observed retirement data than do the curves selected by Concentric. In one case, his recommendation is based on his opinion that the curve he selected is better aligned with the need for NB Power management to control its spending. He also recommended the Board direct further study of certain accounts as part of NB Power's next depreciation study.

[110] The Board will not adopt Mr. Madsen's recommendations because Mr. Kennedy's testimony rebuts Mr. Madsen's assertion that his selected curves produce a better estimate of depreciation expense. Mr. Kennedy demonstrated that Mr. Madsen focused on fitting the curve to historical data without considering other factors that dictate the expected life of assets or gradualism and moderation principles, and that he made unexplained peer comparisons and assessments of mathematical fit.

5.4 Net Earnings request is reasonable

[111] The Net Earnings component of the revenue requirement represents the return to which NB Power is entitled under the Act and pursuant to regulatory principles. As shown in paragraph [19], NB Power proposed Net Earnings of $64.0 million for Fiscal Year 2027, which it expects will improve the equity ratio only slightly. Net Earnings is reasonable as proposed for the reasons below.

[112] In Matter 552, the Board approved Net Earnings of $64 million for each of Fiscal Year 2025 and Fiscal Year 2026. NB Power considers $64 million to be unsustainably low but reasonable in the circumstances. Mr. Murphy and Mr. Justin Urquhart testified about the competing objectives in setting the Net Earnings forecast in the context of the then-ongoing Comprehensive Review of NB Power. According to them, NB Power prioritized investing in its generation fleet and other reliability work over achieving higher test-year Net Earnings to limit the rate increase and because it expects the resulting reliability improvements will lead to sustainably higher Net Earnings

[113] The Act establishes no deadline for achieving the equity goal and does not prohibit NB Power from prioritizing sustainable income over higher short-term income. As major reliability issues have driven down NB Power's Net Earnings in the past, investing in

reliability improvements is a reasonable way to achieve sustainably higher income. Further, the forecast is consistent with the Directive, NB Power expects incremental progress toward the equity goal despite making significant investments over the next three years, and the statutory variance accounts provide some protection against uncontrollable risk.

[114] The Directive instructs NB Power to plan to make “meaningful progress” toward the equity goal over the next three fiscal years and for appropriate earnings to absorb uncontrollable risks, all without putting unnecessary pressure on rates. Like the Act, it establishes no deadline for achieving the equity goal and does not prohibit NB Power from prioritizing sustainable income over higher short-term income. Mr. Justin Urquhart testified NB Power views itself as complying with the Directive because the Three-Year Plan shows “incremental improvement”. He also noted that the statutory variance accounts absorb some of the uncontrollable risks that higher Net Earnings would mitigate.

[115] The Board agrees. The Three-Year Plan not only forecasts incremental improvement toward the equity goal but does so during a period of significant investment. According to the Three-Year Plan, NB Power expects debt levels to increase by almost $4 billion over the planning period primarily due to the increase in lease liabilities associated with the RIGS project and investments in Mactaquac. Further, NB Power previously excluded lease liabilities and finance liabilities from the capital structure but changed its approach because of the forecast growth in these liabilities over the next three years arising from the RIGS project. Despite these significant investments, increase in debt and change in approach, the plan forecasts 0.68 percent improvement in the capital structure by the end of Fiscal Year 2029.

[116] Mr. Murphy suggested the Net Earnings forecast is consistent with the Minister’s expectations because NB Power received no direction to adjust its revenue requirement or Three-Year Plan after presenting them to the Minister as the Directive requires. As to why the Government of New Brunswick would consider minimal Net Earnings in Fiscal 2027 to be reasonable, Mr. Murphy urged the Board to consider the changing government expectations around progressing to the equity goal because of the pending Comprehensive Review. The outcome of the Comprehensive Review is intended to be a report, expected by March 31, 2026, containing recommendations for a sustainable NB Power future. The Directive regarding Net Earnings remains in place only until those recommendations are implemented.

[117] Considering NB Power’s objective to earn sufficient income to achieve a capital structure of at least 20 percent equity, the other mandatory statutory factors, and the then-ongoing Comprehensive Review, the Board concludes that the proposed Net Earnings forecast is

reasonable. The Board will not increase the proposed Net Earnings to offset the disallowances reviewed in Sections 5.2.1, 5.2.3.2 and 5.3.1. The Board has jurisdiction to fix just and reasonable rates that are higher than those NB Power proposes but declines to do so in this case because the proposed Net Earnings forecast is reasonable.

5.5 Revenue Forecast is increased to reflect Net-Zero Rate and AMI Opt-Out fee revenue

[118] NB Power filed its estimated in-province energy sales volume, known as the load forecast, for the ten years from 2026 to 2036. The utility used its load forecast as an input to its PROMOD analysis and to develop its in-province revenue forecast. NB Power also filed its non-firm revenue and out-of-province sales and gross margin forecasts as part of its application.

[119] As detailed in Section 5.1.1, the Board accepts the revenue forecast based on the Q1 PROMOD Results. The Q1 PROMOD Results were based on forecast in-province energy load of 14,775 gigawatt-hours and forecast peak demand of 3,230 megawatts for Fiscal 2027.

[120] The Board accepts NB Power's forecast for in-province revenue, subject to the following adjustments to account for revenue from the new Net-Zero rate and AMI Opt-Out fee. NB Power did not account for any revenue from the Net-Zero Rate or the AMI Opt-Out fee in its proposed revenue requirement. The Board approves the proposed Net-Zero Rate in Section 7.6. NB Power is unable to forecast how many customers will select the Net-Zero Rate. Without evidence of forecast revenue, the Board deems one-third of the $4.2 million full-year revenue NB Power has assumed for pricing purposes to be a reasonable forecast. Accordingly, the Board adjusts the revenue requirement by the amount necessary to account for deemed revenue of $1.4 million. The Board approves the proposed AMI Opt-Out fee Section 7.4. The Board heard evidence that NB Power anticipates two percent of customers will choose a non-standard meter after the completion of its Meter Choice campaign. The Board, therefore, reduces the revenue requirement by the amount necessary to account for the forecast AMI Opt-Out fee revenue for Fiscal Year 2027. NB Power confirmed in its compliance filing dated April 13, 2026, that the appropriate reduction is $252,103.25.

[121] The Board accepts NB Power's test year forecasts for out-of-province sales and gross margin.

5.6 A revenue requirement of $2.7333 billion is approved

[122] The Board is satisfied that NB Power has met its burden of proof concerning revenue requirement categories explicitly addressed in these Reasons. The Board concludes that the proposed revenue requirement related to these forecast costs is reasonable.

[123] The Board approves a revenue requirement in the amount of $2.7333 billion for Fiscal Year 2027. This revenue requirement reflects the adjustments depicted in the table in paragraph [19] and gives NB Power a reasonable opportunity to recover its forecast costs and to earn a fair return in the context of its equity goal and other planning objectives.

[124] The Board cannot arbitrarily restrict the revenue requirement to reduce rates. The Board is acutely aware of the effect of increased rates on NB Power's customers, including low-income residential customers, but cannot reduce rates to punish the utility for past shortcomings. As reviewed in Section 5.2.7, some interveners raised concerns about NB Power's proposed revenue requirement and its seeming inability to maintain spending within past forecasts. They argued in favour of capping the revenue requirement to reduce rates, presumably by forcing NB Power to operate within a smaller budget. In response, NB Power pointed to factors beyond its control, including severe weather and the unforeseen Point Lepreau Nuclear Generating Station outage, and submitted that the proposed revenue requirement is fully supported by the evidence and the spending is necessary to safely and reliably operate its system.

[125] Preventing NB Power from recovering costs where the evidence demonstrates those costs are prudent would harm ratepayers by leading to higher rates in the future or creating unacceptable reliability and safety risks. For better or worse, NB Power's current financial circumstances cannot be ignored. As tempting it may be to do so, setting rates below levels demonstrated to be just and reasonable after a thorough testing of the evidence would only perpetuate and exacerbate the burden on ratepayers.

6 Cost allocation methodology is approved

[126] The Board approves the methodological changes reflected in NB Power's 2026-2027 Class Cost Allocation Study models filed as Exhibits NBP1.98 and NBP1.99CR. The Board confirms that NB Power has complied with the directions given in paragraphs 9 and 10 of the decision dated December 19, 2024, in Matter 554 to allocate fuel and energy purchased power costs classified to energy on a seasonal basis and to evaluate the implicit or explicit capacity benefits of its purchased power agreements and supply mix.

7 Rate design, rates, and charges are approved

[127] Rate design is a regulatory term describing a utility's price structure. Typically, rates should be set based on customer cost causation to spread system cost recovery and benefits fairly among all customers. However, it may be appropriate to compromise cost-based considerations in favour of competitive or strategic considerations or to meet policy objectives.

[128] NB Power has asked the Board to make rates more affordable for Residential customers by applying the percentage rate increase uniformly to all customers. NB Power has also proposed changing the wind balancing charge and Customer Energy Solutions Portfolio prices, implementing a new optional Net-Zero Rate to be included in the Customer Energy Solutions Portfolio and a new AMI Opt-Out fee, increasing fees for users of the eCharge Network, and implementing new rates for public EV charging station operation. For the reasons below, the Board approves these requests as proposed.

7.1 Uniform rates are approved to be more affordable for Residential customers

[129] Historically, Residential customers have paid less for electricity than the cost NB Power incurs to provide service to them, while some other customers have paid more than their cost of service. The Board has taken a gradual approach to address this unfairness, fixing slightly higher percentage rate increases for Residential customers each year and slightly lower percentage rate increases for other rate classes. Several more years of these differential rate increases are required before Residential rates will recover the cost to serve Residential customers.

[130] Rate increases disproportionately affect low-income and other vulnerable customers. NB Power asked the Board to make rates more affordable for Residential customers by pausing the effort to restore fairness and, instead, applying the percentage rate increase uniformly to all customers. A uniform rate increase would lower the Residential rate increase to 4.75 percent instead of 5.42 percent but would slow progress toward recovering the full cost of service.

[131] All interveners asked the Board to consider affordability in fixing just and reasonable rates. The Saint John Human Development Council filed its report titled "2025 Energy Poverty in New Brunswick" as evidence in this proceeding. The report shows that 68.4 percent of low-income New Brunswick households spend at least six percent of their after-tax income on electricity, compared to 25.6 percent of all New Brunswick households. The Board accepts this report as evidence that significantly more low-income households in New Brunswick face high energy cost burdens compared to all households. Based on this evidence and considering the comments from members of the public

expressing affordability concerns, the Board concludes that the affordability benefits of a uniform rate increase outweigh the achievement of moderate progress toward fairness through differential rates.

[132] As an administrative tribunal with authority delegated by statute, the Board does not possess the jurisdiction to establish a rate relief program to support low-income or other vulnerable NB Power customers. The *Electricity Act* requires the Board to fix rates based on NB Power's revenue requirements. The Board evaluates those revenue requirements on a forecast basis to ensure that rates will be fixed to recover only prudently incurred costs. In addition to approving uniform rates, the Board addresses affordability by accepting as prudent NB Power's mandated cost savings target (Section 5.2.4) and a Net Earnings forecast that minimizes progress toward NB Power's equity goal (Section 5.4) while disallowing certain forecast costs that have not been proven to be prudent (Sections 5.2.3.2 and 5.3.1).

[133] For these reasons, the Board approves uniform rates for Fiscal Year 2027 as follows:

	Revenue without Increase (in millions)	Rate Increase	Revenue After rate increase (in millions)	Annual Increase (in millions)
Residential	989.3	4.29%	1031.6	42.3
General Service	375.1	4.29%	391.2	16.1
Small Industrial	76.9	4.29%	80.2	3.3
Large Industrial	284.1	4.29%	296.4	12.3
Wholesale	147.7	4.29%	154.0	6.3
Streetlights	18.9	4.29%	19.7	0.8
Unmetered	6.0	4.29%	6.2	0.2

*Table values may reflect differences due to rounding

[134] NB Power and the Board have taken other steps to support vulnerable NB Power customers. NB Power offers payment assistance resources and energy efficiency tools and ran a winter disconnection moratorium pilot program. NB Power also administers the Enhanced Energy Savings Program, which has reduced the number of New Brunswickers experiencing energy poverty. The Board has facilitated these and other efforts through its orders and directions. NB Power is uniquely positioned to support all stakeholders in understanding energy poverty in New Brunswick by tracking and publishing relevant affordability indicators such as arrears, payment plan and disconnection measures, as well as measures related to the Enhanced Energy Savings Program including participation, waitlist and energy savings information. The Board

expects NB Power to build on the initial work of the Vulnerable Populations Committee to develop a scorecard for this purpose.

[135] The provincial government has the mandate and the necessary social program infrastructure to effectively provide additional support if and how it chooses. The Board recommends that the provincial government consider offering targeted relief to New Brunswickers experiencing energy poverty.

7.2 Wind Balancing Charge is approved

[136] NB Power has asked the Board to approve an increased wind balancing service charge of 0.256 cents per kWh. The charge applies to customers who are supplied by a wind power generation facility having a capacity greater than 100kW instead of NB Power. It is intended to allow NB Power to recover the cost of providing balancing services for that supply and to provide appropriate price signals to customers.

[137] NB Power's proposed charge is based on the results of a wind balancing study conducted in accordance with the Board's approved methodology and in compliance with the Board's direction to refine its cost estimation methodology. Utilities Municipal, on behalf of the only customer subject to the wind balancing charge, did not oppose the proposed rate but questioned the fairness of setting the charge more frequently and through a different proceeding than the Schedule 3(c) rate is set.

[138] Mr. Burgoyne submitted that potential unfairness arises from two sources. First, he raised the possibility that the customer will overpay in Fiscal Year 2027 because the charge is based on the three-year average cost of wind balancing over the next three fiscal years as calculated in a wind balancing study that discloses greater wind production and higher purchased fuel prices in years two and three. Second, he raised the potential for different customers paying different prices for "the same service" because the Schedule 3(c) rate is set during a separate proceeding. Mr. Burgoyne suggested both issues could be resolved by setting the wind balancing charge every three years at the same time as the Schedule 3(c) rate is set.

[139] The Schedule 3(c) service and the wind balancing charge are not the same service. The Schedule 3(c) service is an intra-hour service and is not fully analogous to the proposed wind balancing service that also provides inter-hour service and applies in different circumstances. While the Board acknowledges the potential fairness and efficiency benefits of conducting a wind balancing study every three years to support both rates in the same proceeding, the Board is not convinced that Utilities Municipal's request is justifiable in the circumstances. The continuity of participants between proceedings, the proportionately small amount of revenue earned from the charge and the practical

challenges of setting both rates simultaneously militate against doing so at this time. The Board notes NB Power's offer, made in response to Mr. Burgoyne's submission, to discuss this issue further with Utilities Municipal.

[140] For these reasons, the Board approves NB Power's proposed wind balancing charge and will not require future rates to be set simultaneously with Schedule 3(c). However, the Board may modify the approved methodology if NB Power seeks to support new proposed rates in the next two fiscal years based on a new three-year forward average.

[141] The Board confirms the updated wind balancing study filed as Exhibit NBP2.07 complies with the Board's directions given in paragraph 31 of the decision dated November 8, 2024, in Matter 552.

7.3 CES Portfolio prices are approved

[142] NB Power offers its customers a suite of products and services called Customer Energy Solutions: water heater rentals with 24/7 emergency service, dusk-to-dawn and floodlighting rental and maintenance service, and a backup power solution rental and maintenance service known as SureConnect. The Board regulates the prices of these products and services as a portfolio using market-based considerations because they are offered in competitive markets. Net revenues generated by the CES Portfolio benefit all ratepayers.

[143] NB Power is requesting price increases for each product and service in the CES Portfolio. The Board must ensure that the increased prices continue to be market-based, costs are fully recovered from participating consumers, and the portfolio generates net revenues.

[144] For the following reasons, and considering the role of the CES portfolio in achieving NB Power's planning objectives, the Board approves the prices proposed in the following table:

CES PORTFOLIO APPROVED PRICES FOR FISCAL YEAR 2027		
Water Heater	22 gallons (100L)	$10.99
	40 gallons (180L)	$10.99
	50 gallons (228L) "Stainless Steel"*	$10.99
	60 gallons (270L)	$13.99
	100 gallons (455L)	$26.99
	100 gallons (455L) "Commercial" 208V	$39.99

	100 gallons (455L) “Commercial” 600V	$50.49
Area Lighting	100 Watt HPS Equivalent (LED)	$20.99
	200 Watt HPS Equivalent (LED)	$32.49
	100 Watt high pressure sodium*	$22.99
	200 Watt high pressure sodium*	$35.49
	175 Watt mercury vapor*	$22.99
	400 Watt mercury vapor*	$40.49
	250 Watt Metal Halide Equivalent (LED)	$40.99
	400 Watt Metal Halide Equivalent (LED)	$49.99
	1000 Watt Metal Halide Equivalent (LED)	$85.99
Sure Connect	30 Amp Transfer Switch	$29.99

[145] Detailed financial information filed by NB Power shows that the costs to provide its area lighting services are forecast to decrease in Fiscal Year 2027, while the average in-service costs of water heating rentals and SureConnect service will increase due to rising vendor and installation costs and, in the case of water heating rentals, program growth. NB Power has closed the SureConnect program to new entrants but continues to support existing customers. With the proposed price increases, the CES Portfolio is forecast to generate net revenues of $19.6 million in Fiscal Year 2027.

[146] The Board finds the proposed prices continue to be market-based. NB Power’s water heater rental prices are the lowest in Canada and its area lighting rental pricing is comparable to other providers. While there is no market for rental solutions directly comparable to SureConnect, the Board is satisfied that transfer switch purchase and installation options are available to customers.

[147] Based on these findings, the Board concludes that the proposed prices are just and reasonable.

7.4 AMI Opt-Out fee is approved

[148] AMI meters are NB Power's standard meters. Non-standard meters must be read manually. NB Power is asking the Board to approve a Non-Standard Meter (AMI Opt-Out) fee of $4.65 per month and a one-time AMI Communications Disconnection Fee equal to the Service Call fee, effective September 1, 2026. The stated purpose of the AMI Opt-Out fee is to recover the additional operational cost of six manual meter readings each year. NB Power filed evidence calculating an average annual cost of $55.74 per opt-out customer, equal to $4.65 per month. For the following reasons, the Board concludes the proposed AMI Opt-Out fee is just and reasonable.

[149] Without an AMI Opt-Out fee, all ratepayers would subsidize opt-out customers for the additional costs of manual meter reading. This outcome would violate the principle that customers should pay for the costs they cause and would prevent fair system cost recovery among all customers. NB Power's review of peer utilities showed that similar opt-out fees are common in Canada.

[150] Mr. Burgoyne questioned why four of the five peer utilities have higher monthly opt-out fees than the $4.65 NB Power proposed. While the Board is unable to compare the cost allocation methodologies of NB Power and its peers, there is no evidence that NB Power has underestimated its costs. NB Power's calculated average cost per opt-out customer takes into consideration reasonable factors, specifically meter reading labour, vehicle cost, oversight, overhead and travel time.

[151] As NB Power has committed to do, the Board directs NB Power to file an annual report demonstrating the cost of serving customers with non-standard meters. As Utilities Municipal requested and to the extent the report does not do so, the Board directs NB Power to evaluate the fully allocated labour costs and the cost of equipment and vehicles associated with this service and file the results of the evaluation in the next general rate application. The Board will not require NB Power to include peer reviews or alternative methodologies in the annual report.

[152] For these reasons, the Board approves the AMI Opt-Out fee effective September 1, 2026. An effective date of September 1, 2026, will allow NB Power to inform customers of the approved fee during its upcoming campaign to encourage remaining customers to adopt AMI meters. The Board also approves the proposed one-time AMI Communications Disconnection fee equal to NB Power's Service Call fee. This fee is intended to recover the cost associated with one required site visit.

[153] The Board confirms that the proposed language for the Rate Schedules and Policies Manual presented in Section O-7 of Exhibit NBP1.15 complies with the Board's direction given at paragraph 182 of the decision dated September 4, 2020, in Matter 452.

7.5 Late payment and NSF charges are approved

[154] The Board does not apply general rate increases to NB Power's late payment charge and non-sufficient funds charge. Based on the evidence submitted by NB Power, the Board approves NB Power's proposal to maintain the current late payment charge and non-sufficient funds charge.

7.6 Optional Net-Zero Rate is approved and included in CES Portfolio

[155] In Matter 529, the Board approved NB Power's proposed rate calculation methodology for an optional Net-Zero Rate offering that would give customers the option to purchase 100 percent of their energy from non-emitting energy sources by paying a premium above NB Power's base rates.

[156] NB Power now seeks approval of a Net-Zero Rate of 8.32 cents per kWh for distribution-connected customers and 7.99 cents per kWh for transmission-connected customers. The proposed rates have been calculated according to the methodology approved in Matter 529, which will recover the cost to the system. Net revenue generated by the proposed rates will put downward pressure on electricity rates to the benefit of all ratepayers.

[157] Because it was calculated in accordance with an approved methodology, the Board approves an optional Net-Zero Rate of 8.32 cents per kWh for distribution connected customers and 7.99 cents per kWh for transmission connected customers. The Board also approves the proposed language for the Rate Schedules and Policies Manual presented in Sections G-7 and N-15 of Exhibit NBP1.15.

[158] The Board confirms that NB Power has complied with the directions given in paragraph 19 of the decision dated July 28, 2023, in Matter 529 to file evidence related to subscription and supply with any application for approval of a specific Net-Zero Rate. NB Power has filed the supply agreements it has entered into for renewable energy and does not anticipate requiring subscribers to agree to terms and conditions beyond those in the Rate Schedules and Policies Manual.

[159] The Board grants NB Power's request to add the Net-Zero Rate to the Customer Energy Solutions Portfolio. NB Power presented evidence confirming that proposed rate satisfies the three requirements for membership: there is existing market for a Net-Zero Rate offering and alternative solutions to satisfy demand for electricity sourced from non-

emitting technologies, a cost-effective source of supply in the form of several agreements for renewable energy with federally funded proponents, and net revenue representing margin that will put downward pressure on electricity rates to the benefit of all ratepayers.

7.7 eCharge Network rates are approved

[160] NB Power's eCharge Network is comprised of NB Power-owned chargers and chargers owned by authorized third parties. The Board sets EV charging rates for the eCharge Network to be comparable to other EV charging rates in the region because the purpose of the eCharge Network is to enable EV adoption in the province, which, in turn, will contribute to future increased electricity sales in support of the utility's strategic objectives. This approach continues to be appropriate to foster further growth in demand for EV charging and the continued development of a competitive market.

[161] Users of the eCharge Network pay time-based or session-based fees. NB Power proposes to increase these user fees by 33 percent in the case of Level 2 and Level 3 50kW charging and 50 percent in the case of Level 3 100kW charging.

[162] The Board finds that the proposed fees are comparable to other EV charging rates in the region. While the proposed Level 2 charging fee is higher than other utility network prices in Atlantic Canada, it is within the range of rates charged to users of third-party networks within Atlantic Canada and across the country and lower than some rates charged in New Brunswick. The proposed Level 3 50 kW charging fee is the same as the time-based utility network prices charged in Prince Edward Island, Manitoba and Saskatchewan and the proposed 100 kW charging fee is similar to other time-based rates charged to users of third-party networks within Atlantic Canada and across the country. The Board also finds that the electricity costs associated with charging have increased significantly since the current fees were introduced.

[163] The Board concludes they are just and reasonable because the increases exceed relative increases in electricity costs while remaining comparable to other EV charging rates in the region. These features will address the barriers to third-party investment in the eCharge Network identified by NB Power. For these reasons, the Board approves the user fees to apply presented on page 62 of the Rate Schedules and Policies Manual filed by NB Power on April 13, 2026 to electric vehicle charging at NB Power's eCharge Network.

7.8 New rates for public EV charging station operation are approved

[164] Public electric vehicle (EV) charging station operators pay electricity rates that include charges based on their maximum demand, regardless of how frequently the charging

station is used. These site operators are presently classified as General Service customers, but their load shapes and cost of service differ from the General Service class.

[165] NB Power is proposing a new rate design to apply to public EV charging site operators with a load factor lower than or equal to 20 percent. The proposed rate design would include an escalating demand charge and declining energy charge, both based on the annual load factor of the charging site. The energy charge would vary between on-peak and off-peak periods. For new customers, a load factor tranche will be estimated based on projected utilization as compared to known data from similar sites in a similar or the same location.

[166] In support of its application, NB Power filed a report authored by Jeff Turner. Mr. Turner used NB Power data to demonstrate that the load profile of public EV site operators is characterized by low load factor with brief and variable peak demand, only a small portion of which is drawn during system peaks. Based on this evidence, the Board finds that the proposed design will align with the Board's rate design goals by reasonably reflecting the costs caused by site operators.

[167] The Board approves the creation of a rate class consisting of the owners of public electric vehicle charging sites and the rate design and rates presented in Section N-8 of Appendix "A" to the Board's April 13, 2026 Order.

[168] The Board confirms that NB Power has complied with the Board's directions related to public and fleet electric vehicle charging and residential and general service EV charging given in paragraph 20 of the decision dated July 28, 2023, in Matter 529.

7.9 Interruptible and Surplus Rates are approved

[169] NB Power offers interruptible and surplus energy to qualifying Large Industrial customers. NB Power proposes redesigning its interruptible and surplus rates by replacing on-peak and off-peak pricing with hourly pricing, refining the definition of incremental cost and updating the adders to recover the current NB Power Open Access Transmission Tariff rates and 10 percent of total generation expense (not including fuel and purchased power), normalized by total system energy. NB Power's evidence demonstrates the calculation of the proposed rates.

[170] NB Power reports that all existing interruptible and surplus customers opted to be charged at the proposed hourly rates starting on November 1, 2024. No intervener opposed these redesigned rates.

[171] The proposals align with the Board's rate design goals. Hourly pricing reasonably reflects the incremental cost of providing energy to interruptible and surplus customers and

improves price signals. The proposed adders for NB Power's standard and non-firm transmission offerings reasonably represent contributions to NB Power's fixed costs while recognizing that NB Power's generation planning does not account for interruptible and surplus loads, but transmission planning does.

[172] For these reasons, the Board approves hourly prices for NB Power's interruptible and surplus offerings equal to the incremental hourly cost + 1.125¢/kWh for the standard offering and equal to the incremental hourly cost + 0.902 ¢/kWh for the non-firm transmission offering, as well as the proposed adder pricing methodology.

[173] The Board also approves NB Power's related proposals to interpret the phrase "other firm supply commitments" within the definition of "incremental cost" on page 57 of the Rate Schedules and Policies Manual filed by NB Power on April 13, 2026, to mean all firm sales with a term of at least six months; extend the standard notice period to 36 months while allowing load switching on short notice by exception, if demonstrably beneficial to other ratepayers; and revise the Rate Schedules and Policies Manual to reflect these approvals, including the timing of pricing, and to specify customers' obligation to forecast a material load reduction.

[174] The Board acknowledges NB Power's position that replacing on-peak and off-peak pricing with an hourly price does not require approval because the Rate Schedules and Policies Manual refers to "incremental cost" and neither prescribes nor disallows hourly pricing. In the Board's view, however, the change affects the rate itself and affects all ratepayers. The Board expects NB Power to be diligent in coming to the Board before implementing rate changes.

8 Financial and risk management policies are approved

[175] The transactions of the New Brunswick Energy Marketing Corporation are governed by Financial Risk Management Policies that are approved by the Board. NB Power seeks approval of its revisions to one of those policies, known as NBEMC-6 Renewable Energy Certificate (REC) Risk Policy.

[176] The purpose of the policy is to manage the New Brunswick Energy Marketing Corporation's forecasted exposures to REC prices. In 2024, NB Power extended the date associated with the minimum hedge requirements from January 1 to April 15 to reflect realistic REC eligibility and issuance dates.

[177] For this reason, the Board approves the revised policy in Exhibit NBP1.90.

9 The Minimum Filing Requirements are modified

[178] NB Power files extensive evidence with its general rate application to satisfy the Board's minimum filing requirements. The Board developed these requirements to ensure the regulatory process is effective and efficient.

[179] NB Power is seeking the Board's approval to delete or modify some minimum filing requirements. Except as they pertain to MFR 37, 48 and 79, the Board concludes the changes will improve the effectiveness and efficiency of the regulatory process for the reasons stated by NB Power in Exhibit NBP1.22.

[180] The Board denies NB Power's request to delete MFR 37. MFR 37 requires NB Power to provide a unit cost view of the Fuel and Purchased Power expense breakdown and variances required by MFR 35. The Board disagrees with NB Power's characterization of this full year data as "deceptive". The data adds value to the evidentiary record, despite not recognizing the seasonality of pricing specifically, because it shows the average annual price and can easily be compared to the average price customers pay for their energy. NB Power may supplement this minimum filing requirement with additional data to illustrate pricing seasonality if it wishes to do so.

[181] The Board denies NB Power's request to modify MFR 79. MFR 79 requires NB Power to provide, for all customer classes, a table comparing the forecast energy, energy sales revenue, and unit rate for the test year against the current and previous years' revenue. NB Power asked the Board to delete the unit rate requirement and the comparisons on the grounds that the information is redundant and not useful. The Board disagrees. Similar to MFR 37, the annual unit rate shown by MFR 79 gives context to customers comparing their average rates with other classes and average costs.

[182] The Board approves NB Power's request to modify MFR 48 by removing category "4) Smart Grid OM&A costs" and to renumber the remaining items accordingly but denies the request to remove category "5) Demand Side Management OM&A costs". MFR 48 requires NB Power to provide a table comparing forecast OM&A costs for the test year against the current and previous years, with those costs categorized as Generation, PLNGS, Transmission, Smart Grid, Demand Side Management, Distribution, or NB Energy Marketing. NB Power asked to delete the "Smart Grid" and "Demand Side Management" categories. The Board agrees that isolating smart grid OM&A costs is no longer valuable. The Board sees value in isolating Demand Side Management OM&A costs, however. Because the Board must consider statutory requirements specific to those costs in evaluating the revenue requirement.

[183] The Board approves the proposed modifications to all other minimum filing requirements for the reasons NB Power stated in Exhibit NBP1.22.

[184] To better evaluate rate design impacts, the Board directs NB Power to present in future general rate applications, as a minimum filing requirement, a single view of the typical residential customer bill impact of its requested rates and all other fees and charges, including the statutory rate rider.

10 The Board denies NB Power's request to add a rate rider to customers' bills

[185] The Board requires NB Power to file each rate application no later than the first Wednesday of October to allow sufficient time to conduct rate hearings in early February. This fixed window in the Board's regulatory calendar facilitates rates being implemented by April 1, the first day of NB Power's fiscal year. Implementing new rates on April 1 is important for consistency with the *Electricity Act* and because NB Power presents a full-year revenue requirement to support its application.

[186] NB Power filed this application on October 1, 2025, but the public hearing was held later than usual, between March 9 and March 20, 2026. This delay created a strong possibility that approved rate increases would not be implemented by April 1. Ultimately, the approved rates were implemented on April 14, 2026, causing NB Power to incur shortfall compared to the revenue it would have earned had approved rate increases been implemented on April 1.

[187] Expected shortfalls of this nature are typically addressed through an interim rates order, a recognized exception to the general prohibition against retroactive ratemaking. NB Power filed a motion seeking an interim rates order, but the Board denied its request on the grounds that the regulatory delay was caused by factors within NB Power's control or that were reasonably foreseeable. The Board also denied NB Power's request to implement a rate rider that would recover the shortfall by the end of Fiscal Year 2027 because of a lack of evidence. At the close of this proceeding, NB Power asked the Board again to implement a rate rider.

[188] A rate rider is a credit or charge added to a customer's bill for a set period in addition to rates approved by the Board. The typical regulatory purpose of a rate rider is to allow the utility to recover the difference between its actual and forecast costs for a specified period. Mr. Furey argued that collecting the shortfall through a rate rider would align with regulatory principles by allowing NB Power to recover its full revenue requirement without affecting rates beyond the end of Fiscal Year 2027.

[189] The Board denies NB Power's request because implementing a rate rider would constitute retroactive ratemaking and would shield NB Power from the consequences of the Board's ruling denying its interim rates motion. The Board relies on the decision of the New Brunswick Court of Appeal in *Enbridge Gas New Brunswick Limited Partnership v. New Brunswick Energy and Utilities Board et al.,* 2015 NBCA 65 (CanLII), which upheld the view that the Board is not obligated to give a utility an opportunity to recover expenses incurred in the past and not recovered under rates established for a past period.

11 Conclusion, Orders and Directions

[190] In compliance with the Board's Decision dated April 1, 2026, NB Power refiled its budget incorporating the Board's approved revenue requirement for the test year and a revised cost of service study, revised proof of revenue, and the resulting rates. This compliance filing indicated a revenue requirement of $2.7333 billion for Fiscal Year 2027, and a rate increase of 4.29% applied uniformly across all customer classes each year.

[191] By Order dated April 13, 2026, the Board concluded that the rates described in NB Power's compliance filing, exclusive of any rate riders, are just and reasonable and ordered that the rates become effective as of April 14, 2026, except for the AMI Opt-Out fee which was ordered to become effective as of September 1, 2026.

[192] The Board issues the following Orders and Directions to NB Power:

[193] The Board directs NB Power to apply the assumptions set out in paragraph [66] in its vacancy credit calculation in the next general rate application (Section 5.2.3.2).

[194] For its next general rate application, the Board orders NB Power to include in its continuous improvement credit forecast for the Fiscal Year ending 2028 new savings and sustained savings originating no earlier than April 1, 2024, and to file a proposal for resetting the baseline for the continuous improvement credit and establishing a reasonable rolling, multi-year period for sustaining savings in the credit (Section 5.2.4).

[195] The Board directs NB Power to comply with the Board's previous direction to account for the Continuous Improvement credit and similar future credits in its budgets in a way that shows the revenue requirement and statutory variance accounts benefits (Section 5.2.4).

[196] As NB Power has committed to do, the Board directs NB Power to file an annual report demonstrating the cost of serving customers with non-standard meters. As Utilities Municipal requested and to the extent the report does not do so, the Board also directs NB Power to evaluate the fully allocated labour costs and the cost of equipment and

vehicles associated with this service and file the results of the evaluation in the next general rate application (Section 7.4).

[197] The Board directs NB Power to present in future general rate applications, as a minimum filing requirement, a single view of the typical residential customer bill impact of its requested rates and all other fees and charges, including the statutory rate rider (Section 9).

Dated at Saint John, New Brunswick, this 26th day of August, 2026.

Christopher J. Stewart
Chairperson

Heather Black
Member

Michael Pickup
Member

Appendix A	
Participant	**Witnesses**
NB Power	Darren Murphy, Senior Vice President, Major Projects Justin Urquhart, Chief Financial Officer Diane Fraser, Director, Investment Governance Jordan Drillen, Manager, Financial Planning Vicki Hachey, Senior HR Advisor, Workforce Planning and Organizational Design Sue Moore, Executive Director, Strategic Planning and Transformation Andrew Ottens, Manager, Enterprise Architecture Gillian Ash Richard, Senior Technical Specialist, Corporate Planning Craig Church, Senior Corporate Modeler Ted Leopkey, Manager, Demand Side Management Jeff Good, Director, Treasury and Risk Management Janice Hicks-Gesner, Director, Financial Reporting Abby Davidson, Manager, Financial Reporting Francois Bolduc, Director, Finance Operations Phil Landry, Vice President, Operations (acting) Jason Nouwens, Director, Regulatory and External Affairs (PLNGS) Katie Bacon, Director, Business Planning and Reporting (PLNGS) Veronique Stevenson, Manager, Rates Modernization David Urquhart, Director, Products and Services Gord Perry, Senior Manager, Customer Care

	Larry Kennedy, Senior Vice President, Concentric Advisors, ULC, was declared an expert qualified to give opinion evidence in the areas of depreciation, valuation studies for gas and electric utilities. Jeff Turner, Director, Dunsky Energy + Climate Advisors, was declared an expert qualified to give opinion evidence in the area of electrical vehicle charging, including associated 4 business plans, pricing strategies, and electricity rate designs.
Saint John Human Development Council	Liam Fisher, Data Analyst, Saint John Human Development Council Heather Atcheson, Social Researcher, Saint John Human Development Council
Public Intervener	Dustin Madsen, President, Emrydia Consulting Corporation, was declared an expert qualified to give opinion evidence in the areas of regulatory accounting and finance for utilities, rate regulation, deferral and variance accounts, revenue requirement accounting matters and depreciation expense.