



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 2024/25 fiscal year and for the 2025/26 fiscal year, capital project and other approvals.

(Matter No. 552)

March 31, 2025

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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 2024/25 fiscal year and for the 2025/26 fiscal year, capital project and other approvals. (Matter No 552)

APPLICATION: December 15, 2023
ORAL HEARING: June 24 to August 23, 2024
ORAL DECISION: November 8, 2024
ORDER: December 10, 2024

NEW BRUNSWICK ENERGY AND UTILITIES BOARD:

Chairperson	Christopher Stewart
Member	Heather Black
Member	John Logan

PARTICIPANTS:

New Brunswick Power Corporation	John Furey
Canadian Federation of Independent Business	Louis-Philippe Gauthier
Canadian Manufacturers & Exporters	Ron Marcolin
Forest NB	Kimberly Allen
IBEW Local 37	David Brown
J.D. Irving, Limited	Glenn Zacher
Liberty Utilities	Brandy Gellner
New Brunswick Coalition of Persons with Disabilities	Shelley Petit
Saint John Human Development Council	Randy Hatfield
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 9.25% average rate increase across all rate classes for each of the fiscal years ending 2025 and 2026 to be applied differentially, meaning that customers in some rate classes would see higher-than-average increases and customers in other rate classes would see lower-than-average increases. NB Power says it needs to increase rates because of planned investments to improve reliability and station performance, to make progress toward achieving its equity goal, and because of inflation, market prices, and lower forecast export sales.
- [3] NB Power seeks approval to create several regulatory accounts to smooth or defer the rate impact of its proposed expenditures and is asking the Board to approve a new wind balancing charge, rental rate increases for its customer energy solutions products and services, and other rates, charges, and proposals. The utility is also asking the Board to approve, with retroactive effect, the actual capital project costs of \$66.8 million associated with the replacement of the combustion gas turbine generator at the Bayside Generating Station, pursuant to subsection 107(4) of the Act.
- [4] The Board previously issued a ruling and interim Order fixing rates reflecting differential rates and an average 9.25 percent increase to all customer classes on an interim basis effective April 1, 2024. The Board’s ruling and interim Order did not give final approval to NB Power’s revenue requirements, rates, or other requests.
- [5] In summary and for the following reasons, the Board has determined that:

An average annual rate increase of 9.14% applied differentially across all rate classes, exclusive of the rate rider, is just and reasonable for each of Fiscal Years 2025 and 2026. This is lower than NB Power’s proposed average annual increase of 9.25% because NB Power’s forced loss rate assumption for the Point Lepreau Nuclear Generating Station, an input to the Fiscal Year 2026 forecast, is unreasonably high. Subject to this exception, NB Power has demonstrated that its proposed revenue requirement is reasonable.

NB Power’s proposed regulatory accounts, wind balancing charge, and other rate design measures, rates, and charges are approved, except the proposed customer charge merger.

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NB Power is directed to establish a vulnerable customer liaison committee to better understand and improve the customer experiences of those facing energy poverty or accessibility challenges.

The actual capital project costs associated with the Bayside Generating Station project are approved with retroactive effect.

2 Overview of revenue requirement and rates

- [6] The Board’s primary obligation in this proceeding is to fix just and reasonable rates for Fiscal Years 2025 and 2026 based on NB Power’s revenue requirement for both years. Fiscal Years 2025 and 2026 are referred to as the “test period” in this Decision.
- [7] This application differs from previous NB Power rate applications in the magnitude of the requested annual increases and because the application encompasses two fiscal years. NB Power has identified the following drivers for the successive rate increases it requests in this application:
- 50% for improvements in reliability and station performance
 - 19% due to debt-to-equity requirement
 - 17% due to inflation and market prices
 - 14% due to reduced energy sales outside New Brunswick
- [8] At the Board’s direction, NB Power proposed that its rate increase for in-province electricity sales be applied differentially, meaning that customers in some rate classes would see higher-than-average increases and customers in other rate classes would see lower-than-average increases.
- [9] NB Power’s rate application includes its proposed revenue requirement for the test period. NB Power develops its proposed 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. To calculate its requested rates, NB Power deducts its forecast export sales revenue and other miscellaneous revenues to determine the total revenue requirement it proposes to collect from ratepayers, then allocates that total revenue requirement among rate classes following the Board approved methodology.

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- [10] To fix just and reasonable rates, the Board applies the law and regulatory principles to the evidentiary record. The Board evaluates the proposed revenue requirement and may adjust it to give the utility a reasonable opportunity to recover its prudently incurred costs and earn reasonable Net Earnings. The Board then determines whether recovering the revenue requirement from ratepayers through NB Power’s proposed rates would be just and reasonable in the circumstances.
- [11] Subsection 103(7) of the *Act* prescribes specific factors for the Board to consider when fixing just and reasonable rates based on NB Power’s revenue requirements. These factors include the government’s policy for NB Power, NB Power’s most recent Three-Year Financial Plan and Integrated Resource Plan, Executive Council directives for NB Power, and relevant legal requirements such as those related to demand side management, energy efficiency and renewable energy. These factors are referred to collectively as the “mandatory statutory factors” in this Decision.
- [12] The government’s policy for NB Power, expressed in section 68 of the *Act*, sets an expectation that the utility will be managed and operated in a way that, among other things, provides safe and reliable service that results 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% 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” in this Decision.
- [13] NB Power’s most recent Three-Year Financial Plan for Fiscal Years 2025 to 2027 and its 2023 Integrated Resource Plan were filed as evidence in this proceeding. They reveal NB Power’s plans to make significant investments in generation, transmission, and distribution assets for an extended period to ensure reliability of the integrated electricity system, meet net-zero requirements, satisfy growing in-province load, and update critical systems.
- [14] The Executive Council Directive for NB Power dated September 25, 2023, was issued pursuant to section 69 of the *Act* and was filed in evidence in this proceeding. In it, the Executive Council directs NB Power to make plans to achieve the equity goal by March 31, 2029, and to incorporate that target into its forecast budgets and rates for Fiscal Years 2025 through 2027. The March 31, 2029, target date is referred to as the “equity target date” in this Decision.
- [15] Subsection 103(8) allows the Board to consider any other factors that 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-

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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 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 and considered in Section 5.4 of these Reasons.

[16] The approved revenue requirement for Fiscal Year 2026 is, by its nature, less representative of NB Power’s actual revenue requirement than the approved revenue requirement for Fiscal Year 2025. Two statutory mechanisms counteract this risk; the statutory variance accounts capture some of the difference between the approved and actual revenue requirement and section 105 authorizes the Board, during the test period, to review NB Power’s rates on its own motion or at the request of the Lieutenant-Governor in Council.

3 The hearing process and public participation

[17] Appendix A lists the parties to this proceeding and describes each witness who gave written and oral testimony. NB Power, the Saint John Human Development Council, J.D. Irving, Limited (“JDI”), Utilities Municipal, the Public Intervener, and Board staff made witnesses available for cross-examination during the oral hearing.

[18] Before the oral hearing, the Board heard four presentations from members of the public who participated in public sessions held virtually. The Board also received 21 letters of comment. Senior NB Power executives attended the public sessions.

[19] Submissions from the public are not treated as evidence under the Board’s *Rules of Procedure*, which would otherwise be subject to interrogatory inquiries and cross-examination. However, they form part of the public record and the Board takes them into consideration in its deliberations. The Board appreciates the efforts of those who made submissions or presentations.

4 The issues

[20] Issues related to the revenue requirement

1. Are NB Power’s forecasts for rising costs and lower out-of-province sales reasonable? More particularly,

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- a. is NB Power using reasonable production modelling and assumptions for the performance of the Point Lepreau Nuclear Generating Station (“PLNGS”) to inform its Fuel and Purchased Power expense forecast, energy sales forecast, and other components of the revenue requirement (Section 5.1)?
 - b. Are NB Power’s other forecast cost increases reasonable, including inflation (Section 5.2.4), internal labour (Section 5.2.6), and market prices (Section 5.1.1)?
 - c. Is NB Power’s continuous improvement savings commitment of \$27.5 million each year of the test period reasonable (Section 5.2.3)?
2. In circumstances of rising costs and lower out-of-province sales, is it prudent for NB Power to plan significant spending to improve PLNGS (Sections 5.1.2 and 5.2.2), undertake the Enterprise Resource Planning upgrade initiative (Section 5.2.1), and explore converting the Belledune Generating Station to an alternative fuel (Section 5.2.5)?
 3. In circumstances of rising costs, lower out-of-province sales, and significant planned spending, is NB Power’s requested Net Earnings of \$64 million for Fiscal Year 2025 and \$63.5 million for Fiscal Year 2026 reasonable (Section 5.5)?
 4. Does NB Power propose to establish the new regulatory accounts for the purpose of ensuring the recovery of prudently incurred costs of the Corporation while minimizing the rate impact of those costs (Section 5.4)? Does the proposed adjustment to the PLNGS amortization account ensure that the balance of the deferral account is recovered over the operating life of the refurbished station (Section 5.4.1)?

[21] In addition to these issues, the Board evaluates NB Power’s proposed Depreciation and Amortization expense, DSM spending, OM&A allocations to capital, and other revenue requirement components in Section 5.

[22] **Issues related to rates and rate design**

5. Are the differential rates that result from a prudent revenue requirement unfairly high in the circumstances for some or all rate classes?
6. Is it just and reasonable to impose a wind balancing charge to recover wind balancing and integration costs to serve specific New Brunswick loads and, if so, is NB Power’s proposed charge based on a reasonable estimate of the underlying costs (Section 6.3)?

[23] In addition to these issues, the Board considers other rate design issues, rates, and charges in Section 6.

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[24] Issues related to the Bayside capital project

7. Was it necessary for NB Power to replace the combustion gas turbine generator at the Bayside Generation Station in response to an equipment failure and, if so, is the Board satisfied that the capital expenditure of \$66.8 million was prudent (Section 8)?

5 Evaluation of the revenue requirement

[25] NB Power requests approval of a total revenue requirement of \$2.5879 billion for Fiscal Year 2025 and \$2.7522 billion for Fiscal Year 2026.

[26] To fix just and reasonable rates, the Board adjusts the revenue requirement as shown in the table below. The Board concludes that, as adjusted, this 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.

Component	Fiscal Year 2025			Fiscal Year 2026		
	Submitted	EUB Adjustments		Submitted	EUB Adjustments	
		Approved			Approved	
Fuel and Purchased Power	\$ 1,330.0	-	\$ 1,330.0	\$ 1,282.6	\$ (5.1)	\$ 1,277.5
Operations, Maintenance and Administration	621.3	(1.0)	620.3	648.7	(1.9)	646.8
Depreciation and Amortization	390.2	-	390.2	401.0	-	401.0
Taxes	49.6	-	49.6	50.5	-	50.5
Finance Costs and other income	247.0		247.0	241.3	0.4	241.7
Net Change in Regulatory Balances	(57.9)		(65.6)	129.1	(6.5)	122.6
Rate Rider Adjustment Factor	(56.3)		(49.6)	(64.5)	8.9	(55.6)
Net Earnings	64.0	-	64.0	63.5	-	63.5
Total Revenue Requirement	\$ 2,587.9	\$ (1.9)	\$ 2,586.0	\$ 2,752.2	\$ (4.1)	\$ 2,748.0

[27] Each component of the revenue requirement is evaluated in more detail below.

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5.1 Fuel and Purchased Power Expense reduces by \$5.1 million for 2026

[28] 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 October 2023 commodity prices and other inputs (Q2 PROMOD Results).

[29] Two inputs to these forecasts were at issue in this proceeding:

1. the evidentiary value of the Q2 PROMOD Results compared to more recent production modelling results NB Power filed several weeks before and during the oral hearing; and
2. the performance assumptions underlying NB Power’s forecast replacement energy costs related to outages at PLNGS.

[30] Forecasts derived from the Q2 PROMOD Results indicate that NB Power’s in-province Fuel and Purchased Power costs will increase by \$172.4 million to \$834.6 million in Fiscal Year 2025, then decline slightly in Fiscal Year 2026 to \$823.0 million. For the reasons below, the Board relies on the Q2 PROMOD Results and reduces the Fuel and Purchased Power expense component of the revenue requirement by \$5.1 million to reflect reasonable performance assumptions for PLNGS.

5.1.1 The Board relies on the Q2 PROMOD Results as the basis for the revenue requirement

[31] NB Power’s Fuel and Purchased Power expense forecast is based on the Q2 PROMOD results. NB Power subsequently filed updated forecast evidence using production modelling results based on January 2024 commodity prices and other updated inputs (Q3 PROMOD Update). The Board ordered NB Power to file the Q3 PROMOD Update, having determined in Matter 541 that requiring updated forecast evidence for revenue requirement components that flow through the statutory variance accounts would reduce forecast error and minimize the net variance accounts balance.

[32] If the Board relies on the Q3 PROMOD Update instead of the Q2 PROMOD Results, the test period revenue requirement will be lower than NB Power is proposing. The Q3 PROMOD Update indicates a \$57.4 million improvement in forecast in-province Gross Margin over the test period compared to the forecast based on the Q2 PROMOD Results, comprising a \$37.2 million reduction in revenue that is more than offset by a \$84.7 million reduction in Fuel and Purchased Power expense. For the reasons below, the Board considered the Q3 PROMOD Update but relies on the Q2 PROMOD Results as the basis of the test period revenue requirement.

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- [33] The prohibition against single-issue ratemaking recognizes that parties may suffer prejudice when limited updated forecast evidence is introduced late in the hearing process. The Board mitigates this potential prejudice by scheduling the Q3 PROMOD Update filing several weeks in advance of the oral hearing and by considering all available updated evidence along with the Q3 PROMOD Update.
- [34] The \$57.4 million gross margin improvement in the Q3 PROMOD Update is caused by lower forecast electricity market prices that may continue to fluctuate throughout the test period. This calls the certainty of the Q3 PROMOD Update into question because it stands in contrast to the gross margin improvement in Matter 541, which was largely driven by known and certain out-of-province sales contracts. Further, NB Power revealed during the oral hearing that it expected the then-ongoing outage at PLNGS to continue to November, several months past its scheduled completion date of July 12, 2024. Mr. Church testified that the first two months of the outage extension will cause a \$51 million gross margin deterioration due to higher replacement energy costs. This known and certain evidence erodes the certainty of the improvement shown in the Q3 PROMOD Update.
- [35] Based on this updated evidence and considering the totality of the circumstances, including that replacement energy costs are trending higher with the anticipated November return date for PLNGS, the Board exercises its discretion to rely on the Q2 PROMOD Results as the basis for the revenue requirement. Further, the Board will not establish a specific materiality threshold for considering future Q3 PROMOD updates. The Board concludes that its decision in this Section 5.1.1 illustrates the need to consider the nature of the updated evidence and particular circumstances in each proceeding instead of focusing only on a quantitative threshold.

5.1.2 PLNGS performance assumptions are not all reasonable

- [36] NB Power is planning a 98-day outage for Fiscal Year 2025 and a 35-day outage for Fiscal Year 2026 to perform maintenance and conduct major work as part of a multi-year plan to improve station performance. The utility also expects unplanned, or forced, outages to further reduce station performance by 8% each year of the test period. Replacing the energy PLNGS would otherwise generate on days when the station is not operating contributes \$90.3 million to NB Power's forecast test period Fuel and Purchased Power expense, \$88 million higher for Fiscal Year 2025 than last year's forecast. These costs significantly contribute to the requested 9.25% average annual rate increase, but NB Power considers the improvement work and correcting for past optimism in its forecasts

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to be necessary to carry out the objectives in its Three-Year Financial Plan and mitigate a material risk to its ability to achieve its equity goal.

[37] PLNGS performance is a key assumption in the Three-Year Financial Plan and the Plan identifies lower-than-assumed PLNGS performance as a material risk to its ability to achieve its financial goals. No intervenor questioned the critical nature of improving PLNGS performance, but Mr. Zacher and Mr. Burgoyne argued that NB Power’s multi-year performance improvement plan will not help NB Power achieve the goals in its Three-Year Financial Plan. Mr. Burgoyne asked the Board to require NB Power to file a better plan. He and Mr. Zacher challenged NB Power’s assumptions for unplanned outages, contingency, and forced loss rate (“FLR”) as being unjustified because the utility is forecasting PLNGS performance to show no improvement before the equity target date compared to its own past forecasts or its peer nuclear operators.

[38] The Board accepts NB Power’s performance assumptions for Fiscal Year 2025 because they reasonably represent current performance and risk. The Board also accepts NB Power’s planned outage contingency assumptions for Fiscal Year 2026 but expects some performance improvement in Fiscal Year 2026 as better planning and reliability work begin to show sustainable benefits. The Board concludes that the FLR assumption for Fiscal Year 2026 is unreasonable and, therefore, adjusts the proposed revenue requirement by the amount necessary to reflect a FLR of 7% for Fiscal Year 2026 instead of the proposed 8% FLR.

5.1.2.1 The revenue requirement should be based on realistic performance and risk, not past forecasts or median peer performance

[39] Mr. Zacher argued that, until a better improvement plan is made, ratepayers should pay no more replacement energy costs than NB Power has forecast in previous years or is comparable to median peer performance.

[40] The Board concludes previous forecasts and median peer performance do not represent reasonable ceilings on approved replacement energy costs for the test period. These are unreasonable measures against which to assess NB Power’s improvement plans because they do not represent current station performance and they obscure the performance improvement NB Power expects to achieve as it executes its plans for PLNGS.

[41] Previous forecasts and peer performance have not aligned with actual PLNGS performance, a point made in the Board’s decision in Matter 541 and in Ms. Clark’s testimony in this matter. The Board determined in Matter 541 that NB Power’s forecasts have been tainted by undue optimism, based partly on evidence of past outages that

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frequently exceeded forecast duration, and that optimism has eroded NB Power’s Net Earnings and impeded its plans to build equity. In this matter, Ms. Clark testified that PLNGS performance assumptions have posed “challenges” in covering the utility’s cost of service because unplanned outages require NB Power to purchase or generate more expensive power to maintain energy security for the province. Ms. Clark also testified that NB Power has, in the past, pushed off investing in the station to manage rate increases for customers.

- [42] The Board concludes limiting the revenue requirement to align with past forecasts would perpetuate this cycle and hinder the planned improvement work, and aligning the revenue requirement with the performance standards of a median peer nuclear operator would have similar consequences because PLNGS has not performed to that standard in the past. Further, these limitations would not benefit ratepayers the way Mr. Zacher contended they would because the statutory variance accounts would capture the deficit and pass it on to ratepayers through the rate rider mechanism.
- [43] Considering the risks to the Three-Year Financial Plan arising from lower-than-assumed PLNGS performance and based on the misalignment between actual performance and past forecasts or peer performance, the Board concludes a reasonable estimate of replacement energy costs turns on a realistic estimate of the frequency and duration of PLNGS outages. Prudently incurred costs are not limited to costs that an ideally running utility would incur but include costs reasonably required to allow the utility to improve its performance to run more efficiently.

5.1.2.2 *Fiscal Year 2025 assumptions reasonably represent current performance and risk*

- [44] Interveners argued that NB Power selectively applied stale historical performance statistics and ignored recent performance improvements to inflate the outage assumptions, thereby increasing forecast replacement energy costs. NB Power denies this and says that the assumptions are derived from historical averages to better represent current PLNGS performance and to reflect the benefits of past improvements and the heightened risk from aging equipment.
- [45] The Board concludes that NB Power’s performance assumptions reasonably represent its expected Fiscal Year 2025 performance and operating risk. The evidence does not support interveners’ submissions that NB Power has relied on selective historical results to inflate the outage assumptions. NB Power’s budgeted contingency for Fiscal Year 2025 is 40%, whereas the 5-year actual contingency average was 50% at the time of the budget and has since grown to almost 60%. NB Power is also forecasting an 8% FLR each year of the test period, while the 5-year historical average is greater than 8%, even when the

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historical average encompasses NB Power’s exceptionally low FLR of less than 0.1% in Fiscal Year 2024.

- [46] NB Power engaged Marc Miller, a partner with ScottMadden Management Consultants, to assess NB Power’s PLNGS nuclear outage and reliability plan and its PLNGS capital plan. Mr. Miller was declared an expert qualified to give opinion evidence in the areas of management performance and performance evaluation of nuclear generation facilities and the regulation of utilities operating nuclear generation utilities. His report on the PLNGS nuclear outage and reliability plan concluded based on benchmarking that NB Power’s performance assumptions for the test period were reasonable.
- [47] Mr. Zacher urged the Board to dismiss Mr. Miller’s testimony supporting NB Power’s performance assumptions on the basis that it was unreasonable to expect no improvement in PLNGS performance over the period. The Board agrees with Mr. Zacher and places little weight on Mr. Miller’s evidence because, as Mr. Miller admitted in cross-examination, the PLNGS performance forecast should be based on NB Power’s improvement plans. Mr. Miller did not assess those plans in his report.
- [48] While the Board agrees with Mr. Zacher’s submission that the utility’s efforts over the past several years and its recent partnership with Ontario Power Generation have contributed to PLNGS’s recent improved performance compared to historical averages, the Board is not persuaded that the favourable 2024 metrics with which Mr. Zacher supported his argument represent current performance and risk. A single year’s performance does not demonstrate sustainable performance improvement and does not account for evidence that NB Power anticipates a countervailing trend of increased operating risk to negatively impact its performance over the test period. The Board accepts the testimony of Mr. Nouwens, who described how the utility’s assessment of future PLNGS performance is informed by “more intrusive and comprehensive insight” gained from its lifecycle management plans, engagement with experts, benchmarking work, and a goal of improved station performance. He testified that NB Power factored recent performance improvements into its assumptions, but any risk-moderating benefit of those improvements are at least partially eclipsed by increasing reliability risk posed by aging equipment.
- [49] Consistent with this testimony, the utility’s Performance Improvement Plan, Strategic Capital Plan, Outage 24 Plan, and Outage 25 Plan describe the planned outage work as large motor work that will be more complex, longer, and more frequent than past outage work. The strategic aim of this work is to improve station performance, but it will also heighten the risk of “discovery” work and drive the risk of using more contingency days

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due to the aging and degradation of equipment. There is no evidence that any of the work is unwarranted, or the work planning is unreasonable.

[50] According to the Strategic Capital Plan, the age of large motors also puts PLNGS at the highest risk of an extended forced outage until the outage planned for the spring of 2026 is complete. NB Power describes its Strategic Capital Plan as reflecting a plan that aims to minimize the highest risks first based on careful consideration of the magnitude of risk associated with each component to be replaced. Considering the Strategic Capital Plan, other PLNGS plans, and the updated FLRs to correct for past forecasting optimism, the Board concludes that the Fiscal Year 2025 assumptions reasonably represent current PLNGS performance and operating risk.

5.1.2.3 Contingency and 7% FLR assumptions represent Fiscal Year 2026 performance and risk

[51] Reasonable performance assumptions should place less emphasis on historical performance over time as better planning and completed reliability work begins to show sustainable benefits. The Board concludes that it is unreasonable to maintain the 8% FLR assumption in the Fiscal Year 2026 budget because NB Power expects some sustainable reduction in PLNGS's operating risk by then.

[52] The Strategic Capital Plan and other evidence of NB Power's planning shows operational risk beginning to trend down during Fiscal Year 2026. Two earlier planned outages will be complete by then and NB Power's plans for those outages indicate that the utility expects a reduced risk of a forced outage to be immediately reflected in Net Earnings as the primary operational impact of that work. This expectation is consistent with the timing shown in Table 7 of the Strategic Capital Plan and with Mr. Murphy's acknowledgement that station performance will improve incrementally throughout the improvement period. It is also consistent with Mr. Nouwens's testimony that NB Power has been targeting performance improvement for several years in areas that have triggered previous losses, and his acknowledgement that good Fiscal Year 2024 performance was due, at least in part, to this work and recent Ontario Power Generation support that will be sustained throughout the test period. Based on this evidence and a reasonable expectation that the utility will learn additional lessons from the 2024 Outage that may provide near-term efficiency benefits, the Board concludes that NB Power and ratepayers will begin to see enduring improvement from this work in 2026 in the form of smaller and less volatile replacement energy costs.

[53] The Board views a 7% FLR as representing reasonable incremental improvement for Fiscal Year 2026 considering NB Power's improvement plans, gains in planning excellence, and corrections for past forecasting optimism. The Board favours retaining an ultimate

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objective of a 3% FLR by 2031 as depicted in Table 7 of the Strategic Capital Plan, despite NB Power adjusting it to 4% to correct past forecast optimism. By 2031, a reasonable FLR forecast should not bear a strong relationship to pre-2025 performance and should be fully benefiting from NB Power’s improvement work and gains in planning excellence. The Board will not depart from this expectation without evidence supporting different longer-term performance and concludes that a 7% FLR for Fiscal Year 2026 is a reasonable first step to achieving 3% FLR by 2031 while continuing to allow significant but declining reliance on historical performance.

- [54] The Board accepts the budgeted 40% contingency as reasonable for Fiscal Year 2026. Mr. Nouwens testified that PLNGS planning has improved, partly because of NB Power’s recent partnership with Ontario Power Generation. Given the lack of evidence as to whether or how NB Power’s new planning expertise has been incorporated into the outage plans filed in this proceeding, the Board concludes that the risk to the Three-Year Financial Plan of underestimating the contingency outweighs the risk of unused contingency, most of which will be reimbursed to ratepayers through the rate rider mechanism. However, this conclusion does not negate NB Power’s incentive to work efficiently during the test period. The Board expects one of the early outcomes of NB Power’s new planning expertise to be a vastly reduced outage contingency rate and more representative outage scheduling. Therefore, in the future, the Board will not presume that comparable contingencies are reasonable.

5.1.2.4 Consequential adjustments to the revenue requirement

- [55] Adjusting the Fiscal Year 2026 FLR to 7% lowers the Fuel and Purchased Power expense by \$5.1 million and OM&A Expense by \$0.9 million in the same year, as described in paragraph [82], and causes changes to interruptible/surplus revenues and export margin. The overall revenue requirement impact for the test period is set out in the table in paragraph [26].

5.2 Operations, Maintenance and Administration (“OM&A”) expense is reasonable

- [56] OM&A Expense represents approximately one-quarter of NB Power’s revenue requirement. NB Power budgets \$621.3 million in OM&A Expense for Fiscal Year 2025, an increase of \$27.3 from last year’s approved revenue requirement, and a further increase of \$27.4 million for Fiscal Year 2026. 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 for the test period. This

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is the same work planning and resource allocation process NB Power uses for its capital project spending.

- [57] Interveners opposed NB Power’s plans to spend \$29.1 million in the test period on its ERP Upgrade initiative and challenged some of the assumptions underlying the increase in estimated base spending for intensified generation station reliability and maintenance work and unplanned outages. NB Power identified these as being among the primary drivers of its higher OM&A budget. Interveners also considered NB Power’s proposed \$27.5 million improvement credit to be insufficiently aggressive and the Public Intervener advocated for a 2% “global reduction” in OM&A, partly to address inflationary impacts, and partly to address what he considers to be overstated labour and benefits costs. The Public Intervener also argued that NB Power’s budgeted contingency for another OM&A initiative is inappropriate and that the utility is inflating OM&A expense by undercapitalizing some OM&A costs.
- [58] Each of these issues is examined in this Section 5.2, along with the overall Labour and Benefits budget and estimated DSM spending. For the reasons below, the Board concludes that the proposed spending is reasonable and will not adjust the revenue requirement in relation to NB Power’s proposed OM&A budget.

5.2.1 ERP Upgrade initiative spending is reasonable

- [59] NB Power describes its Enterprise Resource Planning system (“ERP”) as a complex system that manages the lifecycle of tangible and intangible assets and provides critical support and enablement to all of NB Power’s operations. NB Power’s current 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. NB Power asserts that SAP has reached the end of its life and needs to be upgraded. NB Power plans to pursue its ERP Upgrade strategic initiative during the test period but defer its recovery of the costs from ratepayers for several years until the project is complete.
- [60] To varying degrees, most interveners opposed the proposed test period spending. Mr. Zacher, Mr. Burgoyne, and the Public Intervener alleged that NB Power is violating section 107 of the *Act* and/or its own Investment Governance Framework by proceeding with the ERP Upgrade before the project is fully evaluated. They argued that the proposed spending risks cost overruns and premature commitments to future spending, risks to which ERP projects are particularly susceptible. These interveners asked the Board to withhold all or most of the test period project funding.

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[61] For the following reasons, the Board concludes that the proposed spending is reasonable.

5.2.1.1 *No violation of section 107 or Investment Governance Framework*

[62] The Board concludes that NB Power did not violate section 107 of the Act, which requires pre-approval of NB Power’s capital projects having a projected total capital cost over \$50 million, does not apply to the ERP Upgrade because the ERP Upgrade is an OM&A initiative that does not attract capital costs. Further, the Board oversees this significant project spending by discharging its statutory obligations to evaluate NB Power’s forecast-based revenue requirements and its requests to establish regulatory accounts.

[63] The Board finds that NB Power did not violate its investment governance framework by failing to complete a final investment rationale document or business case in support of the ERP Upgrade because the proposed test-period spending relates to critical system components or planning activities and the utility’s analysis is in keeping with its iterative and stage-gated approval process.

[64] NB Power filed evidence to illustrate that many components of the current system are considered critical to NB Power’s operations and must be upgraded, while other components are being evaluated on a separate path to decide whether to add them to the system. The evidence is undisputed that NB Power’s current SAP product will reach its end of life in 2027, after which extended support will be available from SAP at an additional cost until 2030. NB Power’s characterization of SAP as a critical operational system eliminates the possibility of doing nothing and relying on third-party support, leaving the utility with a choice between replacing its current ERP platform with an upgraded SAP product or that of another vendor. The Board finds that SAP is a critical operational system without which NB Power cannot provide services to its customers and concludes that a “do nothing” approach by which NB Power must rely on third-party support beyond 2030 is not a reasonable option. NB Power’s current planning contemplates implementation of “core” in 2027, with a contingency period until 2030 to rely on “best efforts” support at additional cost, if necessary.

[65] The stated purpose of NB Power’s Investment Governance Framework is to optimize all spending initiatives outside of base OM&A spending in support of its strategic objectives. The process includes producing an investment rationale document to define objectives, required resources and costs, the project schedule, and the value or benefit that will be achieved. Proposed initiatives are scored, prioritized and ranked at the enterprise level and are then reviewed by the Investment Management Committee, which makes recommendations to the Audit and Finance Committee[s] of the NB Power Board of Directors.

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- [66] NB Power’s rebuttal evidence and the extensive testimony of Ms. Moore, Ms. Fraser, and Mr. Blackier clarify that NB Power followed its internal evaluation process for the proposed core aspects of the ERP Upgrade, including a preliminary cost estimate and analysis, a preliminary risk assessment, benefits analysis and rationale, and confirmation that the Investment Management Committee and Audit Committee have approved the proposed test period spending. Ms. Moore and Mr. Blackier testified that foundational or “core” elements of the project have already undergone an analysis that determined the SAP upgrade to be least-cost and least-risk alternative and less complex than a third-party option. Ms. Moore and Ms. Fraser confirmed that the recommendation to select SAP for the foundational or core elements of the project was evaluated in a “Phase 1” investment rationale document submitted to and approved by the Investment Management Committee. Foundational or core elements of the project are distinct from other, non-critical elements that would provide additional functionality or constitute net new solutions to achieve benefits through automation, productivity, improved reporting, and cost efficiency. As Mr. Blackier noted, these non-core solutions are being evaluated along a separate path during the test period to determine whether to proceed with them.
- [67] Based on this evidence, the Board finds that NB Power’s evaluation process satisfies the investment governance framework given the predominant “business necessity” character of the budgeted spending.

5.2.1.2 *The risk of delay outweighs the risk of cost overruns*

- [68] For the reasons below, the Board concludes that the risk of delay outweighs the risk of cost overruns during the test period and, therefore, approves the proposed spending.
- [69] Most interveners argued that the proposed spending risks cost overruns and premature financial commitments, risks to which ERP projects are particularly susceptible. Ms. Petit raised concerns about the potential for overspending due to delays in accounting for accessibility requirements related to the upgraded system. Several interveners asked the Board to withhold all or most of the test period project funding, except the amounts necessary to complete a final investment rationale document and/or complete prerequisite data cleanup activities.
- [70] Dustin Madsen, president of 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 requirements, accounting matters, and depreciation expense. He opposed approval of the ERP Upgrade because of the inherent risk of cost overruns. The Board accepts Mr. Madsen’s general caution about the risk of cost overruns in projects of this nature but concludes that the

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risk is minimal in the test period because NB Power intends to limit its project spending to the requested \$29.1 million and has committed to seeking the Board’s approval before proceeding further. This commitment aligns with NB Power’s stage-gated investment governance process, which contemplates additional estimates, analysis, and internal approval before proceeding to the project's Execution Phase.

- [71] The Board’s review of the activities planned for the test period reveals minimal risk that the initial spending will engender an unreasonable commitment to a project path that leads to future cost overruns, the so-called sunk cost dilemma. NB Power intends to prepare an investment rationale document, detailed risk plan, and resource plan to complete the Initiation Phase and then move to the Planning and Design Phase by performing data cleanup activities, planning for the replacement of certain core functions, and assessing new options and planning for certain non-core functions. The Board is guided by Ms. Bastin’s opinion on this issue. Andrea Bastin, a partner with Deloitte, was declared an expert qualified to give opinion evidence in the area of the implementation and operation of enterprise resource planning technology and the optimization of related business processes. She testified that detailed planning and good investment governance are the keys to managing the risk of cost overruns and that data cleanup is not only a critical preliminary step in an ERP upgrade but is prudent regardless of whether ERP systems are upgraded.
- [72] While Mr. Madsen recommended disallowing all test period spending on the grounds that the risk of cost overruns is too great, he did not evaluate the risks of postponing the planning and design work, nor the risk of postponing the benefits of the project. The Board does not accept Mr. Madsen’s recommendation because it would increase NB Power’s operational risk.
- [73] The planned activities involve primarily core functionality and include implementing the SAP Business Technology Platform and the Work Efficiency Component/Work Clearance Management replacement. Postponing these activities until 2027 creates or exacerbates operational risk to NB Power. It hinders NB Power’s ability to conduct detailed planning and rigorous investment governance that will ultimately mitigate project risk within a timeline that offers a reasonable opportunity to implement before 2030, at which time the product will become obsolete with the attendant security, performance, cost, and compliance risks. Pushing the timeline also makes NB Power increasingly vulnerable to a scarcity of resources as more SAP customers seek to conduct similar upgrade projects and endangers the realization of benefits as part of the cost optimization and strategic plan like automation, productivity, improved reporting, and cost efficiencies.

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[74] The Board agrees that ERP projects require close examination and careful management to avoid cost overruns that would endanger future Net Earnings and put future ratepayers at risk of higher rates. On the surface, waiting for the investment rationale to be fully developed may appear to be the obvious way to reduce that risk but this argument fails in the context of a budget proposal for limited funding to plan and prepare for a complex, time-sensitive “must-do” replacement of critical systems. Weighing the risk of delay against the minimal risk of cost overruns in the test period, the Board concludes that withholding funding will delay well-supported spending while unreasonably increasing the utility's operational risk. The Board approves forecast spending of \$29.1 million for the test period.

5.2.1.3 *The Board will mitigate risk of cost overruns and will monitor project progress*

[75] The Board concludes that the nature and magnitude of the ERP Upgrade give rise to a risk of cost overruns which, while minimal during the test period, warrant the ongoing monitoring of project spending and activities.

[76] To minimize ratepayer risk, NB Power has committed to requesting the Board’s approval for additional spending or before proceeding with additional activities and to accompany any such request with a business case/investment rationale, options analysis, scope of work, project schedule, budget, resource plans, and risk plans. The Board expects NB Power to honour its commitment and considers that the operation of the regulatory deferral account will also reduce ratepayer risk because future additions to the account will be restricted to approved expenses that are actually incurred.

[77] The Board is mindful of Ms. Bastin’s testimony acknowledging the importance of satisfying accessibility requirements as part of the project. The Board expects NB Power to comply with all applicable accessibility requirements and to give due consideration to accessibility needs of users in its planning, design, and execution activities for the ERP Upgrade.

[78] To facilitate the ongoing monitoring of the project, the Board orders NB Power to file an ERP Upgrade progress report with the Board no later than June 30, 2025, and annually thereafter until further order of the Board. The progress report should provide up-to-date information on the project schedule, budget, risk assessment and any substantive new or updated business case or investment rationale.

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5.2.1.4 Regulatory deferral account is approved

[79] The Board approves the creation of a regulatory deferral account under section 117.5 of the *Act* to record ERP Upgrade expenses for recovery from ratepayers once the project is complete and allows actual expenditures during the test period, to a limit of \$29.1 million, to be added to the account. The Board concludes the deferral account ensures recovery of prudently incurred costs while maintaining intergenerational equity by matching the recovery of upgrade costs from ratepayers with the expected benefits of the upgrade.

[80] To mitigate the risk to future ratepayers of cost overruns and to monitor NB Power’s cost control efforts related to the project, the Board will restrict future additions to the deferral account to approved expenses actually incurred. The Board concludes that it would be premature to set a recovery period for the account at this time.

5.2.2 PLNGS OM&A spending is reasonable as reduced for the 2026 FLR assumption

[81] NB Power is budgeting an unplanned outage contingency for PLNGS of \$12.6 million for the test period, based on a formula that estimates the average cost per forced outage day using actual costs and days for the last three significant forced outages escalated by 2%. One of the formula’s inputs is the same estimated 8% forced loss rate the Board evaluates in Section 5.1.2.

[82] The Board’s adjustment of the revenue requirement to reflect a forced loss rate for PLNGS of 7% for Fiscal Year 2026 described in Section 5.1.2 reduces the Fiscal Year 2026 OM&A expense by \$0.9 million.

5.2.3 Continuous improvement credit is reasonable

[83] NB Power proposes including a \$27.5 million continuous improvement credit for each year of the test period. \$11.1 million of the credit represents costs NB Power has already eliminated from its budget through its workforce optimization program, which NB Power expects to sustain throughout the test period. The remainder represents the utility’s commitment to eliminate additional costs from its budget in Fiscal Year 2025 and to sustain those “hard” savings in Fiscal Year 2026.

[84] For the following reasons, the Board concludes that the proposed \$27.5 million credit is reasonable.

[85] Mr. Wafaei disagreed that achieving the \$27.5 million credit is ‘challenging’ for NB Power, as Ms. Moore described it. He submitted that \$27.5 million does not constitute the aggressive cost minimization that NB Power’s shareholder has mandated in the Executive

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Council Directive, nor does it meet the Board’s expectations as stated in Matter 541 for NB Power to achieve all possible cost savings to improve its Net Earnings. Mr. Wafaei relied on the final cost optimization review report prepared by PwC Canada to support JDI’s request for the Board to reduce the revenue requirement to reflect \$50 million in savings over the test period, including \$20 million per year in new hard savings.

- [86] The Board concludes that a \$27.5 million continuous improvement credit for each year of the test period is a reasonable estimate of achievable hard savings because PwC’s gross savings estimates fail to account for the investments needed to generate the savings or for the time it will take NB Power to do so. PwC’s cost optimization review produced a set of “charters” listing potential gross savings of up to \$122 million. NB Power estimates that it has since achieved between \$9.9 and 17.3 million in savings, but says that it will not realize the benefits of the remaining PwC initiatives as quickly as they have to date. The remaining initiatives are more complex, cut across multiple processes, and are subject to implementation constraints, including additional investments, competing high-priority work, and resource limitations. Many initiatives cannot be implemented during the test period because they depend on new technology that will not be enabled until NB Power upgrades its ERP platform. PwC identified a dependency on technology as one of the themes of its final report.
- [87] Removing \$40 million from the revenue requirement to represent new hard savings would be unreasonable and would risk eroding forecast Net Earnings instead of facilitating it. While Ms. Moore acknowledged that validated savings to date range from \$11.7 million to \$14.9 million and could increase once NB Power evaluates more charters or where already validated projects exceed current estimates, these are gross savings estimates that do not deduct implementation costs or recognize resource constraints, risks, and other restrictions that limit NB Power’s ability to pursue these opportunities and realize savings in the test period. The Board accepts NB Power’s estimate of \$3.6 million to \$4.0 million in hard savings that will begin to be realized over the test period.
- [88] Mr. Zacher also suggested NB Power could resurrect its workforce optimization program to generate additional savings and asked the Board to recognize the \$5 million in achieved business area improvement savings that were not factored into test period budgets. The Board does not accept these requests. JDI offered no evidence to rebut NB Power’s evidence justifying its test period Labour and Benefits expense forecast and, because last year’s business area improvement savings did not represent only hard savings, savings arising from those projects and other internal initiatives last year is reasonably comparable to NB Power’s forecast of \$12 million in other hard continuous improvement savings over the test period.

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- [89] The Board agrees with Mr. Zacher’s and Mr. Wafaei’s submissions that NB Power must be aggressive in pursuing all reasonable cost-saving opportunities to comply with the expectations of its shareholder and this Board to minimize its costs. These expectations are evident in section 68 of the *Act* and the Executive Council Directive, as well as past Board decisions stating that the Board considers rate increases to be a last resort after cost control efforts have been exhausted.
- [90] The Board concludes that \$27.5 million credit is a reasonable minimum for the purpose of the revenue requirement. This conclusion is based on Ms. Moore’s testimony voicing NB Power’s intention to exceed the proposed \$27.5 million in hard savings if possible and expectation that the utility will begin to realize up to \$65 million in avoided costs, productivity improvements, or debt management savings outside the credit during the test period. The Board encourages the utility to make all available efforts to achieve additional hard savings to meet and improve upon its approved Net Earnings forecast and to otherwise improve productivity and avoid costs. At the same time, the Board recognizes that embedding a larger savings credit in the revenue requirement risks impairing rather than enabling NB Power’s ability to achieve its Net Earnings target, contrary to the expectations in section 68 of the *Act* and the Executive Council Directive.
- [91] The Board also notes that the introduction of the statutory variance accounts has caused some savings that would have been previously categorized as hard savings to now be categorized as cost avoidance or productivity savings. Ms. Moore testified that past fuel and purchased power savings would have likely gone directly to the in-year hard savings target but now flow through the statutory variance accounts. To improve transparency and facilitate the assessment of NB Power’s continuous improvement efforts, the Board directs NB Power to account for the Continuous Improvement credit and similar future credits in its budgets in a way that shows both the revenue requirement and statutory variance accounts benefits.

5.2.4 A global 2% OM&A reduction would not be reasonable

- [92] Mr. Madsen recommended a 2% “global reduction” in NB Power’s proposed OM&A expense to address what he considers to be overstated Labour and Benefits expense and excessive forecast inflation. This approach would reduce the revenue requirement by \$24.5 million over the test period. The Board will not adopt this approach because the vacancy credit component of forecast Labour and Benefits expense is reasonable, and a detailed examination of the cost drivers does not support Mr. Madsen’s inflation-related recommendation.

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- [93] NB Power includes a credit in its Labour and Benefits budget to recognize that it generates savings when budgeted positions are vacant. To calculate this vacancy credit, NB Power assumes a certain number 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.
- [94] NB Power set an assumed vacancy rate of 5% based on recent historical vacancies calculated as of the end of the fiscal year, together with evidence supporting the reasonableness of the assumed vacancy rate and credit. Mr. Madsen challenged this approach on the basis that it is imprecise. In Matter 541, the Board considered a similar argument from Mr. Madsen and concluded that NB Power’s approach to calculating the vacancy credit was reasonable. Mr. Madsen maintains his concerns about the point-in-time calculation of the vacancy rate and the assessment of related backfill costs. Ms. Fraser testified that NB Power has commenced a project to more accurately track backfill costs and Mr. Madsen testified that he sees value in NB Power completing that project.
- [95] The Board heard testimony from Ms. Hachey and Ms. Fraser that the current vacancy rate is approximately 7%. Ms. Fraser explained that some of the vacancies result from a movement away from Hired Services to internal positions in response to PwC charters, challenges within the Human Resources team hampering completion of planned staffing, and the state of the labour market. Considering these factors together with evidence of previous stability and a rolling 5-year average that remains reasonably comparable to recent historical vacancy rates at approximately 5%, the Board sees no justification to depart from the historical evaluation approach that the Board has considered reasonable. If higher vacancy rates endure, they will be reflected in future rolling average rates. The Board, therefore, concludes that a 5% vacancy rate reasonably reflects NB Power’s historical and current vacancies and accepts NB Power’s calculation of the vacancy credit. The Board directs NB Power to complete its initiative to improve backfill cost data capture and to incorporate the data into the vacancy credit calculation for its labour and benefits expense budget in the next general rate application.
- [96] The Board disagrees with Mr. Madsen’s opinion that NB Power’s detailed inflation breakdown and variance analyses are insufficient. The evidence supports Mr. Furey’s submission that all but \$15 million of NB Power’s estimated increase in OM&A costs is driven by factors other than inflation, including the Belledune conversion, the ERP Upgrade, DSM programs, vegetation management, and storm contingency. NB Power filed evidence identifying each contributor to its inflation estimate and detailing the extent to which variances from Fiscal Year 2024 relate to inflationary impacts. NB Power’s estimate totaled \$28.6 million over the test period, which the Board concludes is reasonable.

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5.2.5 OM&A allocations to capital and Belledune contingency are reasonable

- [97] NB Power has been examining the potential conversion of Belledune Generating Station to enable the station to burn alternative fuels. Mr. Madsen raised concerns about the budgeted contingency associated with this OM&A initiative and NB Power’s proposed accounting treatment of the project costs.
- [98] The Board will not adopt Mr. Madsen’s recommendation to disallow the budgeted \$1.323 million contingency and will not require NB Power to capitalize the test period project costs. Mr. Bolduc testified that NB Power does not typically include a contingency for OM&A initiatives but went on to distinguish between typical initiatives that are familiar to NB Power and the new and unfamiliar Belledune initiative. The Board accepts Mr. Bolduc’s characterization of the Belledune initiative as involving research and exploration activities and that the physical alteration of the plant associated with the project will be temporary. This testimony is consistent with NB Power’s evidence that the test period work is preliminary in nature. Based on this evidence and the absence of evidence assessing the probability that future economic benefits will flow to NB Power if the project is successful, the Board concludes that the proposed expense is reasonable.
- [99] Mr. Madsen also challenged NB Power’s approach to capitalization of its human resources costs. Ms. Hicks-Gesner testified that NB Power capitalizes costs for administrative functions based on the accounting concept of direct attribution. The Board will not adopt Mr. Madsen’s recommendation to revert to his preferred approach because Ms. Schulz’s expert evidence on this issue is persuasive. Tarah Schulz, a Deloitte LLP Audit and Assurance partner, was declared an expert qualified to give opinion evidence in accounting and, in particular, the interpretation and application of accounting standards, including international financial reporting standards. She opined that capitalizing indirectly allocated costs the way Mr. Madsen prefers is not reasonable because it does not use the best data available to determine what costs are directly attributable to a capital project.
- [100] The Board will not adjust the revenue requirement to capitalize additional OM&A costs because there is no evidentiary basis for finding that NB Power’s proposed capitalization of these costs is improper.

5.2.6 Labour and Benefits Expense is reasonable

- [101] NB Power is seeking approval of \$428.0 million in Labour and Benefits expense for Fiscal Year 2025, representing almost 69% of its proposed OM&A budget and an increase of \$25.5 million from the Fiscal Year 2024 approved revenue requirement. NB Power

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requests a further increase to \$433.6 million in Fiscal Year 2026. The Board has considered the reasonableness of NB Power’s proposed salaries and wages, number of positions, and vacancy credit and concludes that the forecast is reasonable.

[102] NB Power says that identified increases in planned work are driving its need for 215 net new positions in the test period. The evidence supports the reasonableness of its budgeted number of positions based on expected work requirements. Sections 5.2.1, 5.2.5, and 5.2.7 review the prudence of NB Power’s planned OM&A initiatives, other strategic work, and changes in core operating planned work. NB Power presented a variance analysis detailing how that work drives labour and benefits costs and connected the new positions to those cost drivers by filing written justifications for each new position, many of which are related to work that is found to be reasonable elsewhere in this Section 5.2. Mr. Madsen testified that he reviewed NB Power’s planned level of staffing and its supporting business cases and did not flag it as a concern.

[103] The Board confirms that Exhibit NBP2.28 Appendix Li - Human Resources Overview satisfies the Direction in Section 6.2.1.1 of the Matter 541 Decision to report on its efforts to manage succession planning costs.

5.2.7 Energy Efficiency and Demand Side Management expense is reasonable

[104] Demand-side management (“DSM”) seeks to modify electricity demand by encouraging customers to use energy more efficiently and change their pattern of usage. NB Power’s forecast spending on demand-side management programs for the test period is \$85.6 million, most of which is offset by adjustments to the DSM regulatory deferral account. The growth of \$13.5 million over the test period compared to last year is driven by a significant 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.

[105] For the reasons below, the Board concludes that the proposed test period spending is reasonable.

[106] The Board’s review of NB Power’s DSM programs in this proceeding was prompted by the Board’s concern about the impact on future ratepayers from adding annually increasing amounts to the energy efficiency and demand response deferral account. For the test period, \$68.4 million of the approved \$85.6 million will be added to the account. As directed, NB Power filed a new three-year DSM Plan, together with an evaluation that includes budget and actual participants, expenditures, and energy and peak demand savings.

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- [107] Jennifer Kallay, of Synapse Energy Economics, Inc., was qualified as an expert witness, able to give opinion evidence in the areas of demand-side management programs for electric power utilities, including energy efficiency, demand response, electrification, and renewable energy measures. She recommended that the Board approve the energy efficiency-related budgets and savings proposed by NB Power for the test period but questioned the cost-effectiveness and validity of renewable energy programs based on a lack of clarity in the evidence. Ms. Kallay acknowledged that following her recommendation would require NB Power to spend additional funds to meet the legislated target and would negatively impact customers who have already made the related expenditures in reliance on the incentive or are already contractually obligated to do so.
- [108] Ms. Kallay accepted on cross-examination that breaking out renewable measures from energy efficiency measures in the DSM Plan would be a reasonable regulatory outcome and recommended doing so in a manner consistent with the treatment of demand response and electrification measures. She also recommended showing costs and cost-effectiveness at the measure level in the next DSM plan because, in her opinion, it is important to see how much of the incentive budget within each program is being directed towards different types of efforts. Mr. Leopkey confirmed that NB Power has the capability and willingness to demonstrate that each individual measure in a program is cost effective.
- [109] Based on the DSM reports filed in this proceeding, the testimony of Mr. Leopkey and Ms. Kallay, NB Power's correction of an error in its original filing by reducing the proposed budget by \$1.0 million, and the legislated energy efficiency targets, the Board concludes that the \$85.6 million test period budget represented in Exhibit NBP23.51 is reasonable.
- [110] The Board accepts Ms. Kallay's recommendations to improve transparency by showing costs at the measure level. While the Board assesses cost-effectiveness of these programs at the program level, the ratepayer impact warrants greater transparency. The Board also accepts Mr. Hatfield's submissions relating to the need to measure DSM program effectiveness for low-income customers. He characterized DSM as a way to combat energy poverty and requested that NB Power distinguish between low-income and moderate-income customers for the purpose of evaluating and reporting on its DSM programs.
- [111] Therefore, the Board directs NB Power to take the following steps to improve transparency regarding the costs and benefits of its demand-side management and energy efficiency programs:

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- a. to the extent practicable using the information available to NB Power, track the number of participants in the Enhanced Energy Savings Program and the backlog, incentive amounts, costs, and benefits of that program separately for low-income participants and moderate-income participants;
- b. break out renewable measures from energy efficiency measures in the next DSM Plan, expected to be filed in October 2025;
- c. in the next DSM Plan, provide cost-effectiveness, total cost, incentive cost, and participant cost at the measure level; and
- d. work with Saint John Energy, Edmundston Energy, and the Perth-Andover Electric Light Commission to provide each municipal utility with historical and anticipated customer participation and energy savings information for each program for which their customers are eligible.

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

[112] 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 3.2.2 of NBP2.01 but not explicitly addressed in this Decision. The Board concludes that the proposed revenue requirement related to these forecast costs is reasonable.

[113] For these reasons, the Board makes no adjustments to NB Power's proposed OM&A expense except the \$0.9 million reduction evaluated in Section 5.2.2 of these Reasons.

5.3 Depreciation and Amortization expense is reasonable

[114] NB Power's budgeted Depreciation and Amortization expense of \$390.2 million for Fiscal Year 2025 is \$24.8 million higher than last year's budget due to recent and upcoming capital investments in PLNGS, the Bayside Generation Station and other generation stations, and information systems for Advanced Metering Infrastructure network hardware and distribution assets. NB Power is budgeting a further \$10.8 million increase in Fiscal Year 2026.

[115] The Board evaluated the depreciation rates and asset lives of NB Power's generation assets in this proceeding, including the potential impact on NB Power's debt-equity ratio if the utility's long-term plans for compliance with emission reduction policies force write-downs. In support of its proposed Depreciation and Amortization expense, NB Power filed a study authored by Larry Kennedy, Senior Vice President of Concentric Advisors, ULC, in which he assessed the regulated life estimates related to NB Power's non-hydro

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generation assets as of August 31, 2023. Mr. Kennedy reviewed NB Power’s current cost and accumulated depreciation balances for each plant and related reports, accounting practices and policies, and current Integrated Resource Plan, and performed a comparison against peer utilities. The study concluded that NB Power’s depreciation lives accurately reflect the consumption of average service life of its regulated generation assets and set out recommended average service lives and life span dates.

[116] Mr. Kennedy was declared an expert qualified to give opinion evidence in the areas of depreciation and valuation studies for gas and electric utilities. Based on the study and Mr. Kennedy’s oral testimony, the Board accepts NB Power’s proposed Depreciation Expense related to generation assets for the test period.

[117] Mr. Madsen cited the potential for tightening environmental regulations to support his recommendation for ongoing periodic technical depreciation-related updates for the Coleson Cove Generating Station. The Board concludes that consideration of this recommendation is premature and will not require such updates during the test period.

[118] Mr. Madsen raised concern about the \$187 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 estimates resulting from its 2019 depreciation studies been in place throughout the lives of those assets. Some of that difference has 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. Mr. Madsen recommended accelerating that process by implementing a larger refund in the test period as a rate mitigation mechanism that improves intergenerational equity by having “historical customers who benefitted from potentially lower rate increases contribute to the existing high rate increase proposals” sought in this proceeding.

[119] Mr. Furey stated that NB Power opposes this recommendation on the basis that Mr. Madsen mischaracterizes the difference between calculated reserve and book reserve as an overcollection. NB Power offered the expert testimony of Mr. Kennedy in support of its opposition, who noted the utility intends to conduct a new depreciation study in Fiscal Year 2025. Mr. Kennedy 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 variances between calculated and book reserve are not errors or overcollections and cautioned that variances may disappear over time. Mr. Madsen agreed with these statements in cross-examination. Mr. Kennedy also disagreed with Mr.

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Madsen’s use of simplifying assumptions that, in Mr. Kennedy’s opinion, do not demonstrate sufficient care to form the basis of an accelerated refund.

[120] In Mr. Kennedy’s opinion, this is not the appropriate case for an accelerated refund because there is not sufficient evidence to determine whether the current variance will endure and, if it does, the difference will be refunded through the normal operation of NB Power’s accounting policies. Mr. Madsen countered that the \$187 million difference exceeds the commonly used 5% “band” that is retained in cases of accelerated refunds. Mr. Kennedy questioned whether 5% is still an appropriate band given the energy transition and recommended awaiting the results of the upcoming depreciation study to avoid the risk associated with potentially shortening asset lives.

[121] The Board accepts the recommendation of Mr. Kennedy and will not adjust Depreciation Expense as Mr. Madsen proposes. The upcoming depreciation study of NB Power’s transmission and distribution assets will allow the Board to evaluate the nature of the assets, the causes of the changes in estimated asset lives, and the potential impact of future events including the energy transition on the stability of the variance. Accelerating the refund before the study is completed would introduce a risk of intergenerational inequity and rate instability if the refunded variance disappears over time. Further, the rate mitigation benefit of Mr. Madsen’s recommendation does not justify refunding the variance without awaiting an updated depreciation study because depreciation adjustment is not an appropriate tool to reduce the revenue requirement for rate mitigation purposes. The Board concludes the proposed Depreciation Expense is reasonable.

5.4 Regulatory Accounts are approved

[122] NB Power requested approval to implement three new regulatory accounts as permitted by section 117.5 of the *Act* and to adjust the amortization period associated with the existing PLNGS refurbishment deferral account established under section 139 of the *Act*. Accounts of this nature are common regulatory tools used to defer or smooth the impact of costs on ratepayers. For the reasons and subject to the limitations below, the Board approves the proposals.

5.4.1 PLNGS amortization

[123] NB Power is asking the Board to vary its decision in Matter 171 by extending the estimated PLNGS operating life as used in the administration of the PLNGS refurbishment deferral account by 16 months to March 31, 2041.

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- [124] NB Power completed the refurbishment of the station in 2013. In Matter 171, the Board established a deferral account to record the deferral of certain expenses associated with the refurbishment to be recovered from customers on a levelized basis over the expected 27-year operating period of the plant. The proposed extension maintains the technical design life of the refurbished reactor but lowers the average lifetime capacity factor at which the plant will operate from 89% to 82%. NB Power says this reduction aligns with the proposed life adjustment of the station.
- [125] The Board grants this request to satisfy its ongoing obligation, articulated in subsection 139(4) of the Act and the Matter 171 decision, to ensure that the balance of the deferral account is recovered over the operating life of the refurbished station. The Board concludes that the evidence filed by NB Power showing the 82% expected average capacity factor reasonably reflects actual and projected production levels and the effect on amortization.
- [126] The Board approves NB Power's request to increase the recovery period associated with the PLNGS regulatory account established under section 139(2) of the Act to 28 years and 4 months. The Board accordingly varies its decision in Matter 171.

5.4.2 ERP Deferral Account

- [127] The Board approves the ERP Deferral Account in Section 5.2.1.4 of these Reasons.

5.4.3 Replacement Energy Deferral Account

- [128] NB Power is seeking approval to create an enduring regulatory account under section 117.5 of the Act to level, over recurring two-year periods, the forecast replacement energy costs associated with major planned outages at PLNGS. The purpose of the account is to smooth the revenue requirement impact of fluctuations in replacement energy costs from year to year due to annual differences in the scope and duration of planned outages.
- [129] The Board approves the creation of a regulatory account under section 117.5 of the Act to level the expected replacement energy costs associated with major planned outages at the station, but only in each of the Fiscal Years 2025 and 2026. The Board concludes that the account will ensure the recovery of prudently incurred costs while smoothing the rate impact of fluctuating replacement energy costs from year to year.
- [130] The Board concludes that it is premature to approve an enduring replacement energy regulatory account and will consider any future proposal in the context of all relevant

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circumstances, including forecast outage frequency and duration and other proposed rate smoothing or deferral mechanisms.

5.4.4 Rate Smoothing Account

[131] NB Power proposes creating a regulatory account under section 117.5 of the *Act* to smooth test period rate increases by adjusting Net Earnings on a forecast basis. The proposed measure would contribute to lowering the Fiscal Year 2025 average rate increase from 14.4% to 9.25% and increasing the Fiscal Year 2026 average rate increase from 5.0% to 9.25%.

[132] The Board approves this proposal because it is a reasonable rate mitigation measure in the circumstances. The Board concludes that the proposal accomplishes multiple regulatory objectives by promoting rate stability while allowing the utility a reasonable opportunity to recover its approved Net Earnings.

[133] No intervener opposed using a rate smoothing mechanism as a tool to mitigate the impact of large rate increases on low-income and disabled residential ratepayers. Mr. Madsen characterized the proposed rate smoothing account as a good starting point, but he recommended extending the smoothing period to five years to more equitably spread the burden of the equity goal by the mandated 2029 equity target date between current and future ratepayers. The Board finds that a five-year smoothing horizon would push responsibility for achieving its approved test period Net Earnings onto future ratepayers without assurance of eventual recovery and without concluding that the forecast Net Earnings in years three, four, and five are unreasonably low.

[134] The proposed rate increase is unprecedentedly high, but it does not follow that ratepayers are disproportionately contributing during the test period to NB Power's equity goal. Such a conclusion is inconsistent with the principle of intergenerational equity without evidence that future ratepayers would not contribute a fair share. Further, a five-year smoothing horizon tied to a two-year rate-setting period would remove any assurance that NB Power could recover the deferred portion of its revenue requirement in years three, four, and five, contrary to section 117.5 of the *Act*. NB Power modelled a five-year smoothing mechanism to illustrate that Net Earnings in those years would be significantly higher than currently forecast. The Board is persuaded by the expert opinion of Robert Knecht, who was declared an expert qualified to give opinion evidence in the area of regulatory economics and rate making. He testified that the Board cannot approve a five-year smoothing mechanism in this proceeding without risking NB Power's ability to meet its equity target date unless the Board also concludes that the modelled higher Net Earnings forecast is reasonable. John Todd, president of Elenchus Research

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Associates Inc., was declared an expert qualified to give opinion evidence in the area of the regulation of electric and gas utilities. He also cautioned that extending the smoothing period to five years would bring risks to NB Power's net income and its ability to achieve its equity goal by the equity target date. The Board considers these risks to be unacceptable in the totality of the evidence in this proceeding, including the factual circumstances disclosed by the Integrated Resource Plan and the Three-Year Financial Plan described in paragraph [143], because it would deny NB Power a reasonable opportunity to recover its approved Net Earnings.

[135] For these reasons, the Board approves the creation of a rate smoothing account of finite duration (two years) under section 117.5 of the *Act* to level the rate increases in each of the Fiscal Years 2025 and 2026 by adjusting Net Earnings on a forecast basis.

5.4.5 Net Change in Regulatory Balances

[136] The Board accepts NB Power's evidence showing the impact of the new regulatory deferral accounts on the related regulatory balances.

5.4.6 Cost allocation of new regulatory accounts

[137] The Board approves the following allocations of the new regulatory deferral accounts in the Class Cost Allocation Study model for the Fiscal Years ended 2025 and 2026: allocation of the regulatory deferral account for the ERP Upgrade based on Net Plant, allocation of the PLNGS replacement energy regulatory account based on energy, and allocation of the rate smoothing regulatory account based on each class's share of in-province revenue.

5.5 Net Earnings request is reasonable

[138] NB Power proposes Net Earnings of \$64.0 million for Fiscal Year 2025 and \$63.5 million for Fiscal Year 2026. The Net Earnings component of the revenue requirement represents the return to which NB Power is entitled to under the *Act* and pursuant to regulatory principles.

[139] The Board approves the proposed Net Earnings because the proposal reflects a reasonable balance among the competing mandatory statutory factors by giving NB Power a reasonable opportunity to make minimal progress toward the 2029 equity target date while considering the interests of ratepayers.

[140] Ms. Clark testified that NB Power's test period Net Earnings forecast is driven by plans to achieve its equity goal by the equity target date during a period of significant capital expenditures. Some interveners opposed the proposed Net Earnings as being excessive

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considering NB Power’s request for an unprecedented rate increase, noting that the proposed Net Earnings represents 19% of that increase. Mr. Zacher challenged NB Power’s claims that its financial health is in jeopardy and argued NB Power is making no effort to achieve its equity goal except by way of large rate increases. Mr. Burgoyne acknowledged NB Power’s financial challenges but argued ratepayers should not bear the burden of overcoming them.

5.5.1 NB Power’s financial health requires test period equity goal progress

[141] Mr. Zacher made extensive submissions challenging NB Power’s claims that its financial health is in jeopardy. He pointed out that the statutory variance accounts improve NB Power’s financial risk profile and argued that NB Power offered no evidence of an imminent downgrade of New Brunswick’s credit rating and no direct evidence from provincial officials that NB Power’s debt poses a risk to provincial finances. He compared NB Power’s request to that of Manitoba Hydro in its 2017-19 general rate application, in which the Manitoba Public Utilities Board found that “a particular equity level target and pace to achieve that target should not determine the approved rate increases [...]” and denied the utility’s request for rate increases to meet its self-imposed equity target

[142] The Board agrees that no evidence has been provided of an immediate threat to New Brunswick’s credit rating but disagrees with the suggestion that NB Power should be considered financially healthy unless the credit rating of the province or its finances are under immediate threat. While the statutory variance accounts established in 2022 by statutory amendment may have improved NB Power’s credit risk profile, those amendments do not alter the Board’s obligations under the *Act* to take NB Power’s equity goal and equity target date into consideration when fixing just and reasonable rates. This feature distinguishes the New Brunswick regulatory framework from that governing Manitoba Hydro and the Manitoba Public Utilities Board.

[143] Further, the Executive Council Directive is not the only mandatory statutory factor that requires the Board to consider NB Power’s equity goal and equity target date. The Board must consider the government policy that NB Power’s Net Earnings should be evaluated in the context of its equity goal. This policy also acts as a constraint on the government policy of maintaining rates as low as possible in circumstances where maintaining low rates would be inconsistent with the Net Earnings policy. The Board must also consider the utility’s Three-Year Financial Plan and Integrated Resource Plan, which disclose an intention to achieve the equity goal in accordance with the Executive Council Directive and illustrate that NB Power has entered an extended period in which significant

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investment in its assets will be necessary to maintain reliable service while satisfying its renewable energy requirements.

[144] The mandatory statutory factors, considered together, weigh in favour of test period Net Earnings that give NB Power a reasonable opportunity to achieve its equity goal by the equity target date. In this context, the question becomes whether the proposed Net Earnings forecast is sufficient or excessive. Mr. Zacher contested NB Power’s efforts to pursue other means to meet its equity target date and asked the Board to prioritize lower rates for the test period. The Public Intervener relied on the evidence of Mr. Madsen and Mr. Knecht in submitting that the Board should approve the Net Earnings as proposed.

5.5.2 NB Power is pursuing other means by which to meet the equity goal

[145] Mr. Zacher argued NB Power is making no effort to achieve the equity goal except by way of large rate increases. In his view, NB Power is not planning to meet the equity target date through improved PLNGS performance, minimizing costs, or using alternative financial arrangements. The Board does not accept this argument for the reasons articulated in Sections 5.1.2, 5.2.2, and 5.2.3 of these Reasons and because the Board heard evidence that NB Power is exploring alternative financial arrangements.

5.5.3 Lower rates would deny even minimal equity goal progress

[146] As between two of the mandatory statutory factors, Mr. Zacher urged the Board to prioritize lower rates over the Executive Council Directive’s objectives. This approach is unreasonable for the test period because it would require the Board to fix rates that deny NB Power even minimal progress toward its equity goal while ignoring both the moderation already built into both the Executive Council Directive and the Net Earnings request and the regulatory tools NB Power has employed to reduce and smooth rates.

[147] The Board finds that the Net Earnings request represents the minimum return necessary to give NB Power a reasonable opportunity to achieve its plans to meet the equity goal and satisfy the Executive Council Directive. NB Power’s Three-Year Financial Plan shows forecast Net Earnings largely backended, illustrating a plan that tolerates more risk in the test period and less risk as 2029 approaches. This assessment of NB Power’s risk tolerance is consistent with Mr. Murphy’s testimony that while NB Power is “comfortable” with its Net Earnings request, it is insufficient to make meaningful progress toward the equity goal within the test period and was the result of NB Power’s deliberate effort to moderate its Net Earnings request in recognition of its responsibility to consider ratepayer impacts. Mr. Madsen’s characterized the proposed Net Earnings as “a starting point... that does not permit ‘meaningful’ progress toward achieving the target” by 2029, while Mr. Knecht

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described the proposed Net Earnings as representing very little progress toward achieving the equity goal. The Board concludes that, in this context, lower Net Earnings would unduly defer the risk and responsibility of meeting the equity goal to future ratepayers.

5.5.4 Proposed Net Earnings forecast considers the interests of ratepayers

[148] The evidence supports Mr. Furey’s contention that NB Power’s Net Earnings request balances the utility’s financial health concerns and affordability for its customers. The Executive Council Directive itself demonstrates that NB Power’s shareholder considered affordability in setting the equity target date. The Executive Council Directive’s seventh recital establishes the shareholder’s view that the “appropriate balancing of its concerns regarding affordability for New Brunswickers and the financial health and stability of [NB Power] justifies” the equity target date and the operative paragraphs direct NB Power to make plans to achieve the target while maintaining rates as low as practicable and to reflect those plans in its Three-Year Financial Plan.

[149] The accounts approved in Sections 5.4.3 and 5.4.4 of these Reasons are regulatory tools designed to temper the Fiscal Year 2025 rate impact of the extensive PLNGS outage and step changes in other costs that would otherwise cause a 14.4% average rate increase in Fiscal Year 2025 and a further 5% average rate increase for Fiscal Year 2026. The ERP Deferral account approved in Section 5.2.1.4 will defer the rate consequences of NB Power’s test period spending on the ERP upgrade until the project is complete.

[150] Interveners also challenged the fairness of NB Power’s proposed Net Earnings, invoking the regulatory principles of gradualism and intergenerational equity. The Board addresses these challenges in Section 6.1.2.

[151] For these reasons, the Board concludes that the proposed Net Earnings will allow minimal progress toward the equity goal while considering ratepayers interests through the Executive Council Directive and the approved regulatory accounts.

5.5.5 Proposed Net Earnings forecast is reasonable

[152] For these reasons, the Board concludes that the proposed Net Earnings forecast is reasonable.

[153] The Board will not increase the proposed Net Earnings for Fiscal Year 2026 in an amount equivalent to the disallowance related to reducing the PLNGS forced loss rate assumption reviewed in Section 5.1.2 of these Reasons. 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. The Board notes that

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the statutory variance accounts will capture any negative difference between the approved and actual Fuel and Purchased Power costs for recovery from ratepayers and that NB Power exceeded its continuous improvement target in Fiscal Year 2024. The aggressive pursuit of continuous improvement and outperforming forecasts may allow NB Power to achieve additional Net Earnings in Fiscal Year 2025 and 2026.

5.6 Other revenue requirement components

[154] NB Power indicated in its post-hearing compliance filing dated November 29, 2024, that the following additional adjustments were required to properly reflect the test period revenue requirement:

1. offsetting adjustments to the Rate Rider Adjustment Factor, Finance Charges and other Income, and Net Change in Regulatory Balances, all to reflect the Board’s decision in Matter 573; and
2. offsetting adjustments of \$1.0 million to OM&A and Net Change in Regulatory Balances to correct an error in the test period DSM budget.

[155] The Board approves these adjustments.

5.7 Revenue Forecasts are reasonable as adjusted

[156] The Board accepts NB Power’s test year forecasts for in-province revenue, out-of-province sales, and gross margin, subject to the adjustments associated with reducing the PLNGS forced loss rate assumption for Fiscal 2026 detailed in Section 5.1.2 and the other adjustments described in Section 5.6.

[157] NB Power filed its estimated in-province energy sales volume, known as the load forecast, for the ten years from 2024 to 2034. 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.

[158] As detailed in Section 5.1.1, the Board accepts the revenue forecasts for the test period based on the Q2 PROMOD Results. The Q2 PROMOD Results were based on forecast in-province energy load of 15,272 gigawatt-hours for Fiscal 2025 and 15,397 gigawatt-hours for Fiscal 2026, forecast peak demand of 3,310 megawatts for Fiscal 2025 and 3,330 megawatts for Fiscal 2026.

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[159] The Board’s decision to reduce the assumed Fiscal Year 2026 forced loss rate for PLNGS (Section 5.1.2) causes consequential changes to NB Power’s revenue forecasts. The Board concludes these forecasts are reasonable as adjusted in the table in paragraph [26].

5.8 A revenue requirement of \$2,586.0 million and \$2,748.0 million is approved

[160] The Board approves a revenue requirement in the amount of \$2,586.0 million for Fiscal Year 2025 and \$2,748.0 million for Fiscal Year 2026. This revenue requirement reflects the adjustments depicted in the table in paragraph [26] and gives NB Power a reasonable opportunity to recover its forecast costs and to earn a reasonable return in the context of its equity target date and other planning objectives.

6 Rate design, rates, and charges are approved

[161] The Board directed NB Power to file a proposal for differential rates in this proceeding because the revenue-cost ratios for some of NB Power’s rate classes fall outside of a reasonable range. The revenue-cost ratio for a customer class compares its revenues and costs, where a ratio of 1.0 indicates that revenue generated by that class of customers recovers 100% of the costs of providing service to that class. For practical purposes, the Board considers that revenue-cost ratios that are reasonably close to 1.0 achieve inter-class equity. The ratios for the General Service I and Small Industrial classes have historically been high, indicating that those customers pay more than the cost incurred to provide service, while the Residential class revenue-cost ratio has been low, meaning that Residential customers pay less than the cost incurred to provide service to them.

[162] Revenue-cost ratio “improvement” describes regulatory efforts to move the ratios for all rate classes reasonably close to 1.0 to achieve inter-class equity. This can be accomplished with rate-setting measures, specifically imposing higher rate increases for some classes than for others until equity is restored. Rate design changes intended to resolve existing inequity in the rate structure will inevitably result in some customers paying higher prices and others paying lower prices.

[163] The Board considered two proposed rate design changes in this proceeding with the objective of improving revenue-cost ratios: differential rates (Section 6.1) and the elimination of the General Service II rate class (Section 6.2).

[164] NB Power seeks approval to introduce a wind balancing charge (Section 6.3) and a merged customer charge (Section 6.4), both of which have the stated purpose of improving cost-based equity, and rate increases for products and services where cost-of-service rate design considerations are less relevant in rate-setting (Sections 6.5 and 6.6). The utility

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also proposes a process for seeking expedited approval for special-purpose rate designs and rates for projects, pilots, or soft launches to undertake rate design learning (Section 6.7).

6.1 Differential rates

[165] NB Power complied with the Board’s previous direction to file a proposal for differential rates in this proceeding, as follows:

	(1) RCR at Uniform Rates 2024/25	(2) RCR at Differential Rates 2024/25	(3) Rate Increase % 2024/25	(4) RCR at Uniform Rates 2025/26	(5) RCR at Differential Rates 2025/26	(6) Rate Increase % 2025/26
(1) Residential	0.955	0.960	9.8%	0.960	0.969	9.8%
(2) General Service I	1.179	1.165	7.5%	-	-	7.5%
(3) General Service II	0.975	0.959	8.8%	-	-	9.0%
(4) General Service Total	1.125	1.111	7.8%	1.116	1.088	7.8%
(5) Small Industrial	1.266	1.168	7.3%	1.239	1.131	7.3%
(6) Large Industrial	0.969	0.982	9.8%	0.968	0.984	9.8%
(7) Streetlights & Unmetered	1.284	1.164	7.3%	1.290	1.255	7.3%
(8) Wholesale	0.963	0.967	9.8%	0.959	0.968	9.8%

[166] For the reasons below, the Board approves differential rates for Fiscal Year 2025 and Fiscal Year 2026 in a manner consistent with this table.

[167] NB Power uses internally developed guidelines that establish a plan to improve revenue-cost ratios over time using differential rates. These guidelines inform NB Power’s proposal to impose differential of two percentage points below the average rate increase for rate classes with a revenue-cost ratio above 1.05 and, since no rate classes fall below a revenue-cost ratio of 0.95, the remaining classes would attract a rate increase slightly above average to allow recovery of the proposed revenue requirement.

[168] NB Power did not ask the Board to adopt the proposal but acknowledged that differential rates are an important and necessary step to maintaining equity and fairness across all customer classes. Mr. Zacher and Mr. Burgoyne stated that their clients support differential rates in principle, but they both argued that it is not the appropriate time to implement differential rates because of the magnitude of the average rate increase. The

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Public Intervener supported differential rates, relying on Mr. Knecht’s appraisal that the proposal results in moderate progress toward cost-based rates over the test period.

[169] The Board concludes that the uncertainty over the class cost allocation methodology does not justify delaying achievement of moderate progress toward cost-based rates and that the affordability measures proposed by NB Power represent reasonable rate gradualism in the circumstances.

6.1.1 Cost allocation uncertainty does not justify delay

[170] Delaying the implementation of differential rates until a new class cost allocation methodology has been approved would delay the Board’s efforts to improve revenue-cost ratios as a way of easing the bill protection requirements for customers transitioning to new commercial classes in Fiscal Year 2028. The Board identified this as an objective in Matter 529, concluding that it would consider revenue-cost ratios as part of its approval of rates in the context of all relevant factors. Over a year has elapsed since then. The transition to new customer classes continues to be expected in Fiscal Year 2028, making revenue-cost improvement more urgent than it was in Matter 541. Further, while the class cost allocation study remains under consideration in Matter 554, the parties have had the opportunity to gain familiarity with NB Power’s load research in this matter.

[171] Therefore, the Board concludes that the achievement of moderate progress toward cost-based rates outweighs the continuing uncertainty over the class cost allocation methodology.

6.1.2 Smoothing and minimal Net Earnings facilitate affordability

[172] Differential rate changes intended to resolve existing inequity in the rate structure inevitably result in some customers paying higher prices and others paying lower prices. The differential rates proposed in this proceeding would assign a 9.8% annual increase to large industrial customers and wholesale customers. Residential customers would also be assigned a 9.8% annual increase, raising concerns about affordability for low-income households.

[173] All interveners asked the Board to consider affordability in fixing just and reasonable rates. Mr. Zacher also raised concerns about a loss of competitive advantage and other threats to New Brunswick businesses.

[174] The New Brunswick Coalition of Persons with Disabilities urged the Board to recognize the needs of New Brunswickers with disabilities whose energy dependency can pose affordability challenges. The Saint John Human Development Council filed evidence in the

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form of two reports authored by Liam Fisher, the Council’s data analyst and research coordinator, and Heather Atcheson, a social researcher for the Council. Mr. Fisher and Ms. Atcheson also testified at the oral hearing. One focus of the Council’s evidence was the “energy burden” borne by New Brunswick households and its disproportionate impact on low-income New Brunswickers. The evidence indicated that 53.4% of low-income New Brunswick households spend at least 10% of their household income on energy costs, compared to 14.6% of all New Brunswick households. Mr. Hatfield advocated for the province and NB Power to establish a rate affordability program similar to programs in other Canadian jurisdictions that are funded by taxpayers or pooled investor-owned utility contributions.

[175] The Board is obligated to give NB Power a reasonable opportunity to recover the revenue requirement approved in Section 5 of these Reasons through just and reasonable rates. The Board does not have jurisdiction to create the taxpayer funded programs Mr. Hatfield described. Where otherwise just and reasonable rates create large and sudden bill impacts on customers, regulators may implement rate changes gradually or apply other measures to allow negatively affected customers to adapt to the changes over time, provided that the utility is ultimately allowed to recover its full revenue requirement. This approach is known as rate gradualism.

[176] In this proceeding, NB Power has proposed two regulatory tools to facilitate rate gradualism: the rate smoothing account and the replacement energy deferral account. The Board approves both rate gradualism tools in Sections 5.4.3 and 5.4.4 of this Decision. The Board finds in Section 5.5 that NB Power’s Net Earnings request was founded on a desire to balance the utility’s financial health and affordability for customers and represents the minimum return necessary to give NB Power a reasonable opportunity to achieve its plans to meet the equity goal and satisfy the Executive Council Directive. The Board concludes that these regulatory tools and modest Net Earnings request are reasonable in the context of the mandatory statutory factors and that, while they will not alleviate affordability challenges for all customers, additional gradualism efforts would increase the overall rate impact on customers and jeopardize NB Power’s ability to achieve its plans.

[177] Some interveners suggested that the Board should factor the 3% rate rider currently imposed on ratepayers in determining whether to apply the principle of rate gradualism. As described in paragraph [15], the rate rider is a statutory mechanism designed to ensure NB Power recovers any net statutory variance accounts balance from ratepayers or reimburses any negative balance to ratepayers. The Board has no jurisdiction to adjust the current rate rider in this proceeding and reducing rates to neutralize the impact of

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the rate rider on customers would not achieve the desired purpose. Instead, it would increase the risk of forecast error in the approved revenue requirement, higher debt, and higher rates and rate riders over time.

[178] The Board disagrees with intervener submissions that the proposed rates impose an unfairly high burden on current ratepayers to make progress toward the equity goal compared to previous or future ratepayers. This view cannot be reconciled with the evidence in this proceeding, particularly evidence on the record and reviewed in these Reasons showing that previous rates have failed to make progress toward the equity goal and that the applied-for Net Earnings will make only minimal progress toward the equity goal over the test period.

[179] For these reasons, the Board approves NB Power’s differential rate proposal. The Board shares the affordability concerns expressed by interveners and NB Power. The Board wishes to highlight two valuable outcomes of this proceeding that relate directly to the participation of the Saint John Human Development Council and the New Brunswick Council for Persons with Disabilities. One such outcome is the evidence developed in this proceeding regarding NB Power’s arrears-related data and recent improvements to its customer service practices and procedures, which interested stakeholders may wish to draw upon to explore the issue of affordability in future rate proceedings. The second outcome is that NB Power has committed to establishing a vulnerable customer liaison committee to better understand and improve the customer experiences of those facing energy poverty or accessibility challenges.

[180] The Board considers a vulnerable customer liaison committee to be a valuable tool for NB Power, its customers, and the Board. The Board, therefore, directs NB Power to establish the committee and report to the Board no later than June 30th of each year on NB Power’s investment in the committee, participation, issues raised, and outcomes.

6.2 Elimination of the General Service II rate class

[181] General Service II (“GSII”) customers have been “grandfathered” in a separate General Service class for almost 20 years for policy reasons that are no longer relevant. Eliminating the GSII class would reduce inter-class inequity because there is a material rate difference between the GSI and GSII classes that does not reflect differences in the relative cost to serve those customers. The Board previously directed NB Power to file a proposal to eliminate the GSII class no later than April 1, 2025, and, if appropriate, to propose temporary bill protection for former GSII customers to mitigate rate impacts.

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- [182] For the reasons below, the Board approves NB Power’s proposal to eliminate the GSII rate class by April 1, 2025, as presented in Table 10.6.1 of Exhibit NBP2.01, as well as the proposed bill protection measures.
- [183] NB Power proposes to eliminate the GSII class by increasing the overall general service rates by 7.5% on April 1, 2024, and again on April 1, 2025. NB Power intends to achieve this objective by applying the annual 7.5% increase to each component of the GSI rate, a significantly higher rate increase to the GSII demand charge, and a lower rate increase to the GSII end block energy rate.
- [184] Another key feature of the proposal is a bill protection tool that would cap the electricity bill for affected GSII customers at a 15% increase from the previous year’s base rates to mitigate the abrupt and significant bill impacts of the rate adjustment that a small number of GSII customers will experience. NB Power intends to keep this bill protection measure in place until a broader commercial rate reclassification in Fiscal Year 2028 and will recover the lost revenue from the entire General Service class to maintain revenue neutrality within the merged General Service class.
- [185] The Board concludes that this proposal is reasonable. NB Power filed a report authored by Christensen Energy Associates showing higher average bill impacts for GSII customers than GSI customers, and bill impacts for GSII customers that generally increase with customer size. Ms. Stevensen testified that NB Power selected 15% as the bill protection cap to balance multiple competing goals: maintaining low rates, a minimal number of significantly affected customers and minimal bill impacts on those customers, making progress towards the merged rate, and managing the revenue loss associated with bill protection to be recovered from the entire GS class. Christensen’s supporting analysis showed a 15% bill protection would affect fewer than 200 GSII customers and cost \$0.48 million in Fiscal Year 2025 and \$0.45 million in Fiscal Year 2026.
- [186] Mr. Knecht evaluated NB Power’s proposal and concluded it would bring the merged GS class noticeably closer to unity. His evaluation revealed that low-load factor GSII customers would form the cohort of customers eligible for bill protection as they would experience above-average increases, while large higher-load factor customers would see below-average increases. Mr. Knecht also noted that NB Power’s proposal is consistent with NB Power’s proposed revenue allocation and the Board’s requirement to phase out GSII by April 1, 2025. Mr. Knecht concluded that the proposal is reasonable, though he recommended applying a “first dollar relief” revenue allocation adjustment mechanism if the Board disallowed a portion of the proposed revenue requirement. No party objected to NB Power’s proposal to eliminate the GSII class.

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[187] NB Power’s rates and bill protection proposals contemplate eliminating the kWh-based conditional demand charge that applies to GSII customers for whom it would cost less than the kW-based demand charge. Inadvertently, NB Power retained the conditional demand charge in its RSP manual when interim rates came into effect, though it was removed as intended from the supporting analysis for the proposal itself. NB Power explained this issue in its rebuttal evidence and Ms. Stevensen confirmed in oral testimony that the conditional demand charge has remained in place during the interim rates period. Eliminating the conditional demand charge is consistent with the overall objective of NB Power’s proposal because there is no parallel charge for GSI customers. On the other hand, retaining the conditional demand charge would limit rate increases to a level that would eliminate the need for bill protection. The Board concludes that NB Power’s request is reasonable. Eliminating the conditional demand charge in Fiscal Year 2025 is more consistent with NB Power’s larger plan to merge the GS class and Ms. Stevensen confirmed that bill protection will retroactively extend to the interim rate period.

[188] For these reasons, the Board concludes NB Power’s proposal to eliminate the GSII class by April 1, 2025, is reasonable.

[189] The Board heard testimony that NB Power’s account managers have been communicating with larger customers who are likely to be impacted by this transition. The Board directs NB Power to keep protected customers informed about the transition to merged rates and to quantify the bill protection benefit on their bills.

6.3 Wind Balancing Charge

[190] The Board approves NB Power’s proposed wind balancing charge of 0.227 cents per kWh for Fiscal Years 2025 and 2026.

[191] NB Power is asking the Board to approve a new wind balancing service charge of 0.227 cents per kWh to close what it calls a “gap” in its ability to recover balancing costs it incurs because of wind power production that serves specific loads in New Brunswick. NB Power asserts that its proposed wind balancing service charge will provide more appropriate economic signals to customers and allow more equitable recovery of costs from those customers causing the costs. NB Power intends for the charge to apply to customers supplied by a wind power generation facility having a capacity over 100 kW, in lieu of supply from NB Power.

[192] NB Power conducted a Wind Balancing and Integration Costs Study to evaluate costs incurred to provide the additional automatic generation control (“AGC”) and load

following, and the system dispatch changes required to integrate non-dispatchable wind generation and wind forecast error costs. The study found inter-hour costs, incremental intra-hour costs, and forecast error costs totaling \$2.27 per MWh. In support of its study and results, NB Power filed the results of an independent review of the Wind Balancing and Integration Costs Study conducted by Energy and Environmental Economics Inc. (“E3”). The E3 report concluded that the methodology NB Power used in its study was “reasonable, avoids double-counting and captures appropriate and relevant factors that arise from integrated wind” and “costs results fall within expected ranges,” but identified areas for future improvement for NB Power’s consideration. Zachary Ming, senior director of E3, is the author of the report. He was declared an expert qualified to give opinion evidence in the area of the regulation of electric utilities and, in particular, the impact of renewable energy on the operation of electrical systems.

[193] Utilities Municipal, on behalf of the only customer that would initially be subject to the charge, opposed it on the basis that it overstates costs, unfairly apportions the charge to Saint John Energy and fails to satisfy its stated objective of providing appropriate economic signals.

6.3.1 Proxy costs

[194] Utilities Municipal filed a report authored by William Marshall, principal of WKM Energy Consultants Inc., in which he concluded that the NB Power model overstates costs. Mr. Marshall was declared an expert qualified to give opinion evidence in the area of power systems, planning operations, and transmission tariffs, including the impact of non-dispatchable wind energy and renewable energy on the operation of electricity systems. Mr. Marshall’s review focused on the way NB Power modeled the ACE deadband. The ACE deadband is a tolerance range for the difference between scheduled and actual energy flow at the ISO-New England intertie, known as the area control error. In real-time operation, solving that difference requires regulation from fast-acting automatically pulsed generation units once the ACE deadband tolerance range is exceeded. Mr. Marshall concluded that the PLEXOS model’s five-minute simulations create excessive unserved energy compared to what would be observed in real-world operations, thereby ignoring the regulation benefit provided by the ACE deadband and misstating balancing and integration costs. In Mr. Marshall’s view, modelling both the deadband and AGC as available for dispatch would result in a different and more accurate cost estimate.

[195] E3 observed the same higher-than-expected amount of unserved energy in PLEXOS simulations but disputed Mr. Marshall’s understanding of the model. Unlike Mr. Marshall, Mr. Ming concluded the higher unserved energy in the model did not render NB Power’s

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estimated cost unreasonable. Mr. Ming clarified that the model holds the deadband and AGC resources in reserve to meet fluctuations within the five-minute interval because they are not modelled. He described this mechanism as an industry standard simplification and stated that following Mr. Marshall’s recommendation to model both the deadband and AGC as available for dispatch would be inappropriate.

- [196] Where the expert opinion evidence diverges regarding the modelling of balancing and integration costs in the study, the Board prefers the opinion of Mr. Ming. Mr. Marshall conceded on cross-examination that the model adaptation he originally recommended would not improve the accuracy of the cost estimate because it was based on his erroneous assumption that the PLEXOS model allows the deadband and AGC to be dispatched to meet fluctuations within the five-minute interval. On the other hand, Mr. Ming’s conclusion is founded on his understanding of PLEXOS model and is consistent with Mr. Church’s detailed explanation of NB Power’s modeling mechanisms and how the “intervention costs” are calculated in its model. Relative to Mr. Marshall, Mr. Ming demonstrated a superior command of the PLEXOS model’s inputs and functionality, including the approximation of the cost of manual intervention to meet the unserved energy and industry-standard modelling techniques.
- [197] The evidence of NB Power’s rebuttal, Mr. Church’s explanation and Mr. Ming’s expert opinion demonstrates that the impact of the ACE deadband is captured in the PLEXOS model with reasonable accuracy. This conclusion is consistent with Mr. Ming’s assessment that NB Power’s “relatively balanced” system of flexible and non-flexible resources as supporting a hypothesis that its costs would fall in the middle of a range that spanned from \$1.40 to \$6.90. Within this hypothesis, \$2.27/MWh is comparatively low.
- [198] E3 reported that future wind balancing studies could be improved by increasing the operating reserves held in the model in the day-ahead and hour-ahead unit commitment stages to reduce reliance on proxy costs. This suggestion and NB Power’s acceptance of it does not constitute evidentiary support for adopting Mr. Marshall’s recommendation to fix the wind balancing charge at the approved Schedule 3(c) rate of \$1.25 per MWh until NB Power completes further modeling. Fixing the wind balancing charge at \$1.25 per MWh would not allow NB Power a reasonable opportunity to recover its wind balancing and integration costs because the evidence does not indicate whether or to what extent E3’s suggested refinements will reduce or raise the estimated costs, and the Schedule 3(c) rate is not analogous to the proposed wind balancing charge.
- [199] E3 expects its suggested model refinement to cause several offsetting changes that do not reveal the directionality or materiality of the net cost impact. The Schedule 3(c)

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service is an intra-hour service and is not analogous to the proposed wind balancing service that also provides inter-hour service and applies in different circumstances. Further, the forecast error proxy cost methodology from which NB Power derives the proposed wind balancing charge has been revised since the Schedule 3(c) rate was approved and now uses a weighted average of manual interventions that the Board concludes is reasonable.

[200] The Board directs NB Power to model the refinements for estimating intervention costs recommended by Mr. Ming in Section 2 of Exhibit NBP3.06 as part of an updated wind balancing study and to file the study in its next general rate application, together with an evaluation of the cost impact of those modelling changes.

6.3.2 Apportionment to Saint John Energy

[201] Mr. Burgoyne submitted that apportioning the entire wind balancing charge to Saint John Energy is unfair because the Burchill Wind Farm provides benefits to the system that NB Power is not deducting from the charge and Saint John Energy already contributes to the balancing costs of other non-dispatchable renewable generators through its standard service rates. He also argued Burchill's generation capacity of 42 MW is too low to warrant imposing the charge because the Burchill Wind Farm produces much less than the 75 to 100 MW of incremental customer-specific wind that Mr. Church testified would have a clear and material impact on the wind balancing charge. In Mr. Burgoyne's view, Burchill is instead comparable to the solar net metering program, which has not yet attracted a balancing charge.

[202] Neither argument is persuasive. The Burchill Wind Farm serves a customer-specific load in New Brunswick, so it does not provide the same system benefits as wind farms that provide all their output to NB Power to integrate into its overall portfolio of resources. Mr. Church testified that any other benefits to the system from the Burchill Wind Farm are minor and isolated and the class cost allocation study shows revenue generated from the proposed wind balancing charge is allocated to the wholesale class. Mr. Burgoyne compares two incommensurable measures: the 42 MW Burchill Wind Farm generation capacity that NB Power considered sufficient to justify creating a wind balancing charge and the 75 to 100 MW of incremental customer-specific capacity Mr. Church testified would prompt an increase in the charge. While Mr. Burgoyne also compares the 42 MW Burchill Wind Farm generation capacity to 10.3 MW of net metered solar power generation, the Board concludes this does not make the wind balancing charge unjust or unreasonable.

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[203] The Board agrees with Mr. Burgoyne’s submission regarding the value of an independent review of the balancing costs of all non-dispatchable renewable generation in New Brunswick because the Integrated Resource Plan indicates that NB Power is expecting renewable generation to play an increasing role in the utility’s future. While this request is premature because of the relatively small amount of non-dispatchable renewable generation capacity in New Brunswick, the Board concludes that conducting a review once that generation capacity grows would advance the Board’s rate design objectives for NB Power by promoting fairness among ratepayers and facilitating efficient investment decisions.

6.3.3 Failure to provide appropriate economic signals

[204] Mr. Burgoyne submitted that the proposed wind balancing charge fails to satisfy its stated objective to provide appropriate economic signals to facilitate investment decisions. He is concerned that the charge will, instead, obscure economic signals as more wind and other non-dispatchable renewable resources increase balancing costs at an unknown pace and magnitude. He asked the Board to apply the marginal cost approach Mr. Dalton recommends in his report, by which existing and future wind facilities would be modelled in “tranches” for the purpose of developing balancing and integration charges based on the costs caused by that tranche. John Dalton, president of Power Advisory LLC, was declared an expert qualified to give opinion evidence in the area of electricity markets and of generation technologies and projects within these markets, and in particular the impact of renewable energy.

[205] There is insufficient evidence on the record to rebut the regulatory principle that it is generally equitable for customers receiving the same service to pay the same amount or the testimony of Mr. Church regarding the stability, predictability, and efficiency of fixing a single average wind balancing charge. The Board concludes the NB Power study demonstrating average costs in two cases, with 300 MW and 500 MW added to the system, provides sufficient guidance to potential wind developers at this time.

[206] Mr. Furey informed the Board that NB Power proposes to allow wind facilities to self-supply balancing services and to reflect the potential for these arrangements in its rates schedule. The Board approves the wind balancing service rate schedule proposed in Exhibit NBP2.01 on page 336, with the following language added: *The Customer must either purchase this service from NB Power or make alternative, comparable arrangements to satisfy its wind balancing obligation or any portion thereof.*

[207] To address the concerns expressed by Mr. Burgoyne about the lack of specificity in the rates schedule, the Board sees value in maintaining flexibility in the rates schedule and

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notes Ms. Stevenson’s testimony that NB Power has had no discussions with wind facilities exploring the feasibility of any particular self-supply options. The Board expects NB Power and Saint John Energy to engage with each other to identify feasible self-supply options and to inform the Board of the results of their work.

6.4 Customer Charges

[208] The Board does not approve NB Power’s proposal to merge the rural, urban, and seasonal monthly service charges into a combined residential service charge of \$28.27.

[209] NB Power did not revise its urban and rural customer designations after municipal boundary changes came into force on January 1, 2023. This proposal aims to eliminate this issue. The Board accepts Ms. Stevenson’s testimony that the proposal has administrative and rate design benefits that come with simplifying the charge but is concerned about the potential for the charge to be subject to additional variability because of the upcoming rate design proceeding.

[210] The Board acknowledges that the current and prior differences between the urban and rural charges are not cost-based, so the uneven intra-class impact of the merger by which pre-existing urban customers will experience a larger increase than rural or “new” urban customers may not be unfair. However, that same logic applies to the impact of maintaining the freeze on customers caught by local governance reform until the next phase of the rate design proceeding.

[211] As a related issue, Mr. Knecht identified the rate design underlying the residential customer charge as a potential concern because demand-classified costs are embedded in the customer charge. The Board concludes that it would be unreasonable to exclude demand costs from the customer charge without an evaluation of the allocation of those costs and related rate impacts. The Board considers that a review of the classification and allocation of customer costs may be an appropriate outcome of the upcoming phase of the rate design proceeding.

[212] The Board orders NB Power to continue charging the “rural” and “urban” monthly service charges based on the pre-January 1, 2023, municipal boundaries until further order of the Board. The Board will consider any future proposal to merge the service charges as part of an upcoming phase of the rate design proceeding.

6.5 CES Portfolio

[213] 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

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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.

[214] 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.

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

CES PORTFOLIO APPROVED PRICES			
		FY2025	FY 2026
Water Heater	22 gallons (100L)	\$8.99	\$9.99
	40 gallons (180L)	\$8.99	\$9.99
	50 gallons (228L) “Stainless Steel”*	\$8.99	\$9.99
	60 gallons (270L)	\$11.49	\$12.49
	100 gallons (455L)	\$21.99	\$24.99
	100 gallons (455L) “Commercial” 208V	\$32.99	\$36.99
	100 gallons (455L) “Commercial” 600V	\$41.49	\$46.49
Area Lighting	100 Watt HPS Equivalent (LED)	\$17.49	\$19.49
	200 Watt HPS Equivalent (LED)	\$27.49	\$30.49
	100 Watt high pressure sodium*	\$18.49	\$20.99
	200 Watt high pressure sodium*	\$28.99	\$32.49
	175 Watt mercury vapor*	\$18.49	\$20.99
	400 Watt mercury vapor*	\$32.99	\$36.99
	250 Watt Metal Halide Equivalent (LED)	\$33.99	\$37.99
	400 Watt Metal Halide Equivalent (LED)	\$41.99	\$46.49
Sure Connect	30 Amp Transfer Switch	\$25.99	\$27.99

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- [216] Detailed financial information filed by NB Power shows that the costs to deliver water heating rentals and SureConnect have increased due to persistent supply constraints, labour shortages, and other inflationary pressures and that the area lighting program costs are a function of the number of lights forecast to be replaced with LED bulbs. Without increasing prices, higher costs would erode the excess revenues NB Power earns from the CES Portfolio. With the proposed price increases, the CES Portfolio is forecast to generate net revenues of \$11.0 million in Fiscal Year 2025 and \$16.3 million in Fiscal Year 2026.
- [217] The Board finds the proposed prices continue to be market-based. NB Power's water heater rental prices are the lowest in Canada, its area lighting rental pricing is comparable to other providers in New Brunswick and other Atlantic provinces, and recent growth of SureConnect indicates that the price for that offering is competitive. Based on these findings, the Board concludes that the proposed prices will ensure that the cost of providing the CES Portfolio is recovered from users without subsidization and will generate net revenues to benefit all ratepayers.

6.6 Late payment, NSF, eCharge

- [218] The Board does not apply general rate increases to NB Power's late payment charge, non-sufficient funds charge, and charges for use of NB Power's eCharge Network. Based on the evidence submitted by NB Power, including its report on demand growth, regional rate changes, and other factors that impact EV charging rates, the Board approves NB Power's proposal to maintain the current late payment charge and non-sufficient funds charge and charges for use of NB Power's eCharge Network.

6.7 Rate Design Sandbox

- [219] In Matter 529, the Board directed NB Power to file a detailed proposal for a process by which the utility could seek approval for special-purpose rate designs and rates to undertake rate design learning, and to demonstrate that its proposal establishes an appropriate balance between the need for efficiency and predictability and the need for transparency, reporting, and stakeholder engagement. NB Power is now asking the Board to approve its proposed process for approval of special-purpose rate designs and rates to undertake rate design learning.
- [220] Ms. Stevensen clarified NB Power's proposed approval process in her oral testimony. She confirmed that all rate design proposals would specify the proposed rate and that the accompanying analysis would consider not only benefits and risks to customers, but also the costs to the utility. She testified that NB Power is willing to describe its customer

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selection process, success metrics, and planned reporting frequency in its application, and to confirm whether it plans to undertake additional stakeholder engagement. Ms. Stevensen also elaborated on NB Power’s concept of a Sandbox Manager, explaining that NB Power envisions the Sandbox Manager to be a Board official to whom the Board would delegate limited approval authority over the proposals and who would act as a point of contact with the applicant.

[221] The Board accepts NB Power’s proposal for a Rate Design Learning Sandbox Procedure as a general framework but will not adopt it in its current form. The Board concludes that the approval process would benefit from further development of the application requirements to capture Ms. Stevensen’s testimony and further consideration of the Sandbox Manager’s role. The Board will continue to develop the proposed procedure as a draft Board Rule of Procedure and will invite NB Power and stakeholders to contribute to finalizing the Rule.

7 Performance monitoring

[222] At the Board’s direction, NB Power files and publishes 28 performance indicators quarterly and/or annually to give ratepayers an ongoing and transparent understanding of the utility’s performance.

[223] The Board expects heightened ratepayer interest in NB Power’s performance over the test period, not only because of the magnitude of the rate increases, but by their underlying causes including rising costs, lower out-of-province sales, and efforts to improve generation station reliability and meet the equity goal.

[224] Accessible information enhances ratepayers’ ability to engage with the utility, other stakeholders and this Board. To improve the accessibility and transparency of this information for ratepayers, the Board now directs NB Power to use a consistent, single-view format for all indicators listed in paragraph 200 of the Matter 541 decision. The Board also observes that, for some indicators, NB Power publishes both current and historical results. The Board sees value in making these trends more obvious to ratepayers so they may effectively track the utility’s performance against its objectives over time.

8 Bayside Turbine Replacement Capital Project spending is prudent

[225] NB Power requests retroactive approval of the actual capital project costs of \$66.8 million associated with replacing the combustion gas turbine generator at the Bayside Generating Station. NB Power had planned to replace the gas turbine unit in Fiscal Year

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2024 but advanced the project to Fiscal Year 2023 following a sudden failure that caused significant damage.

- [226] For the reasons below, the Board is satisfied that the capital expenditures were necessary for the reliability, adequacy, or safety of the Bayside Generating Station and that NB Power's capital expenditure of \$66.8 million was prudent. The Board, therefore, approves the Bayside gas turbine replacement project with retroactive effect, pursuant to subsections 107(4) and 107(9) of the *Act*.
- [227] While section 107 of the *Act* generally prohibits NB Power from spending more than 10% of the projected capital cost of a major capital project before the Board has approved the project, subsection 107(4) allows the Board to approve a major capital project with retroactive effect after more than 10% of the projected capital cost has been spent if the expenditures were necessary for the reliability, adequacy, or safety of the integrated electricity system, of NB Power's generation facilities, or of NB Power's distribution system.
- [228] In January 2022, the Bayside Generating Station experienced an equipment failure that damaged its gas turbine and caused a prolonged outage. The failure prompted NB Power to advance its previous plans to replace and upgrade the turbine. The project's actual capital cost was \$66.8 million. This exceeds the \$50 million threshold for Board pre-approval of capital projects required under section 107 of the *Act*.
- [229] The Board finds that the expenditure was necessary to restore the Bayside Generating Station's operability, and no reasonable alternatives were available. The emergency required NB Power to accelerate the project timeline and incur \$18.3 million in additional capital costs. The Board concludes that restoring the station's operability as soon as possible was necessary for the reliability and adequacy of the station and the integrated electricity system because Bayside is a baseload station that is integral to NB Power's ability to serve load. NB Power could have purchased replacement energy to avoid incurring additional capital costs, but that would not have been reasonable because it would have been more expensive than accelerating the project. Therefore, NB Power has satisfied the conditions in subsection 107(4).
- [230] The Board accepts NB Power's evidence that its pre-emergency capital cost estimate was under \$50 million, including a small contingency that did not account for the emergency. The Board concludes that the small contingency was reasonable based on Mr. Coady's testimony that typical contingencies do not account for the type of emergency Bayside encountered, and NB Power expected any change orders to would offset each other. The Board also accepts Mr. Coady's and Mr. Yeomans's testimony explaining that NB Power

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did not expect to sustainably exceed the \$50 million threshold until the accelerated project was underway, at which point the costs and benefits were in flight and uncertain and resources could not be diverted to pursue pre-approval.

[231] The Board is also satisfied that NB Power’s capital expenditure of \$66.8 million was prudent. The Board previously considered the meaning of “prudence” as used in subsection 107(9), concluding that a prudent project must consider both short-term and long-term outcomes and that the demonstrated quantifiable and non-quantifiable benefits to ratepayers must outweigh the expected costs that ratepayers will be asked to bear. In support of its application in this case, NB Power filed evidence including an options analysis, a project description, a business case analysis, a procurement description and related contracts, a cost variance analysis, and a benefits realization analysis, as well as the original 2022 investment rationale document. No intervener challenged these analyses.

[232] The original investment rationale document shows \$254.4 million in forecast ratepayer benefits calculated on a net present value basis in 2022, comfortably outweighing the \$74.2 million total forecast costs, including \$44.6 million in capital costs projected at that time. During the emergency, the capital budget was revised to \$48.3 million. The actual-to-budget variance analysis indicates that actual capital costs were \$66.8 million, while the benefits realization analysis shows a total cost of \$97.1 million compared to total benefits of \$188 million. Despite higher costs due to the acceleration of the project and less favourable forecast fuel and purchased power savings compared to original projections; the benefits realization analysis shows a shorter discounted payback period of 2.6 years. The Board concludes that these analyses and their underlying assumptions and other inputs are reasonable and considers that Bayside is an important element of NB Power’s plan to achieve its strategic goals, including meeting the equity goal by the equity target date.

[233] For these reasons, the Board is satisfied NB Power’s capital expenditure of \$66.8 million was prudent.

[234] The Board is mindful of Mr. Coady’s statements acknowledging the risk of exceeding the 10% threshold before seeking Board approval of a capital project and confirming that NB Power’s normal practice, outside of an emergency, would have caused the utility to file an application upon realizing that the projected costs were exceeding \$50 million. Section 107 of the *Act* is an important mechanism for ensuring rates are just and reasonable and that the Board’s other decisions are made in the public interest. The Board heard testimony from NB Power witnesses throughout this proceeding that NB Power’s cost and

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contingency estimates undergo multiple refinements as project planning continues, which may pose challenges in identifying if and when section 107 would apply to particular capital project. The Board considers that the subsection 107(11) factors, which mirror the mandatory statutory factors described in paragraph [11], underscore NB Power's responsibility to avoid the risk of exceeding the 10% threshold in non-emergency situations. In this regard, the Board notes that subsection 107(3) allows the utility to apply for approval where capital cost estimates are approaching \$50 million.

9 Conclusion, Orders and Directions

[235] The Act requires the Board to fix just and reasonable rates based on NB Power's revenue requirements. The approved revenue requirement approved in the Board's Oral Decision delivered on November 8, 2024, and these Reasons gives NB Power a reasonable opportunity to recover its forecast test period costs and to earn a reasonable return.

[236] In compliance with the Board's Oral Decision, NB Power refiled its budget incorporating the Board's approved revenue requirement for each fiscal year of the test period and a revised cost of service study, revised proof of revenue, and the resulting rates. This compliance filing indicated a revenue requirement of \$2,586.0 million for Fiscal Year 2025 and \$2,748.0 million for Fiscal Year 2026, and an average rate increase of 9.14% applied differentially across all customer classes each year.

[237] By Order dated December 10, 2024, 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 Fiscal Year 2025 rates become effective as of April 1, 2024, and the Fiscal Year 2026 rates become effective on April 1, 2025.

[238] The Board issues the following Orders and Directions to NB Power in these Reasons:

1. NB Power is required to comply with the Board's previous direction to file its third quarter PROMOD forecast no later than January 21st each year, even if no general rate application is ongoing at that time (Section 5.1.1).
2. The Board orders NB Power to file an ERP Upgrade progress report with the Board no later than June 30, 2025, and annually thereafter until further order of the Board. The progress report shall provide up-to-date information on the project schedule, budget, risk assessment and any substantive new or updated business case/investment rationale (Section 5.2.1.3).

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3. The Board directs NB Power to complete its backfill cost data capture initiative and to incorporate the data into the vacancy credit calculation for its labour and benefits expense budget in the next general rate application (Section 5.2.4).
4. The Board directs NB Power to take the steps listed in paragraph [111] to improve transparency regarding the costs and benefits of its demand-side management and energy efficiency programs (Section 5.2.7).
5. The Board directs NB Power 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 5.2.3).
6. The Board directs NB Power to establish a vulnerable customer liaison committee and report to the Board no later than June 30th of each year on NB Power's investment in the committee, participation, issues raised, and outcomes (Section 6.1.2).
7. Regarding General Service II customers who are subject to bill protection measures, the Board directs NB Power to keep those customers informed about the transition to merged General Service rates and to quantify the bill protection benefit on their bills (Section 6.2).
8. The Board directs NB Power to model the refinements for estimating wind intervention costs recommended by Mr. Ming in Section 2 of Exhibit NBP3.06 as part of an updated wind balancing study and to file the study in its next general rate application, together with an evaluation of the cost impact of those modelling changes (Section 6.3).
9. The Board directs NB Power to use a consistent, single-view format for all performance indicators listed in paragraph 200 of the Matter 541 decision (Section 7).

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Dated at Saint John, New Brunswick, this 31st day of March, 2025.



Christopher J. Stewart
Chairperson



Heather Black
Member



John Logan
Member

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APPENDIX A

Participant	Witnesses
<p>NB Power</p>	<p>Lori Clark, President and Chief Executive Officer</p> <p>Darren Murphy, Chief Financial Officer and Senior Vice President, Corporate Services and Major Projects</p> <p>Brad Coady, Executive Director, Business Development and Strategic Partnerships</p> <p>Jeff Good, Director, Treasury and Risk Management</p> <p>Scott VanBuskirk, Manager, Commercial Evaluation</p> <p>Janice Hicks-Gesner, Director, Financial Reporting</p> <p>Diane Fraser, Director, Financial Planning</p> <p>Vicki Hachey, Senior HR Advisor, Workforce Planning and Organizational Design</p> <p>David Blackier, Director, IT Operations</p> <p>Sue Moore, Executive Director, Strategic Planning and Transformation</p> <p>Phil Landry, Executive Director, PMO and Engineering</p> <p>Stephanie Langlais, Senior Project Manager, AMI Portfolio</p> <p>Francois Bolduc, Manager, Financial Planning Operations</p> <p>Jason Nouwens, Director, Regulatory and External Affairs (PLNGS)</p> <p>Katie Bacon, Manager, Nuclear Business Services</p> <p>Darren Clark, Senior Manager, Integrated Resource Planning</p> <p>Gillian Ash-Richard, Power Systems Planning Analyst, Corporate Planning</p> <p>Craig Church, Senior Corporate Modeler</p> <p>Ted Leopkey, Manager, Demand Side Management</p> <p>Blake Hunter, Director, Products and Services</p> <p>Veronique Stevenson, Rate Design Specialist</p>

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	<p>Christina Sinclair, Senior Manager, Customer Care</p> <p>Chris Wilson, Executive Director, Generation</p> <p>Angela Leaman, Director, Finance Operations</p> <p>Jeffrey Yeomans, Senior Technical Advisor – Business Development</p> <p>John Todd, President, Elenchus Research Associates Inc. and Andrew Blair, Senior Consultant, Elenchus Research Associates Inc, were declared experts qualified to give opinion evidence in the areas of the regulation of electric and gas utilities.</p> <p>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.</p> <p>Marc Miller, Partner, ScottMadden Management Consultants, was declared an expert qualified to give opinion evidence in the areas of the management performance and performance evaluation of nuclear generation facilities and the regulation of utilities operating nuclear generation facilities</p> <p>Zachary Ming, Senior Director, Energy and Environmental Economics Inc. (E3) was declared an expert qualified to give opinion evidence in the area of the regulation of electric utilities and, in particular, the impact of renewable energy on the operation of electrical systems.</p> <p>Andrea Bastin, Technology and Transformation Partner, Deloitte, was declared an expert qualified to give opinion evidence in the area of the implementation and operation of enterprise resource planning technology and the optimization of related business processes.</p> <p>Tarah Schulz, Audit and Assurance Partner, Deloitte, was declared an expert qualified to give opinion evidence in accounting and, in particular, the interpretation and application of accounting standards, including international financial reporting standards.</p> <p>Steve Aubin, Audit and Assurance Partner, Deloitte, was declared an expert qualified to give opinion evidence in the area of accounting and, in particular, the interpretation and application of accounting standards, including international financial reporting standards.</p>
<p>Saint John Human Development Council</p>	<p>Liam Fisher, Data Analyst and Research Coordinator, Saint John Human Development Council</p> <p>Heather Atcheson, Social Researcher, Saint John Human Development Council</p>
<p>Utilities Municipal</p>	<p>William Marshall, Principal, WKM Energy Consultants Inc., was declared an expert qualified to give opinion evidence in the areas of power systems, planning operations and transmission tariffs, including the impact of non-dispatchable wind energy and renewable energy on the operation of electricity systems.</p>

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	<p>John Dalton, President, Power Advisory LLC, was declared an expert qualified to give expert opinion evidence in the areas of electricity markets and of generation technologies and projects within these markets, and in particular the impact of renewable energy.</p>
Public Intervener	<p>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 requirements, accounting matters and depreciation expense.</p> <p>Robert Knecht, independent consultant, was declared an expert qualified to give opinion evidence in the areas of regulatory economics and rate making.</p>
Board staff	<p>Jennifer Kallay, Principal Associate, Synapse Energy Economics, Inc., was declared an expert qualified to give opinion evidence in the areas of demand-side management programs for electric power utilities, including energy efficiency, demand response, electrification, and renewable energy measures.</p>