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 rates for the fiscal year commencing April 1, 2018.

AND IN THE MATTER OF an Application by New Brunswick Power Corporation pursuant to section 107 of the *Electricity Act*, S.N.B. 2013, c. 7, for approval of a capital project consisting of the procurement and deployment of Advanced Metering Infrastructure.

(Matter No. 375)

July 20, 2018

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

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NEW BRUNSWICK ENERGY AND UTILITIES BOARD:

Vice-Chairperson:	François Beaulieu
Members:	Michael Costello
	Patrick Ervin
Counsel:	Ellen Desmond, Q.C.
Chief Clerk:	Kathleen Mitchell

APPLICANT:

New Brunswick Power Corporation:	John Furey

INTERVENERS:

Gerald Bourque	
Enbridge Gas New Brunswick:	Jeffery Callaghan
J. D. Irving, Limited:	Christopher Stewart
New Clear Free Solutions:	Chris Rouse
Dr. Roger Richard	
Sussex Sharing Club:	Alfred Smith
Utilities Municipal:	Scott Stoll
Public Intervener:	Heather Black

A. Introduction

[1] The New Brunswick Power Corporation (NB Power or utility) applied to the New Brunswick Energy and Utilities Board (Board) on October 5, 2017 for an order approving proposed rates for services for the fiscal year commencing April 1, 2018 (test year). It sought an average rate increase of 2%, applied to its customer classes on a differential basis, based on revenue requirements of $1,705.5 million. NB Power also sought to implement a rate adjustment mechanism for extraordinary events or circumstances beyond its control.

[2] NB Power also applied for approval of a capital project consisting of the procurement and deployment of Advanced Metering Infrastructure (AMI) having a total capital cost of $90.7 million, and a related order with respect to the creation of a deferral account with respect to the write-off of existing meters to be replaced by smart meters.

[3] In addition, NB Power filed a three-year Demand Side Management (DSM) Plan as part of its Energy Smart New Brunswick plan (Energy Smart NB). This represents an amalgamation of NB Power's own Reduce and Shift Demand (RASD) Program and the former Efficiency NB agency programs.

1. Procedural Background

[4] The Board received evidence from NB Power, interveners and Board staff between October 2017 and the conclusion of the hearing in May 2018, consisting of over 950 documents. The hearing of oral evidence and submissions occupied 31 days from February 7 to May 10. All interveners, with the exception of Sussex Sharing Club, participated in different aspects of the proceeding.

[5] Because of the scope of this matter, it was separated into two parts. Part 1 dealt with the AMI application and Energy Smart NB. Part 2 was in relation to NB Power's general rate application, the rate adjustment mechanism and other relief sought by the utility.

[6] During the course of the hearing, the Board dealt with three significant procedural matters, as detailed in the following sections.

a. Withdrawal of the Rate Adjustment Mechanism

[7] In a letter dated March 23, NB Power requested leave of the Board to withdraw the portion of its application relating to a rate adjustment mechanism. It advised the Board that, based on input received from its shareholder and customers, NB Power's Board of Directors directed management to seek leave to withdraw the rate adjustment mechanism from its application. A Notice of Motion and supporting affidavit were filed on March 26.

[8] Following oral submissions from the parties on March 26, the Board granted leave to withdraw the rate adjustment mechanism from the application.

b. PLNGS Settlement – Revised Schedule and Evidence

[9] By a separate Notice of Motion dated March 26 (Motion), NB Power disclosed that an insurance claim in connection with the Point Lepreau Nuclear Generating Station (PLNGS) was settled on March 22 (PLNGS Settlement). The claim related to material damage and a delay in start-up in connection with the PLNGS refurbishment project. The Motion requested a modification of the hearing and filing schedule to permit the filing of additional evidence.

[10] The Motion was supported by the affidavit of Darren Murphy, Chief Financial Officer and Senior Vice-President, Corporate Services at NB Power. It disclosed that the settlement funds were expected to be paid to NB Power on March 29. As a result, NB Power intended to reduce its request for an average 2% rate increase, and to file additional evidence in support.

[11] On March 27, the Board heard submissions on the Motion. In its ruling, the Board recognized the unique nature of the situation. It allowed a modified hearing and filing schedule for the purposes of permitting NB Power to file a revised rate proposal with supporting evidence.

[12] NB Power subsequently filed evidence to modify its application and to support the proposed accounting treatment of the PLNGS Settlement. Of particular note, NB Power filed a revised test year budget with revised opening balances for net debt and retained earnings, inclusive of the impact of the PLNGS Settlement.

[13] The revised test year budget reflected its most recent estimates of 2017/2018 financial results, which were not as favorable as previously anticipated. In light of the exceptional circumstances introduced by the PLNGS Settlement, the Board allowed the revised test year budget as evidence in support of the general rate application.

[14] The financial revisions affected several areas of NB Power's test year revenue requirements, including lowered depreciation expense, regulatory deferral charges, interest costs and a reduction in Operations, Maintenance and Administration (OM&A), reducing its total revenue requirements by $7.1 million. Consequently, NB Power reduced its requested average rate increase from 2% to 1.5%.

[15] Additional aspects of the PLNGS Settlement are reviewed later in this decision.

c. PLNGS Settlement - Claim for Confidentiality

[16] NB Power filed a Claim for Confidentiality on March 26, requesting that the terms and conditions of the PLNGS Settlement be afforded confidential treatment. It requested that the Minutes of Settlement not be filed with the Board. The claim referred to the terms of the confidentiality provisions of the settlement, and that those terms were important to the commercial interests of both NB Power and the insurers who were the counter-parties to the settlement.

[17] Mr. Murphy's affidavit in support of the Motion to modify the hearing and filing schedule sets out confidentiality provisions governing the PLNGS Settlement, and which form the basis for the Claim for Confidentiality. These provisions acknowledged NB Power's requirement to disclose the settlement amount to the Board, as well as the Board's authority to compel disclosure of relevant documents. NB Power disclosed the settlement amount to the Board on a confidential basis on March 28.

[18] The Claim for Confidentiality recited two ongoing "areas of dispute", one between NB Power and Atomic Energy of Canada Limited (AECL), and the other between the insurers and AECL. Until the outstanding issues with AECL are resolved, NB Power maintains that any disclosure would be harmful to NB Power and its ratepayers.

[19] The Board received objections to the Claim for Confidentiality from J. D. Irving, Limited (JDI) and the Public Intervener. The Board's Chief Clerk also received a letter from

Board Counsel, requesting that the Minutes of Settlement and an associated release (Release) be filed with the Board.

[20] The Board conducted a public interest hearing on April 3 in accordance with Rule 6.5.6 of the Board's *Rules of Procedure* (Rules) to determine whether, under section 34 of the *Energy and Utilities Board Act*, the publication or revelation of the information relating to the settlement was necessary in the public interest. NB Power, JDI, the Public Intervener and Board Counsel made submissions to the Board.

[21] In its ruling issued on April 4, the Board determined that the nature of the information in question is confidential. The circumstances of NB Power's Claim for Confidentiality are unique and any undue disclosure of the settlement terms would be detrimental to NB Power and ratepayer interests.

[22] The Board stated that the need for confidentiality must be balanced against the need for appropriate parties to be able to question the disposition of the settlement proceeds, in a way that assists the Board in fixing just and reasonable rates.

[23] The Board determined that the role of the Public Intervener, as set out in subsection 6(5) of *An Act Respecting a Public Intervener for the Energy Sector*, was sufficient to ensure that the public interest was served in this proceeding and ordered NB Power to:

(a) File in confidence unredacted copies of the Minutes of Settlement and Release;

(b) Provide the Public Intervener with unredacted copies of the letter disclosing the settlement amount, the Minutes of Settlement and Release, under the conditions of the undertaking previously signed by the Public Intervener; and

(c) Provide redacted copies of the same documents to the Chief Clerk for publication on the public record.

[24] As a result of the Board's ruling, a number of the revised line items in the revenue requirements were required to be kept confidential. However, the Board, the Public Intervener and Board staff were provided with unredacted copies of the confidential documents. The Public Intervener and Board staff were provided with the opportunity to conduct cross-examination, *in camera*, on the confidential information.

2. Public Participation

[25] Apart from the formal hearing process, the Board held a public session in Saint John on February 7 and heard eight presentations. The Board also received sixteen letters of comment.

[26] Opinions about the AMI project were both in favour and against. Those supporting AMI cited potential resulting economic development and innovation. Those against noted concerns about health impacts on residents and whether AMI is affordable.

[27] Representatives from certain municipalities expressed opposition to a proposed increase in the streetlight fee, noting that, unlike other rate classes, the streetlight class pays well in excess of its share of costs.

[28] The Board also heard from ratepayers who were opposed to the proposed rate increase, based on concerns about the utility's alleged waste and inefficiency.

[29] Submissions from the public are not treated as evidence under the Rules, which would otherwise be subject to interrogatory inquiries and cross-examination. However, they are considered by the Board in its deliberations. The Board appreciates the efforts of those who made submissions or presentations.

B. The AMI Application

[30] In its opening statement by Mr. Murphy, NB Power portrayed Part 1 of the hearing as a choice between addressing "… rapidly changing and uncertain future environments for the utility or continuing to operate in a traditional generation transmission and distribution fashion, in spite of the evolution of the industry." NB Power suggested that a key strategy for meeting the challenges of the future is Energy Smart NB, of which AMI plays a key role.

[31] The AMI portion of NB Power's application is in accordance with section 107 of the *Electricity Act* (Act), which provides that NB Power must obtain Board approval of any capital project with a projected capital cost of $50 million or more.

[32] NB Power proposes to upgrade its metering capabilities to AMI, which will enable two-way communications between customer meters and NB Power. In its main evidence, it

states that AMI "…is essential to building a smarter, cleaner, more reliable and efficient power grid and will lay the foundation for many of the long-term customer benefits that NB Power will deliver through its Energy Smart NB Plan."

[33] The AMI application relied in part on the Investment Rationale prepared by Util-Assist Inc. (Investment Rationale). The financial analysis for the AMI project indicated a total capital cost of $90.7 million over 15 years, and operating costs of $32 million, on a net present value (NPV) basis.

1. Overview of AMI

[34] NB Power plans to install approximately 355,000 smart meters at customer sites. Most currently installed meters rely on readings at or near the meter. A smart meter records and stores energy consumption data at a granular level, as frequently as five-minute intervals. Data would be transmitted between adjacent meters, and to a network of about 250 local collectors throughout the province, and then on to a head-end system. The system would be integrated with a customer information and billing system, among others. Customers would be able to review their consumption within a day of this process. In this context, the AMI project scope includes the entire system infrastructure and enabling technology.

[35] AMI offers several functions not available with traditional meters. For example, since usage data is automatically sent to a billing system, the utility is not required to send resources to customer locations to collect monthly data. It would also improve the quality of data available for class cost allocation studies and load forecasting.

[36] NB Power currently relies on customer reports of localized power outages before it can respond. With AMI, such outages are detected and reported in real time, allowing for timely and accurate outage response. Distribution network losses, including theft detection, are improved. More detailed consumption information is available to customers who wish to monitor and adjust their consumption habits.

2. The Investment Rationale

[37] The Investment Rationale analyzed the quantifiable and non-quantifiable benefits of AMI, and the projected capital and operating costs.

[38] The quantifiable measures are estimated present values, based on a 15-year investment. As originally presented in evidence, the present value of the total capital and operating

costs of the project was $122.7 million and the present value of AMI benefits was $121.4 million. The project therefore had a NPV of negative $1.3 million. This equates to a recovery period of 15.12 years, which is beyond the investment period.

a. Project Costs

[39] The capital costs include the AMI investments of $63.7 million, consisting of the cost of meters and related hardware ($39.7 million), and installation ($13.2 million), plus other items related to communications infrastructure ($10.8 million).

[40] The capital costs also include the meter data management (MDM) system related costs ($7.6 million), workforce management, demand response, integration and customer education costs ($8.3 million) and various other costs ($11.1 million).

b. Project Quantifiable Benefits

[41] The Investment Rationale listed 15 quantifiable benefits, mostly being estimated cost avoidance or cost reduction items, following full deployment. Seven of the items range from $1.1 to $0.5 million in claimed benefits, and represent 5% of the total quantifiable benefits. None of those items were challenged. The Board accepts the associated amounts to these claimed benefits.

[42] The remaining eight items constituted 95% of the quantifiable benefits. Evidence and submissions before the Board challenged three of these items. The three areas of contention were the KWh Reduction Program (referred to as Social Benchmarking), Conservation Voltage Reduction and the remaining book value of smart meters. These are reviewed below. The Board accepts the associated amounts of the remaining five claimed benefits.

i. Social Benchmarking

[43] NB Power's current social benchmarking program consists of a paper-based Home Energy Report (HER) mailed to 125,000 customers, and online benchmarking available to all customers, based on monthly consumption data.

[44] The Investment Rationale stated that AMI-enabled social benchmarking programs will allow customers to compare their energy consumption with others and help them modify

consumption patterns. It claimed that similar programs in North America have resulted in reductions of 1% to 2% among participating customers. Util-Assist assumed a reduction of approximately 1%. The $28.9 million benefit was calculated as the resulting energy reduction multiplied by the avoided cost of power.

[45] Tim Woolf, Vice-President of Synapse, was retained by Board staff. He was qualified as an expert in electric utility revenue requirements, rate making and rate design, integrated resource planning, energy efficiency planning and program design, demand response planning and program design, advanced metering infrastructure planning and cost effectiveness, grid modernization and performance incentive mechanisms. The Synapse report expressed a concern that NB Power may have inappropriately counted benefits from its existing social benchmarking program as part of the AMI benefits. Mr. Woolf asserted that only those benefits that are additional to the current program should be part of the Investment Rationale, and that the claimed benefits should be reduced by at least $3.9 million.

[46] Mr. Woolf recommended that the Investment Rationale should be revised to correct "…the deficiencies … detailed in the analysis of AMI impacts on social benchmarking or other conservation programs." This will be reviewed below, in relation to NB Power's later adjustments to the Investment Rationale.

ii. Conservation Voltage Reduction

[47] Conservation Voltage Reduction (CVR) uses AMI to reduce energy consumption and peak demand by optimizing voltage levels and by providing information that improves the operation of substation voltage regulators. Similar projects have shown that this can deliver 1% to 3% reductions in energy consumption. The Investment Rationale used a factor of 0.25% in energy reductions to calculate the total benefit of $5.3 million.

[48] The Investment Rationale assumed that the CVR program begins in year seven. NB Power's evidence included details of NB Power's CVR Engineering Studies and Planning project. The 20-month project included a pilot project to validate CVR performance and goals.

[49] Edmund Finamore, President of Valutech Solutions, Inc., was retained by the Public Intervener. He was qualified as an expert in the areas of AMI system development, business and technical planning implementation and evaluation. He stated that NB

Power's benefits justification envisioned a full system implementation of advanced CVR technologies. To his knowledge, such technologies have not yet been deployed across an entire network at other North American utilities.

[50] Mr. Woolf stated that NB Power has not sufficiently justified the need to wait for seven years after the smart meters are deployed to begin CVR.

[51] The Board finds that NB Power has used a conservative estimation of value of this benefit, by assuming a 0.25% energy reduction factor and by not beginning this benefit before year seven following the start of meter deployment. For these reasons, the Board accepts the amount of this claimed benefit.

iii. Remaining Book Value of Meters

[52] The final item was the remaining book value of the AMI investment at the end of the 15-year investment period. This was based on the fact that the majority of meters will be installed over a two year period, and that not all meters will have been fully depreciated at the end of the investment period. NB Power quantified this as a $5.3 million benefit.

[53] The Synapse report stated that NB Power's claimed benefit should be replaced with a $2.5 million net cost. In its submission, rather than count the remaining book value of the smart meters at the end of the 15-year investment period as a $5.3 million (NPV) benefit, the depreciation of the meters over that period should be treated as a $7.8 million (NPV) cost. With respect to this, NB Power submitted that the residual book value of the current meters is a sunk cost, and as such, are not relevant to the investment decision.

[54] The Board agrees that the remaining book value of the smart meters at the end of the investment period is a valid benefit.

c. Project Non-quantifiable Benefits

[55] The Investment Rationale also listed a number of non-quantifiable benefits and opportunities for future quantifiable benefits. The non-quantifiable benefits included, for example, improved customer satisfaction and enabling customer service representatives to address customer questions more effectively. There would also be operational benefits for the utility, such as enabling better load data for research, better insight into transformer loading, and improved billing processes.

[56] The Board acknowledges that there may be a number of non-quantifiable benefits that AMI would accrue to ratepayers and the utility. For the purposes of this application, however, the Board does not consider non-quantifiable benefits as a factor that would overcome a negative business case.

d. Adjustments to the Investment Rationale

[57] During the hearing, Util-Assist made adjustments to the original Investment Rationale in accordance with Synapse's recommendations for the Social Benchmarking Program and Time-Based Pricing. NB Power accordingly revised its evidence in an undertaking. With these revisions, NB Power submitted that the NPV of the AMI project changed from negative $1.3 million to positive $8.7 million.

[58] With respect to Social Benchmarking, NB Power made two adjustments. First, it reduced the benefit from $28.9 million to $10.8 million, in order to capture only the AMI benefits incremental to the current program. Second, it added the avoided cost of $23.2 million in running the current HER, which AMI would replace with a more cost-effective program. These adjustments would result in a net increase in the Social Benchmarking benefit by $5.2 million.

[59] In its closing argument, NB Power referred to the avoided costs of the current HER program, which relies on mail-outs to participants, and the fact that an AMI enabled program would extend to all customers, with the exception of a control group. The Board disagrees with this argument. NB Power is in a position to avoid the costs of mail-outs of home energy reports without the implementation of AMI. Customers may receive such reports included in their monthly billings, whether received by mail or other means. For this reason, the $23.2 million avoided cost claimed by NB Power is not a valid quantifiable benefit.

[60] As a result, the quantifiable benefit of Social Benchmarking would be $10.8 million, and not $28.9 million, as was originally presented in the Investment Rationale.

[61] With respect to the second adjustment, Time-Based Pricing, the original Investment Rationale did not include it as a quantifiable benefit. It stated that time-based pricing is a benefit that is “…of interest to NB Power” that could be considered once AMI is in place. However, the adjusted Investment Rationale included time-based pricing as a quantifiable

benefit. It assumes that 16,543 customers would eventually opt-in to time-based rates enabled by AMI. This would increase the overall net quantifiable benefit by $5.6 million.

[62] The principal concerns of Utilities Municipal in relation to the benefits of time-of-use rates enabled by AMI were the insufficient evidence and the lack of expert evidence to assist the Board in understanding the business case. In his submission, Scott Stoll, counsel for Utilities Municipal, characterized NB Power's evidence as a "rudimentary financial analysis."

[63] Utilities Municipal submitted that time-of-use rates can and should be analyzed immediately and there should be a commitment on the part of NB Power to implement time-of-use rates immediately upon the installation of smart meters. Without such an approach, significant benefits of AMI would be deferred.

[64] The Public Intervener argued that there was a lack of information as to when or whether time-based rates will be implemented, and the nature of such rates.

[65] NB Power correctly excluded any time-of-use proposal in its original application, because the Board has not evaluated such a rate design. Lacking any certainty about whether time-based pricing will be approved, it is not appropriate to include it as an AMI benefit.

3. Health and Safety Considerations

[66] An issue raised by Dr. Roger Richard related to the health and safety impacts of AMI, and in particular, the radio frequency (RF) electromagnetic energy emitted by smart meters. Daniel LeBlanc, who spoke on behalf of Dr. Richard on this issue, stated that the health concern of AMI was the primary reason for Dr. Richard's involvement in this proceeding.

[67] The Board heard evidence that the smart meters proposed by NB Power comply with a federal government standard issued by Health Canada, referred to as Safety Code 6 (2015) (Safety Code 6). The Board was also referred during testimony to Table 10-2 in a 2013 decision of the British Columbia Utilities Commission (Identification Document No. 17), which considered, among other matters, health and safety impacts of smart meters. The table indicates that RF exposure from AMI emissions in relation to that case

fell substantially below the limits in Safety Code 6, and even well below RF emissions from cell phones. This was not challenged.

[68] Dr. Richard produced Dr. Paul Héroux as a witness. He testified that, in his view, Safety Code 6 has been heavily influenced by industry, and does not sufficiently protect human health.

[69] The health and safety concerns raised by Dr. Richard and others were sincere, and for the purposes of informing the Board. The evidence, however, was insufficient to convince the Board that the installation of smart meters poses any undue threat to health and safety. The evidence did not provide the Board with any foundation to disregard or discount Safety Code 6 as the appropriate and acceptable standard relating to human exposure to RF emissions in Canada.

[70] The Board accepts that Safety Code 6 is the applicable industry safety standard in relation to RF emissions with respect to the smart meters proposed by NB Power. Further, the Board accepts the evidence that the smart meters proposed by NB Power fall well within federal government standards, as set out in Safety Code 6.

4. The Prudence Threshold

[71] In the current matter, the Board is called upon to assess the prudence of the proposed AMI capital project. In making this determination, the Board is governed by section 107 of the Act. If it is satisfied, the Board is required under subsection 107(9) to approve it. Section 107 states in part as follows:

> **107(1)** Subject to subsections (4) and (6), if the total projected capital cost to the Corporation of a capital project is $50 million or more, the Corporation shall not incur, in relation to the capital project, capital expenditures in excess of an amount equal to 10% of the total projected capital cost of the capital project before the capital project has been approved by the Board.
>
> **107(2)** For the purposes of subsection (1), the Corporation shall make an application to the Board.
>
> **107(9)** If satisfied as to the prudence of a capital project for which approval is applied for under this section, the Board shall approve the capital project.
>
> **107(11)** In making a decision under subsection (9) or (10), the Board shall take into consideration:

(a) the policy set out in section 68,

(b) the most recent integrated resource plan approved or deemed to be approved by the Executive Council under section 100,

(c) the most recent strategic, financial and capital investment plan filed with the Board under section 101,

(d) any requirements imposed by law on the Corporation that may be relevant to the application, including, without limitation, requirements regarding demand-side management and energy efficiency plans and renewable energy requirements,

(e) any directive issued by the Executive Council under section 69 that may be relevant to the application,

(f) any policy established by a regulation made under paragraph 142(1)(f) that may be relevant to the application, and

(g) any other factors that the Board considers relevant.

[72] The Board must first consider the meaning of "prudence" as used in subsection 107(9). Within the context of the Act, the reference to prudence is unique. The word "prudence" is only used in sections 107 and 108, both of which relate to the approval of capital projects. The legislation does not provide specific guidance as to how "prudence" is to be interpreted.

[73] How the term "prudence" is to be applied by the Board in the current application was debated during the hearing. The Board heard a variety of interpretations of how this section should be applied.

[74] The Board is bound by the Act, including paragraphs 107(11) (a) to (g). These inform the Board of existing policies, future investments and forward-looking plans. The general rule of statutory interpretation is that words are to be interpreted in their entire context and in their ordinary sense, harmoniously with the object of the Act and legislative intent.

[75] An overarching factor is the Board's role to make decisions in the public interest. Section 131 of the Act states that any decision of the Board is subject to any terms or conditions that it "…considers necessary in the public interest."

[76] A prudent project must consider both short-term and long-term outcomes. The demonstrated benefits to ratepayers must outweigh the expected costs that ratepayers will be asked to bear. These can be both quantifiable and non-quantifiable. The Board must exercise its discretion to determine what is prudent, using the factors in subsection 107(11) and the specific evidentiary record.

[77] Having considered the meaning of "prudence" as used in subsection 107(9) of the Act, the submissions of the parties are reviewed below, followed by the Board's conclusions.

5. General Submissions

[78] NB Power submitted that the Board should consider the known and quantifiable costs and benefits of the AMI capital project, as well as non-quantifiable benefits attributable to the project. NB Power stressed that economics should not be the only basis of the Board's determination, and that any difficulty in quantifying a benefit should not preclude the Board from considering it.

[79] NB Power stated that it must evolve to meet the future needs of its customers to make electricity consumption choices. In NB Power's submission, grid modernization is necessary and inevitable, and the risk of implementing AMI too late outweighs the risk of starting too early.

[80] Dr. Richard and Enbridge Gas New Brunswick (EGNB) opposed the introduction of AMI, albeit on different grounds. Dr. Richard's health and safety concerns have been considered by the Board, as noted above. EGNB suggested that other load-shedding initiatives would obviate the need for AMI, but did not provide any supporting evidence or analysis. EGNB also submitted that rates to mitigate seasonal peak demand can be accomplished without AMI.

[81] Gerald Bourque submitted that NB Power should get its finances in order before embarking on AMI spending. He believed, however, that smart meters are "the way of the future."

[82] Chris Rouse, on behalf of New Clear Free Solutions (NCFS), also opposed AMI and submitted that AMI does not take into account lost revenues as a result of system energy reductions.

[83] Christopher Stewart, counsel for JDI, submitted that the AMI application should be denied by the Board, but "without prejudice" to any later application. In his submission, NB Power did not provide sufficient cost-benefit evidence to establish the prudence of the project.

[84] Mr. Stoll supported the AMI application. He submitted that NB Power should adopt a time-based rate structure upon completion of the installation.

[85] Both Mr. Stewart and Mr. Stoll commented on the lack of expert testimony provided by NB Power to validate the Investment Rationale. It was suggested that the Board should place the appropriate weight on NB Power's evidence and testimony, on this basis.

[86] The Public Intervener submitted that the Board should not approve the project. In her submission, the evidence in relation to a significant portion of the claimed benefits is not reliable.

6. Board Conclusions - AMI

[87] The fundamental issue for the Board's determination, in relation to the AMI portion of NB Power's application is whether it is satisfied of the prudence of the capital project.

[88] The preponderance of the evidence and submissions leads the Board to view AMI as an evolutionary step towards grid modernization in Canada and elsewhere. Most interveners expressed qualified support for AMI, but not at this time.

[89] The quantifiable costs and benefits of the project are significant considerations in the Board's analysis. The project, as originally proposed, had a negative NPV. During the hearing, NB Power submitted additional evidence to modify its original Social Benchmarking benefit, and by adding time-based pricing benefits. According to this evidence, NB Power submitted that the NPV of the project was positive.

[90] Based on the Board's consideration of the additional evidence as reviewed above, the NPV of the project would have a larger negative value than the negative $1.3 million identified by the utility in its original Investment Rationale. The Board finds that NB Power's HER benefits should be reduced. In addition, the Board rejects the inclusion of the avoided costs of running the current HER as a benefit. As a result, the Board concludes that the costs of the AMI investment outweigh the benefits.

[91] The Board has considered the evidence and submissions of the parties, as well as the factors outlined in subsection 107(11) of the Act, which incorporates the goals of maintaining low and stable rates and achieving a capital structure goal.

[92] Given all of these considerations, the Board is not satisfied of the prudence of the AMI capital project. Consequently, it is not in the public interest. The fundamental reason behind this conclusion is the Board's finding that no positive business case was established in the evidence. The demonstrated benefits to ratepayers must outweigh the expected costs that ratepayers will bear.

[93] The application under section 107 of the Act is not approved. This does not preclude a future application by NB Power.

7. Impact on Revenue Requirements - AMI

[94] Having disallowed the AMI project, the Board must determine the impact on the test year revenue requirements. To quantify the impact, the Board has chosen to use the conservative scenario of a one-year delay. This approach does not imply that the Board has deferred the approval of the project by one year.

[95] NB Power provided evidence, in response to an interrogatory, which summarized the impact of a one-year delay in the implementation of AMI on its revenue requirements. Given this evidence, the Board reduces the revenue requirements by $100,000, as detailed below.

AMI Reductions in Revenue Requirements*	
OM&A	($2.0)
Depreciation and Amortization	$ 3.1
Net Change in Regulatory Balance	($1.0)
Net Reduction	**$ 0.1**

*All amounts are expressed in millions.

C. The Energy Smart NB Plan

1. Overview of Energy Smart NB

[96] Energy Smart NB includes three interrelated initiatives: Smart Habits, Smart Grid and Smart Solutions.

[97] Smart Habits is a continuation of NB Power's DSM programs, which are intended to assist customers to reduce and/or shift their energy consumption. These include programs such as home insulation programs, efficiency product rebates and programmable thermostats.

[98] Smart Grid is aimed at grid modernization, a key component of which is the AMI project. It is aimed at providing a foundation for NB Power to provide a range of benefits, many of which have been reviewed in the AMI portion of this decision.

[99] Smart Solutions offers new products and services to customers to assist with the management of energy consumption and to shift load. It is also aimed at providing NB Power with new and diversified sources of revenue in order to mitigate the impacts of reduced load growth.

[100] NB Power describes Energy Smart NB as "an essential part" of its Integrated Resource Plan (IRP), which states: "An important part of the integrated resource planning process is recognizing that conservation, energy efficiency and load demand management…is a potential low-cost alternative to developing new power plants."

[101] Energy Smart NB is projected to achieve net benefits of $1.1 billion (NPV) over the IRP planning period of 25 years, representing a benefit-cost ratio of 1.85. This is based on capacity and energy reductions of 59 MW and 215 GWh by 2019/20, growing to 621 MW and 2,301 GWh by 2040/41.

[102] Energy Smart NB is also designed to support NB Power's Strategic Plan for 2011-2040, and in particular, one of its three strategic objectives: "Invest in technology, educate customers and incent consumption that will reduce and shift demand for electricity and ultimately defer the next significant generation investment."

[103] There are five Key Performance Indicators which Energy Smart NB aims to achieve:

(a) In-province energy reduction;

(b) Annual peak hour demand reduction;

(c) Product and service net income;

(d) Conservation Voltage Reduction; and

(e) Meter-to-cash operational savings.

[104] The test year budget for Energy Smart NB is $40.5 million for OM&A and $49.5 million in capital expenditures. It plans to update the costs and benefits on a consistent basis to continue to evaluate the viability of the plan as conditions change.

2. Considerations under the *Electricity Act*

[105] Subsection 103(8) of the Act is particularly relevant to the Board's evaluation of Energy Smart NB. It states in part:

> **103(8)** In approving or fixing just and reasonable rates, the Board shall take into consideration
>
> > (d) the Corporation's demand-side management and energy efficiency plans…

[106] The Act also contains NB Power's responsibilities and powers in relation to energy efficiency, energy conservation and demand-side management. Section 117.1 states:

> **117.1** The Corporation is responsible for the following:
>
> > (a) promoting the efficient use of energy and the conservation of energy in the Province;
> >
> > (b) developing and delivering programs and initiatives in relation to energy efficiency, energy conservation and demand-side management;
> >
> > (c) developing and delivering programs and initiatives in relation to energy efficiency, energy conservation and demand-side management for low-income homeowners on behalf of the Province, provided that these programs and initiatives are paid for by the Province;

(d) developing and delivering programs and initiatives in relation to energy efficiency, energy conservation and demand-side management on behalf of a third party for its customers, provided that these programs and initiatives are paid for by the third party;

(e) promoting the development of an energy efficiency services industry;

(f) acting as the primary organization for the promotion of energy efficiency, energy conservation and demand-side management in the Province;

(g) raising awareness among energy consumers of energy use; and

(h) implementing demand-side management and energy efficiency plans.

3. Board Conclusions – Energy Smart NB

a. Cost Effectiveness Tests

[107] There are several industry-standard effectiveness tests that can be used to evaluate DSM plans. With each of the tests, a ratio of 1.0 or higher implies that the benefits of a program or portfolio of programs is cost effective. In other words, the benefits of the program are equal to or greater than the costs. The differences between effectiveness tests depend on what is measured as a benefit or a cost.

[108] NB Power employs the Program Administrator Cost Test (PACT) as its primary screening test, which it applies on a portfolio basis. This test compares the benefits from a utility perspective (such as avoided fuel costs) against the utility's investment, including program administration costs and customer incentives.

[109] NB Power also uses the Participant Cost Test (PCT) for informational purposes. It provides an indication of the program effectiveness from a customer/participant perspective, in terms of their bill savings, as against the participant costs and incentive payments made.

[110] Other standard efficiency test methods include the Rate Impact Measure (RIM) and the Total Resource Cost (TRC) test.

[111] The RIM test measures the impact of DSM programs on utility rates. Costs include both program costs and the reduced revenue resulting from lower energy sales. The benefits are the utility's avoided costs. NCFS submitted that this test is based on a non-participant perspective, and appropriately ignores the benefits gained by program participants. Mr. Rouse argued that this should be the principal efficiency test.

[112] The TRC test measures the net benefits of the program as a whole. The costs include the utility costs and participant costs, which was referred to in evidence as the "TRC – cash" test. An extended version of the test includes non-energy or societal costs, such as environmental impacts, referred to as the "TRC – societal" test.

[113] Mr. Woolf's testimony endorsed the use by NB Power of the PACT test as "…the best test for determining cost effectiveness in New Brunswick."

[114] Robert Knecht, expert witness for the Public Intervener, was qualified as an expert in the areas of regulatory economics and ratemaking. He also agreed that the PACT test was appropriate, if the goal of program evaluation is to minimize utility costs. If, however, the goal was to minimize both utility and participant costs, the TRC – cash test would be the proper test. That test, in Mr. Knecht's opinion, reflects all of the costs and benefits of each program. He acknowledged that the choice between PACT and TRC comes down to a choice between minimizing utility costs, versus minimizing total costs.

[115] The Public Intervener, in her closing argument, stressed that the choice of an appropriate effectiveness test depends on the Board's primary objective in overseeing NB Power's DSM plan for 2018/19 – 2020/21 (DSM Plan), within the context of the considerations set out in the Act.

[116] The Board recognizes that each of the tests described above has its strengths and shortcomings, and that the choice of a primary test reflects the policy goals of its user. It is the Board's view that the PACT test provides a basic economic analysis of net benefits of DSM programs to the utility.

[117] The Board therefore approves the PACT test as the most appropriate evaluation standard for Energy Smart NB. The test will be applied, however, on a program basis, rather than a portfolio or sector basis. Any individual program that does not achieve a score of 1.0 or higher, using test year costs and benefits, will be deemed to be not cost effective. The

Board is of the view that this approach is appropriate for NB Power's current financial circumstances.

[118] The Board will continue to use its discretion, in terms of assessing the prudence of any DSM program, regardless of the outcome of the PACT test. The Board views the other efficiency tests mentioned above (PCT, RIM and TRC) as useful, especially in terms of longer term scenario analysis for the IRP. These tests also provide additional metrics about the impacts of programs, which will assist the Board in exercising its discretion.

b. Smart Habits

[119] The Smart Habits initiative is primarily focused on DSM and is intended to assist customers to reduce and/or shift energy consumption.

[120] Smart Habits consists of 12 programs plus enabling activities, as listed below, with the test year OM&A budget for each.

	Program	**2018/19 Budgeted***
1.	Energy Efficient Product Rebates	$1.9
2.	Residential Home Retrofit + Direct Install	$3.3
3.	Home Energy Report	$2.3
4.	Low-Income Energy Savings	$4.0
5.	Residential New Construction	$1.2
6.	Residential Demand Response	$0.8
7.	Commercial Building Retrofit	$1.9
8.	Small Business Lighting	$1.9
9.	Commercial New Construction	$0
10.	Small/Medium Industrial	$0.4
11.	Large Industrial	$3.1
12.	Commercial/Industrial Demand Response	$0.8
13.	Enabling	$1.6
14.	**Total – Smart Habits**	**$23.2**

*All amounts are expressed in millions. Numbers do not total due to rounding.

[121] NB Power presented PACT test results for each of these programs, individually, on a sector level (Residential versus Commercial and Industrial), and on an entire portfolio level. The PACT test results of the Smart Habits programs are 1.6 (Residential), 2.5 (Commercial/Industrial) and 2.0 (portfolio).

[122] However, when assessed at a program level, four programs have PACT results below 1.0. These include the Home Energy Report, Low-Income Energy Savings, Residential Demand Response and Commercial/Industrial Demand Response programs. These are reviewed below, together with enabling activities.

i. Home Energy Report

[123] The HER program in the DSM Plan provides energy consumption reports to households and compares energy consumption to comparable households. The DSM Plan indicates that the present value of benefits is $6.1 million, compared to costs of $6.6 million. The PACT ratio is therefore 0.9, and is therefore found by the Board to be ineffective. The test year budget for this program is $2.3 million, compared to $1.7 million for 2017/18, based on a program expansion from 125,000 households to 170,000.

[124] The Board is of the view that an expansion of the program is not justified at this time. For this reason, the Board will only allow $1.7 million in OM&A in the test year, a reduction of $0.6 million from the proposed budget. The Board will allow the current HER program to continue for the test year, in order to permit NB Power to reassess or improve the program.

ii. Low-Income Energy Savings

[125] Under subsection 117.1(c) of the Act, NB Power "…is responsible for":

> (c) developing and delivering programs and initiatives in relation to energy efficiency, energy conservation and demand-side management for low-income homeowners on behalf of the Province, provided that these programs and initiatives are paid for by the Province;

[126] Until last year, the Low-Income Energy Savings program was completely funded by the Department of Social Development, to reach 220 participants each year. Partly because of a waiting list of program applicants, NB Power budgeted $2.0 million of its own funding to the program in 2018/19, to augment the Province's funding of $2 million. This would provide the program to 560 participants.

[127] The Board must decide whether the Act precludes NB Power from providing ratepayer funding to augment low-income DSM programs funded by the Province.

[128] NB Power submitted that there is no such preclusion. John Furey, counsel for NB Power, argued that, whereas section 117.1 relates to all fuels, NB Power's own funding is devoted only to electricity customers, and thus does not cross-subsidize non-electric customers.

[129] Mr. Stoll disagreed. In his submission, subsection 117.1(c) restricts NB Power's ability to provide its own funding. He submitted that the Act is "…a direct recognition that low income programs are best funded outside of NB Power's revenue requirement."

[130] Subsection 117.1(c) of the Act includes the phrase: "…provided that these programs and initiatives are paid for by the Province." The Board concludes that this requires NB Power to develop and deliver such programs on behalf of the Province, but subject to the proviso that the Province funds such programs. This precludes NB Power from funding low-income DSM programs.

[131] Accordingly, the Board cannot allow the proposed test year budget of $2.0 million based on NB Power funding, as this is solely a government responsibility.

iii. Residential and Commercial/Industrial Demand Response Programs

[132] The Residential and Commercial/Industrial Demand Response programs, according to NB Power's DSM Plan, is to "leverage" previously conducted technical pilots aimed at testing demand response technology and measures. Pilots and programs would be developed to coincide with Smart Grid implementation and to utilize AMI and integrated load management infrastructure.

[133] The PACT results for each of the programs project benefits of $0.8 million against costs of $3.7 million, resulting in ratios of 0.2. The Synapse report stated that NB Power has not yet completed the details of its demand response program, which would include incentive types, eligibility, and program guidelines. Although some information on outreach and marketing regarding the soft launch of the commercial/industrial program was provided, no information on outreach and marketing strategy for the residential program was available.

[134] For these reasons, the Board concludes that the evidence does not support a conclusion that the programs are effective. The Board disallows both budgeted amounts of $0.8

million (a total of $1.6 million) for the Residential Demand Response and Commercial/Industrial Demand Response programs.

iv. Enabling

[135] As part of its three-year DSM Plan, NB Power allocated $5.7 million towards enabling activities. This covers planning and design for the portfolio of DSM programs, evaluation, measurement and verification (EMV) of the programs and market-focused activities, such as building awareness of the programs. The test year budget is $1.6 million.

[136] The planning and design component consists of an assessment of potential savings opportunities from DSM, program and policy development, and regulatory activities. This includes a DSM Potential Study (Potential Study) during 2018/19, to assess achievable DSM opportunities. NB Power plans to have this study completed by the end of 2018. The portion of the enabling test year budget devoted to planning is $0.9 million.

[137] Mr. Woolf recommended that NB Power complete the Potential Study, as planned, which will allow NB Power to continue to explore DSM opportunities.

[138] The EMV component of Enabling is mainly directed at impact and process evaluations, most of which are conducted by a third-party evaluator, to ensure transparency and independence. The test year budget for EMV is $0.4 million.

[139] The Board is of the view that certain elements of enabling strategies must continue in the test year, and in particular, the Potential Study. In addition, EMV is an ongoing requirement to assess the net impact of DSM programs. The Board therefore approves these costs of $1.3 million.

[140] However, the Board is of the view that market-oriented activities should be deferred until after the Potential Study is completed and assessed by the Board. The remaining $0.3 million is accordingly disallowed from the test year budget.

v. Smart Habits - Summary

[141] The Board approves a revised budget of $18.7 million for the Smart Habits programs. Budgets for all elements of the program are approved as proposed by NB Power, with the exception of the following revised amounts:

(a) Home Energy Report: $1.7 million;

(b) Low-Income Energy Savings: $2.0 million (paid for by the Province);

(c) Residential and Commercial/Industrial Demand Responses: $0; and

(d) Enabling: $1.3 million.

c. Smart Grid

[142] The Smart Grid initiative is a grid modernization to facilitate the transformation of NB Power's system to accommodate future expectations and requirements. It consists of new technologies including engineering and design work, along with the internal process changes and enhanced business capabilities required to implement and optimize the technology.

[143] The initiative consists of seven programs and are listed below with 2018/19 OM&A budget.

	Program	**2018/19 Budgeted***
1.	General Administration/Labour/PMO	$2.7
2.	Smart Customer Service	$3.0
3.	Smart Network Operations	$1.2
4.	Smart Organization	$0.6
5.	Smart Products Portfolio Management	$0.4
6.	Smart Energy	$0.1
7.	Smart Asset & Work Management	$0
8.	**Total – Smart Grid**	**$8.0**

*All amounts are expressed in millions.

[144] The Board reviewed above the revenue requirements impact of its decision to deny the AMI capital project application, including OM&A, based on the evidence provided by NB Power. The Board accepted this evidence. Elements of the OM&A impacts are related to some of the Smart Grid programs listed above. The Board approves the budgeted amount, subject to those impacts related to the Board's decision with respect to AMI.

d. Smart Solutions

[145] The Smart Solutions initiative is aimed at new product and service offerings to customers to assist with managing energy consumption.

[146] NB Power budgeted $9.3 million in OM&A spending on six programs to expand its current portfolio of products and services. These are detailed below.

	Program	**2018/19 Budgeted***
1.	General	$3.0
2.	Solar & Storage	$3.0
3.	Electric Vehicle Chargers	$1.3
4.	Safety & Resiliency	$0.9
5.	Smart Homes	$0.8
6.	Demand Response Technical Pilots	$0.4
7.	**Total – Smart Solutions**	**$9.3**

*All amounts are expressed in millions. Numbers do not total due to rounding.

[147] The Board has concerns regarding three of the above programs. These are discussed below.

i. Solar & Storage

[148] The Dunsky Energy Consulting report dated May 2017, submitted by NB Power, recommended that the utility invest in solar development via a solar lease program to offset losses in energy sales. However, the report did not consider potential risks associated with this business opportunity.

[149] NB Power plans to conduct customer research this year to determine interest in solar products and services. The research results will help NB Power develop a business plan for this program. At the time of the hearing, a business plan was under development.

[150] NB Power's evidence was that its research and the small number of customers enrolled in NB Power's net metering program indicate that the solar photo-voltaic (PV) market in New Brunswick is in the early stages of growth. Given the financial pressures facing the utility and the nascent nature of the PV market, the Board disallows $2.0 million, reducing the approved budget to $1.0 million.

ii. Electric Vehicle Chargers

[151] NB Power has established a network of charging stations to allow electric vehicle (EV) drivers to travel around the province. Currently, the network consists of approximately 77 Level 2 charging stations, of which 38 are owned by NB Power. The network also includes 11 public Level 3 charging stations, of which 10 are owned by NB Power. It plans to expand this network by 15 stations along major highways in New Brunswick.

[152] The EV market is in its early stages in New Brunswick. Developing these stations requires considerable up-front investment. EV charging stations are not within the core business of NB Power and are already provided by the private sector, without any ratepayer investment.

[153] Without a convincing business case, NB Power should not be expanding this program. The Board disallows the budgeted amount of $1.3 million.

iii. Smart Homes

[154] NB Power intends to offer a revenue-based package to customers, which includes rental of Wi-Fi enabled gateways, thermostats, light switches and water heater energy monitors. The utility has provided a high-level market plan for the Smart Homes program, with no analysis of risk exposure. It is currently reviewing its business model for this program.

[155] The program was expected to be launched in October 2017. During the proceeding, testimony confirmed that the program had not begun. The Board is concerned with the implementation delays and disallows the budgeted amount of $0.8 million for this program.

iv. Smart Solutions - Summary

[156] The Board approves a revised budget of $5.2 million for the Smart Solutions programs. Budgets for all elements of the program are approved as proposed by NB Power, with the exception of the following revised amounts:

(a) Solar & Storage: $1.0 million;

(b) Electric Vehicle Chargers: $0 million; and

(c) Smart Homes: $0 million.

4. Impact on Revenue Requirements – Energy Smart NB

[157] The table below summarizes the reductions in the revenue requirements as a result of the Board's conclusions with respect to Energy Smart NB:

Energy Smart NB Reductions in Revenue Requirements*	
Smart Habits:	
Home Energy Report	$0.6
Low-Income Energy Savings	$2.0
Residential and Commercial/Industrial Demand Responses Programs	$1.6
Enabling	$0.3
Smart Solutions:	
Solar and Storage	$2.0
Electric Vehicle Chargers	$1.3
Smart Homes	$0.8
Total Reductions:	
Energy Smart NB	**$ 8.6**

*All amounts are expressed in millions.

D. The General Rate Application

[158] Subsection 103(2) of the Act requires NB Power to apply annually to the Board for approval of its schedules of rates it proposes to charge. Such applications must include the projection of its load and revenue for the test year, its revenue requirements and a proposed schedules of rates.

[159] The Board will approve the rates applied for, if satisfied that they are just and reasonable, or the Board will fix other rates that it finds to be just and reasonable. In approving or fixing just and reasonable rates, the Board bases its decision on the revenue requirements, taking into consideration the items set out in subsections 103(7) and 103(8) of the Act.

1. Load Forecast

[160] The load forecast is the foundation of NB Power's revenue budget. A forecast is normally based on past loads and trends using data from customer surveys along with key assumptions about economic, demographic, technological and other factors affecting the utilization of electrical energy.

[161] A new load forecast is generally produced annually. In this proceeding, NB Power's evidence consisted of a load forecast update for 2018/19 to 2026/27. According to its evidence, "…a partial load forecast refresh was completed in order to align the forecasts." It explained that due to the timing of the 2017 IRP, a new load forecast was required in advance of the normal budget cycle. Accordingly, the historical data upon which much of the forecast relies does not include the most recent year. NB Power described this in testimony as "atypical."

[162] Because of this timing, only significant updates affecting DSM and the large industrial renewable energy purchase programs (LIREPP) were completed by NB Power for the load forecast update.

[163] Utilities Municipal expressed concern with this approach. It argued that the departure from the typical process introduced a higher than normal degree of uncertainty in NB Power's forecasts.

[164] Electrical energy required to meet in-province load for 2018/19 was forecasted at 14,104 GWh, a slight decrease from the forecast for 2017/18. The maximum one-hour annual peak demand was forecasted to decrease to 3,060 MW, a decrease from 2017/18.

[165] While the Board acknowledges its shortcomings, the load forecast is accepted as filed. In future general rate applications, the Board requires that NB Power present full and comprehensive load forecasts, based on the most recent data available. This includes years in which NB Power is preparing its integrated resource plan.

[166] In its decision in Matter 336, the Board directed NB Power to provide an update on its progress relating to short-term forecasting models. A previous audit of forecasting methods suggested that short-term models may provide more accurate forecasts than models based on an extended history.

[167] NB Power's evidence in the current matter provided an update, which included a work plan to determine whether short-term load forecasting methodology methods are warranted. If so, recommendations will be implemented in the 2019-2029 load forecast as part of the 2019/20 general rate application.

[168] The Board directs NB Power to provide a report in the next general rate application in relation to the implementation of short-term forecasting methods.

2. Accounting Treatment of the PLNGS Settlement Amount

[169] As set out in the procedural background, NB Power filed additional evidence in relation to the PLNGS Settlement. It identified changes to the revenue requirements as originally filed, based on the proposed accounting treatment of the PLNGS Settlement amount.

[170] Expert evidence relating to the accounting treatment of the settlement amount was provided by NB Power, the Public Intervener and the Board. All experts agreed that the allocation methodologies used by NB Power were reasonable and appropriate. Andrew Logan, the expert retained by the Board, testified that NB Power's ratepayers will receive the full benefit of the settlement proceeds over the useful life of the PLNGS, some of which will be immediate. The other experts agreed with this in their testimony.

[171] The Board approves the accounting treatment of the PLNGS Settlement, as proposed by NB Power. In particular:

(a) The proceeds related to the material damage claim will be recorded as a reduction of the costs originally capitalized to property, plant & equipment;

(b) The proceeds related to the delay in start up will be recorded as a reduction of the costs originally capitalized to the PLNGS regulatory deferral asset account. Maritime Electric Company Limited funded 4.72% of the PLNGS refurbishment costs. As a result, 4.72% of the settlement amount related to the refurbishment costs will be recorded as payable to Maritime Electric Company Limited; and

(c) The proceeds related to costs incurred related to filing the claim will be recorded as miscellaneous revenue in the period received.

3. Revenue Requirements

[172] NB Power's evidence is based on revised revenue requirements totaling $1,698.4 million. The following table summarizes the original and revised proposed revenue requirements, along with the revenue requirements allowed by the Board in the 2017/18 general rate application.

	Item	**2017/18 Allowed***	**2018/19 Budgeted***	**2018/19 Revised Budgeted***
1.	Fuel and Purchased Power Expense	$634.8	$597.1	$597.1
2.	Operations, Maintenance and Administration	$468.4	$499.1	$498.4
3.	Depreciation and Amortization**	$250.6	$274.4	[redacted]
4.	Taxes	$44.3	$45.1	$45.1
5.	Finance Costs and Other Income**	$220.9	$216.0	[redacted]
6.	Net Change in Regulatory Balances**	$11.4	$11.3	[redacted]
7.	Net Earnings**	$90.6	$62.3	[redacted]
8.	**Total – Revenue Requirements**	**$1,720.9**	**$1,705.5**	**$1,698.4**

*All amounts are expressed in millions. Numbers may not total due to rounding.
**Items 3, 5, 6 and 7 are kept confidential following
the oral decision of the Board on April 4.

[173] There were no challenges with respect to Fuel and Purchased Power and Taxes. Each of these items was supported by evidence. The Board finds those items are reasonable, and are approved as filed.

[174] As indicated earlier, revised items 5 (Finance Costs and Other Income) and 7 (Net Earnings) in the above table of revenue requirements were kept confidential, as a result of the PLNGS Settlement. If these amounts were to be publicly disclosed, the confidentiality of the PLNGS Settlement would be compromised. The Board has carefully considered the confidential information and proposed amounts to the Finance Costs and Other Income, and the Net Earnings. The Board is satisfied that the amounts, as proposed, are reasonable, and the Board approves these amounts.

[175] Similarly, the Board has carefully considered the confidential information related to revised items 3 (Depreciation and Amortization) and 6 (Net Change in Regulatory Balances).

[176] In Part 1 of this decision, the Board determined the impacts of its decisions with respect to the AMI application. Depreciation and Amortization was reduced by $3.1 million, and Net Change in Regulatory Balances was increased by $1.0 million. Except with respect to these changes, no other changes are being made.

[177] The area of challenge focused on OM&A.

a. Operations, Maintenance and Administration

[178] The OM&A expense includes NB Power's several divisions, including generating facilities, distribution and transmission infrastructure and Corporate Services. It also includes Energy Smart NB initiatives. The original OM&A budget was revised to $498.4 million, which reflects reduced legal expenses as a result of the PLNGS Settlement.

[179] OM&A spending has increased in recent years. For example, measured against energy generation, OM&A has increased from $25.45/MWh in 2015/16 to $32.78/MWh, based on the 2018/19 budget as originally filed. Actual or estimated OM&A has exceeded the approved or budgeted costs in both 2016/17 and 2017/18.

[180] NB Power explained that the variances resulted from increases in Corporate Services (within the Hired Services cost category), Energy Smart NB, new legislative mandates, new regulatory requirements, and the decision to improve the performance of the PLNGS.

[181] Utilities Municipal recognized the unique and serious financial challenges that NB Power faces. In its view, improving fiscal discipline is an absolute necessity. JDI observed that OM&A costs have consistently increased in recent years and that actual OM&A frequently exceeds budgeted or Board approved costs. Similar concerns were expressed by other interveners as well.

[182] According to Mr. Woolf, there is a need for the utility to reduce or reverse the trend of rising costs. In his opinion, in light of limited growth in both in-province and out-of-

province sales and the forthcoming greenhouse gas requirements, lower costs and improved productivity will be necessary to achieve low rates and debt reduction.

[183] The Board shares these concerns. NB Power must find ways to control its costs in order to ameliorate this trend.

[184] In Part 1 of this decision, the Board determined the test year revenue requirement OM&A impacts of its decisions with respect to the AMI application and the Energy Smart NB Plan. This was determined to be a $6.6 million net reduction, based on a $8.6 million reduction in the Energy Smart NB budget, offset by a $2.0 million AMI-related increase. Except with respect to these changes, no other changes are being made.

b. Summary of Approved Revenue Requirements

[185] The table below summarizes the reductions in the revenue requirements as a result of the Board’s conclusions with respect to AMI, Energy Smart NB, and the review of the revenue requirements.

	Item	**2018/19 Revised Budgeted***	**Revenue Requirement Reductions***	**2018/19 Approved Budgeted***
1.	Fuel and Purchased Power Expense	$597.1	0	$597.1
2.	Operations, Maintenance and Administration	$498.4	$6.6	$491.8
	a) AMI related: ($2.0)			
	b) Energy Smart NB related: $8.6			
3.	Depreciation and Amortization	[redacted]	$3.1	[redacted]
4.	Taxes	$45.1	0	$45.1
5.	Finance Costs and Other Income	[redacted]	0	[redacted]
6.	Net Change in Regulatory Balances	[redacted]	($1.0)	[redacted]
7.	Net Earnings	[redacted]	0	[redacted]
8.	**Total –Revenue Requirements**	**$1,698.4**	**$8.7**	**$1,689.7**

*All amounts are expressed in millions.

E. Other Issues

1. Class Cost Allocation Study

[186] In its application, NB Power proposed eight changes to its Class Cost Allocation Study (CCAS) methodology resulting from the Board's decision in Matter 336 and stakeholder sessions. These changes relate to the following areas:

(a) Treat LIREPP costs and revenues to include the LIREPP loads in the energy and demand allocation factors and LIREPP revenues in the revenue-cost calculations;

(b) Treat the power purchase agreement with the City of Edmundston in the same manner as any other purchases of renewable energy;

(c) Modify the methodology by defining the coincident peak derivation as the highest of the three monthly coincident peaks;

(d) Interest and net income be allocated on the basis of rate base inclusive of large deferral accounts, rather than based only on net plant;

(e) Plant property taxes be directly functionalized to the appropriate asset categories rather than on net plant;

(f) Distribution OM&A expenses be functionalized into primary and secondary voltage categories in proportion to the functionalized plant;

(g) The classification of distribution OM&A expenses be based on average plant classification; and

(h) Refine the classification of poles and conductors depreciation expenses, as the utility's treatment of contributions in aid of construction was inconsistent between plant costs and depreciation costs.

[187] Elenchus was engaged by NB Power to conduct each of the above methodology changes to the CCAS model. For each of the above, Elenchus recommended that the modifications be adopted. NB Power filed its recommended CCAS model, which incorporated the changes.

[188] In addition, Elenchus reviewed two intervener-proposed refinements to the allocation of energy efficiency program costs. Neither Elenchus nor NB Power supported these refinements.

[189] The first refinement, previously proposed by Utilities Municipal, was to eliminate any allocation of energy efficiency costs to the Wholesale class. The Board finds that energy efficiency programs are a benefit to the entire system and all rates classes should share such costs.

[190] The second refinement, proposed by Mr. Knecht in last year's proceeding, was to reduce the portion of energy efficiency costs that are deemed to be system-related costs to zero. This issue is dealt with below.

[191] The Public Intervener raised four issues regarding the recommended model.

[192] First, Mr. Knecht disagreed with the allocation treatment of the regulatory deferral accounts. In his opinion, since NB Power confirmed that regulatory deferral accounts increase the equity financing requirement, the deferrals should be treated like other assets that require both debt and equity financing.

[193] Jonathan Dobson, NB Power's Director of Treasury and Financial Risk, testified that NB Power's assumption is that regulatory deferral accounts are financed through long-term debt, and should only be assigned interest costs.

[194] The Board agrees with Mr. Dobson's testimony and finds that the deferral account is financed with debt. It is appropriate to allocate interest costs on this basis.

[195] The second issue related to energy efficiency costs was raised by Mr. Knecht in Matter 336, being the second refinement considered by Elenchus. Mr. Knecht believed that energy efficiency should not be considered as system costs and assigned to the classes which benefit from the programs. The Board finds that energy efficiency is a benefit to the system and accepts this aspect of NB Power's treatment of energy efficiency costs.

[196] Thirdly, Mr. Knecht submitted that energy efficiency programs appear to include costs related to low-income programs, and that revenues received from the Province for these programs should be considered as an offset to such costs.

[197] The Board agrees that the revenues received from the Province for low-income programs are not allocated appropriately. The Board finds that the most appropriate allocation is solely to the residential class. NB Power is therefore directed to make this adjustment to the CCAS model.

[198] Finally, Mr. Knecht supported the idea of removing certain market-based services from the cost allocation model; specifically, street lights and water heaters. This is because the rental component of these services is subject to market-based pricing and not cost-based pricing. NB Power testified that it is reviewing its approach to such market-based services. The Board will review this issue at the appropriate time.

[199] The Board accepts NB Power's recommended CCAS model, subject to the modification in relation to revenues from the low-income program. The Board directs NB Power to make these changes to the model in the next general rate application.

2. Bright Line Rule

[200] In a decision issued in 2006, the Board adopted a range of reasonableness for revenue to cost ratios of 0.95 to 1.05. There was no guidance at that time, in relation to what rounding rules should be applied. NB Power requested clarity on this issue, which was referred to as a "Bright Line Rule."

[201] The Board directs that revenue to cost ratios shall be calculated to two decimal places for this proceeding, and three decimal places in the 2019/20 general rate application and beyond.

3. Street Lights and Unmetered Rates

[202] The Board heard concerns from the Union of Municipalities of New Brunswick during the public session regarding proposed rate increases for the street lights and unmetered rate classes. A specific issue was the revenue to cost ratio for street lights when compared to the range of reasonableness. In its view, municipalities are being over-billed for this service, and requested that such rates be frozen until this issue is resolved.

[203] The Board will not grant the request to freeze the rates. However, the Board directs that the issues related to such services be dealt with in the rate design hearing.

4. Rate Design – Matter 357

[204] In an oral decision in Matter 357 on September 21, 2017, the Board ordered that the rate design hearing was to be heard with the 2019/20 general rate application. The Board heard submissions from some interveners during this proceeding, as to whether or not Matter 357 should be heard in conjunction with the next general rate application.

[205] As Matter 357 does not include the same interveners as this hearing, the Board concludes that it would be procedurally unfair to determine whether or not the order should be varied at this time. The Board will provide further directions as to how this matter will be treated.

5. Marginal Cost Study

[206] EGNB filed a report prepared by Ralph Zarumba, Vice President of Concentric Energy Advisors. He was qualified as an expert in the areas of economics and policy relating to regulated utilities. His evidence related to energy efficiency programs and the need for a marginal cost study.

[207] Mr. Zarumba testified that many of the issues facing NB Power related to rate design and energy efficiency cannot be properly addressed without a better understanding of the utility's marginal cost. He recommended that the Board order a study examining the marginal costs during the different seasons and times of the day. He suggested that the study be completed prior to the rate design hearing.

[208] The Board finds that the nature, benefits and priority of a marginal cost study would be best considered as part of the rate design process in Matter 357.

6. Integrated Resource Plan

[209] The IRP is a long-range plan which helps NB Power develop a strategy to meet the future energy needs of customers. The plan uses modeling software to find the best combination of conventional and alternative supply options including DSM options.

[210] Mr. Rouse argued that the IRP was flawed, as it did not consider a scenario with almost 100% renewable energy, financed in part by a carbon tax. He submitted that the utility should include such a scenario in its next version, and that the scenario include a sensitivity with "very little" energy efficiency.

[211] NB Power opposed this, and argued that such a scenario would diminish the advantages of finding the least cost mix of generation and efficiency. The utility stated that it would be difficult to model such a scenario, and of little value.

[212] Given the financial constraints of NB Power and limitations of the existing generation fleet, the Board concludes that the scenario proposed by NCFS is not feasible and would not be of any value to the Board.

7. Point Lepreau Nuclear Generating Station

[213] During the hearing, Board staff asked a number of questions with respect to the PLNGS, focused on the condition of the plant and future investments.

[214] Michael Hare, NB Power's Deputy Chief Nuclear Officer, testified that a number of different initiatives have taken place to bring the PLNGS to industry standards. Perry Cheeks, Director of Nuclear Business Services, testified that the utility will be spending $432 million on capital projects in the next five years.

[215] While NB Power has explained the need for the investment at the PLNGS, these costs are significant. The Board will continue to closely monitor and review these costs in future rate applications.

F. Approval of Rates

[216] NB Power proposed an average rate increase of 1.5%, which incorporated the impact of the PLNGS Settlement. In order to continue to move rate classes within a revenue-to-cost ratio between 0.95 to 1.05, it proposed differential increases of approximately 1.64% for all classes, with the exception of Street Lights and Unmetered classes, being 1.5%, and the General Service I class, being 0.68%.

[217] As noted above, the Board has disallowed $8.7 million from test year revenue requirements. There was some discussion regarding alternative approaches to treating the disallowed costs. One was to apply the reductions to increase Net Earnings, rather than to lower the average rate increase.

[218] The Board concludes that it is appropriate in this matter to remain consistent with the Board's standard regulatory approach, which is to apply the cost disallowances to reduce the requested average rate increase.

[219] Another area of discussion was with respect to the use of differential rates. Mr. Knecht recommended a differential rate increase be applied to the General Service I class. He stated that this would be consistent with that approved by the Board in Matter 336. In that proceeding, the Board approved NB Power's objective of moving the General Service I class within the range of reasonableness.

[220] Paula Zarnett, Vice President of BDR North America Inc., was qualified as an expert in the area of utility regulation in respect of cost allocation, rate design, and rate policy. She testified as a witness for Utilities Municipal. Ms. Zarnett stated that differential increases are not appropriate at this time, and that the Board should approve a uniform rate increase across all rates classes. In her opinion, there are too many unresolved issues with respect to rate design, customer class allocation studies, potential changes to customer class criteria, and other matters, that need to be resolved first.

[221] The Board recognizes the challenges posed by Ms. Zarnett. Resolution of the issues mentioned above will likely impact how effectively differential rates will achieve revenue to cost ratio targets. Notwithstanding these concerns, the Board will approve differential rates in this matter.

[222] With these changes, NB Power is directed to provide the Board for review, its calculation of revised average and differential rate increases for all customer classes, and a revised proposed schedules of rates.

[223] Subject to its review and validation of the information provided by NB Power, the Board will approve the revised schedules of rates and set the time at which the rates are to take effect.

Dated at Saint John, New Brunswick, this 20th day of July, 2018.

François Beaulieu
Vice-Chairperson

Michael Costello
Member

Patrick Ervin
Member