Énergie NB Power

NB Power's 10-Year Plan

Fiscal Years 2021 to 2030

Prepared: September 2019

NB Power's 10-Year Plan
Fiscal Years 2021 to 2030

Contents

Executive Summary

Legislative Requirement and Purpose of 10-Year Plan

Under Section 101 of the *Electricity Act*, New Brunswick Power Corporation (NB Power) is required to prepare a strategic, financial and capital investment plan covering the next ten fiscal years and file such plan with the Energy & Utilities Board (EUB) on an annual basis. This 10-year plan is for informational purposes, but is to be taken into consideration in assessing annual general rate applications and NB Power's progress and forecasted ability to achieve long-term legislated goals and objectives.

The 10-year plan financial forecast is based on a number of key assumptions which are sourced from a combination of internal resources, external consultants, and external publications. The financial forecast is largely driven by a number of variable factors, the majority of which are outside of managements control and can vary from year to year. Changes to commodity and market prices, foreign exchange rates, interest rates, and other various factors can significantly alter the 10-year plan financial forecast from year to year[1]. This variability limits the ability to present a firm long-term financial forecast and as such, the 10-year plan should be considered for informational purposes and not as a finite plan.

The following 10-year plan has been prepared in compliance with the requirements of the *Electricity Act* and covers the period of fiscal years 2020/21 to 2029/30.

Financial Objectives

The overarching financial goals of NB Power are to reduce debt and to create equity in order to provide the utility with some flexibility to manage operating and financial risk, to respond to changing markets and technologies, and to better prepare for future investment requirements. These financial goals are also a legislative obligation as the *Electricity Act* states that rates charged to customers should be sufficient to permit a just and reasonable return that will allow NB Power to earn sufficient income in order to achieve and sustain a capital structure of at least 20 per cent equity. NB Power also recognizes that improving the financial health of the company also supports the overall economic well-being of New Brunswick.

In previous general rate applications, NB Power has put forth evidence with respect to the determination of a long-term capital structure for NB Power. The evidence identified criteria to consider with respect to determining the amount of net income to include in rates, inclusive of the following key considerations:

- The legislated equity target of at least 20% equity is interpreted as being the minimal level of equity
- Rates should be set so that there is steady progress that results in achieving the equity target on a timely basis
- The prospective rate increase trajectory required to reach and maintain the minimum equity ratio should not require increases that exceed the current year increase
- Once achieved, rates should be set such that the forecasted equity ratio does not decline below the minimum equity target
- An equity target above 20% may be appropriate in advance of major investments that will put pressure on the capital structure

[1] *The impact of the potential variability in a several key factors is discussed in the Scenario Analysis section and further illustrated in Appendix C.*

NB Power continues to support these over-arching principles in developing a long-term rate strategy. NB Power also recognizes that improvements in the financial health of NB Power must also consider other objectives established in the *Electricity Act* which indicates that, to the extent practical, rates charged by NB Power for the sale of electricity within the province shall be maintained as low as possible and changes in rates shall be stable and predictable from year to year. Stable and predictable rate increases should however be high enough to achieve the minimum equity ratio target on a timely basis.

Material Risks & Uncertainties

The 10-year plan financial results are subject to a wide array of material risks and uncertainties, including changes to commodity and market prices, foreign exchange rates, interest rates, in-province and export load, and hydro and nuclear production, all of which can have a significant impact on forecasted results. Other key material risks and uncertainties of note include the following:

- *Mactaquac Project* - NB Power has announced its recommendation of a "life achievement" project to maintain Mactaquac to its original intended lifespan of approximately 2068. This is a major project that is presently estimated to have costs in the range of $2.7 to $3.7 billion. For financial planning purposes, this 10-year plan includes capital expenditures that are based on a mid-point estimate of expenditures which total approximately $1.9 billion within the 10-year plan period. Changes to the recommended approach or cost estimates could lead to a difference in the timing and magnitude of capital expenditures and expenses than what is otherwise assumed in the 10-year plan.
- *Carbon / Climate Change Costs* – uncertainty remains with respect to the potential cost of carbon emissions. The base 10-year plan results are inclusive of costs based on the proposed carbon pricing system that was submitted to the federal government as a made-in-New Brunswick alternative to the federal government's backstop output-based pricing system (OBPS). The federal government is currently assessing the New Brunswick government's carbon pricing plan and if the plan is not accepted, NB Power may be subject to the federal OBPS and higher carbon costs. Other potential climate change impacts, such as the early phase out of coal generation, could further impact financial results and could require additional rate increases to be implemented to cover the increased costs[2].
- *Rate Increases* – the 10-year plan assumes annual rate increases occur throughout the period of the plan, all of which are subject to EUB approval. If some portion of the forecasted rate increases were not approved, then revenue projections could vary materially.
- *Natural Gas Supply* – the 10-year plan assumes that natural gas is able to be sourced from Western Canada as a result of long-term pipeline commitments being contracted. The financial results reflect the costs and benefits of this fuel source to the end of 2026, the current end of life of the Bayside Generating Station. As a final decision has not yet been made on the long-term operations of the Bayside Generating Station and on how the pipeline commitment will be utilized post 2026, the current plan does not assume any costs or benefits associated with these pipeline commitments after 2026. As such, results will be impacted post 2026 upon finalizing a plan to best utilize the transport commitment.
- *Demand Side Management (DSM) Spending* – the 10-year plan reflects a gradual increase in annual DSM spending over the period, spending levels which are lower than those forecasted in prior years. A more comprehensive evaluation of the impact of various DSM spending levels will be completed during the update of the next Integrated Resource Plan (IRP) which is to be completed over the course of the next year. Changes to the DSM spending levels would impact in-province revenue, fuel and purchased power costs, and OM&A expenses which could materially impact results.

[2] *Refer to the Carbon Pricing & Emission Regulation section for further information.*

Please refer to the Material Risk & Uncertainties and Scenario Analysis sections for further information on key items that can impact forecasted results.

Changes from Prior Year

The variability in uncontrollable costs has again been very evident in the preparation of the current 10-year plan. The prior year 10-year plan noted significant increases in certain commodity prices, interest rates, and foreign exchange rates that significantly impacted results. Since that time, market prices for a number of commodities have decreased, particularly in the near-term period. Interest rates have also declined or are no longer forecasted to increase as quickly or as high as previously indicated, and a lower cost natural gas supply option has also become available to the Maritime region. As a result of these changes in assumptions, the 10-year plan reflects lower supply costs, higher export opportunities, and lower financing costs over the period in comparison to the prior year. These improvements to costs are particularly evident in the initial years of the 10-year plan period.

Outside of changes to the forward and market price assumptions, several other notable key changes to estimates or assumptions have been factored in to the current 10-year plan, particularly with respect to the following items:

- *DSM Deferral Account* – the prior year 10-year plan included the forecasted establishment of a regulatory account for DSM expenditures that would allow amounts to be capitalized and amortized over a period of 10 years. The establishment of the account was not approved by the EUB and is thus not included in the current 10-year plan.
- *DSM Spending* – NB Power recognizes the importance and long-term benefits of DSM spending but also recognizes the rate challenges that it presents when having to expense amounts annually that have a longer-term benefit period. Given the recent decision to disallow the creation of a regulatory account to recover DSM expenses in rates over a longer period of time, NB Power was forced to re-evaluate the level of planned DSM spending. In an effort to reflect the balancing of the achievement of the various financial objectives, the current 10-year plan is forecasting lower DSM spending levels in comparison to those estimated in previous years. As a result, in-province load estimates have increased and OM&A expenditures have decreased throughout the period of the current plan. Due to the increased load estimates, a corresponding impact is also seen in the fuel and purchased power cost estimates. NB Power will continue to assess how best to balance the longer-term benefits of DSM spending with the near-term rate pressures it results in as part of the IRP update process to be completed over the coming year.
- *Natural Gas Supply* – as noted above, the 10-year plan assumes that natural gas is able to be sourced from Western Canada as a result of long-term pipeline capacity that became available to the Maritime region. Larger gas volumes are forecasted to become available in fiscal 2021/22 and as a result, the Bayside Generating Station becomes much more utilized than previously forecasted due to the economic benefits of the lower cost natural gas.
- *Milltown Generating Station* – the 10-year plan assumes that the Milltown Generating Station is decommissioned.
- *Carbon / Climate Change Costs* – the current 10-year plan is inclusive of a carbon pricing provision based on the proposed pricing plan issued by the Province of New Brunswick. The prior year 10-year plan did not include a carbon pricing provision in the base results.

Financial Highlights

A summary of the key financial highlights of the 10-year plan is provided in Figure 1 below.

Figure 1: Financial Highlights

Fiscal Year Ending March 31 (in millions $)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Average Rate Increase	2.00%	1.75%	1.75%	1.50%	1.50%	1.50%	1.50%	1.50%	2.00%	2.00%
Gross Margin	1,065	1,115	1,109	1,157	1,137	1,210	1,179	1,213	1,203	1,257
Net Earnings	41	81	72	102	68	134	131	111	53	53
Return on Equity	7.4%	13.1%	10.5%	13.2%	7.9%	13.9%	11.9%	9.1%	4.1%	4%
Capital Expenditures	354	349	352	305	374	292	709	752	775	749
Net Debt	4,884	4,804	4,751	4,646	4,543	4,323	4,463	4,708	4,972	5,209
Change in Net Debt	(19)	(81)	(53)	(104)	(104)	(219)	139	246	264	236
% Debt in Capital Structure	89.5%	88.0%	86.7%	84.8%	83.5%	80.7%	79.3%	78.7%	78.9%	79.1%

Annual rate increases are within a range of 1.50% to 2.0% over the period of the 10-Year plan and result in an annual average increase of 1.70%. The rate increases gradually decline over the initial period of the plan, remaining at 1.50% for a five year period, and then increase in the latter years of the period as a result of the impact of the Mactaquac project costs starting to be included in the annual revenue requirement. The rate increases are required for progress to be made in the debt-to-equity ratio while also working to reduce debt levels over time. The *Electricity Act* calls for NB Power to achieve a minimum debt-to-equity ratio of 80/20. Based on current estimates and the assumed rate increases noted, an 80/20 debt-to-equity ratio is forecasted to be achieved in 2027 and maintained slightly below that level through the remainder of the plan period. The rate increases noted are lower than those estimated in the prior year on account of the changes to key cost estimates that have been previously outlined.

Annual net earnings average approximately $85 million per year over the period the plan. Net income amounts generally increase over time due to the cumulative impact of the assumed annual rate increases and due to other changes in various cost items. Annual net income amounts are however subject to some variability given the impact of the biennial maintenance outages planned for the Point Lepreau Generating Station after 2021. Net income levels decline in the final two years of the plan period as a result of the impact of the costs associated with the Mactaquac project. Overall, the average annual net income amounts are comparable to the prior year 10-year plan but variability exists within the individual years and the comparable average income levels are achieved through lower rate increases.

Debt levels are forecasted to decline in each year of the plan until 2027, reaching a low of just over $4.3 billion. Debt levels begin to increase subsequent to 2026 as a result of the capital expenditures associated with the Mactaquac project.

Financial Commentary

The 10-year plan has been developed based on a balancing of the achievement of the policy objectives set out in the *Electricity Act* while continuing to consider the over-arching principles previously established for the development of the long-term rate strategy. The rate strategy is based on the principles of making steady progress towards the achievement of a minimum capital structure of 20% equity within a reasonable timeframe and maintaining the minimum equity target once achieved, while attempting to maintain rates as low as possible and reducing variability in rate changes from year to year. The current plan forecasts the achievement of the minimum debt-to-equity capital structure in 2027 and illustrates the rate increases that would be required to maintain an equity level slightly below the minimum target throughout the remaining period of the plan.

As has been previously noted, significant uncertainty exists within the 10-year plan. NB Power is subject to significant variability in its annual net earnings and this inherent variability is ever more pronounced in the context of the 10-year plan. This variability has been particularly evident over the past few years as significant cost increases were seen in the creation of the prior year 10-year plan, a number of which have been reduced or alleviated in the current 10-year plan as a result of changing market conditions or market price projections. As the 10-year plan is updated each year based on new estimates for commodity prices, interest rates, and foreign exchange rates, annual variability in the financial projections should be expected. As a result, the 10-year plan should not be viewed as a recommended and finite plan but as an informational tool that provides directional information. At a minimum, the 10-year plan illustrates that the rate increase requested for fiscal 2020/21 is appropriate and consistent with the principles previously established for the development of a long-term rate strategy.

Additional information on details of the 10-year plan and the assumptions contained within can be found in the sections following and in the included appendices.

Corporate Overview

NB Power is a Crown corporation, an agent of the Crown, that is responsible for the generation, transmission and distribution of electricity throughout New Brunswick. With over 2,500 employees across the Province, NB Power is dedicated to providing customer value and supplying energy to over 400,000 direct and indirect customers by way of over 21,000 km of distribution lines, substations, terminals and switchyards that are interconnected by over 6,900 km of transmission lines. NB Power has developed one of the most diverse generation fleets in North America to meet the unique daily and seasonal power needs of New Brunswick. Electricity requirements are supplied by 14 generating stations spread throughout the province, through wind and other third-party power purchase agreements (PPA's), or by importing electricity from neighbouring jurisdictions when markets are favourable.

NB Power has four main operating divisions:

- *Customer Service* – Responsible for delivering safe, reliable and reasonably priced energy to customers
- *Generation* – Maintains and operates the diverse system consisting of 13 hydro, coal, oil, natural gas and diesel-powered generating stations
- *Nuclear* – Maintains and operates the Point Lepreau Nuclear Generating Station (PLNGS), the only nuclear facility in Atlantic Canada
- *Transmission & System Operator* – Responsible for maintaining and operating the terminals, switchyards and interconnected transmission lines, as well as ensuring a reliable system is maintained

A Corporate Services department also exists that provides strategic direction, communications, finance, legal, human resources, supply chain, and other various support services to the rest of the corporation.

New Brunswick Energy Marketing Corporation, a wholly-owned subsidiary of NB Power, conducts energy trading activities in markets outside of New Brunswick, purchases electricity to serve load in and outside New Brunswick, and markets excess energy generated in New Brunswick to other jurisdictions.

As a provincial Crown corporation, the owner and sole shareholder of NB Power is the Government of New Brunswick. NB Power reports to the government through the Minister of Energy and Resource Development. The government's expectations are expressed through legislation, policies and mandate letters.

Additional information on NB Power can be found on our corporate website at www.nbpower.com.

Mandate

NB Power’s mandate is set by the *Electricity Act*. Specifically, section 68 provides direction regarding:

- Rates charged by NB Power for sale of electricity within the province
- The management and operation of NB Power’s resources and facilities for the generation, supply, transmission and distribution of electricity within the province

The *Electricity Act* also establishes that, to the extent practical, rates charged by NB Power for sale of electricity within the province shall be maintained as low as possible and changes in rates shall be stable and predictable from year to year.

In addition, the Minister, by way of a mandate letter, has given NB Power the responsibility for delivery of the following:

- Maintaining and creating jobs in the resource sector in an economically sustainable fashion
- Working with the other Atlantic Provinces and neighbouring jurisdictions to improve regional cooperation
- Working with the federal government in ongoing investment and energy-related issues
- Meeting debt reduction targets as established in NB Power’s 10-year plan
- Protecting and improving the environment

Strategy

NB Power is committed to a vision of sustainable energy for future generations. NB Power’s mission is to be our customers’ partner of choice for energy solutions. There are four core values that are essential to the utility’s success: Safety, Quality, Diversity and Innovation.

Based on the mandate established, NB Power’s Board of Directors and management have developed the strategic direction of the Corporation, taking into consideration emerging risks and opportunities. The strategic objectives established provide the foundation for NB Power’s business plans, investment decisions and business initiatives that will enable the Corporation to continue to provide sustainable energy for future generations. Three strategic objectives have been established to help guide the utility’s actions and to help enable the achievement of the corporate mission and vision.

Strategy One: *Become Among the Best at What We Do*

NB Power remains committed to becoming among the top-performing utilities in North America. For NB Power, becoming a top performer means demonstrating excellence in the strategic areas of safety, customer, organizational, reliability, and environmental. To strengthen the efforts to achieve excellence, NB Power has established an overall Excellence Framework. This framework will help NB Power to chart a path to becoming top quartile in these key areas over time.

Strategy Two: *Reduce Our Debt so We can Invest in the Future*

NB Power has committed to a reduction in debt over the 10-year plan period so that it is in a financial position to invest in new generation and transmission infrastructure when necessary to ensure stable rates for New Brunswickers. This reduction in debt will improve NB Power's capital structure, reduce exposure to rising interest rates, and help ensure there is financial flexibility to make necessary investment decisions in the future.

Strategy Three: *Reduce and Shift Electricity Demand*

New Brunswick's use of energy is highly seasonal and can also swing significantly at certain times of day. The IRP outlines our energy needs for the next 25 years and current projections reflect a need to address supply and demand issues within this time frame. Emerging technology and environmental factors are also introducing significant changes to the energy industry and marketplace. Through this strategy and associated initiatives, NB Power will invest in technology, educate customers and promote efficiencies that will help to reduce and shift demand for electricity and ultimately defer or remove required future investment in generation.

By executing on these three strategic objectives, NB Power will continue to provide value to the Province of New Brunswick and our customers and position ourselves as a North American leader in innovation in the electricity sector. Additional information on NB Power's strategic plan can be found on the NB Power website at the following link: https://www.nbpower.com/en/about-us/accountability-reports/strategic-plans/

Integrated Resource Plan (IRP)

As outlined in the *Electricity Act*, NB Power is required to prepare an IRP that covers a planning period of not less than 20 years and update it at least once every three years. The IRP is a long-term plan that considers economics, the environment, long-term societal interests and various sensitivities of these features. The most recent IRP was completed in 2017 and extends to FY2041/42, a copy of which can be found on the NB Power website at: https://www.nbpower.com/en/about-us/accountability-reports/strategic-plans/

Some of the key considerations and assumptions factored into the 2017 IRP were as follows:

- The IRP included an aggressive but cost-effective, capacity and energy reduction schedule that assumed a savings of approximately 620 MW and 2.3 TWh by 2041/42.
- Through the Province of New Brunswick's *Electricity from Renewable Resources Regulation*, 80 MW of cost-effective Locally-Owned Renewable Energy Projects that are Small Scale (LORESS) community resources and 13 MW of customer-owned Embedded Generation were targeted by 2020. These programs, along with the Energy Smart NB (ESNB) plan will help meet the Regulation's 40 per cent Renewable Portfolio Standard requirement.
- Greenhouse gas (GHG) levels for the IRP planning period remain below 2005 historical levels.
- The IRP assumed that life extensions were completed for the Millbank and Ste. Rose generating stations in response to their planned retirements in 2031 as it was the most economic choice for meeting continued peak load requirements.
- Mactaquac's continued operation was reflected in the IRP through life achievement activities culminating in 2068.[3]
- The PLNGS was assumed to be replaced in-kind upon the end of its assumed life in 2040.

The planning period of the 2017 IRP extends to FY2041/42, which includes the retirement of the Point Lepreau, Belledune and Coleson Cove generating stations. It is recognized that significant investment will be needed to replace these assets and although assumptions have been made around their replacement, it is recognized that NB Power will need to look for opportunities to separate and spread out the required investments over a broader period of time.

IRP analysis is part of a continual process that requires periodic load and resource estimate updates as conditions evolve and change over time. NB Power continues to monitor changes to load and resource options, existing supply technology options and costing, as well as emerging technologies to ensure the latest information is available for subsequent IRP's as the need for new supply requirements approaches.

A summary of the key activities or actions factored into the 2017 IRP to meet future resource requirements is outlined below in Figure 2.

[3] *Analysis supporting the Mactaquac life achievement option has been completed and will be filed with the EUB as part of a separate review application.*

Figure 2: Integrated Resource Plan

Fiscal Year	Integrated Resource Plan	Scheduled Retirements
2018	ESNB plan (-621 MW over period)	
2019		
2020	Embedded Generation (+13 MW) LORESS (+80 MW)	
…		
2025		Grandview (-95 MW)
2026		Grand Manan (-26 MW)
2027		Bayside (-277 MW)
…		
2031	Millbank / Ste Rose (+3 x 99 MW)	Millbank / Ste Rose (-496 MW)
2032		
2033	Mactaquac Life Achievement	
…		
2040	Point Lepreau Replacement-in-Kind (+660 MW)	Point Lepreau (-660 MW)
2041	Natural Gas Combined Cycle (+3 x 412 MW) Millbank / Ste Rose (+2 x 99 MW)	Belledune (-467 MW) Coleson Cove (-972 MW)

In summary, the strategic direction recommended by the 2017 IRP over the immediate term is:

- Continued development of the LORESS and Embedded Generation programs to meet the Renewable Portfolio Standard
- Continuation of the ESNB plan
- Continuation of technical work with regards to new generation options and business models that might be viable in New Brunswick, especially options from customer-owned renewable resources

The assumptions contained within this 10-year plan are consistent with the IRP noted above, with the exception of the volume of energy and demand reductions (DSM) expected to be achieved, which are lower in this 10-year plan. DSM expenditures produce long term benefits but having to fully expense amounts on an annual basis puts increased pressure on the requirement for higher rate increases. As previously noted, given the recent decision to disallow the creation of a regulatory account to recover DSM expenses in rates over a longer period of time, DSM related expenditure levels were modified in this 10-year plan in an effort to reflect the balancing of the achievement of the various financial objectives. Future DSM spending levels will be more fully assessed during the next IRP update which is scheduled to occur over the course of the next year.

Key Assumptions / Sensitivities

The assumptions incorporated into this 10-year plan were compiled based on a combination of information obtained from internal resources, market indications and from external consultants or publications. A listing of key assumptions is provided in Appendix A. A table outlining the 10-year plan's sensitivity to changes in certain significant key assumptions is presented in Appendix B.

Material Risks & Uncertainties

In the normal course of operations, NB Power's net earnings can vary significantly from forecasted results due to changes in factors such as fuel and purchased power prices, foreign exchange rates, interest rates, weather, hydro flows and various other risk items. Some of the key factors that could significantly impact actual results are as follows:

Point Lepreau Nuclear Generating Station Capacity Factor – fuel and purchased power costs could differ materially if the assumed PLNGS capacity factor is not achieved.

Hydro Generation – the 10-year plan is based on expected long-term median hydro flows. When actual hydro flows are below anticipated levels, other more expensive fuels are used to account for the generation shortfall and when hydro flows are higher than forecast, surplus hydro generation reduces the use of more expensive fuels and decreases overall generation costs. Hydro flows that differ substantially from long-term average can therefore materially impact fuel and purchased power costs.

Export Contracts – the 10-year plan assumes that NB Power will renew certain existing export contracts as they expire and achieve certain margins on these contracts. Failure to be the successful bidder of these contracts or to renew at forecasted margin levels will impact results.

Market Conditions – volatility in near-term fuel and purchased power prices and the Canadian dollar is largely managed through NB Power's financial hedging program. In the mid to long-term, NB Power is however exposed to changes in commodity prices and exchange rates.

Natural Gas Supply – fuel and purchased power costs are based on current estimates for the future pricing of natural gas. This 10-year plan also assumes that natural gas is able to be sourced from Western Canada as a result of long-term pipeline commitments being contracted. The financial results reflect the costs and benefits of this fuel source to the end of 2026, the current end of life of the Bayside Generating Station. As a final decision has not yet been made on the long-term operations of the Bayside Generating Station and on how the pipeline commitment will be utilized post 2026, the current plan does not assume any costs or benefits associated with these pipeline commitments after 2026. As such, results will either be positively or negatively impacted post 2026 once a plan has been finalized on how best to utilize the transport commitment. Variations in the actual supply and price of natural gas from assumptions will therefore result in fluctuations in fuel and purchased power costs.

Economic Conditions – if future load growth falls short of the forecast or if there are unanticipated industrial closures, or conversely, if new load is added that is not included in the load forecast then this could materially impact forecasted in-province revenue.

Interest Rates – given NB Power's debt levels, volatility in interest rates can have a significant impact on results as existing debt issues mature and need to be refinanced, as new debt needs to be issued to cover significant capital expenditures and/or as short-term debt costs fluctuate based on market movements.

Used Nuclear Fuel Management and Decommissioning – liability and funding estimates for used nuclear fuel management reflect current engineering estimates and standards. These estimates include cash flows which extend out over 150 years and are therefore subject to change. Revised estimates could impact annual used nuclear fuel management and decommissioning costs, as well as overall funding requirements.

Regulatory Framework - the *Electricity Act* includes a regulatory framework that subjects all of NB Power to oversight by the EUB and requires NB Power to seek annual approval of its rates (regardless of the amount of any rate change). All of the forecasted annual rate increases included in this 10-year plan are therefore subject to EUB approval. If some portion of the forecasted rate increases were ultimately not approved, then revenue projections could vary materially. A reduction in a forecasted rate increase in the earlier years of the 10-year plan can significantly impact results over the duration of the plan due to the cumulative impact that a rate adjustment can have in future years.

Mactaquac Project - projected net earnings and debt levels are subject to change based on final approval of the proposal to pursue the Life Achievement option for the Mactaquac Hydro Generating Station. Changes to the recommended approach or cost estimates could lead to a difference in the timing and magnitude of capital expenditures and expenses than what is otherwise assumed in the 10-year plan.

Advanced Metering Infrastructure (AMI) Capital Project – projected financial results are subject to change based on NB Power's reapplication of the Advanced Metering Infrastructure business case and assumed approval by the EUB. A change in the timing and nature of the decision could lead to different financial results than what is currently assumed in the 10-year plan.

System Reliability and Risks – the 10-year plan is based on specific assumptions around planned plant maintenance outages and interconnection opportunities with neighbouring utilities. Any unplanned interruption of generation facilities or interconnection points may result in additional costs to NB Power for fuel and purchased power.

Advanced / Disruptive Technology – new technology continues to emerge that has the potential to change existing operations. Such technology could result in increased opportunities from new products and services but could also result in reduced future revenue from existing sources and the potential for stranded assets should a significant decline in load and energy requirements occur over time.

Major Weather Events – financial results can be impacted materially due to severe weather events which can result in lengthy unplanned outages and significant restoration costs.

DSM Spending – financial results are subject to change should DSM spending levels differ over the forecast period. Changes to the DSM spending levels would impact in-province revenue, fuel and purchased power costs, and OM&A expenses which could materially impact results.

Carbon / Climate Change Costs – the base 10-year plan includes a provision for the potential cost of carbon emissions based on the proposed carbon pricing system that was submitted to the federal government as a made-in-New Brunswick alternative to the federal government's backstop output-based pricing system. The federal government is currently assessing the proposed plan and if not accepted, then NB Power would be subject to higher carbon costs under their pricing system. The implementation of other climate change actions, such as the early phase out of coal generation, during the forecast period could also materially impact fuel and purchased power costs, export revenues, depreciation expense, and/or future capital expenditure requirements.

Revenue Requirement

NB Power's costs are driven by the cost of fuel and purchased power, costs required to run and maintain operation of the utility, capital investments, costs required to finance operations and investments, and the recovery of regulatory deferral account balances. NB Power's forecasted revenues, expenses and net earnings for the 10-year plan period are presented below in Figure 3.

Figure 3: Forecasted Revenue Requirement

Fiscal Year Ending March 31 (in millions $)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Revenue										
Sales of Power										
In-Province	$ 1,496	$ 1,530	$ 1,567	$ 1,616	$ 1,643	$ 1,669	$ 1,699	$ 1,727	$ 1,767	$ 1,805
Out-of-Province	196	179	183	170	174	179	169	167	171	176
Miscellaneous	88	87	89	90	94	99	102	106	111	113
Total Revenue	**1,780**	**1,795**	**1,839**	**1,876**	**1,910**	**1,947**	**1,970**	**2,000**	**2,049**	**2,093**
Expenses										
Fuel and Purchased Power	625	590	637	629	679	637	689	681	734	724
Operations, Maintenance and Administration	507	511	524	531	529	546	542	557	562	582
Depreciation	332	341	342	350	353	353	347	373	403	418
Taxes	49	50	51	52	53	54	56	57	58	59
Total Expenses	**1,515**	**1,496**	**1,558**	**1,563**	**1,614**	**1,590**	**1,633**	**1,668**	**1,757**	**1,783**
Earnings before Undernoted Items	265	299	281	313	296	357	337	332	292	311
Finance Charges and Other Income	210	207	198	195	187	182	166	179	196	212
Net Changes in Regulatory Balances	14	12	10	16	40	42	40	41	43	45
Net Earnings	**$ 41**	**$ 81**	**$ 72**	**$ 102**	**$ 68**	**$ 134**	**$ 131**	**$ 111**	**$ 53**	**$ 53**

Sales of Power - In-Province

Load in New Brunswick is forecasted to grow by approximately 0.6% per year during the 10-year plan period. Normal growth is partially offset by the impact of ESNB programs. Refer to the In-Province Load section for additional information on forecasted load requirements and load growth. The increase over the period to in-province sales is largely related to the assumed rate increases implemented. Annual rate increases ranging between 1.5% and 2.0% are modelled during the 10-year plan period in pursuit of achieving and maintaining a minimum capital structure of at least 20% equity. Planned rate increases are however uncertain as future costs can be heavily impacted by the various factors outlined in the Material Risks & Uncertainties section.

Sales of Power - Out-of-Province

NB Power takes advantage of its geographical location and diverse generation mix to sell surplus energy into neighboring jurisdictions such as Prince Edward Island, Nova Scotia, Quebec and New England. Out-of-province sales benefit in-province customers by keeping rates lower than they otherwise would be as a result of the positive margin generated by the sales opportunities. The 10-year plan assumes that certain export contract relationships are maintained over time and that excess capacity is used to export energy when it is economic to do so. Management has used its best estimate on the expected ability to retain or renew existing export contracts for the forecast period, considering NB Power's historical relationship with external parties and any competitive advantage in the marketplace that NB Power may have. The 10-year plan does not reflect new export contracts or other sales arrangements, but is reflective of forecasted changes in export load requirements.

Out-of-province sales revenue declines initially over the forecast period due to assumed contract renewal pricing and the estimated impact of an increasingly competitive marketplace. Sales amounts then generally increase over time due to increasing fuel and purchased power supply costs required to supply the assumed export load requirements which impacts the assumed sales pricing. Out-of-province sales are impacted on a year-over-year basis as a result of the biennial maintenance outages planned at PLNGS (post 2021).

Miscellaneous Revenue

Miscellaneous revenue is comprised mainly of revenue derived from water heater rentals, transmission tariffs, connection and surcharge fees, pole attachment fees, third-party work performed for other utilities, customer contributions and forecasted margins for new products and services. The 10-year plan includes a high-level estimate for increases in margin attributed to new products and services. The amount and timing of these increases are subject to change, depending upon the success and ultimate timeline of the specific offerings to be marketed. Miscellaneous revenue increases over the period mainly due to the forecasted increase in new products and services margin, increased transmission tariff revenue, and other general increases due to assumed escalation.

Fuel and Purchased Power

Fuel expense reflects the cost of oil, coal, petroleum coke, natural gas, and diesel fuel used in NB Power's thermal stations, as well as the cost of uranium used at the PLNGS. NB Power also purchases energy and capacity under long-term agreements from wind, hydro, biomass and natural gas generators in the province, as well as through market electricity purchases from utilities in neighbouring jurisdictions.

Fuel and purchased power expense variances over the forecast period are driven by:

- Changes to in-province load and export sales volumes
- Changes to forecasted commodity prices, market prices, and foreign exchange rates
- Changes in the availability and source of a natural gas supply
- Biennial maintenance outages at PLNGS (post 2021)
- Maintenance outage cycles at Belledune
- Changes to sources of supply due to the scheduled retirements outlined in the IRP

As previously noted, fuel and purchased power expense is based on an estimate of future commodity prices, market prices, and foreign exchange rate assumptions at the time of the preparation of the 10-year plan. Changes to these assumptions can have a material impact on forecasted fuel and purchased power expense.

Operations, Maintenance & Administration (OM&A)

OM&A includes labour, materials, hired services, travel, insurance and other costs associated with operating and managing the utility. NB Power is committed to continuous process improvement and cost management by way of process reviews and efficiencies, regional collaboration, technology improvements and automation.

Generally, OM&A expense is expected to increase annually by inflation throughout the 10 years, which is forecasted at 2.0%. Other year-over-year fluctuations are largely reflective of the implications of the maintenance outage cycles for PLNGS and Belledune, which result in a higher allocation to capital assets during an outage year, changes in estimated requirements at PLNGS, and changes in annual spending related to ESNB related activities. Increases in OM&A expense are partially offset by an assumed increase in process improvement savings, driven both by savings from ESNB related initiatives and a commitment to continuous improvement. Over the period of the 10-year plan, the amounts for process improvement savings increase from roughly $30 million to over $50 million annually, inclusive of savings from strategic sourcing initiatives and those associated with the forecasted rollout of AMI.

Depreciation

Depreciation expense is driven by NB Power's investment in capital assets and is based on expected useful service lives and the straight-line method of depreciation. Depreciation expense also reflects a component of charges to income to account for the future decommissioning of generating stations and the management of used nuclear fuel. Depreciation expense varies over the forecast period due to ongoing investments in generating stations, ESNB related capital expenditures, and investments in transmission and distribution (T&D) infrastructure. Depreciation expense increases at the end of the period primarily as a result of the commencement of depreciation of the Mactaquac project.

Taxes

NB Power is subject to property tax, utility tax and right of way tax. Taxes are assumed to generally escalate at 2.0% per year during the forecast period.

Finance Charges and Other Income

NB Power uses a combination of long and short-term debt to finance its operations and all principal and interest is payable to the Province of New Brunswick. NB Power incurs a debt portfolio management fee (0.65% of debt outstanding at the end of the prior fiscal year) that is also payable to the Province as a result of these borrowing arrangements.

Other components of finance charges and other income partially offset interest expense and the debt portfolio management fee. These include earnings on investment and sinking funds, as well as interest during construction which capitalizes interest on funds expended on capital projects not yet in service (i.e. work-in-progress). Finance charges also include an expense that recognizes the time value of money on the estimated expenditures for decommissioning and used nuclear fuel management liabilities. This is referred to as accretion expense and essentially represents an annual interest charge on these forecasted liability balances.

During the 10-year plan period, both long and short-term interest rates are expected to increase, resulting in higher interest expense. Accretion charges also increase over time due to increasing liability balances. These cost increases are offset , or partially offset in some years, by a reduction in overall debt levels and higher earnings on the investment and sinking funds. Finance charges start to increase towards the end of the period due to a portion of the finance costs associated with the Mactaquac project no longer being capitalized to the project as certain components are assumed to be brought into service.

Net Changes in Regulatory Balances

The annual net changes in regulatory balances amount is mainly driven by the two existing regulatory accounts and one regulatory account assumed to be established. The regulatory accounts impacting the 10-year plan results are as follows:

- *PLNGS Refurbishment (existing)* - Pursuant to the *Electricity Act*, certain costs incurred during the PLNGS refurbishment outage were accumulated and capitalized as a regulatory asset and are now being amortized and recovered from customers on a levelized basis over the life of the refurbished station (assumed to be 2040). The expense amount for this account increases over time as the assumed finance charges associated with the deferral amount decline as amounts are recovered from customers.

- *PDVSA Settlement*[4] *(existing)* - In August 2007, the EUB approved the implementation of a regulatory deferral account to enable the savings associated with the lawsuit settlement with PDVSA to be provided to customers on a levelized basis over a period of 17 years to 2024. In 2025, the net changes in regulatory balances amount increases as the benefit allocated to customers resulting from the PDVSA settlement is completed in 2024, while actual benefit amounts are recognized over the assumed life of the Coleson Cove Generating Station (2041).

- *Meter Write-Off (proposed)* - As part of the forecasted rollout of AMI, certain existing meter costs are expected to be written off as existing meters are removed from service and replaced with smart meters before the end of their assumed life. For planning purposes, a portion of these expenses have been assumed to be deferred and the expense recognized evenly over the five year period between 2022 to 2026. The establishment of this deferral account will require regulatory approval by the EUB.

[4] Petróleos de Venezuela, S.A.

In-Province Load

During the summer of 2019, NB Power completed a 10-year Load Forecast for the FY2020/21 to FY2029/30 period. The key assumptions used in this forecast include:

- Average Gross Domestic Product growth of 0.8 per cent annually based on the provincial government's *Economic Outlook* released in March 2019
- Known major industrial additions and load changes based on account manager input and public announcements
- The addition of approximately 20,000 new year-round residential customers by FY2029/2030 based on historical customer growth trends and population projections
- Normal weather (4,618 heating-degree-days) based on a rolling average using the latest 30 years
- Penetration of electric space heating, water heating and air conditioning based on NB Power's 2018 Energy Planning Survey of residential customers
- Estimates of energy reductions from NB Power's ESNB initiative, as well as non-program driven energy conservation savings

Figure 4 shows the total forecasted in-province load and year-over-year growth.

Figure 4: Forecasted In-Province Load

Fiscal Year Ending March 31 (in GWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
In-Province Load										
Residential	5,351	5,379	5,407	5,433	5,438	5,453	5,467	5,485	5,503	5,521
Industrial	4,258	4,303	4,387	4,630	4,624	4,620	4,613	4,606	4,600	4,591
General Service	2,349	2,364	2,370	2,377	2,374	2,374	2,377	2,380	2,387	2,390
Wholesale	1,268	1,277	1,283	1,290	1,297	1,302	1,308	1,313	1,317	1,324
Street Lights	44	45	45	45	46	46	46	47	47	47
Sub-total	13,270	13,368	13,493	13,775	13,778	13,796	13,811	13,831	13,854	13,873
LIREPP	326	339	356	378	410	455	495	499	499	499
System Losses	840	845	855	865	865	862	868	870	872	873
Total In-Province Load	**14,436**	**14,552**	**14,704**	**15,018**	**15,053**	**15,112**	**15,174**	**15,201**	**15,225**	**15,246**
In-Province Load Growth										
Residential	(1%)	1%	1%	0%	0%	0%	0%	0%	0%	0%
Industrial	1.8%	1.1%	2.0%	5.52%	(0%)	(0.1%)	(0.2%)	(0.2%)	(0.1%)	(0.2%)
General Service	0.99%	0.66%	0.27%	0.26%	(0.1%)	0.02%	0.10%	0.16%	0.27%	0.14%
Wholesale	0.24%	0.7%	0.5%	0.5%	0.5%	0.4%	0.4%	0.43%	0.27%	0.53%
Street Lights	0.8%	0.9%	0.9%	0.9%	0.9%	0.9%	0.4%	0.86%	0.43%	0.85%
Total In-Province Load Growth	**0.5%**	**0.7%**	**0.9%**	**2.1%**	**0.0%**	**0.1%**	**0.1%**	**0.1%**	**0.2%**	**0.1%**

In-Province Revenue

Average forecasted annual rate increases, and the resulting revenue based on the sales projections detailed in Figure 4, are outlined below in Figure 5. Overall load growth contributes to increases over the period of the plan but the annual increases in revenue are largely driven by the assumed annual rate increases. Variances in the assumed annual rate increases can have a significant impact on financial results. A 1% increase in the initial year of the plan is equivalent to approximately $14.5 million and has a cumulative impact to in-province revenue over the plan period in the range of $160 million based on the assumed rate increases. A 1% variance in rates is equal to roughly $18 million per year by the end of the plan period based on the assumed rate increases.

Future rate increases will vary by customer class as NB Power continues to move toward all customer classes being within a revenue-to-cost ratio of 0.95 – 1.05 (range of reasonableness). Although future rate increases may be different by rate class, the overall aggregate increase will equal the average rate increase.

Figure 5: Forecasted Annual Rate Increases & In-Province Revenue

Fiscal Year Ending March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Rate Increase	2.00%	1.75%	1.75%	1.50%	1.50%	1.50%	1.50%	1.50%	2.00%	2.00%
Total In-Province Sales of Power ($millions)	$ 1,496	$ 1,530	$ 1,567	$ 1,616	$ 1,643	$ 1,669	$ 1,699	$ 1,727	$ 1,767	$ 1,805

Capital Plan

The 10-year plan calls for total capital expenditures of approximately $5 billion over the next 10 years. This total is inclusive of part of the provision for Mactaquac in the range of $1.9 billion. A final decision on the life achievement option for Mactaquac requires a regulatory review and approval process.

NB Power is also planning to invest in technologies and processes to support the ESNB plan over the period of the 10-year plan. Additional ongoing investments will also be required to maintain, upgrade and expand the generation and T&D assets that generate and deliver electricity to customers throughout the province. Life extension projects for the Belledune and Coleson Cove generating stations appear in the latter part of the plan. A breakdown of forecasted capital spending is provided in Figure 6.

Figure 6: 10-Year Capital Plan

Fiscal Year Ending March 31 (in millions $)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Major Projects										
Mactaquac	$ 19	$ 19	$ 11	$ 24	$ 61	$ 69	$ 456	$ 389	$ 422	$ 428
Belledune	-	-	-	-	2	6	10	66	-	-
Coleson	-	-	-	-	-	2	6	32	30	23
Energy Smart NB Projects										
Smart Grid Technology & Capabilities	8	16	15	7	3	1	2	2	2	2
Advanced Metering Infrastructure	11	22	29	10	0	1	0	0	0	0
Digital Communications Network	1	1	1	1	1	1	1	1	1	1
Smart Communities	24	7	3	0	0	0	0	0	0	0
Intangible Expenditures	17	9	8	6	2	2	1	1	1	1
Major Outage/Inspection Expenditures	65	60	47	36	83	25	50	69	75	37
Intangible Expenditures	2	4	8	8	3	0	6	0	0	
General Capital Expenditures	208	212	229	214	218	185	178	191	243	257
Total Capital Expenditures	**$ 354**	**$ 349**	**$ 352**	**$ 305**	**$ 374**	**$ 292**	**$ 709**	**$ 752**	**$ 775**	**$ 749**

Mactaquac

A major capital project during the 10-year period revolves around the future of Mactaquac. Mactaquac produces about 1.6 TWh annually and can produce 672 MW at full capacity. Since it was constructed in the late 1960's, the Station has provided New Brunswickers with low cost, reliable, emission free energy. In the 1980's, however, it was determined that a condition known as Alkali Aggregate Reaction (AAR) was causing the concrete in the structures to slowly expand. The AAR growth rate has been steady and sustained over the past four decades. The present expected end of service life for the concrete structures at the station with the current maintenance program is approximately 2030 based on engineering estimates, while the original intended lifespan of Mactaquac was approximately 2068.

NB Power has evaluated options for addressing the projected condition of the concrete structures and equipment and decided to pursue the option to operate the current concrete facilities beyond 2030 to approximately 2068, through a modified intensive maintenance program and replacement of aged equipment ("life achievement").

As noted in last year's plan, there are various approaches associated with the life achievement option, with different spending amounts and varying timing for capital expenditures. Consistent with the prior year, this year's plan assumes a total project cost that is in the middle of the range of forecasted base expenditures for life achievement. Additionally, more funds have been allocated early in the project timeline to better reflect expected expenditures in those years.

In the coming years, NB Power will refine its plan and seek appropriate environmental and capital expenditure approvals.

Belledune & Coleson Cove Generating Station Life Extensions

The 10-year plan includes provisions for the assumed life extensions of the Belledune and Coleson Cove generating stations. The life extension of these facilities is consistent with the assumptions utilized in the development of the 2017 IRP. The provisions included are preliminary estimates and the amounts and the timing of the expenditures will be subject to further refinement over time.

Energy Smart NB

Energy Smart NB (ESNB) is a long-term plan with the goal to fulfill the strategic objective of reducing and shifting in-province demand for electricity and therefore ultimately deferring the next significant generation investment. The ESNB plan includes three interrelated components:

- *Smart Grid* - Grid modernization technology and software, including engineering and design work, along with the internal process changes and enhanced business capabilities required to implement and optimize the technology

- *Smart Habits* - DSM, including energy efficiency and demand response programs

- *Smart Solutions* - New products and services that leverage both DSM initiatives and smart grid technology, engage consumers as more active participants in managing energy, and serve as new revenue streams for NB Power

Smart Grid is the focus of investments in the capital plan. New "smart" technologies are available that can improve the efficiency, flexibility and reliability of the grid while enabling important new benefits. By modernizing the grid, NB Power can better understand how and when energy is being consumed and use that information to operate more efficiently, as well as provide customers with better service, new energy-saving products and services, and more flexible rate plans. In addition, grid modernization lays the foundation for a wide range of reliability benefits, including more efficient outage response, which can greatly aid in storm restoration, and enhanced ability to detect and correct issues on the grid before they affect customers.

Smart Grid is also essential to the expansion of renewable and distributed energy sources. As more variable energy sources are connected to the grid, NB Power will face greater challenges in managing that variability to balance supply and demand while maintaining the stability of the grid. By building smart technologies into the grid, NB Power can support greater customer participation in renewables while also improving reliability and efficiency and offering customers more choice, control, and convenience as well.

A subset of Smart Grid is Smart Energy Communities. This includes three smart energy community projects that will contribute to the design, enablement and success of NB Power's ESNB programs. This will occur by NB Power deploying and testing new smart energy technologies and rate schemes, while working with Siemens to build new cloud-based software platforms that control and optimize Distributed Energy Resources (DER's) to minimize their impact on the local grid, lessening the need for peaking power plants and increasing resiliency for customers. This will facilitate DER's adding positive value to both consumers and the overall grid and result in more clean energy, lower system costs, improved resilience, and active consumer engagement.

AMI is a foundational technology required to modernize the grid. AMI enables a wide range of benefits made possible by a secure, two-way flow of digital communications. Among many benefits, it provides usage information to customers so that they can manage their bills. It also enables time-variant pricing to encourage load shifting, supports demand response programs for reducing and shifting load, and provides visibility to customer outages. Within NB Power's day-to-day operations, AMI will also increase efficiency of meter data collection, billing and disconnects/reconnects. Power restoration times will also improve as a result of immediately knowing when a customer's power is out and having access to additional information to better pinpoint the cause of the outage.

Grid modernization efforts comprise the foundation enabling investments in ESNB infrastructure. This infrastructure supports development of efficiency and demand response programs, and development of products and services that drive revenue program and operational improvements in the field. In turn, the revenue programs, efficiency and demand response programs, and operational improvements drive customer benefits, which include lower costs and higher quality service.

Major Outage / Inspection Expenditures

Major outage and inspection expenditures are the forecasted costs for planned maintenance outages and inspections at NB Power's nuclear and thermal generating stations. These costs reflect periodic outage assumptions for PLNGS, Belledune, and Coleson Cove, as well as various other outage costs associated with the remaining thermal facilities.

General Intangible Expenditures

General intangible expenditures reflect forecasted costs associated with various planning and management software systems. Spending over the period reflects requirements to implement, upgrade or refurbish these systems over time.

General Capital Expenditures

NB Power's 10-year capital plan has been developed through the corporate-wide adoption of a standard project management methodology. This includes a robust process during the identification phase of projects and factoring continuous improvement into future capital planning. NB Power's investment governance framework includes capital review committees at both the corporate and divisional levels. The corporate level committee is responsible for oversight of the framework and both the corporate and the divisional level committees are responsible for vetting capital requirements within the 10-year plan.

NB Power is forecasting general capital expenditures of an average of approximately $213 million per year over the next 10 years. Continuous investments are required in the generating stations and T&D system to ensure reliability, the safety of employees and the public, and to meet expected customer growth in the province. Annual expenditures on information technology, communications equipment, vehicles, tools and equipment are necessary to support day-to-day operations.

In addition to ongoing capital investments made to sustain daily operations, NB Power also considers capital investments that are intended to provide future economic benefits (i.e. will reduce operating costs and/or increase revenues). NB Power's investment governance process evaluates potential projects across the organization to determine which projects should be included in the capital plan within available capital and human resource constraints.

NB Power's capital projects and programs can largely be categorized as follows:

- *Asset Reliability Projects* - Include generation facility, substation, terminal and T&D system reliability and upgrade projects to address equipment aging, obsolescence and reliability improvements. Also included in this category are vehicle purchases, tools and equipment, and property improvements.

- *Obligation-to-Serve Projects* - Include work in response to customer demands, water heater purchases and a portion of planned system improvements that are related to load growth, joint use (i.e. used by other utilities in the province) and load shift projects.

- *Safety and Regulatory Compliance Projects* - Include replacement of deteriorated assets which are a potential safety risk and projects that are required to maintain operating licenses or meet regulatory requirements (i.e. PLNGS).

- *Asset Optimization/Productivity Projects* - Include improvement projects that typically have a short payback period and provide net benefits and present value savings to the organization.

Carbon Pricing & Emission Regulation

In June 2019, the Government of New Brunswick released “Holding Large Emitters Accountable: New Brunswick’s Output Based Pricing System”. This proposed carbon pricing system was submitted to the federal government as a made-in-New Brunswick alternative to the federal government’s backstop output-based pricing system (OBPS), as contemplated by the Pan-Canadian Framework on Clean Growth and Climate Change. The proposed New Brunswick carbon pricing system sets a price for CO2 equivalent (CO2e) emissions from generators that emit more than 50 kilo tonnes of emissions annually and exceed the following output-based standards:

- For generators using solid fuels: 820 t/GWh in 2019, 811 t/GWh in 2020, 802 t/GWh in 2021 and 793 t/GWh in 2022
- For generators using liquid fuels: 800 t/GWh in 2019, 795 t/GWh in 2020, 790 t/GWh in 2021 and 785 t/GWh in 2022
- For generators using gaseous fuels: 420 t/GWh for all years

The price on emissions from generators that exceed the limits will start at $20/tonne in 2019 and rise by $10/tonne each year to a final price of $50/tonne in 2022.

The New Brunswick carbon pricing system has been integrated into the dispatch within the fuel and purchased power simulations and estimated amounts are included in fuel and purchase power costs. The annual amounts included in the 10-year plan range from approximately $3 to $8 million per year and total around $65 million over the plan period.

The federal government is currently assessing the New Brunswick government’s carbon pricing plan. If the plan is not accepted, NB Power may be subject to the federal OBPS which would consider the following emission intensity standards[5] :

- For generators using solid fuels: 800 t/GWh in 2019, 650 t/GWh in 2020, declining linearly to 370 t/GWh in 2030
- For generators using liquid fuels: 550 t/GWh for all years
- For generators using gaseous fuels: 370 t/GWh for all years

Given the difference in the emission intensity levels, NB Power would be subject to higher costs should the New Brunswick government’s carbon pricing plan not be accepted and NB Power was subjected to the federal OBPS. The impact of this would be significant as preliminary estimates completed indicate additional cost impacts in the range of $3 to $67 million per year, with an estimated cumulative impact of close to $380 million over the plan period.

It is recognized that the future of carbon pricing and emission regulation remains highly uncertain. NB Power continues to participate in the national and provincial conversations on the matter to better understand the impacts on NB Power and its customers of whatever course is taken

[5] Source: https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/pricing-pollution/obps-regulatory-proposal-en.pdf

by the provincial and federal governments. Currently the focus is on the near term impacts from any federal or provincial carbon pricing plan. Further uncertainty however also exists over the medium to long-term, if the proposed standards on the early phase out of coal come into force. An accelerated coal phase out would lead NB Power to pursue mitigating options such as, but not limited to, pursuing alternative fuel options at the Belledune generating station, carbon capture technology adoption, assisting government in negotiating an equivalency agreement, or potentially closing the Belledune generating station around 2030. All are possibilities, some of which could be combined, but each potentially bearing a significant cost.

Scenario Analysis

As has been identified, the forecasted financial results within the 10-year plan period are susceptible to change and volatility as a result of a variety of material risks and uncertainties. Some of the impacts to changes in key assumptions can be found in the sensitivity table provided in Appendix B or have been identified in various sections throughout the 10-year plan.

To demonstrate the potential effect on forecasted financial outcomes, a scenario analysis was completed to assess the impact of reasonable variations in the following assumptions:

- *Hydro generation* – a higher or lower hydro generation amount of roughly 150 GWH, equivalent to a one standard deviation in the long-term median generation amount
- *Nuclear generation* – an improvement to the forced loss rate of 2% or an additional 2 weeks of outage time during the outage years
- *In-Province load* – a higher or lower in-province load forecast based upon the mean average per cent error that has been seen in historical load forecasts
- *Carbon costs* – the inclusion of additional costs based on the estimated differential between the proposed carbon pricing system of the New Brunswick government versus the federal OBPS.

These items were chosen for scenario analysis purposes as they have historically proven to cause intra-year variability in financial outcomes or with respect to carbon costs, have the potential to directly impact results in the near future. These items are however only a few of the variables that can significantly impact the future financial results of NB Power and the potential cost impacts to customers. This analysis is not intended to be all encompassing, but to demonstrate the impact of a few key variables and highlight that future forecasted results are subject to change.

Best and worst credible case scenarios were then developed based on the change in assumptions. The positive case scenario assumed high in-province load, high hydro output and an increase in the capacity factor for PLNGS. In contrast, the negative case scenario assumed low in-province load, low hydro output, an increase in the outage days for PLNGS, and the inclusion of carbon costs based on the federal OBPS in forecasted requirements. The current 10-year plan, based on forecasted assumptions (the “base case”), was then compared to the positive and negative scenarios.

The analysis completed identified the following:

- In the absence of any rate changes, the debt-to-equity ratio would end up at roughly 94/6 at the end of the plan period under the negative case scenario
- In order to end up with a similar debt-to-equity ratio as the base case by the end of the plan period, the negative case scenario would require an additional annual rate increase of approximately 0.93% for all years (average annual rate increase of roughly 2.63%)
- In the absence of any rate changes, the debt-to-equity ratio would end up at roughly 71/19 at the end of the plan period under the positive case scenario
- In order to end up with a similar debt-to-equity ratio as the base case by the end of the plan period, the positive case scenario would enable an annual rate reduction of approximately 0.55% for all years (average annual rate increase of 1.15%)

Appendix C provides a summary of the key financial measure results under the various scenarios, with and without a change to the proposed rate increase strategy. Several charts have also been provided to present the impact on net debt, the capital structure, and the impact to rates.

Appendix A – Key Assumptions

Figure 7: Key Assumptions

Fiscal Year Ending March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Financial, Economic & Market Assumptions										
Consumer Price Index	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Average Rate Increase	2.00%	1.75%	1.75%	1.50%	1.50%	1.50%	1.50%	1.50%	2.00%	2.00%
Short-term Interest Rates	2.00%	2.30%	2.30%	2.30%	2.40%	2.60%	2.80%	2.80%	2.80%	2.80%
Long-term Interest Rates	3.70%	4.10%	4.10%	4.10%	4.30%	4.40%	4.60%	4.60%	4.60%	4.60%
Foreign Exchange Rate ($CDN/$US)	0.75	0.75	0.75	0.77	0.79	0.81	0.83	0.83	0.83	0.83
Heavy Fuel Oil Price ($US/bbl) [1]	58.81	60.68	60.23	60.17	60.02	59.87	59.72	61.12	62.72	64.90
Coal Price ($US/ton) [1]	77.52	84.02	90.59	84.18	81.10	78.01	74.92	76.59	78.33	80.15
Petcoke Price ($US/ton) [1]	80.00	75.00	75.00	81.09	79.20	77.30	75.41	77.05	78.74	80.50
NYMEX Natural Gas Price - Winter ($US/mmbtu) [1]	2.78	2.78	2.82	3.87	4.00	4.08	4.15	4.23	4.32	4.42
NYMEX Natural Gas Price - Summer ($US/mmbtu) [1]	2.52	2.52	2.52	3.46	3.62	3.72	3.77	3.84	3.92	4.00
AGT Natural Gas Price - Winter ($US/mmbtu) [1]	7.02	7.10	7.14	7.46	8.02	8.61	9.23	9.41	9.60	9.80
AGT Natural Gas Price - Summer ($US/mmbtu) [1]	2.52	2.56	2.55	3.05	3.33	3.61	3.85	3.92	4.01	4.09
Mass Hub Electricity Price - Winter ($US/MWh) [1]	56.35	54.97	55.60	58.99	62.39	65.79	69.19	70.06	71.76	73.00
Mass Hub Electricity Price - Summer ($US/MWh) [1]	28.52	29.03	27.59	30.67	33.75	36.83	39.91	40.54	41.50	42.76
Continuous Improvement Savings ($ millions)	(30)	(32)	(38)	(50)	(52)	(54)	(53)	(54)	(55)	(56)
Carbon Pricing Provision ($ millions)	3	5	6	5	6	7	8	8	8	8
Load & Generation Assumptions										
In-Province Sales (GWh)	13,270	13,368	13,493	13,775	13,778	13,796	13,811	13,831	13,854	13,873
Out-of-Province Sales (GWh)	2,505	2,293	2,311	2,116	2,028	2,242	1,958	1,991	1,941	2,035
Point Lepreau Capacity Factor	82%	96%	82%	96%	82%	96%	84%	96%	80%	96%
Hydro Generation (GWh)	2,775	2,765	2,761	2,765	2,765	2,765	2,756	2,700	2,700	2,700
Thermal Generation (GWh)	3,771	3,712	4,471	4,266	4,522	5,256	4,247	3,717	4,400	4,144
Nuclear Generation (GWh)	4,766	5,550	4,714	5,566	4,714	5,550	4,866	5,566	4,638	5,550
Purchases (GWh)	5,453	4,612	4,852	4,220	4,739	3,387	4,835	4,774	4,999	4,447
Total Sources of Supply (GWh)	**16,765**	**16,639**	**16,798**	**16,817**	**16,740**	**16,959**	**16,704**	**16,756**	**16,737**	**16,842**

[1] *Prices identified are representative of assumed market price indications, not the final cost to NB Power. Additional adjustments to prices would be made to indications noted to result in final costs included in the forecasted results based on contractual terms, historical adders / discounts, or managements best estimate.*

Appendix B – Sensitivity Table

Figure 8: Sensitivity Table

Fiscal Year Ending March 31 (in millions $)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1% Change in Rate Increase (annual impact)	14.7	15.1	15.5	16.0	16.2	16.5	16.8	17.1	17.4	17.8
$0.05 Change in Foreign Exchange Rate ($CDN/$US)[1]	1.5	12.3	14.9	16.5	16.6	15.0	18.1	17.6	20.0	19.1
$1.00 Change in Natural Gas Prices	5.5	11.1	19.1	19.3	17.9	14.6	0.0	0.0	0.0	0.0
$5.00 Change in Coal and Petcoke Prices[1]	2.7	5.3	4.4	4.7	5.6	6.7	8.3	7.0	8.7	8.0
$5.00 Change in Purchased Power Prices[1]	5.6	7.1	8.1	5.3	11.1	8.3	15.3	15.2	16.2	13.6
10% Change in Sales Price of Exports[1]	8.2	7.3	7.0	5.4	15.0	15.5	14.6	14.3	14.7	15.1
5% Change in Long-Term Average of Hydro[2]	9.4	9.6	9.1	10.0	9.1	11.2	10.2	10.1	10.4	11.4
2% Change in the Capacity Factor of Point Lepreau[2]	7.9	8.0	7.6	8.4	7.6	9.4	8.5	8.7	8.9	9.8
1% Change in OM&A Expenses	5.1	5.1	5.2	5.3	5.3	5.5	5.4	5.6	5.6	5.8
1% Change in Long-Term Interest Rates[3]										
- Current Year Impact	2.5	1.0	1.4	0.6	0.0	0.2	1.0	2.5	2.2	2.2
- Full Year Impact	3.0	3.0	1.5	2.0	0.0	0.5	2.0	5.0	4.5	4.5
1% Change in Short-Term Interest Rates	6.8	6.7	6.9	7.0	7.2	7.2	7.2	7.4	7.3	7.4
10% Change in Weather Heating Degree Days[4]	20.6	21.1	21.6	22.1	22.7	23.3	23.8	24.4	25.1	25.7
1% Change in Discount Factor for Nuclear Decommissioning/UFM Liabilities	24.5	25.1	24.5	25.2	24.7	24.7	24.6	24.5	24.4	24.2
1% Change in Investment/Sinking Funds Earnings[5]	12.8	13.3	13.2	13.5	14.1	15.1	16.1	17.1	18.0	19.1

[1] *Sensitivities in early years are reduced due to firm contracts and/or through hedging using financial instruments.*

[2] *Based on an average incremental purchased power replacement energy cost for each year.*

[3] *Current-year impact amount reflects the impact in the year resulting from the timing of the issue. The full-year impact amount reflects an annualized impact.*

[4] *The analysis assumes a 40% gross margin factor.*

[5] *Reflects the approximate current-year impact of a change in the earnings rate on an annualized basis. Amounts are not cumulative.*

Appendix C – Results of Scenario Modelling

Figure 9: Scenario Analysis – Key Financial Measure Results and Required Rate Strategies

	Fiscal Year Ending March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Base Case - 10 Year Plan										
(1)	Rate Increase	2.00%	1.75%	1.75%	1.50%	1.50%	1.50%	1.50%	1.50%	2.00%	2.00%
(2)	Cumulative Rate Increase	2.00%	3.79%	5.60%	7.19%	8.79%	10.42%	12.08%	13.76%	16.04%	18.36%
(3)	In-Province Revenue	1,496	1,530	1,567	1,616	1,643	1,669	1,699	1,727	1,767	1,805
(4)	Net Income	41	81	72	102	68	134	131	111	53	53
(5)	Net Debt	4,884	4,804	4,751	4,646	4,543	4,323	4,463	4,708	4,972	5,209
(6)	Change in Net Debt	(19)	(81)	(53)	(104)	(104)	(219)	139	246	264	236
(7)	% Debt in Capital Structure	89.5%	88.0%	86.7%	84.8%	83.5%	80.7%	79.3%	78.7%	78.9%	79.1%
	Negative Case - No Rate Change										
(8)	Rate Increase	2.00%	1.75%	1.75%	1.50%	1.50%	1.50%	1.50%	1.50%	2.00%	2.00%
(9)	Cumulative Rate Increase	2.00%	3.79%	5.60%	7.19%	8.79%	10.42%	12.08%	13.76%	16.04%	18.36%
(10)	In-Province Revenue	1,496	1,530	1,567	1,616	1,643	1,670	1,701	1,729	1,770	1,807
(11)	Net Income	(8)	37	13	40	(14)	35	3	(19)	(113)	(105)
(12)	Net Debt	4,933	4,896	4,902	4,859	4,836	4,712	4,977	5,354	5,779	6,176
(13)	Change in Net Debt	30	(37)	7	(43)	(24)	(124)	265	377	425	397
(14)	% Debt in Capital Structure	90.4%	89.7%	89.5%	88.7%	88.9%	88.1%	88.6%	89.6%	91.9%	93.9%
	Negative Case - Rate Change										
(15)	Rate Increase	2.93%	2.68%	2.68%	2.43%	2.43%	2.43%	2.43%	2.43%	2.93%	2.93%
(16)	Cumulative Rate Increase	2.93%	5.69%	8.52%	11.16%	13.86%	16.63%	19.46%	22.36%	25.95%	29.64%
(17)	In-Province Revenue	1,510	1,558	1,610	1,675	1,719	1,763	1,811	1,858	1,919	1,977
(18)	Net Income	6	65	57	103	67	137	127	127	59	95
(19)	Net Debt	4,919	4,854	4,816	4,711	4,606	4,380	4,522	4,752	5,005	5,202
(20)	Change in Net Debt	16	(66)	(38)	(105)	(105)	(225)	142	230	253	197
(21)	% Debt in Capital Structure	90.1%	88.9%	87.9%	86.0%	84.7%	81.9%	80.5%	79.5%	79.6%	79.1%
	Positive Case - No Rate Change										
(22)	Rate Increase	2.00%	1.75%	1.75%	1.50%	1.50%	1.50%	1.50%	1.50%	2.00%	2.00%
(23)	Cumulative Rate Increase	2.00%	3.79%	5.60%	7.19%	8.79%	10.42%	12.08%	13.76%	16.04%	18.36%
(24)	In-Province Revenue	1,496	1,530	1,567	1,616	1,642	1,668	1,698	1,726	1,766	1,804
(25)	Net Income	73	116	111	145	119	188	190	184	132	141
(26)	Net Debt	4,852	4,735	4,644	4,497	4,343	4,071	4,149	4,325	4,510	4,660
(27)	Change in Net Debt	(51)	(117)	(92)	(146)	(154)	(272)	78	175	185	150
(28)	% Debt in Capital Structure	88.9%	86.8%	84.8%	82.1%	79.8%	76.0%	73.8%	72.3%	71.6%	70.7%
	Positive Case - Rate Change										
(29)	Rate Increase	1.45%	1.20%	1.20%	0.95%	0.95%	0.95%	0.95%	0.95%	1.45%	1.45%
(30)	Cumulative Rate Increase	1.45%	2.66%	3.88%	4.87%	5.86%	6.86%	7.87%	8.89%	10.46%	12.06%
(31)	In-Province Revenue	1,488	1,514	1,542	1,581	1,598	1,615	1,635	1,653	1,682	1,709
(32)	Net Income	65	100	85	108	72	129	119	100	35	29
(33)	Net Debt	4,860	4,760	4,695	4,585	4,478	4,264	4,413	4,672	4,954	5,216
(34)	Change in Net Debt	(43)	(100)	(66)	(110)	(107)	(214)	149	259	282	262
(35)	% Debt in Capital Structure	89.0%	87.2%	85.7%	83.7%	82.3%	79.6%	78.5%	78.1%	78.6%	79.1%

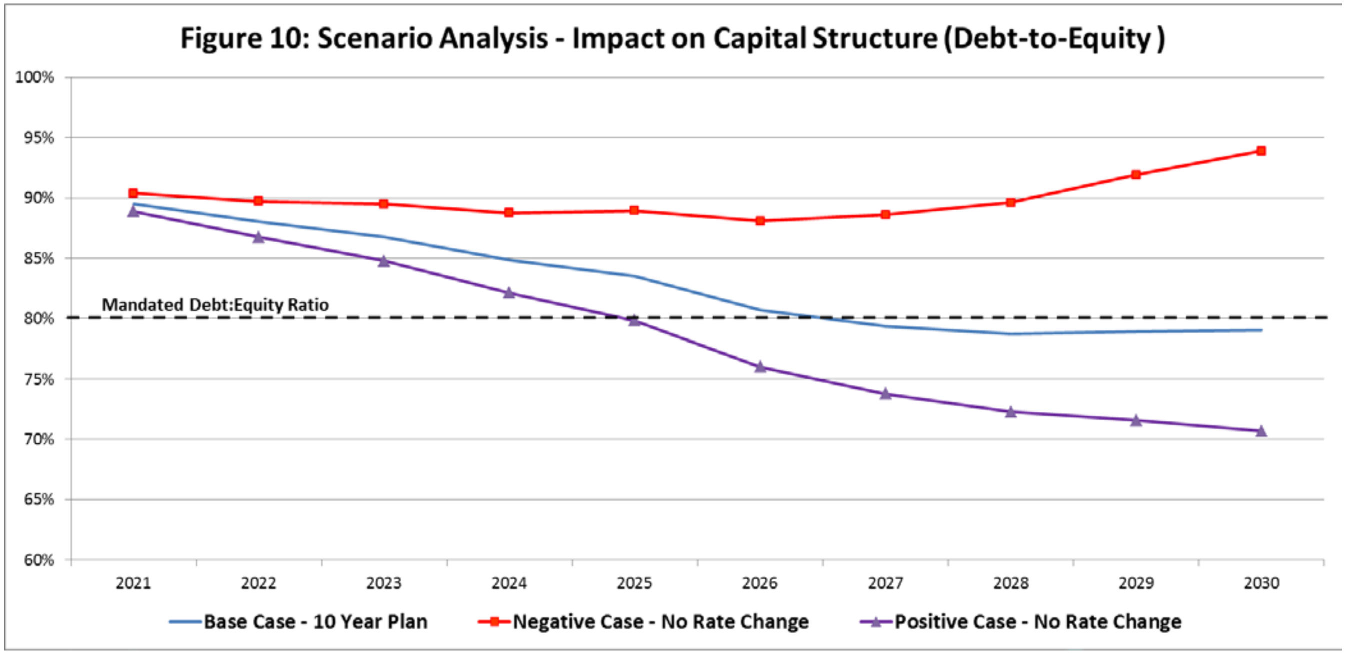
Figure 10: Scenario Analysis - Impact on Capital Structure (Debt-to-Equity)
100%
95%
90%
85%
80%
75%
70%
65%
60%
Mandated Debt:Equity Ratio
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Base Case - 10 Year Plan
Negative Case - No Rate Change
Positive Case - No Rate Change

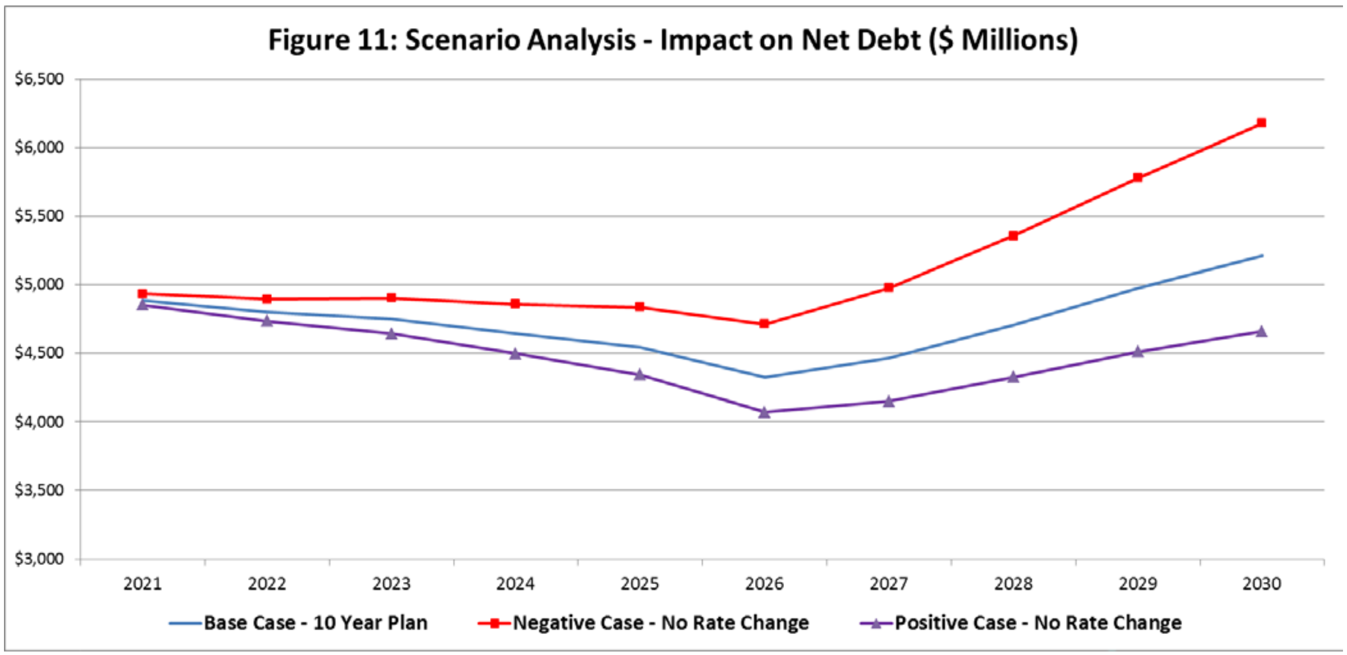
Figure 11: Scenario Analysis - Impact on Net Debt ($ Millions)
$6,500
$6,000
$5,500
$5,000
$4,500
$4,000
$3,500
$3,000
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Base Case - 10 Year Plan
Negative Case - No Rate Change
Positive Case - No Rate Change

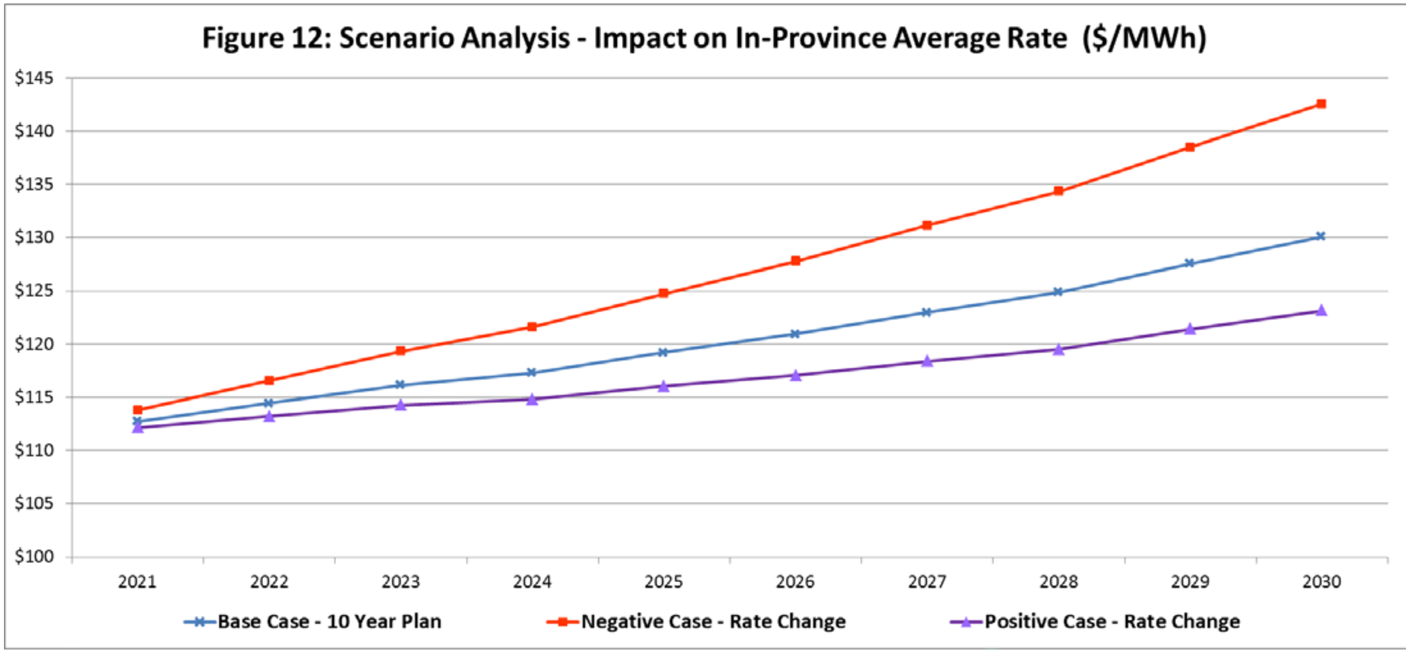
Figure 12: Scenario Analysis - Impact on In-Province Average Rate ($/MWh)
$145
$140
$135
$130
$125
$120
$115
$110
$105
$100
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Base Case - 10 Year Plan
Negative Case - Rate Change
Positive Case - Rate Change

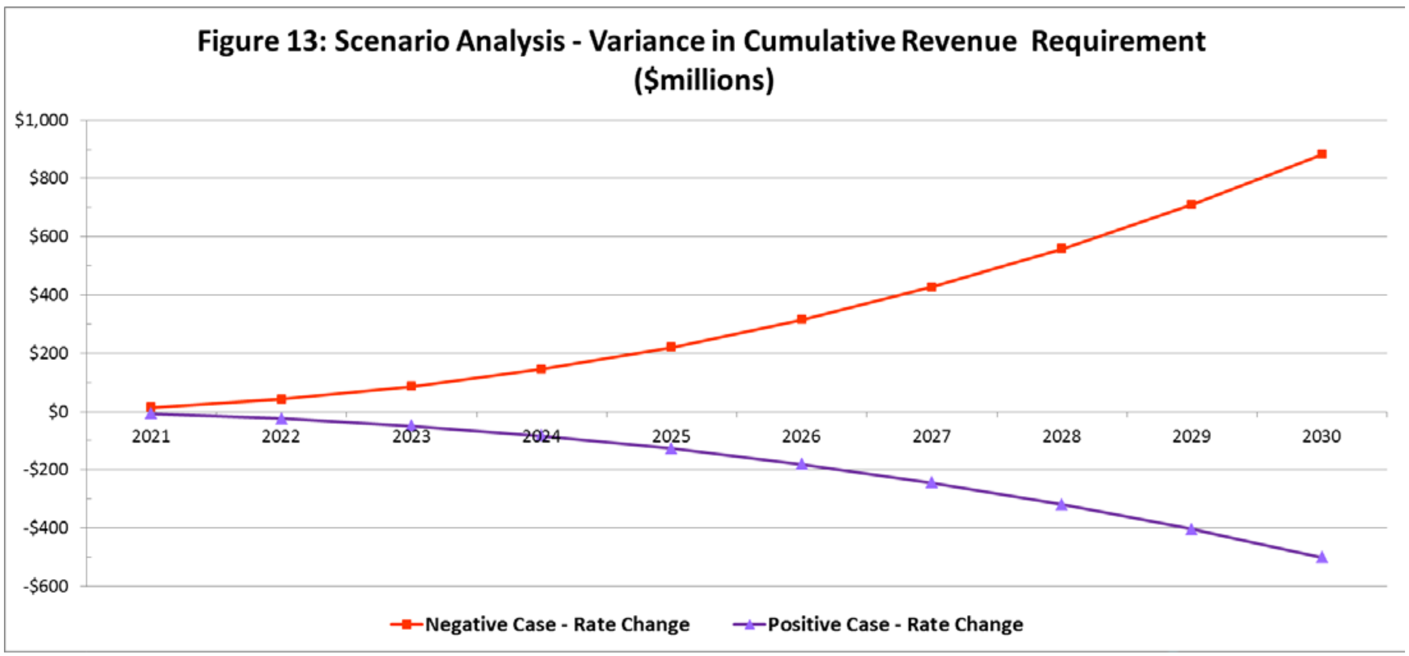
Figure 13: Scenario Analysis - Variance in Cumulative Revenue Requirement ($millions)
$1,000
$800
$600
$400
$200
$0
-$200
-$400
-$600
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Negative Case - Rate Change
Positive Case - Rate Change

Appendix D – Statement of Cash Flows & Change in Net Debt

Figure 14: Statement of Cash Flows

Fiscal Year Ending March 31 (in millions $)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Operating Activities										
Cash Receipts from Customers	1,771	1,787	1,832	1,868	1,902	1,938	1,961	1,991	2,039	2,084
Cash Paid to Suppliers and Employees	(1,192)	(1,141)	(1,225)	(1,263)	(1,239)	(1,249)	(1,202)	(1,279)	(1,334)	(1,360)
Customer Contributions	15	11	3	3	3	9	3	3	3	3
Post-employment Benefits	(6)	(6)	(6)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
Interest Paid	(233)	(228)	(223)	(221)	(214)	(214)	(215)	(230)	(249)	(267)
Cash Provided by Operating Activities	**355**	**423**	**381**	**381**	**446**	**478**	**540**	**478**	**452**	**453**
Investing Activities										
Expenditures on Property, Plant and Equipment, Net of Proceeds	(347)	(341)	(343)	(295)	(361)	(276)	(679)	(724)	(747)	(722)
Used Fuel Management and Decommissioning Fund Withdrawals	16	21	19	8	11	11	11	11	11	11
Cash Expenditures on Decommissioning	(19)	(39)	(19)	(10)	(13)	(16)	(38)	(40)	(12)	(12)
Cash Used in Investing Activities	**(350)**	**(358)**	**(344)**	**(296)**	**(362)**	**(281)**	**(705)**	**(752)**	**(748)**	**(723)**
Financing Activities										
Proceeds from Issuance of Long-term Debt	300	300	150	200	-	50	200	500	450	450
Debt Retirements	(365)	(400)	(233)	(300)	(50)	(200)	-	(220)	(100)	(200)
Lease Obligation	(5)	(5)	(4)	(3)	(2)	(3)	(3)	(3)	(3)	(3)
Increase (Decrease) in Short-term Indebtedness	(43)	35	2	22	7	(4)	10	15	(16)	23
Sinking Fund Installments	(45)	(47)	(43)	(42)	(44)	(42)	(42)	(44)	(47)	(48)
Sinking Fund Redemptions	153	51	91	38	5	2	-	27	12	49
Cash Provided by/(Used in) Financing Activities	**(6)**	**(65)**	**(37)**	**(85)**	**(84)**	**(196)**	**165**	**275**	**296**	**271**
Net Cash Inflow (Outflow)	-	-	-	-	-	-	-	-	-	-
Cash, Beginning of Year	1	1	1	1	1	1	1	1	1	1
Cash, End of Year	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**

Figure 15: Statement of Change in Net Debt

Fiscal Year Ending March 31 (in millions $)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Opening Net Debt	4,903	4,884	4,804	4,751	4,646	4,543	4,323	4,463	4,708	4,972
Ending Net Debt	4,884	4,804	4,751	4,646	4,543	4,323	4,463	4,708	4,972	5,209
Change in Net Debt	**(19)**	**(80)**	**(53)**	**(104)**	**(104)**	**(219)**	**139**	**246**	**264**	**236**
Reconciliation:										
Cash Provided by Operating Activities	355	423	381	381	446	478	540	478	452	453
Cash Used in Investing Activities	(350)	(358)	(344)	(296)	(362)	(281)	(705)	(752)	(748)	(723)
Sinking Fund Earnings	18	21	20	23	24	27	30	32	35	38
Foreign Exchange Adjustment on USD Debt	1	0	0	-	-	-	-	-	-	-
Amortization of Debt Premiums/Discounts	(1)	(1)	(0)	(0)	(1)	(1)	(1)	(1)	(0)	(0)
Lease Obligation	(5)	(5)	(4)	(3)	(2)	(3)	(3)	(3)	(3)	(3)
Cash Available for Net Debt Reduction	**19**	**80**	**53**	**104**	**104**	**219**	**(139)**	**(246)**	**(264)**	**(236)**

Appendix E – Statement of Financial Position

Figure 16: Statement of Financial Position

Fiscal Year Ending March 31 (in millions $)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ASSETS										
Current Assets										
Cash	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
Accounts Receivable	275	282	287	293	299	305	311	317	323	330
Materials, Supplies and Fuel	198	201	208	212	216	221	225	229	234	239
Prepaid Expenses	14	14	14	14	15	15	15	15	16	16
Current Portion of Derivative Assets	7	7	7	-	-	-	-	-	-	-
Total Current Assets	**495**	**505**	**517**	**520**	**531**	**541**	**552**	**563**	**574**	**586**
Non-Current Assets										
Land, Building and Equipment	7,165	7,484	7,798	8,056	8,424	8,714	9,416	10,167	10,940	11,687
Less: Accumulated Amortization	(2,541)	(2,853)	(3,156)	(3,489)	(3,823)	(4,161)	(4,495)	(4,856)	(5,249)	(5,662)
Property, Plant and Equipment	4,624	4,632	4,641	4,567	4,601	4,554	4,921	5,310	5,691	6,026
Intangible Assets	49	47	49	78	66	53	48	38	29	24
Decommissioning and Used Fuel Management Funds	815	835	859	893	926	961	997	1,035	1,076	1,118
Sinking Funds Receivable	481	497	470	497	559	626	698	747	817	854
Derivative Assets	-	-	-	-	-	-	-	-	-	-
Total Non-Current Assets	**5,969**	**6,011**	**6,019**	**6,036**	**6,152**	**6,193**	**6,664**	**7,130**	**7,612**	**8,022**
Total Assets	**6,464**	**6,516**	**6,536**	**6,556**	**6,683**	**6,734**	**7,216**	**7,693**	**8,187**	**8,608**
Regulatory Assets	858	846	836	819	779	738	698	656	613	569
Total Assets and Regulatory Balances	**$ 7,322**	**$ 7,362**	**$ 7,372**	**$ 7,376**	**$ 7,462**	**$ 7,472**	**$ 7,913**	**$ 8,349**	**$ 8,800**	**$ 9,176**

Figure 16: Statement of Financial Position (*continued*)

Fiscal Year Ending March 31 (in millions $)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
LIABILITIES										
Current Liabilities										
Short Term Indebtedness	$ 656	$ 691	$ 693	$ 715	$ 722	$ 718	$ 728	$ 743	$ 727	$ 750
Accounts Payable and Accruals	247	253	241	184	202	183	261	270	282	279
Accrued Interest	35	35	32	31	30	30	30	29	29	27
Current Portion of Long-term Debt	400	233	300	50	200	-	220	100	200	-
Current Portion of Derivative Liabilities	6	6	6	-	-	-	-	-	-	-
Total Current Liabilities	**1,344**	**1,218**	**1,272**	**980**	**1,154**	**931**	**1,239**	**1,142**	**1,238**	**1,057**
Long-Term Debt										
Debentures	4,310	4,378	4,229	4,379	4,180	4,232	4,213	4,613	4,864	5,314
Non-Current Liabilities										
Decommissioning and Used Fuel Management Liability	1,002	1,014	1,047	1,091	1,135	1,177	1,200	1,223	1,276	1,332
Post-employment Benefits	119	120	121	121	121	120	120	120	120	121
Provisions for Other Liabilities and Charges	58	63	63	64	64	70	70	69	69	68
Derivative Liabilities	1	1	1	-	-	-	-	-	-	-
Leases	27	25	22	19	17	14	11	9	5	2
Total Non-Current Liabilities	**1,207**	**1,223**	**1,254**	**1,295**	**1,336**	**1,382**	**1,402**	**1,421**	**1,470**	**1,522**
Total Liabilities	**6,861**	**6,819**	**6,755**	**6,655**	**6,671**	**6,545**	**6,854**	**7,176**	**7,572**	**7,892**
SHAREHOLDER'S EQUITY										
Accumulated Other Comprehensive Income	(114)	(112)	(110)	(109)	(107)	(105)	(103)	(101)	(99)	(96)
Retained Earnings	574	655	727	830	898	1,032	1,163	1,274	1,327	1,380
Total Shareholder's Equity	**460**	**543**	**617**	**721**	**791**	**927**	**1,059**	**1,173**	**1,228**	**1,284**
Total Liabilities & Shareholder's Equity	**$ 7,322**	**$ 7,362**	**$ 7,372**	**$ 7,376**	**$ 7,462**	**$ 7,472**	**$ 7,913**	**$ 8,349**	**$ 8,800**	**$ 9,176**