

**Assessment of the Rate Impacts of  
the Amended Agreement Between  
New Brunswick and Quebec  
Regarding NB Power**

**February 2010**

## **I. Introduction and Executive Summary**

In conjunction with its discussions with the Government of Quebec regarding cooperation in energy matters, the Government of New Brunswick retained NERA Economic Consulting (“NERA”) to assist in evaluating the merits of different courses of action in relation to New Brunswick Power Holding Corporation and its subsidiaries (collectively, “NB Power”). On October 29, 2009, the two Governments signed a Memorandum of Understanding (MOU) which outlined the economic and regulatory framework for a transaction in which Quebec (acting through Hydro-Québec (HQ)) would acquire the bulk of the assets of NB Power. On January 20, 2010 the Governments announced an amended agreement under which the province of New Brunswick would retain ownership of the transmission and distribution assets of NB Power and HQ would acquire the bulk of the generation assets and commit to a long-term supply of heritage pool power at assured real prices (“Amended Agreement”). Implementation of the Amended Agreement is subject to, among other things, due diligence, settlement of definitive agreements and action by the legislatures of both Provinces.

An element of NERA’s assignment was to construct rate forecast models for the Government’s internal use that would quantify the rates that would result from NB Power continuing to “stand-alone” and those that would result from the transaction under the terms outlined in the original MOU. We described the results of that analysis in our November 18, 2009 report entitled “Assessment of the Rate Impacts of the Memorandum of Understanding Between New Brunswick and Quebec Regarding NB Power”. We have subsequently updated our analysis to reflect the terms of the Amended Agreement and we are providing this report to describe our updated results. Our approach to analyzing the rate impact of the Amended Agreement is the same as we used in analyzing the original MOU. Based on detailed information obtained from NB Power and assumptions concerning items such as future inflation, fuel prices and environmental regulation, NERA constructed a spreadsheet model which forecasts the rates which would be required to be charged by NB Power over a 30 year period to serve demand in New Brunswick while maintaining reliability and the financial viability of NB Power. We refer to this as the “stand-alone case”. NERA also constructed a similar model, using the same assumptions wherever applicable, based on the implementation of the Amended Agreement. We refer to this as the “Amended Agreement case”. NERA then estimated the present value of the difference between the two rate forecasts and conducted sensitivity analyses to demonstrate the

impact of variations in key assumptions. As described in our original report, NERA reviewed its overall modeling structure and key assumptions with NB Power and the New Brunswick Departments of Energy and Finance.

Table 1 summarizes the net present value (“NPV”) of the difference between the rates which are forecast to be charged if the Amended Agreement is implemented and those forecast to be charged if NB Power continues in its present form and regulatory context under current Government policy.

<b>Table 1</b>				
<b>Value of Rate Reductions Under the Revised Agreement</b>				
<b>Net Present Value (\$Billions at March 31, 2010)</b>				
	<b>2011-2040</b>	<b>Terminal Value</b>	<b>Total</b>	<b>Share of Total</b>
Residential, Commercial, and Wholesale Customers	2.1	1.3	3.4	68%
Large Industrial Customers	1.1	0.5	1.6	32%
<b>Total</b>	<b>3.2</b>	<b>1.8</b>	<b>5.0</b>	<b>100%</b>

Table 1 indicates that the NPV of the forecast benefit resulting from implementation of the Amended Agreement is estimated to be \$5.0 billion. These rate reduction benefits are made possible by replacing the expected costs of power supply from NB Power’s existing generating plants with a lower-priced heritage pool of power from HQ. The rate savings from the heritage pool power comes in large part from three major sources. The first is the avoidance of substantial future capital expenditures which would be required if the stand-alone status of NB Power is maintained. The second is avoided exposure to escalation in fuel and purchased power prices above the rate of inflation (real fuel price escalation). The third is the avoidance of potentially significant costs of complying with future limitations on carbon emissions. These power supply cost savings enable New Brunswick to implement significant up-front rate reductions for large industrial customers and a five-year match of HQ industrial rate increases, a five year rate freeze for all other customers and, after the initial five year period, significantly

lower forecast power rates for all customers in the Amended Agreement case than could be achieved in the stand-alone case.

Residential, commercial, and wholesale (“RCW”) customers are expected to receive approximately 68 percent of the total NPV rate savings, with large industrial customers receiving the remaining 32 percent. As we discuss below, the timing of these benefits differs between the two groups since industrial customers receive an immediate rate reduction, while the benefits to RCW customers build over time due to the 5-year rate freeze.

NERA is an economic consulting firm with over 450 economists with offices in North America, Europe, Asia and Australia. NERA was founded in 1961 and its primary focus at the time was providing economic advice in connection with energy regulation. Since its founding NERA has advised utilities, governments and regulators on the economics of regulated industries. NERA has no financial interest in the consummation of the Amended Agreement. NERA provides advice based on its experience and professional competence but assumes no responsibility for the judgements made by any party based thereon. The results of the models referred to in this report depend on assumptions which cover a period of 30 years. While experience over such a period can be expected to vary from that assumed, the process used to arrive at the assumptions and to develop the models is, in NERA’s experience, customary practice in matters that involve the development of and comparison of long term rate forecasts. In recognition of the sensitivity of the results to different assumptions, NERA has provided sensitivity analysis demonstrating the impact of differences in certain key assumptions. NERA’s work was directed by Mr. Eugene T. Meehan, a Senior Vice President in NERA’s Washington DC office and Mr. Meehan assumes responsibility for NERA’s analyses and advice.

## **II. Overview of Approach to Modeling Electricity Rates**

To develop these estimates of expected rate savings, NERA developed long-term forecasts of power rates under the stand-alone case and the Amended Agreement case.

## **A. Modeling NB Stand-Alone Electricity Rates**

The stand-alone case is modeled as a “rate minimization” case and is designed to reflect the lowest feasible rates that could be achieved over time if NB Power continued to plan and operate the NB Power System. In this “rate minimization” approach we assume that rate increases are 3 percent annually for the first 3 years followed by 2 years of 1% increases. These rate increases are needed to avoid an increase in the aggregate level of debt while respecting the limits imposed by current government policy that increases will be limited to 3% annually during this period. After the 5-year period, NB Power rates are modeled to be as low as possible to just cover forecast operating expenses and debt amortization payments, an assumption that provides minimal NB Power earnings (limited to 1.1 times interest coverage on distribution and transmission debt) and no contingency for unexpected expenses. The “rate minimization” approach was designed to ensure that forecasts of stand-alone rates, and hence of rate savings, are comparable in terms of cash flows to the government with the Amended Agreement case. In the Amended Agreement case, the government will not receive income tax revenue nor will the government receive any profit from NB Power. By removing income taxes and profits from the stand-alone case, the cases are comparable.<sup>1</sup> The stand-alone case also includes a variety of conservative assumptions (that is, assumptions that tend to understate the rates required in that case), such as no cost for carbon emissions from NB Power plants through the remaining original life of the fossil fuel generating assets.

## **B. Modeling NB Rates in the Amended Agreement Case**

The Amended Agreement case provides a forecast of the rates that would prevail if the transaction contemplated by the Amended Agreement were implemented. In this case HQ acquires the bulk of the NB Power generation assets and commits to provide up to 14 TWh of heritage pool power supply at a price of \$73.50/MWh frozen in nominal terms for 5 years and then escalating with inflation as measured by the NB CPI thereafter into perpetuity. Transmission and distribution service would continue to be provided by NB Power at rates regulated by the New Brunswick EUB.

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<sup>1</sup> The stand-alone case does provide the government with revenue from the provincial debt portfolio management fee of 0.65% of outstanding debt. This revenue was left in the stand-alone case based on the assumption that there is a cost to the province of the debt guarantee associated with this fee.

### III. Key Assumptions in Modeling Electricity Rates

The key assumptions used in our analysis, apart from the terms of the Amended Agreement, are largely unchanged from our November 2009 report. The long-term rate forecast models were based on the most recent available data supplied by NB Power and assumptions concerning long-term trends in factors such as inflation, fuel prices and environmental regulation. NERA reviewed the details of the models with NB Power, the NB Department of Energy and NB Department of Finance to obtain their input. A broad consensus was reached that the stand-alone case provides a realistic and in fact a conservative view of the rates that would be expected to prevail in the stand-alone case.

Key assumptions used in the forecast include:

- 1) General inflation – based on the September 2009 Conference Board forecast of NB CPI, which is 2.6 percent in 2010, 2.44 percent in 2011, 2.2 percent in 2012, and averages 1.8 percent from 2013 to 2030.
- 2) Load growth – provided by NB Power for 2010-2020 and summarized below:

<b>Figure 2</b>											
<b>Forecast Energy Sales Growth Rates</b>											
	<b>Forecast year ending Mar 31</b>										
	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>
Residential	0.6%	2.2%	0.8%	0.8%	1.0%	1.0%	1.2%	1.2%	1.3%	1.3%	1.3%
General Service	1.5%	0.0%	-1.7%	-1.6%	-0.7%	-0.1%	0.5%	0.9%	1.4%	1.7%	1.9%
Industrial Distribution	-1.0%	0.6%	0.6%	0.6%	0.7%	0.9%	0.9%	0.9%	0.9%	0.8%	0.8%
Industrial Transmission	0.8%	2.6%	-8.7%	6.2%	3.4%	1.9%	2.4%	0.9%	0.9%	0.9%	0.9%
Industrial Interruptible	5.2%	2.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wholesale	-1.8%	-0.5%	-1.7%	-0.2%	0.3%	0.6%	0.7%	1.1%	1.3%	1.2%	1.5%
Street Lighting	1.3%	0.0%	0.0%	1.3%	0.0%	0.0%	1.3%	0.0%	0.0%	1.3%	0.0%
Total In-Province Sales	0.6%	1.6%	-2.4%	1.6%	1.2%	1.0%	1.3%	1.0%	1.1%	1.2%	1.2%

Beyond 2020 we assume constant load growth for each class at the 2020 growth rate.

- 3) Fuel and purchased power – based on NB Power forecasts for 2011 and 2012, including an average NYMEX gas price of \$7.30/MMBtu in 2012, and capacity factors of 94.9 percent for Point Lepreau and 96.9 percent for Belledune. Beyond 2012, we assumed an 89.5 percent capacity factor for Belledune throughout the forecast and an average 91 percent capacity factor for Point Lepreau through 2023, followed by a decline in capacity factor consistent with projections provided by NB Power. We also assumed a 1 percent real escalation in non-nuclear fuel and purchased power costs, generally consistent with the escalation provisions in NB Power's

existing power purchase contracts and expectations for gas and coal costs reflected in forward prices and publicly available forecasts produced by the U.S. Department of Energy.

- 4) Off system sales revenues – the NB Power forecast for off system sale revenue for the year ending March 31, 2012 is escalated at inflation without any escalation in real terms. While the prices received for these sales should generally be linked to fuel prices, which we assume will escalate at 1 percent real escalation, we assume the market for opportunity sales will potentially be diminished over time as adjoining states and provinces add renewable resources which can reduce the costs of plants operating at the margin.
- 5) Operations, maintenance, and administration costs – based on NB power forecasts for 2011 and 2012, increasing at inflation with no real escalation thereafter. Since electricity sales are growing, this results in declining real costs per MWh and implied productivity gains for transmission and distribution expenses equal to the rate of sales growth.
- 6) Major capital additions – we include capital expenditures of \$2.3B (current year \$) to refurbish Mactaquac by 2030, \$275MM to refurbish Belledune by 2033, and \$1.6B (including capitalized replacement power costs) for another refurbishment of Point Lepreau by 2035. The estimates for Mactaquac and Belledune were provided by NB Power, while the Point Lepreau cost is based on the expected cost of the current refurbishment project. NB Power has forecast additional capital expenditures starting in 2025 to replace other retiring fossil capacity and expiring power purchase agreements (PPAs). In the stand-alone case we have assumed that the fossil assets remain available throughout the forecast period and that expiring PPAs can be replaced with new supply with no increase in costs.
- 7) Carbon cost – we assume that NB Power will receive sufficient free allowances under any Canadian or provincial carbon cap-and-trade program to cover the output of Belledune through its remaining original life and the limited output of the other fossil assets. However, we assume this favorable treatment ends after the refurbishment and life extension of Belledune in 2033. Thereafter, we assume NB Power must purchase allowances to cover Belledune emissions at a price of \$20/ton (2012\$). This carbon price is well below the public forecasts of carbon prices under recent regulatory regimes proposed for the United States and modeled by the United States Department of Energy and the Environmental Protection Agency.
- 8) New supply – based on NB Power’s load forecast, the company will require additional power supply over the amounts produced by existing generating assets in its 2012 forecast (adjusted to normalize capacity factors). We assume that the cost of this new supply will be \$85 per MWh in 2011, escalating at inflation. We also assume that supply beyond the heritage pool volumes that HQ will provide as per the Amended Agreement will be acquired through a competitive bid process at the same price. This price is generally consistent with the all-in cost of energy from a new gas fired combined cycle plant and with the cost of recent wind power proposals received by NB Power.

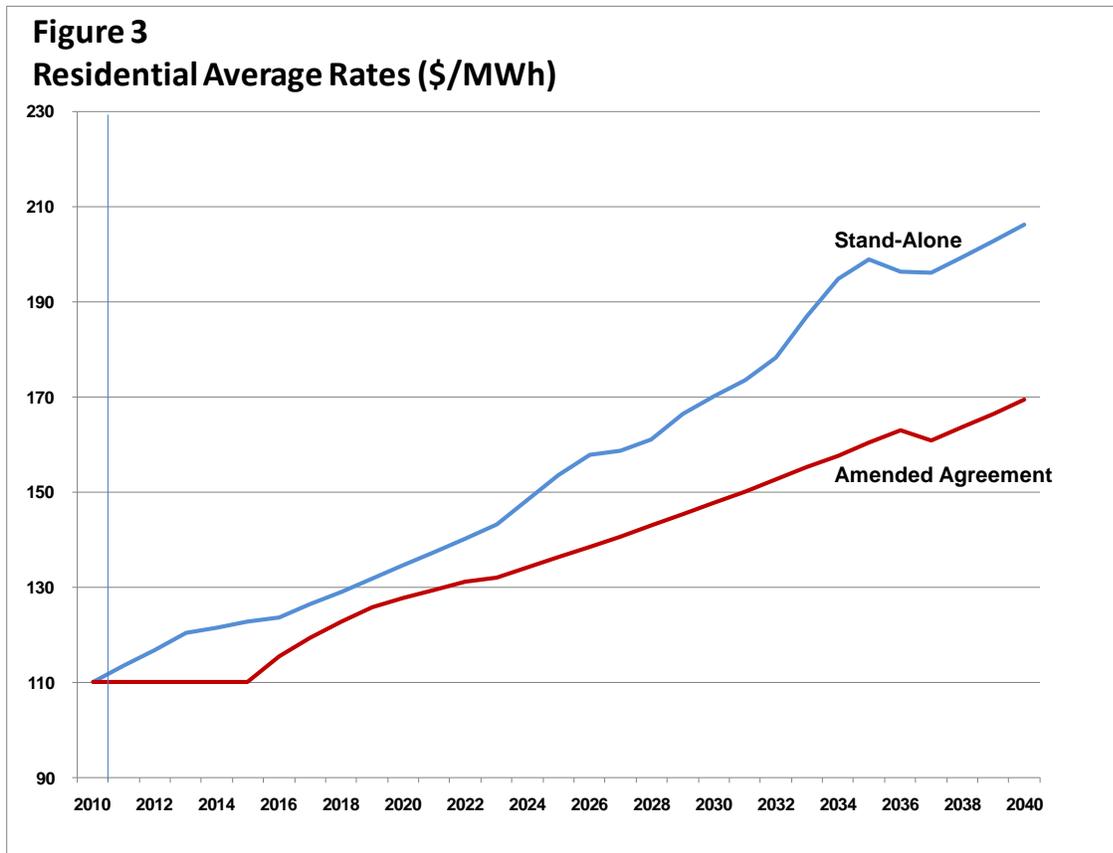
- 9) Ratemaking assumptions – in the stand-alone case, consistent with the “rate minimization” concept, we assume that transmission and distribution rates are based on a minimal interest coverage ratio of 1.1x with generation costs passed through without any profit. In the Amended Agreement case we forecast the transmission and distribution component of rates assuming NB Power receives cost of service ratemaking for transmission and distribution services.
- 10) Financing costs and allowed returns – we assume a weighted average interest rate of 5.6 percent in the stand-alone case, reflecting NB Power’s forecast average cost of long-term debt at March 31, 2010 of 5.3 percent, a short-term debt cost of 3.0 percent (consistent with an inflation forecast of approximately 2 percent), short-term debt constituting 15 percent of total debt, and a 0.65 percent debt portfolio management fee. The cost of long-term debt is likely to decline slightly over the next few years as certain higher-cost debt issues mature, but this is assumed to be offset by a reduction in the amount of short-term debt after completion of the Point Lepreau refurbishment. In the Amended Agreement scenario, we assume the same interest rate but allow for an equity return on a portion of transmission rate base.
- 11) Discount rate and terminal value methodology – our \$5.0 billion estimate of rate savings is based on a 6 percent discount rate. This discount rate is in the range of costs of capital assumed in the two scenarios and we believe it represents a reasonable midpoint for expressing the long-term stream of rate savings in a single net present value.
- 12) Terminal value methodology – since our explicit forecast covers only the period from 2011 through 2040, we need a methodology for capturing the terminal value, or value of rate savings beyond 2040. We assume that savings remain constant beyond 2040 and then value this as a net present value in perpetuity with no growth in the rate gap.

There are several assumptions that are unresolved, including the disposition of holding company costs currently allocated to the generation and nuclear businesses, fossil plant decommissioning costs, the Lepreau “off-ramp” provision in the Amended Agreement, fuel inventories at certain plants, and surplus revenues to allow for sales mix changes. These factors have not been reflected in our rate forecasts, but they are likely to have somewhat offsetting impacts and we do not expect the net impact of these factors to have a material impact on the rate forecasts and total rate savings included in this report. The intent of the assumptions we have made is to develop a realistic view of future conditions, but one that if biased would tend to understate as opposed to overstate the rate savings from implementing the transaction contemplated by the Amended Agreement. Nonetheless it is essential to recognize that any forecast of this nature is very sensitive to the assumptions. The sensitivity analyses discussed below illustrate the impacts of some of these uncertainties in assumptions on the estimated rate savings.

## IV. Base Case Estimated Rate Savings

### A. Rate Forecasts

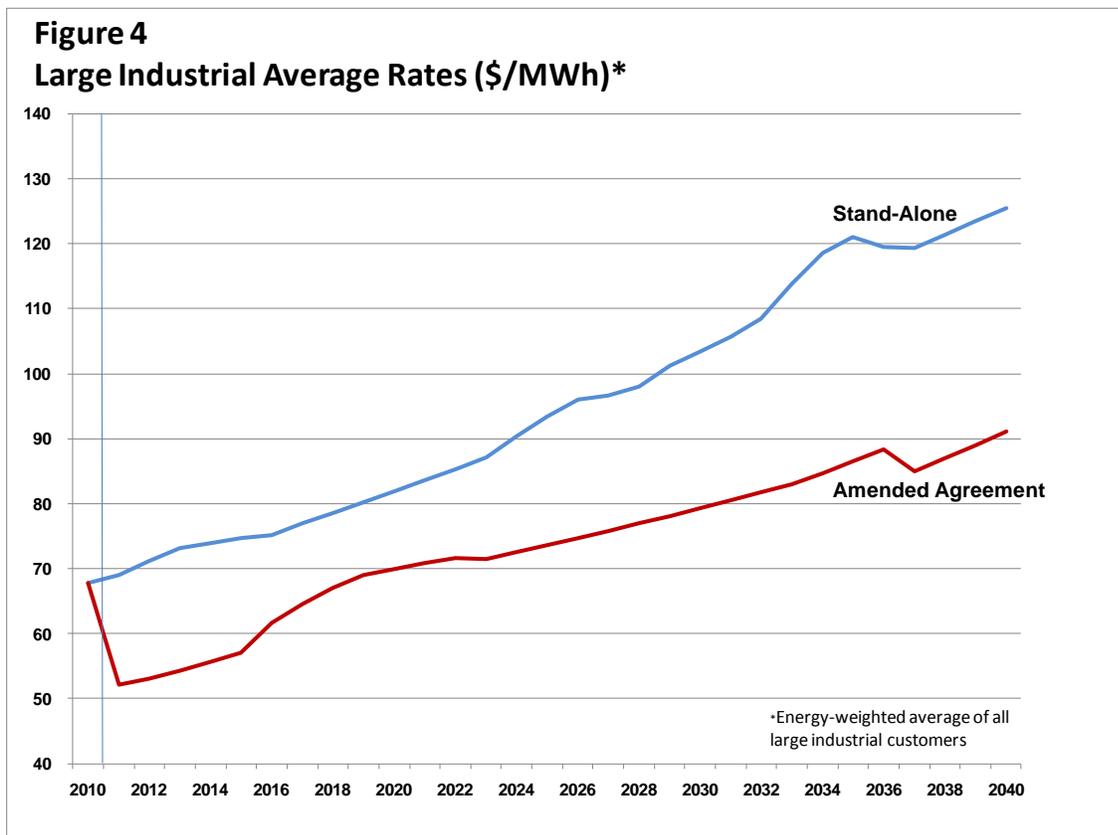
The following charts show our forecasts of rates under the Amended Agreement as compared to rates in the stand-alone case. Figure 3 shows the comparison of forecast rates for residential customers.



Residential rates in the Amended Agreement case will be lower than in the stand-alone case due to the five-year rate freeze, and this benefit grows over the five year period. By 2015, our forecast indicates residential rates in the Amended Agreement case will be approximately 10% lower than they would have been in the stand-alone case. At the expiration of the rate freeze, rates in the Amended Agreement case increase in 2016 to reflect escalation in heritage pool prices at the rate of inflation, transmission and distribution cost increases, and the commencement of amortization of the regulatory deferral account associated with the extended outage at the Point Lepreau nuclear generating facility. However, residential rates in the Amended Agreement case remain well below those expected in the stand-alone case over the

entire forecast period, and the advantage widens over time as NB Power is expected to face increasing costs due to major capital expenditures, real escalation in fuel and purchased power costs, and future costs of carbon regulation in the stand-alone case, and these cost increases are greater than the expected escalation in the heritage pool price. While actual rate levels differ for commercial, small industrial, and wholesale customers, the pattern of rate increases and the percentage differences between rates in the Amended Agreement and stand-alone cases are expected to be the same for these customers as they are for residential.

Figure 4 shows the comparison of forecast rates for large industrial customers.

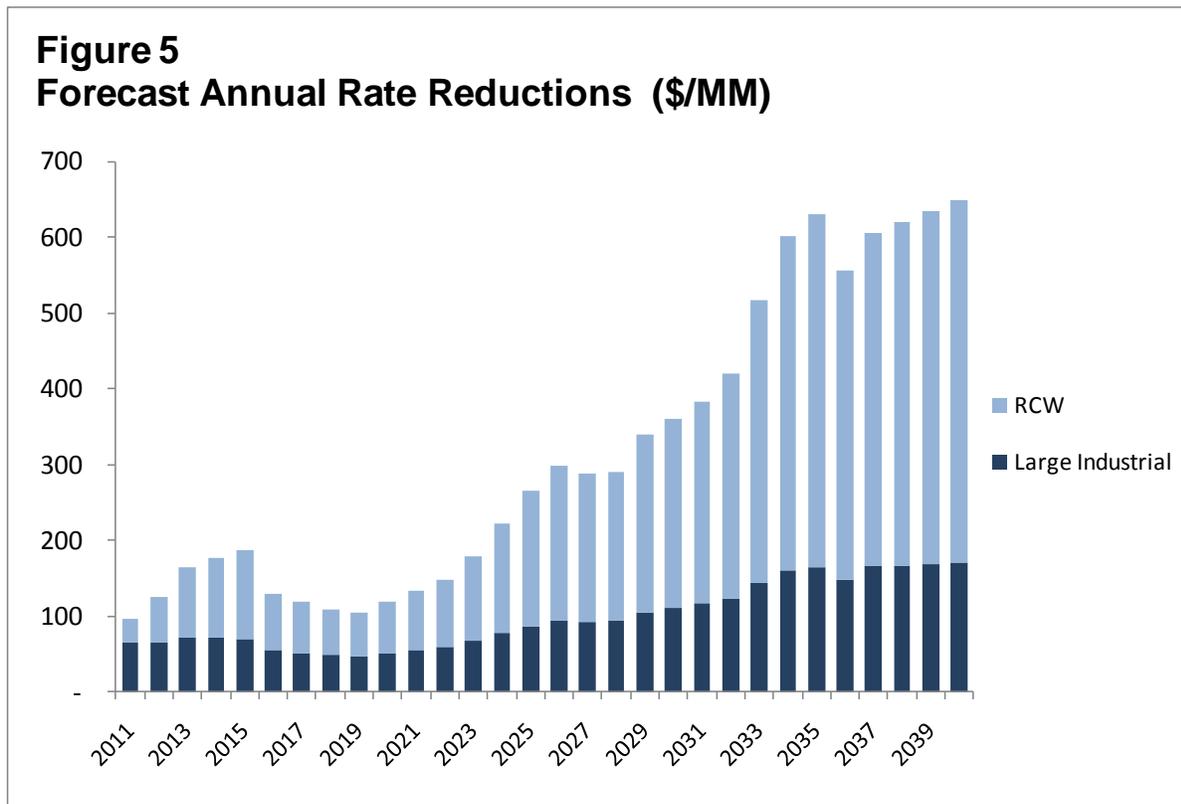


Large industrial rates decrease in the first year due to the government’s commitment to reduce these rates to levels closer to the corresponding large industrial rates in Quebec. For the next four years, large industrial rates increase in line with forecast increases in HQ’s large industrial rates. At the expiration of this rate commitment period in 2016, large industrial rates in the Amended Agreement case increase to reflect escalation in heritage pool prices at the rate of inflation, transmission and distribution cost increases, and the commencement of amortization of the

regulatory deferral account associated with the extended outage at the Point Lepreau nuclear generating facility. However, large industrial rates under the Amended Agreement remain well below those expected in the stand-alone case over the entire forecast period, and the advantage widens over time as a result of generally the same factors driving stand-alone residential rates.

### B. Savings by Customer Category

The difference between these rate curves represents the forecast rate savings to customers under the Amended Agreement. Our forecasts indicate that using base case assumptions these rate savings would be approximately \$200 million per year by 2015 and approximately \$600 million per year in the long term (see Figure 5). When totaled over the entire 2011-40 forecast period and expressed in NPV terms, and including a terminal value to reflect the value of expected savings beyond the forecast period, these savings amount to approximately \$5.0 billion in lower power rates to NB electricity customers under the Amended Agreement versus a stand-alone case.



We estimate that approximately 68 percent of these savings would go to RCW customers and the remainder to large industrial customers. However, the timing of these benefits differs somewhat between the two groups. Under the terms of the Amended Agreement, large industrial customers receive an immediate rate reduction averaging approximately 23 percent to move them closer to HQ's industrial rates. As a result, they receive about 68 percent of the total estimated rate savings in the first year. RCW customers benefit from a rate freeze and, by avoiding the 3 percent rate increase that would otherwise occur on April 1, 2010, receive approximately 32 percent of the first-year savings. The share of benefits going to RCW customers is forecast to increase over the next 5 years as industrial rates rise along with HQ's rates while NB residential, commercial, and wholesale rates remain frozen for 5 years. In year two, residential, commercial, and wholesale customers receive about 49% of the total rate savings and this increases to 57% in year three. In year five we estimate that residential and commercial customers will be receiving approximately 62 percent of the annual rate savings. The forecast model was designed primarily to measure total rates and, apart from the provisions specified in the Amended Agreement concerning the heritage pools, generally divides revenue requirements among rate classes assuming equal percentage rate changes. In practice the EUB may examine detailed cost allocation schedules and divide the revenue requirement differently than modeled.

### **C. Overall Timing of Rate Savings**

Beyond 2015, we forecast that rates would increase in the stand-alone case due to inflationary pressures, fuel price escalation, the cost of new power supply, and the impact of major capital expenditures required to replace existing generating assets in the next 15 to 25 years. Rates will increase under the Amended Agreement due to the recovery of the Lepreau deferral account (which we assume is phased-in over a three-year period), the impact of inflation on the heritage pool price, the cost of new supply required above the heritage pool amounts and inflationary effects on the costs of distribution and transmission service. We forecast that annual savings will temporarily decline to about \$100 million after the initial five-year rate commitments (mainly due to recovery of the Lepreau deferral), but we forecast that savings will increase significantly thereafter as the Amended Agreement insulates New Brunswick customers from fuel price escalation associated with existing assets, from replacement capital for existing plants and from carbon regulation associated with existing plants. On the other hand, should real fuel costs or

costs of replacement generating equipment decline, New Brunswick customers will not benefit from those declines to the extent that supply comes from the heritage pool supply.<sup>2</sup>

#### **D. Major Sources of Rate Savings in the Amended Agreement Case**

The \$5.0 billion NPV of forecast rate savings in the base case comes in large part from three sources:

- 1) Savings from capital expenditures that NB Power would otherwise need to make**
  - On a stand-alone basis, NB Power would need to make substantial capital expenditures to refurbish or replace generating plants in the future.
  - While these expenditures are 15 to 25 years into the future, they are in the billions of dollars – for example, over 2 billion in current year dollars (over \$3 billion in nominal dollars) for Mactaquac alone.
  
- 2) Savings from avoided real fuel price escalation**
  - Absent the transaction contemplated by the Amended Agreement, NB Power rates would reflect fuel prices (oil, gas and coal prices as well contract purchase prices) that are potentially subject to real price increases, that is increases above the rate of inflation. Current projections by the United States Department of Energy’s Energy Information Administration forecast real increases in these prices.
  - The heritage pool supply of power is provided at prices linked to inflation avoiding exposure to real increases in fuel prices.
  
- 3) Savings from avoided carbon costs**
  - Absent the transaction contemplated by the Amended Agreement, NB Power rates would reflect the cost of complying with any future regulation of carbon emissions from existing generating facilities.
  - In our base case forecast, we assume NB Power would begin to incur costs associated with carbon emissions in 2033 with the Belledune plant reaching the end of its planned life.
  - NB Power customers would not be exposed to these costs under the Amended Agreement.

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<sup>2</sup> This is not necessarily the case for industrial customers. The Amended Agreement provides that industrial customers will have open unbundled access to the transmission and distribution system and will be able to buy supply from sources other than HQ.

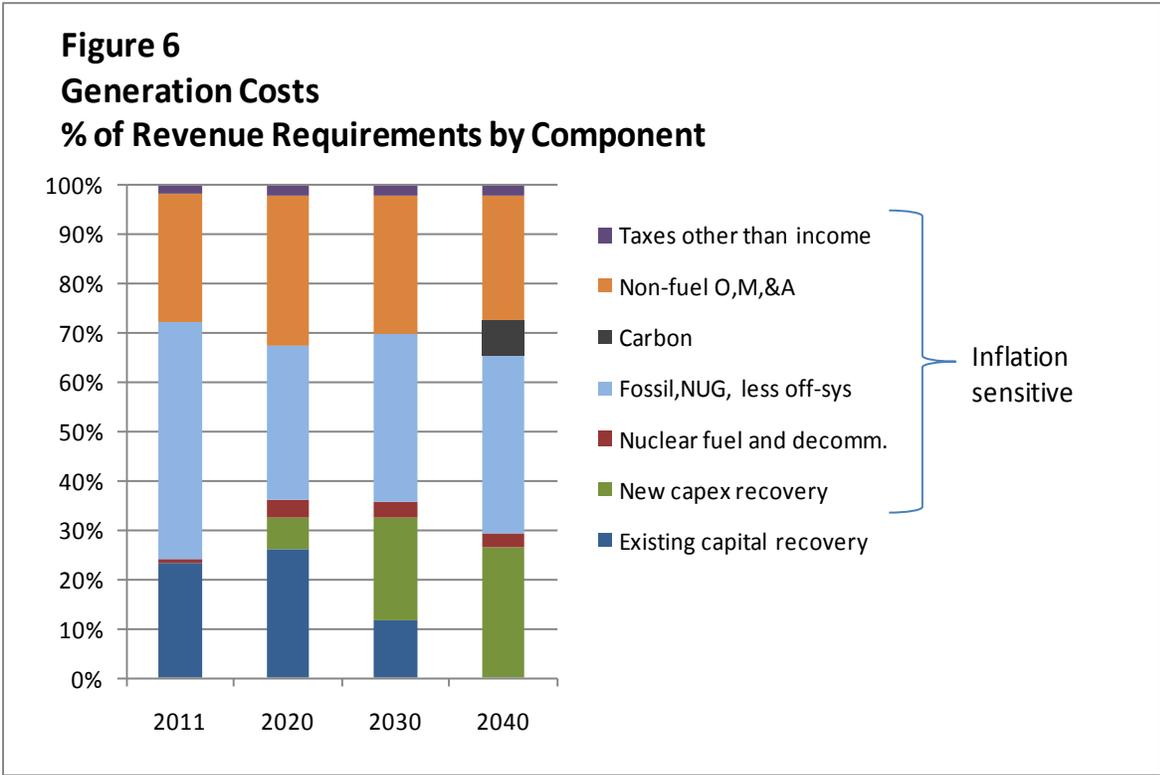
As with any forecast, it is important to recognize that actual results may differ and could be higher or lower, and that alternate assumptions could result in higher or lower estimates of rate savings.

## **V. Risks that Influence the Level of Potential Rate Savings**

NB Power is subject to a variety of risks that could impact rates in the stand-alone case some of which do not affect the Amended Agreement case and thus could affect the level of potential rate savings. The most significant risks include the following:

- Carbon regulation;
- Coal/petcoke/natural gas and oil price volatility;
- The outage of a single large generation facility;
- Foreign exchange rates;
- Construction cost overruns for major generating unit refurbishments/replacements; and
- Interest rates at the time that NB Power needs to raise large amounts of capital for generation refurbishments/replacements.

The acquisition by HQ as outlined in the Amended Agreement would remove these risks from NB electricity users. Under the Amended Agreement case, NB electricity customers would continue to be exposed to potential rate increases driven by general inflation. However, NB Power is also exposed to inflationary pressures in the stand-alone case, particularly over the longer-term as existing assets must be replaced. Figure 6 shows the composition of generation-related costs in the stand-alone case.



Since all of NB Power’s stand-alone generation costs are subject to inflationary pressures in the long-term, our forecasts indicate that the sensitivity of rates to general inflation is similar in both the stand-alone and Amended Agreement cases.

Many of the risks listed above can go in either direction. For example, fuel prices, foreign exchange rates, interest rates and replacement construction costs could be either higher or lower than our base case assumptions. However, some risks borne by NB customers in the stand-alone case, like carbon regulation or the outage of a single large generation facility, are more likely to cause higher rates than we have forecast for the stand-alone case rather than lower rates. NB electricity customers would not be exposed to these risks in the Amended Agreement case.

**VI. Sensitivity Analyses**

NERA prepared sensitivity analyses to illustrate the impacts on estimated rate savings of changes in certain key assumptions. These sensitivities and the resulting present value of rate savings under each case are summarized below.

- *Carbon regulation* – for this sensitivity analysis, NERA assumed that carbon prices would follow the trajectory forecast by the U.S. Department of Energy in its August 2009 assessment of the proposed Waxman-Markey bill<sup>3</sup> and that NB Power’s free allocation of allowances would decline from 100 percent of its emissions through 2020 to zero by 2030. By avoiding the significant carbon costs assumed in this scenario, the NPV of rate savings under the Amended Agreement case in this instance would increase by up to \$2.4 billion relative to the base case, for a total of up to \$ 7.4 billion of savings. It is possible that NB Power could take action in the case to lower the impact, for example by shutting down some existing fossil generation plants, but the impact would still be to substantially increase the savings available under the Amended Agreement relative to the stand-alone case.
- *Inflation* – for this sensitivity analysis, NERA assumed that inflation was 4 percent as opposed to the Canadian Conference Board forecast of about 1.9 percent. This affects operating expense increases in both the stand-alone case and the Amended Agreement case, the cost of equity in the Amended Agreement case, and the discount rate. It would also likely increase the cost of debt as existing debt matures and is refinanced. The net effect is an increase in the NPV of rate savings to \$5.3 billion if we consider only the expense impacts, increased cost of equity in the Amended Agreement case, and higher discount rate. This estimate would likely increase if we included impacts on the cost of debt, although that is more difficult to estimate since it depends on the maturities of future debt issues. What is significant is that substantially higher inflation does not reduce, and in fact appears to slightly increase, the estimated rate savings.
- *Real escalation in fuel and purchased power costs* – for this sensitivity analysis, NERA assumed no real escalation in fuel and purchased power costs rather than the 1 percent assumption in the base case. The NPV of rate saving in this case would decrease to \$ 3.4 billion. This indicates that fuel price assumptions are a major driver of the value of the estimated rate savings.
- *Real escalation in off-system sales revenues, interruptible prices and new supply costs* – for this sensitivity analysis, NERA assumed that off-system sales revenues and interruptible prices escalate at 1 percent above inflation in real terms and that new supply costs escalate at 0.5 percent in real terms. New supply costs escalate less than market revenues as a portion will be fixed once constructed. The net effect of this would be a reduction in benefits to \$ 4.5 billion.
- *Replacement capital costs* – for this sensitivity analysis, NERA assumed 50 percent cost overruns in NB Power’s refurbishment of Mactaquac and Belledune, and a second Point Lepreau refurbishment. Since these costs would be avoided under the Amended Agreement case, the net effect is an increase in customer savings to \$6.0 billion.

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<sup>3</sup> “Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009”; Energy Information Administration, U.S. Department of Energy; August 2009

- *Discount rate* – an increase in the discount rate to 6.5 percent from the base assumption of 6.0 percent would decrease the NPV of rate savings to \$4.4 billion, while a decrease in the discount rate to 5.5 would increase the NPV of savings to \$5.8 billion.

## **VII. Qualifications, Assumptions and Limiting Conditions**

The following qualifications, assumptions and limiting conditions are in addition to those set forth in other sections of this document. Information furnished by others which is incorporated or reflected in the rate forecasts is believed to be reasonable but has not been verified by NERA. No assurance is given by NERA as to the accuracy of such information. Public information and industry and statistical data which is included or reflected in this document are from sources considered by NERA to be unbiased; however, NERA makes no representation as to the accuracy or completeness of such information and has accepted the information without further verification. The forecasts are based on current data and what NERA believes to be reasonable assumptions such as the assumption that expense levels will increase commensurate with inflation. Such assumptions represent judgments that NERA believes to be reasonable, and have been reviewed with NB Power, but have not been developed using statistical methods or using historical trends. The rate forecasts, as are any such forecasts, are subject to inherent risks and uncertainties. In particular, actual results could be impacted by future events which cannot be predicted or controlled, including, without limitation, changes in technology, changes in fuel prices and exchange rates, changes in market and industry conditions, the outcome of contingencies and changes in law or regulations. NERA accepts no responsibility for actual results or future events. No obligation is assumed on the part of NERA to revise this document or the forecasts herein to reflect changes, events or conditions which occur subsequent to the date hereof. NERA does not accept any liability with respect to any party's use of this document or the forecasts herein. In particular, NERA shall not have any liability to any party in respect of this document or the forecasts contained herein or any actions taken or decisions made as a consequence of this document and the forecasts contained herein.