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September 20, 2019

Ms. G. Cheryl Blundon
Director of Corporate Services and Board Secretary
Newfoundland and Labrador Board of Commissioners
of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

Dear Ms. Blundon:

Re: **Muskrat Falls Rate Mitigation Options and Impacts Review (the "Review") – Pre-Filed Testimony**

Further to the above-noted matter, enclosed please find the original and eight (8) copies of the pre-filed testimony of Mr. Patrick Bowman, Principal and Consultant with InterGroup Consultants Ltd., filed on behalf of the Island Industrial Customers Group ("IIC").

Mr. Bowman will be the only witness called by the IIC at the Review's public hearing. Mr. Bowman is expected to give testimony with respect the following issues:

- The importance of rate mitigation for the IIC's members;
- Liberty Consulting's comments on foregoing Government benefits and returns;
- Liberty Consulting's conclusions on increasing cost efficiency through integration of Newfoundland and Labrador Hydro and Nalcor Energy;
- Liberty Consulting's conclusions on rate mitigation through changes in depreciation methodology;
- Synapse Energy's conclusions on rate mitigation through electrification and peak load reductions;
- Synapse Energy's conclusions on conservation and demand management; and
- Issues arising from the pre-filed evidence filed by or on behalf of the other Intervenors.

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September 20, 2019

We trust you will find this to be in order.

Yours very truly,

Denis J. Fleming

DJF/js
Encl.

c.c. <u>Public Utilities Board</u>
Jacqui Glynn
Maureen Greene
Kim Simms
Rate Mitigation Review
<u>Naclor Energy</u>
Gregory J. Connors
Peter Hickman
Jennifer Gray
David Eaton
<u>Newfoundland and Labrador Hydro</u>
Geoff Young, Q.C.
NLH Regulatory
<u>Newfoundland Power Inc.</u>
Kelly Hopkins
Liam O'Brien
NP Regulatory
<u>Industrial Customer Group</u>
Paul Coxworthy, Stewart McKelvey
Dean Porter, Poole Althouse
<u>Consumer Advocate</u>
Dennis Browne, Q.C.
Stephen Fitzgerald
Sarah Fitzgerald
Bernice Bailey
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Newfoundland and Labrador
The Board of Commissioners of Public Utilities

Muskrat Falls Project
Rate Mitigation Options and Impacts Review

Pre-filed Testimony
of Patrick Bowman

InterGroup
CONSULTANTS

Submitted to:
The Board of Commissioners of Public Utilities
on behalf of Island Industrial Customers Group

September 20, 2019

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1.0 INTRODUCTION

This testimony has been prepared for three Island Interconnected Industrial Customers (known collectively as the "IIC Group")[1] of Newfoundland and Labrador Hydro ("Hydro" or "NLH") by Mr. Patrick Bowman, Principal and Consultant with InterGroup Consultants Ltd. ("InterGroup"). This evidence is submitted in relation to the public hearing into the Muskrat Falls Rate Mitigation Options and Impacts by the Board of Commissioners of Public Utilities ("Board" or "PUB").

The IIC Group includes three large industrial companies currently operating in Newfoundland and Labrador. These companies are:

- Corner Brook Pulp and Paper Limited ("CBPP");
- NARL Refining Limited Partnership ("NARL"); and
- Vale Newfoundland and Labrador Limited ("Vale").

Mr. Bowman's qualifications are set out in Appendix A.

InterGroup was initially retained in June 2001 to assist in addressing the 2001 Hydro Rate Review, and subsequently assisted the IIC in the 2003, 2006, 2013 and 2017 rate reviews, as well as the 2009 review of the Rate Stabilization Plan ("RSP"), as well as the ongoing NLH Cost of Service review, submitting evidence for each application. InterGroup also provided limited advice in the 2012 review of depreciation methodology but did not provide evidence.

In preparation for this testimony, the following information was reviewed:

- The primary focus was on the September 3, 2019 reports prepared by Liberty Consulting Group ("Liberty") and Synapse Energy Economics ("Synapse");
- The Request for Information ("RFI") responses from NALCOR Energy Corporation (together with its subsidiaries and affiliates, "Nalcor") and Newfoundland Power; and
- Regulatory filings and decisions from the PUB's website and certain other publicly available information.

InterGroup has been asked to identify and evaluate issues of interest to industrial customers, taking into account normal regulatory review procedures and principles appropriate for Canadian electric power utilities.

[1] This evidence refers to all industrial customers in the Island Interconnected system as Industrial Customers, or IC.

2.0 SUMMARY OF RECOMMENDATIONS

The following recommendations are made for the reasons set out in the discussion and analysis in this report.

- **Recommendation 1:** Dividends and water rentals from LCP and dividends from MF Excess Energy should be targeted to rate mitigation to help address the unacceptable impacts from the MFP coming into service.
- **Recommendation 2:** Absent direct and compelling evidence of difficulties accessing capital markets (for NLH or Government), Hydro's equity target should be revised to 20% or lower. The resulting benefit in the form of dividends (or potentially a lowered ROE target) should be part of rate mitigation to customers.
- **Recommendation 3:** In support of evidence of self-sufficiency and regulatory independence, the Board should recommend a broadening of the scope of regulation, including certain currently unregulated aspects of the Nalcor operations such as LCP and NEM.
- **Recommendation 4:** There does not appear to be material benefits available from NP/NLH asset transfers, and this topic should not be prioritized as a mitigation action.
- **Recommendation 5:** To avoid over-investment by NP in assets that do not produce economic output, NP should be directed to evaluate resource planning decisions based on consolidated IIS marginal costs, and not the wholesale rates paid by NP.
- **Recommendation 6:** NLH should be directed to aggressively pursue operating and integration cost savings in the areas identified by Liberty and report on progress at the next GRA.
- **Recommendation 7:** Investigation into the potential for alternative approaches to depreciation (including non-straight-line) and other delayed capital recovery methods should not be terminated. If limits exist in the commercial agreements which prevent achieving mitigation on the basis of revised depreciation approaches, discussions with partners may be necessary to ensure the benefits can form part of the rate mitigation.
- **Recommendation 8:** The PUB should recommend Government conduct a comprehensive review of industrial competitiveness in regard to both load retention, competitiveness of existing energy-intensive firms, and attraction of new industrial loads, in support of maximizing the value of the MFP surplus.
- **Recommendation 9:** Electrification should be pursued to yield both overall rate mitigation benefits to all ratepayers, while also yielding customer cost savings benefits to participants.

- **Recommendation 10:** Electrification efforts should be packaged with programs to reduce peak load, including Demand Response and industrial curtailment and capacity assistance programs.
- **Recommendation 11:** NLH and NP should primarily restrict CDM to activities where it can be shown that the programming results in reductions to rates (e.g., a positive RIM test) compared to the rate levels required without the CDM programs.

3.0 THE INTERGROUP ASSIGNMENT

InterGroup was retained to focus on issues of interest to industrial customers generally, and to the IIC Group in particular.

The members of the IIC Group are large energy consumers who are presently in production and operate with high load factors (i.e. they have relatively comparable levels of energy use throughout the day and throughout the year).

There are two other Hydro industrial customers who are part of the same industrial class (Teck and Praxair). During the review of Hydro's 2017 GRA, Hydro stated the energy purchases for Teck reflect continued mine site reclamation and environmental protection requirements as Teck's mine closure activities are continuing. Hydro also confirmed that Teck is purchasing power at transmission voltage and will continue to be treated as an industrial customer at low load levels.[2] Praxair represents about 7% of total IC load.

The customers that comprise the IIC Group have a forecast of 691 GW.h of firm electricity in 2019 (about 10% of the total firm energy delivered by Hydro to the Island Interconnected system). The entire industrial class (i.e. including Teck and Praxair) has a forecast firm load of 743 GW.h for the 2019 test year, with $45.7 million in total allocated costs.[3]

Island industrial customers are engaged in capacity assistance and load curtailment agreements with Hydro that are used to minimize disruptions of load to all IIS customers in the event of a contingency or to maintain sufficient level of operating reserves for reliable operation of the grid.[4]

Industrial Customer concerns are normally focused around the following:

- Long-term stability and predictability in electricity rates;
- Fair allocation of costs between the various customer classes to be served;
- Flexibility to tailor electrical service options to suit their operation, so as to achieve an appropriately firm supply at the lowest cost for the load being served (i.e. using a mix of self-generation, Hydro firm power, Hydro interruptible power, curtailable service, etc.);
- Continued reliability of power supply; and
- Lowest cost for power that can be achieved within the above considerations.

The concerns of the IIC Group reflect the size of their capital investments in Newfoundland and Labrador, the long-term perspective essential to such investments, and the major stake that a customer with these investments typically has in continued large-scale power purchases from Hydro.

[2] 2017 GRA, IC-NLH-080.

[3] Based on Hydro's 2017 GRA Compliance Filing, 2019 Test Year Cost of Service Study, Schedule 1.3.1.

[4] Hydro's 2017 GRA Volume I, page 3.25.

4.0 OVERVIEW OF REFERENCE

4.1 BACKGROUND

The Muskrat Falls Rate Mitigation Options and Impacts review was initiated by the Government of Newfoundland and Labrador via a Reference ("Reference") under section 5 of the *Electrical Power Control Act, 1994* ("EPCA, 1994") dated September 5, 2018.[5]

The focus of the reference is the Muskrat Falls Project ("MFP") comprising the Muskrat Falls Lower Churchill Generation Project ("LCP"), the Labrador Transmission Assets ("LTA") and the Labrador Island Link ("LIL"). Under current assumptions, the addition of the MFP to the Island Interconnected System ("IIS") will cause material increases to power rates to IIS customers of Newfoundland and Labrador Hydro ("NLH") and also consequently to retail customers of Newfoundland Power ("NP").

The reference questions focus on 3 areas:

1) Options to reduce the impact of MFP costs on electricity rates;
2) The amount of energy and capacity required by IIS customers, and available for export; and
3) The potential rate impacts of options identified in (1) above.

The above reference questions were originally understood to include options for financing arrangements for the MFP. This scope was later revised in April 2019 to exclude financing options, pending discussions between the federal and provincial governments about potential rate mitigation opportunities.[6]

In the absence of solutions arising from the mitigation review, recent estimates indicate industrial customers on the IIS could face rate impacts that are extreme, and likely to impair the competitiveness and profitability of the operating companies. In the concurrent Cost of Service review, Hydro indicated the average rate for industrial customers on the IIS (under Hydro's proposal cost allocation approach) would rise from 5.22 cents/kW.h in 2019, to 12.44 cents/kW.h after the MFP is fully in service,[7] an increase of 7.22 cents/kW.h or 138%. Though there is no universal definition, many conventional definitions of rate shock suggest caution when increases exceed approximately 15% in a year.

The issues arising from this rate impact are particularly acute given the expected gap between the average industrial rate paid, and the average revenue that could be secured from that same kW.h had it been freed up from industrial use and instead sold on the export markets. As detailed in the Synapse report, the expected marginal value to NLH from avoided energy use on the IIS is 3.3 cents/kW.h.[8] In essence, this same quantity of renewable energy can either yield NLH 3.3 cents from sales on the export market, or multiples of this amount if sold domestically to industrials.

[5] Letter from Minister of Natural Resources to Board of Commissioners of Public Utilities, dated September 5, 2018.

[6] Liberty Phase Two Final Report, September 3, 2019, page 2.

[7] Page 21 of Hydro Cost of Service Methodology Review Application, November 15, 2018.

[8] Synapse Phase 2 Report, September 3, 2019.

Clearly, the best outcome is support of a robust domestic industrial energy-intensive sector. At the same time, a 138% rate increase is directly and materially frustrating this beneficial outcome.

In support of the above conclusion, the Government of Newfoundland announced in April 2019 a plan entitled "Protecting You from the Cost Impacts of Muskrat Falls".[9] That plan (which it appears has not yet been fully detailed) included a provision to "Add Value to Energy Surplus" to achieve a net benefit of $35.5 million, based on two strategies: "Attract new large-scale customers" and "Introduce a new, competitive Data Centre Rate". This represents reasonable and sensible types of initiatives that should be considered for a province with a material energy surplus, and relatively low value export markets, though obviously there are significant issues that must be managed (e.g., why Data Centres may qualify for rates to which more employment-intensive industries may not have access, and why the focus is only on "new" customers and how retention and competitiveness of existing customers may fit in). Note that it is not clear how the $35.5 million value was determined.

The outcome of the above pressures is a system that must optimize all available opportunities for efficiency and rate mitigation, while remaining intensely vigilant regarding any new proposals that unnecessarily raise rates outside of critical initiatives for safety or reliability reasons. This is consistent with the reference questions which focus on the metric of rates (rather than, say, net energy bills to specific classes).

In sum, the reference questions that remain (after elimination of financing options) and are of particular interest to industrial customers on the IIS appear to focus primarily on actions that can occur in five different areas:

1) **Foregoing Government Benefits and Returns:** Liberty's assessment of actions that could be taken by the Government of Newfoundland and Labrador to lower costs via a reduced requirement for Hydro to earn a Return on Equity and maintain specified equity targets (Liberty Chapter II, Section E), as well as opportunities for Government to utilize other sources of energy-sector benefits for rate mitigation (e.g., Churchill Falls dividends and water rentals at Chapter II, Section C, NALCOR Energy Marketing ("NEM") Off-System Sales dividends at Chapter II, Section D) in addition to of the very material MFP Dividends and water rentals (Chapter II, Section B, including LCP, LIL and LTA).
2) **Increased Cost Efficiency:** Liberty's assessment of efficiencies that Hydro and/or NP could achieve to lower overall costs (e.g., Liberty Chapters IV, V, VI).
3) **Depreciation:** Liberty's assessment that there is little upside benefit in alternative approaches to depreciation (Chapter II, Section H).
4) **Benefits from Added Electrification along with Peak Load Reductions:** Synapse's conclusions (e.g., Major conclusions #2, #4, #5) that increasing loads while mitigating demand at a few critical periods during the year can have a beneficial impact on rates.
5) **CDM potential for Bill Savings, only at the Cost of Higher Rates:** Synapse's conclusions (e.g., Major conclusions #3, #6) are more problematic, seeking to implement programs that would increase rates to all customers so that a subset of customers who can

[9] Government of Newfoundland and Labrador. https://www.gov.nl.ca/nr/muskratfallsframework/files/Framework.pdf [accessed on September 18, 2019].

reduce their loads can pay lower overall energy bills, giving rise to material concerns regarding fairness and distributional effects.

Each of the above five action areas is addressed in this submission.

4.2 MITIGATION CONCEPTS

The concept of mitigation is outlined in the Reference letter dated September 5, 2018. The key focus is on rate impacts, as follows:[10]

> … the June 23, 2017 [Muskrat Falls Project] update forecasts that, without taking mitigating actions, rates for domestic customers on the Island of Newfoundland will increase to 22.89 cents per kilowatt hour in 2021, and related increases are expected for other Island rate classes.

The Reference document specifically notes that "Government's position is that the projected rate increases associated with the Muskrat Falls Project costs are not acceptable."[11]

Task #1 for the Board is to investigate "Options to reduce the impact of MFP costs <u>on electricity rates</u> up to year 2030…" (emphasis added).[12]

In relation to the concept of mitigation, Government released a plan dated April 2019 entitled "Protecting you from the Cost Impacts of Muskrat Falls" which included a tentative plan for mitigation, noting: "(w)e will use the PUB's final report, expected in January 2020, to inform our final plan on paying for Muskrat Falls".[13]

Under the tentative plan, a series of actions are highlighted which would be understood to frame the scope of activities anticipated to be under consideration to address rate mitigation. The topic areas and valuation are summarized in the following figure from the Government tentative plan.

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[10] Letter from Minister of Natural Resources to Board of Commissioners of Public Utilities, dated September 5, 2018. Page 2.

[11] Letter from Minister of Natural Resources to Board of Commissioners of Public Utilities, dated September 5, 2018. Page 2.

[12] Letter from Minister of Natural Resources to Board of Commissioners of Public Utilities, dated September 5, 2018. Page 2.

[13] Government of Newfoundland and Labrador Muskrat Falls Framework: "Protecting You from the Cost Impacts of Muskrat Falls", page 2. https://www.gov.nl.ca/nr/muskratfallsframework/files/Framework.pdf [accessed on September 18, 2019].

Figure 1: Managing Muskrat Falls Tentative Plan from "Protecting you from the Cost Impacts of Muskrat Falls"[14]

Managing Muskrat Falls

		For the Year 2021	Amount Remaining
Funding Requirement (millions)[1]		**725.9**	
	NL Hydro Net Operations Savings - $178.2		
1	Holyrood net fuel savings and inflation impacts	-178.2	547.7
	NL Investment - $249.1 million:		
2	NL Hydro surplus energy	-49.1	498.6
3	Nalcor dividend	-200.0	298.6
	Reducing Expenses - $39.4 million:		
4	Organizational change	-20.0	278.6
5	Muskrat Falls operations and maintenance	-12.0	266.6
6	Isolated diesel systems	-7.4	259.2
	Raising Revenue - $59.2 million:		
7	Fuel Switching / Electrification	-15.0	244.2
8	Add value to energy surplus	-35.5	208.7
9	Holyrood Performance Credits (carbon credits)	-8.7	200.0
	Financial Management - $200 million:		
10	Collaborate with Government of Canada	-200.0	0.0
Cost Impact on You: $0			
Total Provincial Sources: $525.9 M		**Federal Involvement: Addressing $200 M Gap**	

The scope of activities set out above comprises both cost changes that will happen naturally with the in-service of MFP (e.g., Holyrood reduced fuel) as well as changes to costs that will only happen with Government action.

It is important to note that a significant portion of the mitigation activities relate to changes to the assumed financial model under which Government would otherwise profit from the MFP, at the expense of ratepayers. The largest single category referenced is "NL investment" at $249.1 million from funds which, under a previously assumed financial model, were withdrawn from the electricity sector to pay to Government.

[14] Government of Newfoundland and Labrador Muskrat Falls Framework: "Protecting You from the Cost Impacts of Muskrat Falls", page 5.

It is also important to note that other than the placeholder $200 million conceptual support from the Government of Canada, the other forms of mitigation noted all directly or indirectly relate to changing the cost or revenue structure of Nalcor or NLH (e.g., through affecting the cost of capital, or operational costs, or maximizing the value of export energy already anticipated to be produced by the assets being paid for by ratepayers.). The anticipated actions are not in the form of explicit subsidies from government general revenues. In order to address affordability issues and the difficult transition to in-service of a new major generating station, some period of direct subsidies may be advisable (e.g., compared to permanently losing a beneficial long-term commercial or industrial load due to competitiveness factors), but this should generally be a lesser priority consideration until all valid cost change opportunities have been explored.

5.0 COMMENTS ON THE LIBERTY REPORT

The Liberty report (September 3, 2019) addresses rate mitigation options focused on the total revenue requirements of NLH and NP, the structure of Nalcor, and potential efficiencies from operations. Three of the five areas of comment in this submission relate to topics contained in Liberty's report.

5.1 FOREGOING GOVERNMENT BENEFITS AND RETURNS

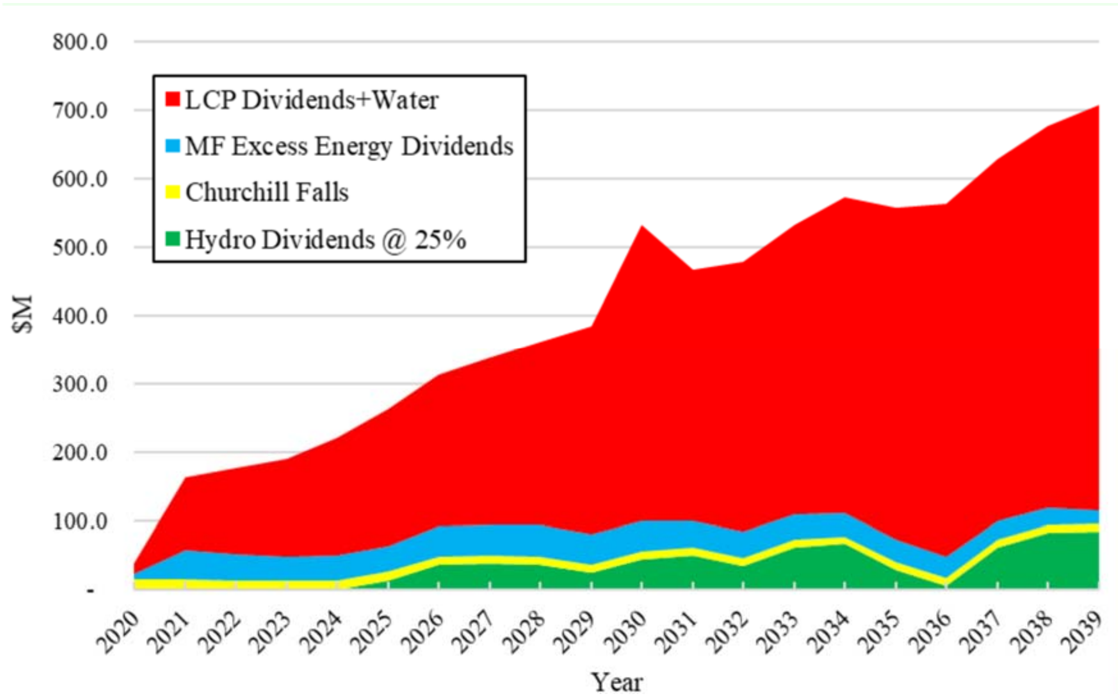
The original concept for the MFP included a premise that the provincial Government would secure material returns or other benefits from the MFP development. Some aspects of these benefits, such as taxes earned from construction employment, will have already occurred by the time of the project in-service. Other aspects relate to payments to Government in the form of ongoing charges or fees (particularly water rentals), and dividends from the various MFP components, as well as revenues from export of power. These fees and dividends have been assumed to be paid, absent mitigation, even though the MFP project in question is not commercially viable and cannot sustain such payments or fees without excessive increases to rates.

On top of the MFP components, the existing regulated operations of NLH, as well as the operations of Churchill Falls, generate benefits to Government tied to net income in these companies, growth in retained earnings, and in some cases, dividends.

The Liberty report suggests reconsideration of this entire suite of benefits targeted to Government, in favour of needed rate mitigation. This suite of actions is described by Liberty as "Financial Opportunities", as shown in Figure VII.2 of the Liberty Report, reproduced below:[15]

[15] For example, see Liberty Phase Two Final Report, September 3, 2019, page 93.

Figure 2: Potential Annual Mitigation from Financial Opportunities[16]



As noted in Figure 2 above, the Liberty assessment of potential mitigation benefits from foregone Government benefits is a substantial and growing amount. However, the largest values only arise later in the 20 year sequence portrayed. In the early years (approximately 2021 to 2024) the benefits total less than $200 million per year, primarily comprised of foregone Lower Churchill dividends and water rentals, and foregone dividends associated with MFP excess energy. The existing Churchill Falls dividends make up a small proportion of the potential mitigation resources, and foregone earnings from the regulated parts of NLH makes up very little if any.

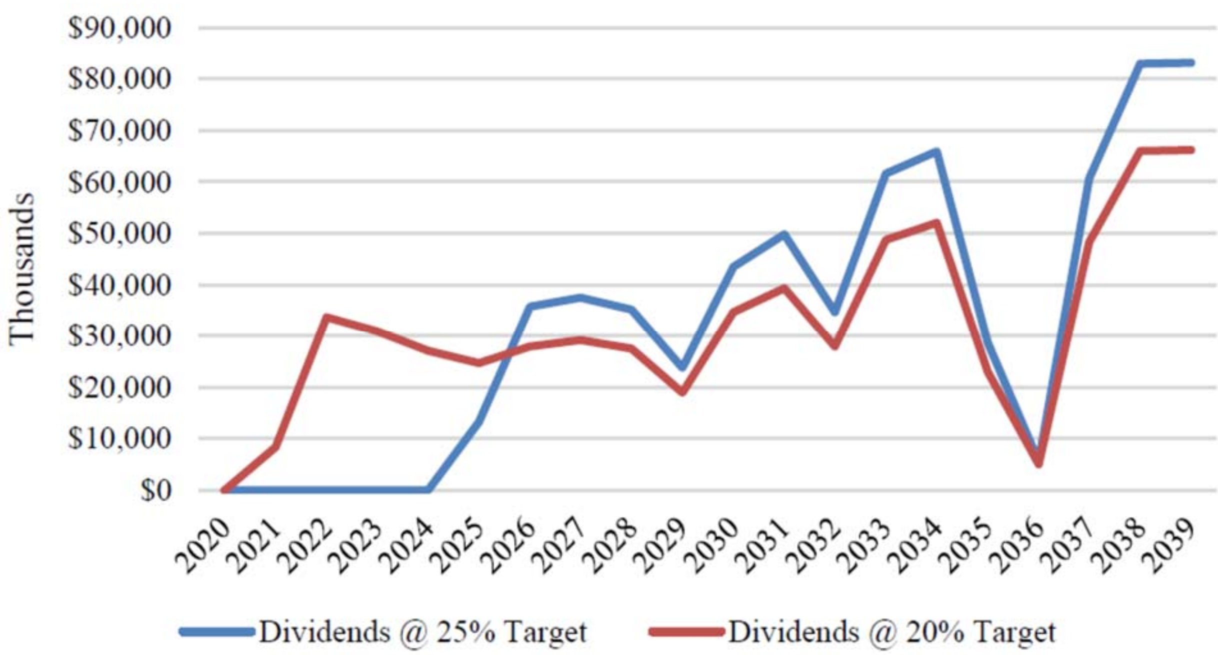
The benefits that can arise from foregone LCP dividends and water rentals are material to rate mitigation. Absent a full pursuit of these benefits, it does not appear that there is much in the way of mitigation that can replace these beneficial effects to alter the unacceptable rate forecasts. Further, the excess energy from the MFP is being produced from assets that are largely funded by IIS ratepayers, and should be reflected in the benefits ratepayers receive from the projects.

The Churchill Falls dividends appear to bear less direct relevance to the MFP rate impacts and are of a much smaller magnitude. The rationale for including these dividends in rate mitigation appears to relate mostly to the fact that they tangentially relate to the power sector.

[16] Liberty Phase Two Final Report, September 3, 2019, page 93, Figure VII.2.

The limitation in regard to the Hydro dividends is that the regulated company is presently at a 18.8 per cent debt:equity level,[17] but is targeting to achieve a 25 per cent equity ratio pursuant to Government policy, and no dividends are available to fund mitigation activities until the 25 per cent ratio is reached in approximately 2024. Liberty notes that having NLH adopt an alternative 20 per cent equity ratio target rather than a 25 per cent target would result in the ability to pay dividends starting in 2021 (based on exceeding the 20 per cent equity ratio in that year) which could be targeted to rate mitigation, as shown in Liberty's Figure II.8, reproduced below:

Figure 3: Dividends at 20 and 25 Percent Equity Maintenance Levels[18]



The above Figure 3 illustrates that under a 25 per cent equity target (the blue line), there are no dividends from the regulated utility to assist in supporting rate mitigation until after 2024, while under a 20 per cent target (the red line), dividends are available starting 2021. In the years where dividends are noted as being available, there is the opportunity to reduce rates (and the returns built into rates) to allow Hydro's regulated costs to be set at a lower level.

Liberty cautions that adjusting the NLH equity target could risk the perception of NLH as a "self-sustaining entity"[19] which Liberty indicates could adversely affect the Province's credit.

[17] Liberty Phase Two Final Report, September 3, 2019, page 22.

[18] Liberty Phase Two Final Report, September 3, 2019, page 93, Figure II.8.

[19] Liberty Phase Two Final Report, September 3, 2019, page 21.

The Liberty report concludes that "financial sources of mitigation offer by far the largest opportunities",[20] totalling on the order of 3-4 cents/kW.h in the 2021-2025 period.[21]

On balance, the Liberty report highlights 4 areas, each of which is worthy of pursuit at the level noted, if not at an enhanced level. For example, the LCP and MF Excess Energy Dividends combined with Water Rentals, as calculated by Liberty, total somewhere on the order of $150 million per year, per Figure VII.2 from the Liberty September 3, 2019 report, while the Government mitigation plan indicates a potential for $249.1 million from these same general sources (which potentially does not even yet include water rental relief) at page 6 of the April 2019 plan, "Protecting you from the Cost Impacts of Muskrat Falls". Each of these components is a potential material contributor to efforts at mitigation. Care should be taken to ensure the highest reasonable values are being achieved.

> **Recommendation 1:** Dividends and water rentals from LCP and dividends from MF Excess Energy should be targeted to rate mitigation to help address the unacceptable impacts from the MFP coming into service.

In regard to the potential adjustment of Hydro's regulated equity target, it would make little sense to continue with a path of building equity in Hydro, at the expense of ratepayers, at a time when mitigation efforts are underway and ratepayers are effectively unable to fund these increases. Part of the benefit of a Crown utility is the opportunity to manage or relax financial targets where the broader public interest is served by a longer-term outlook. For example, in Manitoba, a similar major hydraulic generation development is underway (Keeyask Generating Station, as well as Bipole III HVDC Transmission). A lengthy and detailed Manitoba Public Utilities Board (MPUB) hearing of 34 days was held in 2017/18 to evaluate (and ultimately reject) a proposed new financial plan that sought to build equity during the period that the new projects were coming into service, so as to achieve a 25% equity ratio within 10 years. At the time, Manitoba Hydro exhibited a 16% equity ratio (down from a previous 25% level achieved during the 2009-2014 period, before the major new expansion proceeded). The 2017/18 hearing included extensive evidence regarding capital markets and the potential impact of a Crown utility on the parent Government's credit ratings, including input from specific Capital Markets experts (Morrison Park Advisors). The MPUB ultimately adopted a scenario that was "directionally consistent with the Board's directions in this Order"[22] and permitted the equity level to drop to 12% over approximately 10 years before growing to 25% by year 20.[23] The MPUB concluded:[24]

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[20] Liberty Phase Two Final Report, September 3, 2019, page 92.

[21] Liberty Phase Two Final Report, September 3, 2019, Figure VII.3, page 94.

[22] Manitoba Public Utilities Board Order No. 59/18, page 173. Available at http://www.pubmanitoba.ca/v1/proceedings-decisions/orders/pubs/2018%20orders/59-18.pdf [accessed on September 18, 2019].

[23] Manitoba Hydro 2017/18 GRA, Exhibit MH-93. Available at http://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/pubs/2017%20mh%20gra/mh%20exhibits/mh-93%20-%20follow%20up%20questions%20to%20mh%20undertaking%207%20and%208%20from%20mipug.pdf [accessed on September 18, 2019].

[24] Manitoba Public Utilities Board Order No. 59/18, page 20.

> …the Board finds that a particular equity level or pace to achieve such a target should not determine the rate increases approved in this GRA, particularly when Manitoba Hydro is undergoing record expansion in the value of its capital assets.

This was consistent with previous MPUB recommendations when the major new generation and transmission was being embarked upon in 2013, when the MPUB produced a recommendation to Government as follows:[25]

> The Panel supports a relaxation of Manitoba Hydro's 75/25 debt-to-equity ratio to smooth out rate increases and the Panel concludes that Manitoba Hydro would still be left with sufficient retained earnings if the equity level was decreased.

On the matter of potential impacts on Government credit ratings, the MPUB noted:[26]

> The Board accepts Morrison Park Advisors' evidence that debt-to-equity is a questionable metric for a vertically integrated monopoly Crown utility with a debt guarantee from the provincial government. The equity level target does not have the prominence suggested by Manitoba Hydro given the context in which the Utility operates.

Further:[27]

> The Board accepts the evidence of Morrison Park Advisors that the capital markets will be reassured by a long-term rate plan that acceptably manages Manitoba Hydro's risks and by this Board's regulatory action where required to address circumstances as they arise.

It is noted that Liberty highlighted the importance of capital markets and credit rating agencies in relation to the potential to adjust NLH's equity target, at pages 21-23. Liberty notes that changes to NLH's equity target have a theoretical potential to adversely affect the Province's borrowing costs. It is not clear that Liberty retained a specific credit rating or capital market expert to generate this conclusion, which would be appropriate and necessary to make a defensible assessment in these areas. While Liberty's conclusion is that yielding on the equity target (to 20%) would produce "a smoother future rate path"[28] and free up $111 million of potential mitigation support,[29] and this is clearly a benefit to mitigation efforts, Liberty did not include the financial impacts on this change in the summary of Financial Sources of Rate Mitigation at Figure II.9.

Concerns arise regarding Liberty's apparent caution in this area, as follows:

- **Limited Importance of Equity:** Liberty focuses on an implied interest of capital markets in "What equity level is required to keep Hydro self-sustaining" so that the Province does not "risk change to its financial standing due to issues and uncertainties at and involving

[25] Manitoba Public Utilities Board Order No. 59/18, page 64, quoting from the MPUB Report to Government on the Needs For and Alternatives To Manitoba Hydro's Preferred Development Plan, June 2014, page 29.

[26] Manitoba Public Utilities Board Order No. 59/18, page 63.

[27] Manitoba Public Utilities Board Order No. 59/18, page 69.

[28] Liberty Phase Two Final Report, September 3, 2019, page 24.

[29] Liberty Phase Two Final Report, September 3, 2019, page 25.

Hydro".[30] Evidence from the Manitoba Hydro hearing highlighted the extent to which credit rating agencies have exhibited limited interest in short-term equity ratio changes (including erosion), focusing instead on cash flows to meet debt servicing obligations (known as FFO:Debt), competitiveness, and on progress towards long-term targets. Further, Manitoba demonstrated that no adverse credit rating activity (or limits on capital market access) occurred when Manitoba Hydro embarked on a development plan that was expected to reduce its equity ratio from 25% to below 10%, before the new capital assets would begin to permit resumption of growth in equity levels.[31]

- **Importance of Self-Supporting Status:** Liberty also adopts a logical connection that is not borne out in fact, in citing that "A self-sufficient Hydro is material in avoiding adverse rating consequences for the Province. A self-sufficient Hydro keeps some $1.8 billion of Hydro debt and $7-$8 billion of "contingency debt" related to LCP off the Province's books."[32] While the relationship is true (government-related entities deemed not self-sufficient do typically have their debt consolidated into the debt of the parent government), the immediate conclusion that this would be an adverse rating consequence is not, in fact, a given. For example, in recent years S&P has revised their ratings approach for Crown entities and removed the self-supporting status from some utilities such as Manitoba Hydro, SaskPower and NB Power.[33] Manitoba Hydro has indicated that even under their most aggressive financial plans, there is no expectation of meeting S&Ps new criteria for self-supporting status at any time.[34] However, specifically in the case of Manitoba, this has not necessarily led to any downgrading of S&P's Provincial credit ratings. It is also important to note that in S&P's criteria for rating Local and Regional Governments,[35] the criteria specify that when a Government-Related Entity (GRE, such as a Crown Corporation) is deemed not self-supporting "…we consolidate in the tax-supported debt ratio all the GRE's debt and <u>own commercial revenues</u>…" (emphasis added).[36] In other words, if NLH were deemed non-self-supporting, the S&P calculations of the Province's credit would take into account NLH's (or Nalcor's) debt, as well as the associated revenues. As NLH can readily pay all utility costs each year as well as record a positive net income, this consolidation would not necessarily represent an adverse impact on the province. In some cases cited by S&P, such consolidation can yield net positive impacts on the parent government.[37] Proper analysis is required to understand the implications and potential impacts on access

[30] Liberty Phase Two Final Report, September 3, 2019, page 22-23.

[31] Manitoba Public Utilities Board Order No. 59/18.

[32] Liberty Phase Two Final Report, September 3, 2019, page 22.

[33] Manitoba Hydro 2017/18 and 2018/19 General Rate Application, response to MIPUG-MH-I-8h.

[34] Manitoba Hydro 2017/18 and 2018/19 General Rate Application, response to MIPUG-MH-II-17d.

[35] Provided in Manitoba Hydro 2017/18 and 2018/19 General Rate Application, response to MIPUG-MH-I-8a-k Attachment. S&P Global Ratings "Methodology For Rating Non-U.S. Local And Regional Governments", page 44.

[36] Provided in Manitoba Hydro 2017/18 and 2018/19 General Rate Application, response to MIPUG-MH-I-8a-k Attachment. S&P Global Ratings "Methodology For Rating Non-U.S. Local And Regional Governments", page 44.

[37] This is in fact specifically recognized in the S&P methodology, at paragraph 131, where S&P notes that in some cases the parent Government rating could become worse off if the GRE became deemed self-supporting. S&P Global Ratings "Methodology For Rating Non-U.S. Local And Regional Governments", page 36.

to credit markets before assumptions are made regarding the implications for Newfoundland of yielding on Hydro's equity ratio.

- **Credit Rating Impacts of Rate Increases:** A key factor to note from the credit rating reports that have been produced on Hydro (from DBRS)[38] is that the number one cited challenge facing Hydro is "pressure on rates from the Muskrat Falls Project", not pressure on equity ratios or finances. DBRS specifically notes: "DBRS remains concerned about the potential rate shock to ratepayers, which could severely reduce electricity volumes as well as their ability to afford their bills, in turn negatively affecting the Company's earnings and cash flows."[39] This is consistent with the view that ongoing revenues and cash flows are more critical to ratings agencies than any Balance Sheet equity value. This factor also operates in favour of serious consideration being given to adjusting Hydro's equity target in favour of enhancing rate mitigation by the noted $111 million over 2021-2024 (by adjusting Hydro's equity target to 20% or lower), the period where the rate shock is most acute.
- **Importance of Reducing Costs, versus Subsidies:** One factor that may have an impact on the self-supporting status of Hydro is the extent to which mitigation supports are achieved by way of reducing costs to customers, such as reduced return on equity, or water rentals, or redirected export revenues (or potentially redirected dividends), as opposed to subsidies from government general funds. Government financial supports that arise from general revenues are more likely to be viewed as undermining self-supporting status.
- **Other Relevant Considerations for Self-Supporting Status:** For the concerns noted about protecting the Province, it is notable that many of the typical criteria considered by ratings agencies have not been prioritized in Newfoundland and Labrador, despite their potential function in supporting this determination. For example, the S&P criteria specify that a broad scope of regulatory powers to set rates, with limited political intervention, is supporting of "Regulatory Independence and Insulation".[40] The approach to assessment of the MFP, and the structuring of the various unregulated components (LCP, NEM) and targeting of export revenue to Provincial dividends, as highlighted at Section III of Liberty's report, would not generally be viewed as consistent with criteria used to assess whether NLH is self-supporting.

Taking the above factors into account, the mitigation benefits of a potential revision to Hydro's equity target cannot be dismissed lightly. Indeed, failure to adjust Hydro's equity target at a time of severe rate shock is likely to be an adverse impact on loads and competitiveness which may undermine credit ratings by a greater degree than any short-term downward adjustment to the targeted Balance Sheet equity values.

Recommendation 2: Absent direct and compelling evidence of difficulties accessing capital markets (for NLH or Government), Hydro's equity target should be revised to 20%

[38] PUB-Nalcor-213, Attachment 11, page 2 of 9.

[39] DBRS Ratings report March 19, 2019 in PUB-Nalcor-2013 Attachment 11, page 1 of 9.

[40] Provided in Manitoba Hydro 2017/18 and 2018/19 General Rate Application, response to MIPUG-MH-I-8a-k, page 5.

or lower. The resulting benefit in the form of dividends (or potentially a lowered ROE target) should be part of rate mitigation to customers.

Recommendation 3: In support of evidence of self-sufficiency and regulatory independence, the Board should recommend a broadening of the scope of regulation, including certain currently unregulated aspects of the Nalcor operations such as LCP and NEM.

5.2 INCREASED COST EFFICIENCY

Liberty addresses issues related to lowering operating costs on a broad scale, including the Nalcor companies as well as NP. The conclusions suggest a basis for optimism regarding the ability of cost reductions and optimization to support rate mitigation.

Liberty's key conclusion is that cost reductions and efficiencies, including from Nalcor corporate reorganization, were studied "with an expectation of finding modest savings from such transfers, compared with those involving the financial sources of mitigation" and that "Phase Two work proved them even somewhat more modest than expected".[41] Nonetheless, functionally combining Power Supply and Hydro under a unified operating entity could permit a reduction of 113 full-time equivalent (FTE) employees producing $12.7 to $21 million in savings per year.[42] In contrast, scenarios that reflect asset transfers or functional integration with NP were at best small, complicated and difficult to achieve compared to likely costs and complexity in negotiating new arrangements between the utilities.[43] On potential asset transfers, Liberty highlighted that NP has higher carrying costs for capital investments (including income tax), and, as such, any asset transfers must yield operational or efficiency benefits to outweigh this cost of capital disadvantage, which Liberty concluded was unlikely. As a result, Liberty did not recommend asset transfers or transfers of operating responsibilities with NP. The Liberty conclusions in this area appear sound and directionally consistent with expectations and should be adopted.

Recommendation 4: There does not appear to be material benefits available from NP/NLH asset transfers, and this topic should not be prioritized as a mitigation action.

Liberty also highlighted general concerns with the scale of capital spending under the five-year capital plans of NLH and NP, which total $0.5 billion.[44] Without proposing specific alternatives, Liberty recommended these spending levels should be carefully examined, which appears merited.

One area of potential concern is the capital spending incentives applied to NP in respect of their own hydraulic generation. In the future, the marginal value of energy on the IIS is expected to be low. However, the rates expected to be charged to NP (reflecting substantial embedded costs) will be much higher. Under this framework, NP may be incented to evaluate their own resource options, such as whether to retire versus life extend small hydraulic stations, based on the value of output tied to the wholesale rate rather than the true underlying marginal cost of power on the IIS. This

[41] Liberty Phase Two Final Report, September 3, 2019, page 5.
[42] Liberty Phase Two Final Report, September 3, 2019, page 6.
[43] Liberty Phase Two Final Report, September 3, 2019, page 7.
[44] Liberty Phase Two Final Report, September 3, 2019, page 7.

is an economic issue as the NP resource planning should reflect the underlying marginal IIS cost (e.g., 3.3 cents/kW.h).

> **Recommendation 5:** To avoid over-investment by NP in assets that do not produce economic output, NP should be directed to evaluate resource planning decisions based on consolidated IIS marginal costs, and not the wholesale rates paid by NP.

For LCP, Liberty indicated the periods assumed to reach an efficient steady-state operation have been overestimated, and that budgets will likely transition from the new in-service phase to the steady state phase more quickly than presently assumed, aiding O&M costs by up to $12 million in years 3-5 of the project.[45]

Liberty's work is not in the form of detailed cost estimates as would be expected at a GRA, and cannot be immediately quantified or imposed on the companies. However, the conclusions are based on a relatively comprehensive review, working closely with the utilities, and should be given significant weight in the PUB's final recommendations as being worthy of aggressive and detailed pursuit.

> **Recommendation 6:** NLH should be directed to aggressively pursue operating and integration cost savings in the areas identified by Liberty and report on progress at the next GRA.

5.3 DEPRECIATION

The topic of asset depreciation is addressed by Liberty in respect of both NLH, and of the LCP. It is not uncommon to see changes to utility costs arise from reviewing depreciation, in the form of adjustments to asset lives, and to depreciation practices. As a result, reviewing depreciation as part of identifying all potential mitigation options is a prudent course for Liberty to take.

Unsurprisingly, review of NLH depreciation provisions indicated little in the way of potential benefits or cost savings.[46] This is consistent with the fact that depreciation was a material topic in the recent NLH General Rate Application and both service lives and depreciation practices were updated and negotiated with customers. As a result, Liberty identified no obvious further benefits from changes to NLH depreciation.

In respect of the MFP related assets, a review of depreciation in respect of both lives and practices may still be beneficial. However, there are two major limitations that appear to frame the Liberty conclusions:

First, any change to depreciation is a non-cash effect. Reduced depreciation can, in some cases, lead to lower rates to customers, but this will simply be from less cash being provided to the company in question. In the case of mitigation, so long as the cash being generated is being returned to customers as part of mitigation efforts (as discussed in Section 5.1 above), adjusting depreciation expense to reduce cash generation will ultimately lead to no net mitigation benefit. This is the root of Liberty's conclusion that depreciation savings show "a one-to-one correspondence between revenue requirements benefits from depreciation changes and dividends

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[45] Liberty Phase Two Final Report, September 3, 2019, page 7.

[46] Liberty Phase Two Final Report, September 3, 2019, page 27.

available for mitigation".[47] Note however that this conclusion only holds to the extent that 100% of dividends are returned as mitigation support – in the event that dividends are not fully committed to mitigation, cost reductions from depreciation changes would improve mitigation outcomes.

Second, Liberty relies upon the response to Nalcor-PUB-264, which indicates that depreciation for accounting purposes is not necessarily the relevant measure for costs that will be built into rates. The response notes that depreciation for the purposes of developing MFP charges and financing is tied to repayment of debt and an assumed "service life" of the assets that is specified at 50 years. While the response is not precise in wording, Nalcor indicates this could trigger a requirement for agreement among parties not involved in the mitigation inquiry, namely: "These extensions would require that certain commercial agreements be amended and could require the consent of Canada, the Province and other effected (sic) parties."[48]

The Liberty assessments were tied to a theoretical premise that lives of the MFP assets were extended from a 50 year life to a hypothetical 75 year life, though this appears to be simply to test the mathematical outcomes and not necessarily an advocacy from Liberty that 75 years is an appropriate life span. It does not appear that Liberty has taken into account the full potential of depreciation savings that could arise under not just a revision to service life, but also to depreciation methods, and in particular the adoption of non-straight-line methods.

In determining depreciation expense, it is necessary to determine an expected life of an asset, and to allocate the full original cost of the asset to the years of expected service. The most typical way to accomplish this in the utility industry is through straight-line methods – namely, attempting to allocate an equal nominal dollar share of the asset's value to each year of expected service. Such an approach is of serious and detrimental effect when a very long-lived asset, such as a hydro generating station, is first put into service, as the nominal depreciation values are very high in the early years. If the asset life unfolds as expected, this same nominal value of depreciation will be booked as an expense each year – however, as this is an equal nominal value, the real cost of depreciation declines over time. In addition, the cost of financing the asset declines over time as debt is retired. Consequently the combined capital-related costs (interest and depreciation) are heavily front-end loaded. For this reason, alternative depreciation approaches using non-straight-line methods, which are based on recording low nominal depreciation expense in the early years, and inclining depreciation expense with each passing year, can produce a more favourable and fairer allocation of the service value of the asset across all relevant service years. Such approaches are not foreign to the utility industry, including the "sinking fund" approach which was previously used by NLH up to 2012[49] and similar compound interest methods. The Alberta Utilities Commission engaged Foster Associates to study alternatives for delaying capital recovery after a major transmission build-out in that province.[50] The basic conclusion that drives the need for such approaches is highlighted by Foster as follows:

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[47] Liberty Phase Two Final Report, September 3, 2019, page 28.

[48] PUB-Nalcor-264.

[49] Newfoundland and Labrador Board of Commissioners of Public Utilities Order P.U. 40-2012.

[50] AUC Proceeding 2421 Exhibit 2421-X0002. Evaluating Depreciation Alternatives for Delaying Capital Recovery. Foster Associates. February 2014.

> Recalling that capital recovery is the sum of both return of and return on investor supplied capital, the straight–line method will produce a pattern of recovery in which revenue requirements are higher in early years than in later years regardless of the physical units of service provided by an item of plant.[51]

The Foster report conclusion includes the following:

> Regulatory practices that deliberately defer recognition and recovery of depreciation are not necessarily in conflict with cost allocation and accounting theory as long as the opportunity for capital recovery is preserved by the absence of significant competition.[52]

Related mechanisms have been used in past major electric utility developments to avoid the adverse impacts of straight-line depreciation. One example was a leaseback arrangement used to finance the Bipole I and II HVDC lines in Manitoba through a third party (Atomic Energy of Canada, or AECL), described in a document provided to the Manitoba PUB in 2014 as follows:

> Atomic Energy of Canada owned the transmission line, and under the agreement it leased the line to Manitoba Hydro. From 1971 payments to Canada were based on a share of the revenue from sales of electricity over the line; however, the payments fell far short of the annual interest payments (interest rate of 5.625 per cent). In 1977 a repayment schedule was worked out that gradually increased from $2.5 million in 1977/78 to $22.5 million in 1988/89. Any balance remaining at that time was to be amortized over the next thirty years (to 2018/2019) at the original 5.625 per cent interest rate. Unpaid interest accrued to capital which increased from an initial sum of approximately $227 million to approximately $370 million as at 1987. This lease back arrangement enabled Manitoba Hydro to develop the Kettle Rapids hydro generating station, which would not have been viable had the HVDC line been capitalized with the project.
>
> Lease payments for the transmission line were structured to provide economic relief to ratepayers in the early years of development, with anticipated higher rates during the later years. In 1991-1992, Manitoba Hydro bought-out the lease agreement for $198.1 million, resulting in lower charges to operations in the future should they have continued with the arrangement.[53]

The above arrangement obviously involved parties that go beyond the simple Crown utility and provincial Government owner (in this case, AECL). However the own/leaseback arrangement was designed precisely to enable the utility to face lower costs in the early years, akin to mitigation, as a mechanism to avoid the adverse impacts of straight-line depreciation as well as, in that case, a portion of interest that would otherwise be payable.

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[51] AUC Proceeding 2421 Exhibit 2421-X0002. Evaluating Depreciation Alternatives for Delaying Capital Recovery. Foster Associates. February 2014. Page 9.

[52] AUC Proceeding 2421 Exhibit 2421-X0002. Evaluating Depreciation Alternatives for Delaying Capital Recovery. Foster Associates. February 2014. Page 19.

[53] MIPUG Exhibit #26, Manitoba Hydro Need For and Alternative To Review. May 12, 2014.

A key challenge for the current review is the degree of uncertainty as to whether alternative methods of depreciation, such as compound interest, could be practically implemented without agreement of parties who are not presently engaged in the mitigation review, and similarly whether reduction of cash flows associated with depreciation changes would be equal and offsetting to the lost potential use of dividends for mitigation actions. For this reason, clear recommendations to pursue depreciation alternatives cannot be made. However, investigations are merited into mechanisms such as non straight-line depreciation to ensure that the potential impact, which has been used to benefit in past developments such as Manitoba's Bipole I and II, are not foregone.

> **Recommendation 7:** Investigation into the potential for alternative approaches to depreciation (including non-straight-line) and other delayed capital recovery methods should not be terminated. If limits exist in the commercial agreements which prevent achieving mitigation on the basis of revised depreciation approaches, discussions with partners may be necessary to ensure the benefits can form part of the rate mitigation.

6.0 COMMENTS ON THE SYNAPSE REPORT

The Synapse report (September 3, 2019) addresses rate mitigation focused on loads and exports, including Conservation and Demand Management ("CDM").

A significant part of Synapse's report is focused on maximizing export revenue and modelling export values. In general, such efforts merit little comment, as Nalcor has already indicated they plan to maximize export revenue and explore further market optimization, including from such potential options as ponding.[54] Maximizing export revenues through marketing actions should be a high priority item and of no controversy.

Synapse was also asked to weigh on "whether it is more advantageous to Ratepayers to maximize domestic load or maximize exports".[55] The numerical work produced by Synapse should provide a clear answer to this question – it is more advantageous to maximize domestic load with only very few narrow exceptions (e.g., not at heavily discounted domestic rates that are below marginal cost, and ideally not at the expense of managing high peak load hours).

Synapse fails to address one high priority items for industrial customers, the impacts of rate disruption. Synapse includes one paragraph in regard to Load Retention rates (page 121), which are a very specific and limited form of industrial support that Synapse further limits to only situations where "there is a demonstrated and verified risk that load would depart the system without the rate discount".[56] The use of the term "discount" is troubling when contrasted with imposing an uncompetitive and uneconomic source of generation on customers, driving a 138% rate increase while dividends from purported profits on the generation are being paid out to equity investors. Beyond this, Synapse has failed to specifically address impacts on usage patterns of industrial customers, competitiveness factors, and the importance of power rates to factors such as internal competition (whether a particular plant receives capital investment priority within the larger company). Synapse has also addressed the quantification of elasticities, or the price responsiveness of loads to power cost changes, only on an aggregate basis without consideration of class effects. It is well known in the utility literature that classes have different price responses, and industrial are typically among the highest elasticities (due in part to competitiveness reasons).[57] For this reason, Synapse has failed to appropriately address industrial competitiveness factors, and this matter should be more comprehensively addressed as part of the PUB recommendations to Government. This also includes Synapse's failure to address key Government priorities as outlined in the "Protecting You From the Cost of Muskrat Falls" document[58], such as attracting new industrial loads and data centers.

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[54] Nalcor letter to PUB, January 9, 2019, commenting on Phase I reports.

[55] Synapse Phase Two Report, September 3, 2019, page 3.

[56] Synapse Phase Two Report, September 3, 2019, page 121.

[57] Synapse acknowledges this at Synapse Phase Two Report, September 3, 2019, page 26.

[58] Government of Newfoundland and Labrador. https://www.gov.nl.ca/nr/muskratfallsframework/files/Framework.pdf [accessed on September 18, 2019].

> **Recommendation 8:** The PUB should recommend Government conduct a comprehensive review of industrial competitiveness in regard to both load retention, competitiveness of existing energy-intensive firms, and attraction of new industrial loads, in support of maximizing the value of the MFP surplus.

It is important to recognize that Synapse's report is an analysis of scenarios. Synapse has not conducted detailed market or program design for achieving success under the scenarios, and similarly has not precisely refined the degree of program costs or support that would be necessary to achieve the noted scenario outcomes. For example, under scenarios with significant electrification, Synapse has estimated that $350 to $1000 per ton would need to be applied as an incentive to get customers to install heat pumps where the customers currently use oil boilers.[59] As discussed at the Technical Conference on August 1, 2019, it is understood that there is significant uptake of heat pumps currently occurring on the IIS, so the evidence for these precise incentives being required is not apparent. Detailed program design is required before such market assessment can be properly and fully concluded. For this reason, the Synapse recommendations should be understood as directionally valid, and likely quantitatively appropriate within a wide range, but would not generally qualify as detailed estimates of economic impacts.

6.1 ELECTRIFICATION AND PEAK LOAD REDUCTIONS

Synapse does a relatively extensive review of options for electrification, and separately for peak load reductions. The two topics are closely linked, as NLH's future resource needs reflect a relative surplus of energy at a low marginal cost (3.3 cents/kW.h) but a potential shortfall of peak capacity at a limited number of peak hours, at a relatively high marginal cost ($317 per kW-year). Load building through electrification at rates above 3.3 cents/kW.h (particularly at the full retail rate) is therefore highly advised, so long as peak loads can be contained.

Synapse has developed a series of cases involving what is considered "high electrification" (primarily Case #10) and applying various peak load management efforts. In the first instance (electrification without extra peak load management), Synapse achieves among the best rate impact outcomes of all cases studied, as follows, focused on 2025 (Per Table 2, page 8):

- Pursuing high electrification adds $67 million in sales to NLH, while $13 million of export sales are lost. The net benefit of the added revenue is therefore $54 million.
- In order to achieve the scenario, an annualized cost of $3 million is necessary to incur (e.g. programming).
- Since the loads have increased, there will be a need to invest in more peak capacity resources for the few hours where the system is at its highest point. The annualized cost of this is $17 million.

[59] Synapse Phase Two Report, September 3, 2019, page 52.

- The net benefit to the utility from electrification is therefore $54 million added revenues, less $3 million in program costs, less $17 million in capacity costs, for a net $34 million benefit.

The resulting $34 million comprises all relevant cost and revenue changes to NLH. This is a net revenue requirement impact that yields an opportunity to lower rates to all customers. Synapse calculates the net impact on rates as a 0.49 cent/kW.h benefit. Note that this is a sustainable annual benefit, and further that this 0.49 cents/kW.h is solely the beneficial impact on all ratepayers – for the customers participating in electrification, there is a further benefit from avoiding costs for oil and instead using electricity in a heat pump or electric vehicle, as described in Synapse's report Section 5.4.

Based on the above assessment, electrification is a material and valid component of both rate mitigation and energy optimization on the IIS and should be pursued vigorously, so long as the electrification is not excessively driving new demand peaks (e.g., programs should have substantial energy use through as much of the year as can be accommodated, not just acute peaks at times that are already demand constrained). Incentives should be carefully tested to ensure aggressive program targets can be achieved, without overpaying incentives to generate free ridership (or incentives being paid beyond the level actually needed to encourage adoption).

> **Recommendation 9:** Electrification should be pursued to yield both overall rate mitigation benefits to all ratepayers, while also yielding customer cost savings benefits to participants.

As an enhancement to electrification, Synapse has considered various potential programs to reduce the impacts of electrification on driving new demand peaks. This includes both incentives for electric vehicles to charge at off-peak hours (Case #12), and for adding a Demand Response program (Case #12a). Outside of cases that Synapse models with uncontrollable variables benefitting NLH (e.g., high export prices), Case #12a most fully satisfies the scope that was required for the Synapse investigation – namely, maximizing the mitigation of MPF costs on electricity rates. In contrast to Case #10, Case #12a makes immaterial differences to domestic or export revenues but invests $4 million annualized in added program costs to avoid $10 million annualized in capacity related costs, to bring the net benefit from $34 million (Case #10), to $41 million (Case 12a).[60] The resulting impact on rates improves from 0.49 cents/kW.h to 0.6 cents/kW.h.[61] As with Case #10, Case #12a is similarly a win-win scenario as all ratepayers collectively benefit from the lower rate, and participants further benefit from their adoption of electrification.

At the same time, it must be recognized that Demand Response (such as industrial curtailable and capacity assistance programs) can only be achieved with cooperation of customers and appropriate compensation for taking on the risks of the loss of supply at key times. NLH has a successful history with such programs, and it should be assumed these are able to continue to be part of managing demand on the IIS.

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[60] Synapse Phase Two Report, September 3, 2019, page 8. Table 2.

[61] Synapse Phase Two Report, September 3, 2019, page 7. Table 1.

Recommendation 10: Electrification efforts should be packaged with programs to reduce peak load, including Demand Response and industrial curtailment and capacity assistance programs.

Other peak load management options discussed in the report relate to Critical Peak Pricing (CPP) combined with Time of Use (TOU) rates. Given the form of load on the IIS, this is not expected to be a significant opportunity to shape industrial loads outside of loads that have their own generation (CBPP). For CBPP, which has its own generation and therefore some flexibility about dispatch timing, it is understood that forms of new pricing mechanisms are intended to be addressed as part of NLH's upcoming Rate Design review process.

6.2 CDM

The Synapse report presents a basic assessment of Conservation and Demand Management (CDM) in Chapter 6. Under no scenario assessed does CDM assist in achieving the objective of the Reference in respect of reducing the impact of MFP costs on electricity rates.

Looking first to CDM on its own, the utility impact is as follows:

- Pursuing high CDM reduces sales to NLH by $61 million. Added exports replace $14 million of this lost revenue. The net adverse impact of the CDM to revenue requirement is therefore $47 million.
- In order to achieve the scenario, an annualized cost of $9 million is necessary to incur (e.g. programming).
- Since the loads have decreased, there will be an opportunity to invest in less peak capacity resources for the few hours where the system is at its highest point. The annualized savings from this effect is $16 million.
- The net adverse impact to the utility revenue requirement from CDM is therefore $47 million reduced revenues, plus $9 million in program costs, offset by $16 million in capacity savings, for a net $40 million impact to rates (needed rate increase).[62]

The effect of this rate increase is to drive rates up by 0.549 cents/kW.h from where they would otherwise be set. This type of effect is not only inconsistent with rate mitigation, it drives a significant issue for allocation, given that some customers will face added rate increases to explicitly subsidize the opportunity for other customers to receive incentives to use less power and thus cause the rate increase in the first place. Such win-lose scenarios are problematic for fairness and rate design.

This same effect continues for compound cases which include CDM with other actions like electrification. For example, beginning with the above optimized case of High Electrification (Case

[62] Synapse Phase Two Report, September 3, 2019, page 8. Table 2.

#10, with a benefit to rates of $34 million), the following CDM scenarios show how adding conservation only erodes the rate effects[63]:

- Add Low CDM (Case #15 versus Case #10) benefit drops from $34 million to $31 million.
- Add Demand Response with Low CDM (Case #15a versus #10a) – CDM drops benefit from $40 million to $37 million.
- Add High CDM (Case #16 versus Case #10) benefit drops from $34 million to negative $2 million.
- Add High CDM with Demand Response (Case # 16a versus #10a) benefit drops from $40 million to $4 million.

The comparisons continue with each case of CDM being a net negative impact on rates compared to the equivalent case without CDM.

It is important to note that not all CDM undertaken by utilities will have a negative rate impact on other customers. There are multiple assessments and tools used to evaluate CDM, and one such measure (the "Rate Impact Measure" or RIM) is specifically designed to screen for CDM activities that will not have this type of win-lose effect. Where CDM can be pursued with a positive RIM test, such programming will be of value broadly and can be an important part of mitigation activities.

For this reason, it is recommended that a strong caution be noted in regard to CDM program options which cannot be demonstrated to bring rates down for customers broadly.

> **Recommendation 11:** NLH and NP should primarily restrict CDM to activities where it can be shown that the programming results in reductions to rates (e.g., a positive RIM test) compared to the rate levels required without the CDM programs.

[63] Data from Synapse Phase Two Report, September 3, 2019, page 120. Table 51.

APPENDIX A:
Resume

InterGroup CONSULTANTS

PATRICK BOWMAN

PRINCIPAL AND CONSULTANT

AREAS OF EXPERIENCE:

- Utility Regulation and Rates
- Project Development and Planning
- Utility Resource Planning

EDUCATION:

- MNRM (Master of Natural Resources Management), University of Manitoba, 1998
- Bachelor of Arts (Human Development and Outdoor Education), Prescott College (Arizona), 1994

PROFESSIONAL EXPERIENCE:

InterGroup Consultants Ltd., Winnipeg, Manitoba

1998 – Present – Research Analyst/Consultant/Principal

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in eight Canadian provinces and territories and international. Prepare evidence and expert testimony for regulatory hearings. Assist in utility capital and operations planning to assess impact on rates and long-term rate stability. Major clients included the following:

- **For Manitoba Industrial Power Users Group (1998 – Present):** Prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in General Rate Application and revenue requirement reviews, the Needs For and Alternatives To (NFAT) resource planning hearing, depreciation, cost of service, and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor (Centra Gas) by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures, surplus energy rates and demand side management initiatives including curtailable rates and load displacement.

- **For Northwest Territories Power Corporation (2000 - Present):** Provide technical analysis and support regarding General Rate Applications and related Public Utilities Board filings. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return. Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity).
- **For Industrial Customers of Newfoundland and Labrador Hydro (2001 – Present):** Prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Provide advice on interventions in respect of major new transmission facilities, depreciation, rate mitigation for major new capital spending. Appear before PUB as expert in cost of service and rate design matters.
- **For Nelson Hydro (2013 - Present):** Development and updating of a Cost of Service model and filings before the BCUC.
- **For City of Chestermere (2015 – present):** Analysis of rate proposals from Chestermere Utilities Inc. and review of strategic options for utility.
- **For the Office of the Utilities Consumer Advocate of Alberta (2016 – Present):** Providing expert witness and strategic support of depreciation matters in the Altalink Management Ltd. 2017 – 2018 General Rate Tariff Application (Proceeding 21341) and in the 2019 – 2020 GTA (Proceeding 23848). This includes ongoing participation in depreciation working group discussions on behalf of the UCA. Provide expert witness and strategic support of depreciation matters in the ATCO Pipelines 2017 – 2018 General Rate Application (Proceeding 22011). This includes ongoing support in Compliance Filing (Proceedings 22986) and in Review & Vary filing (Proceeding 23539). Provide expert witness and strategic support on all areas of the ATCO Pipelines 2019 – 2020 GRA (Proceeding 23793, 23799).
- **Vancouver Airport Fuel Facilities Corporation (2019-present):** Review pipeline tolling application on revenue requirement and depreciation, prepare interrogatories, draft issues for evidence.
- **Jamaica Public Service (2019):** Assist in preparation of regulatory documents, Executive Summary, review of strategic issues for General Rate Application.
- **For Hualapai Tribal Utility Authority (2017-2018):** Provided strategic advice to the HTUA Board, and completion of a feasibility study and Cost of Service analysis for the development of a municipally owned distribution utility, including power purchase and transmission, asset purchase (acquisition value) and replacement costs, and ongoing operation and maintenance costs. The assignment included a review of comparable jurisdiction cost and rate structures, building a financial model with input cost variables, reporting and presenting in HTUA Board meetings.

- **For Yukon Energy Corporation (1998 - 2014):** Provide analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters, depreciation, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers.
- **For City of Swift Current (2013 - 2014):** Utility system valuation approach.
- **For Municipal Customers of City of Calgary Water Utility (2012 – 2017):** Analysis of proposed new development charges and reasonableness of water and wastewater rates (City of Chestermere, City of Airdrie, Town of Cochrane, and Town of Strathmore).
- **For Yukon Development Corporation (1998 - 2012):** Prepare analysis and submission on energy matters to Government. Participate in development of options for government rate subsidy programs. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.
- **For NorthWest Company Ltd. (2004 - 2006):** Review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio- economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

- **For Yukon Energy Corporation (2005 - 2014):** Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on 2010 update. Project Manager for all planning phases of the Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.
- **For Northwest Territories Power Corporation (2010 - 2012):** Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. Provide economic and rate analysis of potential major transmission build-out to interconnect to southern jurisdictions. Conduct business case analysis for regulatory review of projects $400,000-$5 million, and major PUB Project Permit reviews of projects >$5 million.
- **For Northwest Territories Energy Corporation (2003 - 2005):** Provided analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects.

- **For Kwadacha First Nation and Tsay Keh Dene (2002 - 2004):** Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.
- **For Manitoba Hydro Power Major Projects Planning Department (1999 - 2002):** Initial review and analysis of socio-economic impacts of proposed new northern generation stations and associated transmission. Participate in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).
- **For Manitoba Hydro Mitigation Department (1999 - 2002):** Provided analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.
- **For International Joint Commission (1998):** Analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of alternative floodplain management policies.
- **For Nelson River Sturgeon Co-Management Board (1998 and 2005):** An assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

Government of Northwest Territories, Yellowknife, Northwest Territories
1996 – 1998 Land Use Policy Analyst

- Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001-02	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006-08	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008-09	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation	BCUC	BC Municipal Electrical Utilities	2009-10	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009-10	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2010-11	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2015	Yes
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2016	Yes
Chestermere Utilities Inc.	2017 Rate Increase Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2016	Presentation to Council
Newfoundland Hydro	2017 General Rate Application	Pre-Filed Evidence and Negotiatied Settlement	NLPUB	Newfoundland Industrial Customers	2017-2018	No - Negotiated Settlement
Altalink Management Limited	2017-18 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on depreciation matters	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016-17	No - Negotiated Settlement
ATCO Pipelines	2017-18 General Rate Application	Analysis, Preparation of Intervenor Evidence on depreciation matters	AUC	UCA	2016-17	No - Written Process only
Manitoba Hydro	2017/18 and 2018/19 General Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2017-18	Yes
ATCO Pipelines	2017-18 GRA Review and Vary	Analysis and Case Preparation	AUC	UCA	2017-18	No - Written Process only
ATCO Pipelines	2019-20 General Rate Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - present	No
Altalink Management Limited	2019-20 General Tariff Application	Analysis on depreciation matters, evidence in preparation.	AUC	UCA	2018 - present	ongoing
ATCO Pipelines	Keephills Transmission Facilities Assessment	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - present	No
Manitoba Hydro	2019/20 Electric Rate Application	Analysis, Preparation of Intervenor Evidence and Exper Testimony	MPUB	MIPUG	2019	Yes
ATCO Electric Distribution	Distribution Depreciation	Analysis and Case Preparation	AUC	UCA	2019	No
AltaGas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only (ongoing)

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