STEWART McKELVEY
LAWYERS • AVOCATS

Cabot Place, 1100 – 100 New Gower Street, P.O. Box 5038
St. John's NL A1C 5V3 Canada tel: 709.722.4270 fax: 709.722.4565 stewartmckelvey.com

October 15, 2021

Paul L. Coxworthy
Direct Dial: 709.570.8830
pcoxworthy@stewartmckelvey.com

**Via Electronic Mail**

Newfoundland and Labrador Board
of Commissioners of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

**Attention: Ms. G. Cheryl Blundon, Director of Corporate Services and Board Secretary**

Dear Ms. Blundon:

**Re: Hydro Supply Cost Accounting Application**
**- Island Industrial Customer Group Submission**

Please find enclosed the Submission of the Island Industrial Customer (IIC) Group on the above Application. We have included in our Submission, for ease of reference, copies of the previous evidence from IIC Group experts filed with the Board in the 2017 Hydro GRA and 2013 Hydro GRA, referenced at page 6, lines 8-9 of the Submission.

We trust you will find the enclosed to be in order.

Yours truly,

Stewart McKelvey

Paul L. Coxworthy

PLC/tas

c. Shirley Walsh, Newfoundland and Labrador Hydro
Dominic J. Foley, Newfoundland Power
Lindsay S.A. Hollett, Newfoundland Power
Dennis Browne, Q.C., Consumer Advocate
Stephen Fitzgerald, Consumer Advocate
Sarah G. Fitzgerald, Consumer Advocate
Bernice Bailey, Consumer Advocate
Bernard M. Coffey, Q.C., Consumer Advocate
Dean A. Porter, Industrial Customers
Denis J. Fleming, Industrial Customers
Gregory A.C. Moores, Iron Ore Company of Canada
Senwung F. Luk, Labrador Interconnected Group
Julia K.G. Brown, Labrador Interconnected Group
Sheryl E. Nisenbaum, Praxair Canada Inc.

Peter Strong, Praxair Canada Inc.
Shawn Kinsella, Teck Resources Limited

**IN THE MATTER OF** the *Electrical Power Control Act*, 1994, SNL 1994, Chapter E-5.1 (the "EPCA") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the "Act"), and regulations thereunder; and

**IN THE MATTER OF** an application by Newfoundland and Labrador Hydro ("Hydro") pursuant to Section 58, 71 and 80 of the Act, for the approval of deferral accounts to address material changes in system costs as a result of the Muskrat Falls Project ("Project") and the phasing out of the Holyrood Thermal Generation Station ("Holyrood TGS") as a generating facility

---

# WRITTEN SUBMISSIONS OF THE ISLAND INDUSTRIAL CUSTOMER GROUP

---

These are the submissions of the Island Industrial Customer Group, Corner Brook Pulp and Paper Limited (CBPPL), NARL Refining Limited Partnership (NARL) and Vale Newfoundland and Labrador Limited (Vale), hereinafter referred to as the IIC Group, in relation to the above Application.

## Overview of the position of the IIC Group on the Application

By this Application, Hydro has requested that the Board approve:

(i) The proposed Supply Cost Variance Deferral Account, for which the account definition is provided in Schedule 1, Appendix A, to become effective on the date upon which Hydro is required to begin payments under the Muskrat Falls PPA;

(ii) The proposed discontinuance of the: RSP; Revised Energy Supply Cost Variance Deferral Account; Isolated Systems Supply Cost Variance Deferral Account; and the Holyrood Conversion Rate Deferral Account to occur on the date of the implementation of the Supply Cost Variance Deferral Account;

(iii) The proposed Holyrood TGS Accelerated Depreciation Deferral Account, for which the account definition is provided in Schedule 1, Appendix B, to become effective January 1, 2022;

(iv) The proposal to deviate from IFRS, using IFRS 14 – Regulatory Deferral Accounts, which would allow Hydro to recognize the power purchase costs relating to the delivery of post-commissioning energy in accordance with the commercial terms of the Muskrat Falls PPA and the TFA; and

(v) The proposed Muskrat Falls PPA Sustaining Capital Deferral Account, for which the account definition is provided in Schedule 1, Appendix C.

The IIC Group does not object to, or have any comment to make in respect of, the sought-after approvals of items (ii), (iv) or (v) above.

With respect to item (i), the sought-after approval of the proposed Supply Cost Variance Deferral Account, the IIC Group do wish to make comment on:

(a) the interim and preliminary nature of the Account definition;

(b) Hydro's proposed use of Weighted Average Cost of Capital (WACC) as the measure of the financing costs for amounts accruing in the Account;

(c) Hydro's non-inclusion in the Account of the proceeds of greenhouse gas credits already sold by Hydro.

With respect to item (iii) above, the sought-after approval of a proposed Holyrood TGS Accelerated Depreciation Deferral Account, the IIC Group object to the sought-after approval.

**Interim and Preliminary Nature of the proposed Supply Cost Variance Deferral Account**

Hydro is not proposing, by this Application, a mechanism or methodology for recovery from Hydro ratepayers of amounts that will accrue (to the extent not offset) in the proposed Supply Cost Variance Deferral Account. Hydro acknowledges, due to continuing uncertainty about the timing of the full Project commissioning[1], and about the timing and mechanisms for rate mitigation, that it is not possible for Hydro to propose a mechanism or methodology for recovery from ratepayers at this time. In this regard, the IIC Group would make two submissions:

(1) that any proposals for the methodology and mechanisms for recovery from Hydro ratepayers should be made by a General Rate Application, to provide sufficient opportunity for a fulsome review of what is proposed, in the context of all factors to be considered in setting rates; and

(2) that the Account definition components should be considered to be interim and preliminary, to be subject to full review and revision in the context of the review of Hydro's proposed recovery methodology and mechanisms in a General Rate Application.

**Weighted Average Cost of Capital (WACC)**

Hydro has requested that the new Supply Cost Deferral account accrue interest at the Weighted Average Cost of Capital (WACC), which is particularly made up of long-term capital such as

---

[1] By its October 7, 2021 filing of its LIL Monthly Update in the Board's RRAS Review, Hydro has advised that the overall Project completion date of November 26, 2021 is not achievable; no new revised date has yet been provided by Hydro.

equity and long-term debt. The capital underlying the WACC is primarily driven by, and associated with, investments in Rate Base. WACC is typically a much higher interest rate than shorter-term capital would attract, such as short-term debt. As set out by IC Group's expert, Mr. Patrick Bowman, in his 2017 GRA Evidence (page 29, December 4, 2017):

> As a concept, rate base is typically understood to represent the value of a utility's property that is dedicated to long-term service to regulated ratepayers. It is primarily made up of undepreciated capital assets, with some smaller amounts of intangibles and working capital. The concept of rate base is tied to the concept of this balance being financed by a utility's long-term capital. In turn, the utility's long-term capital is made up of various forms of financial resources, at a cost commensurate with the risks that the utility experiences for its operation of the regulated business (e.g., business risks, risks of stranded assets, capital write-downs, underperformance, losses caused by weather, etc.).

In establishing deferral accounts, it is typical to assign to the account a rule to charge/pay interest on the outstanding balance at a previously agreed-upon rate. Most of Hydro's current accounts, including the RSP, accrue interest on the basis of WACC.

The proposed Supply Cost Variance Account differs from these accounts however, including the RSP, in material ways. These differences indicate that the use of a WACC carrying cost at this time is not justified at this time, and should instead be considered in the next General Rate Application. The material differences between the existing accounts and the proposed Supply Cost Variance Account include the following:

1) The proposed Supply Cost Variance Account balance in at least the near-term (at least to 2023, and after the end of the next GRA) provides a means to defer costs, but not any material revenues, to the account (Application, Schedule 1, Appendix A). As a result, the

account will only be able to operate with negative balances (the status where Hydro earns interest at the approved carrying cost). Using a WACC, rather than a short-term interest rate, Hydro will earn more interest and ratepayers will face higher costs in future. By contrast, existing accounts such as the RSP can operate with both positive and negative balances, balancing the benefits that might be received from WACC between Hydro and its ratepayers.

2) The proposed Supply Cost Variance Account balance is expected to be (very) material and fast-growing in the period up to the next GRA. This includes almost $70 million of costs to the paid each month under the Muskrat Falls PPA and TFA (Application, Schedule 1, Section 6.1), as well as balances rolled into the Account from previous deferral accounts. Depending on the time to the next GRA, this balance could become very large, and the resulting monthly carrying costs could become a large new credit to compensate Hydro for the theoretical costs of equity and long-term debt that it did not actually use for this Account.

3) Notwithstanding that the carrying costs are proposed to be established to compensate Hydro for the costs of equity and long-term debt, Hydro does not expect to use its equity and long-term debt to finance the Account balances. Hydro specifically notes that it intends to make payments using short-term debt financing for at least the first five months (PUB-NLH-022) and that after that financing would be expected (or at least hoped) to come from rate mitigation funding from Government. We note that PUB-NLH-022 asked Hydro how it expects to finance these payments and no reference to issuance of new or additional equity or long-term debt is indicated by Hydro's response. Without actual higher-priced equity and long-term debt being used to finance the account, at least until about 2023, there is no basis to charge the account for such higher priced capital.

The IIC Group queried Hydro on why it proposes to use WACC as the carrying cost, by IIC-NLH-023. In its response, Hydro noted that WACC is traditionally applied to deferral accounts that operate outside of rate base as a preferred method to including the balances in Hydro's rate base, since inclusion in rate base is difficult as the account balances vary significantly over time (e.g., as compared to other components of rate base, such as fixed assets). Hydro's response ignores, however, the potential to maintain the proposed Account outside of rate base AND to apply only a short-term debt rate as the carrying cost. Previous evidence from the IIC Group experts (e.g., P. Bowman in the 2017 GRA, page 30; P. Bowman and C. Osler in the 2003 GRA, pages 67-68) have identified a large number of such accounts among Canadian utilities.

The Board has previously considered cases where short-term debt rates were proposed for application to deferral accounts, and in particular a large RSP surplus that was targeted for imminent payout to customers (P.U. 49 (2016)). That situation was, however, not analogous to the present situation. Primarily, that situation was a proposal to revise Hydro's 2015 Revenue Requirement to assume the RSP payout was (or could be) financed by short-term debt, as the payouts were assumed to be imminent. By assuming this, Hydro could have included more short-term debt in financing its test year rate base, lowering its revenue requirement. This proposal was rejected by the PUB (P.U. 49 (2016), page 61), as the facts as then known by the Board did not support a factual finding that short-term debt would be used, or that an imminent payout would occur (the Board noted the payout may not in fact be completed even by the end of 2016). As such, the Board rejected the proposal to consider short-term debt as it was inconsistent with the facts in that case.

The current situation is distinct from that past decision. First, the IIC Group proposal is to accrue to the new deferral Account only short-term interest rates as carrying costs, not to revise any of Hydro's test year Revenue Requirements. Second, in this case the facts explicitly support the use of short-term money to finance the account (PUB-NLH-022).

Given the above considerations, and the need to minimize impacts on ratepayers, the IIC Group submit that it is inconsistent with rate mitigation to compensate Hydro for high cost long-term capital to finance this account, when Hydro will in fact use lower-cost capital for this purpose. Until at least the next GRA, the Board should only permit Hydro to accrue interest on this account at prevailing short-term borrowing rates.

**Greenhouse gas performance credits**

By Hydro's responses to IIC-NLH-009 and IIC-NLH-010, Hydro has confirmed that it has sold greenhouse gas performance credits received for the years 2019 and 2020 and has sold or proposes to sell greenhouse gas performance credits received for 2021, but does not intend to credit these revenues to the proposed Supply Cost Variance Account. Hydro's reasoning for this decision is simply that the Account is "prospective" in nature.

Hydro's response ignores that the proposed Supply Cost Variance Account can hardly be considered to be a *tabula rasa*, as it will have rolled into it balances from existing deferral accounts. More pointedly, there is a decided unfairness in not crediting to the Account, for the benefits of ratepayers, greenhouse gas performance credits that have only been received by Hydro as a result of the Muskrat Falls Project, a Project that the ratepayers must pay for.

The IIC Group submit that any approval of the proposed Supply Cost Variance Account should be subject to the condition that all revenues for greenhouse gas performance credits for the years 2019, 2020 and 2021, regardless of whether they have already been sold, should be credited to the Account to the benefit of Hydro's ratepayers. The crediting to the benefit of Hydro's customers of green gas performance credits arising from the Muskrat Falls Project should not depend on the happenstance of when Hydro chose to bring this Application or to sell the credits.

**Proposed Holyrood TGS Accelerated Depreciation Deferral Account**

Hydro proposes to establish a Holyrood TGS Accelerated Depreciation Deferral Account (Schedule 1, Appendix B). The account is proposed to include deferral, for future recovery, the difference between the depreciation expense for the Holyrood TGS in 2022 and the depreciation expense for Holyrood included in the 2019 Test Year. The balance in the account is proposed for future recovery from customers.

The IIC Group submit that the account is unnecessary, and inconsistent with fair prospective ratemaking, and with the likely future scenarios regarding the life of Holyrood TGS.

Hydro indicates (as of the date of this Application) that Holyrood TGS is slated for retirement by March 31, 2023. This Application filing pre-dates the latest information (per footnote 1 above) that continuing LIL software issues have further delayed full Project completion. With this latest delay, and no new (early) revised date having been provided by Hydro for full Project commissioning, the IIC Group respectfully submit that the March 31, 2023 Holyrood retirement date is, at best, implausible.

Moreover, on the core Holyrood assets as they were confirmed for the 2019 Test Year, Hydro has already seen material reductions in depreciation expense. This is shown by IIC-NLH-020, Attachment 1, which indicates that Hydro's rates included $16.9 million in depreciation for these assets, but that Hydro recorded or expects to record materially lower depreciation expenses in 2020 ($8.7 million), and 2021 ($5.5 million). These lower depreciation amounts on this group of assets would serve to increase Hydro's net income, and the benefits have not been proposed to be deferred to the benefit of customers.

At the same time, IIC-NLH-020, Attachment 1 also indicates Hydro added assets to the Holyrood Accelerated Depreciation Schedule for pre-2019 assets. This inclusion represents presumably an oversight on Hydro's part at the 2019 GRA and it is not clear that these amounts are properly considered as an item on which Hydro could claim added revenues outside of a new Test Year being established.

Furthermore, IIC-NLH-020, Attachment 1 also identifies new asset additions since 2019, which Hydro proposes to include in the deferral account. It is common and well-accepted practice that rates are adjusted for new additions of assets, and disposals of old assets, at the time of a new GRA Test Year, and not before. The functions of Hydro's proposed deferral account would be for Hydro to receive benefits of 2022 being a Test Year for the purposes only of Holyrood depreciation increases, and no other cost changes. This is inconsistent with normal future forward test year regulation.

As yet a further matter of concern, Hydro attempts to include 2022 additions that it indicates must be "depreciated" over one year. Assets that are added for use that does not exceed 12 months are not capital additions, and are not depreciated, they are expensed. There is no basis to include the $8.8 Million for 2022 single-year assets in an "accelerated depreciation" account.

Considering all of the above, the uncertainty with respect to Holyrood terminal date, and the clearly unbalanced risk profile that arises from Hydro deferring added costs to ratepayers but not crediting ratepayers with cost savings, the proposal for this account is not justified and the IIC Group respectfully submit that it should not be approved by the Board.

**ALL OF WHICH IS RESPECTFULLY SUBMITTED BY THE ISLAND INDUSTRIAL CUSTOMER GROUP.**

**DATED** at St. John's, in the Province of Newfoundland and Labrador, this 15th day of October, 2021.

POOL ALTHOUSE

Per: ______________________________

Dean A. Porter

STEWART MCKELVEY

Per: ______________________________

Paul L. Coxworthy

COX & PALMER

Per: ______________________________

Denis J. Fleming

TO: The Board of Commissioners of Public Utilities
Suite E210, Prince Charles Building
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2
Attention: Board Secretary

TO: Newfoundland & Labrador Hydro
P.O. Box 12400
500 Columbus Drive
St. John's, NL A1B 4K7
Attention: Shirley Walsh

TO: Newfoundland Power Inc.
P.O. Box 8910
55 Kenmount Road
St. John's, NL A1B 3P6
Attention: Dominic J. Foley
Lindsay S.A. Hollett

TO: Browne Fitzgerald Morgan & Avis
Churchill Park Law Offices
P.O. Box 23135
Terrace on the Square, Level II
St. John's, NL A1B 4J9
Attention: Dennis M. Browne Q.C.
Stephen Fitzgerald
Sarah G. Fitzgerald
Bernice Bailey

TO: Bernard M. Coffey, Q.C.
1st Flr, The Law Chambers
263 Duckworth Street
St. John's NL A1C 1G9

TO: Iron Ore Company of Canada
c/o Stewart McKelvey
100 New Gower Street, Suite 1100
St. John's, NL A1C 5V3
Attention: Gregory A.C. Moores

TO: Labrador Interconnect Group
c/o Olthuis Kleer Townshend LLP
250 University Ave #8
Toronto, ON M5H 3E5
Attention: Senwung F. Luk
Julia K.G. Brown

TO: Praxair Canada Inc.
123 Clyde Avenue
Mount Pearl, NL A1N 4R9

Attention: Sheryl E. Nisenbaum
Peter Strong

TO: Teck Resources Limited
Suite 3300, Bentall 5
550 Burrard Street
Vancouver BC V6C 0B3
Attention: Shawn Kinsella

STEWART McKELVEY
LAWYERS • AVOCATS

Cabot Place, 1100 – 100 New Gower Street, P.O. Box 5038
St. John's NL A1C 5V3 Canada tel: 709.722.4270 fax: 709.722.4565 stewartmckelvey.com

December 4, 2017

Paul L. Coxworthy
Direct Dial: 709.570.8830
pcoxworthy@stewartmckelvey.com

**Via Electronic Mail and Courier**

Newfoundland and Labrador Board
of Commissioners of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

**Attention: Ms. G. Cheryl Blundon, Director of Corporate Services and Board Secretary**

Dear Ms. Blundon:

**Re: NLH 2017 General Rate Application - Pre-Filed Evidence of the Island Industrial Customer Group**

We enclose for filing, on behalf of the Island Industrial Customer Group, the original and thirteen (13) copies of the Pre-Filed Evidence of InterGroup (Patrick Bowman) and of Patricia Lee (BCRI Inc.).

We trust you will find the enclosed to be in order.

Yours truly,

Stewart McKelvey

Paul L. Coxworthy

PLC/kmcd

Enclosures
c: Tracey Pennell, Senior Legal Counsel, Newfoundland and Labrador Hydro
Dennis M. Brown, Q.C., Consumer Advocate
Gerard Hayes, Newfoundland Power
Dean A. Porter, Poole Althouse
Denis J. Fleming, Cox & Palmer
Van Alexopoulos, Iron Ore Company of Canada
Benoit Pepin, Rio Tinto
Senwung Luk, Labrador Interconnected Group

361205 v1

**PRE-FILED TESTIMONY OF**

**P. BOWMAN**

**IN REGARD TO NEWFOUNDLAND & LABRADOR HYDRO**

**2017 GENERAL RATE APPLICATION**

**(INCLUDING THE SUBMISSION OF P.LEE)**

*Submitted to:*

The Board of Commissioners of Public Utilities

*on behalf of*

Island Industrial Customers Group

*Prepared by:*


InterGroup Consultants Ltd.

500-280 Smith Street

Winnipeg, MB R3C 1K2


December 4, 2017

# TABLE OF CONTENTS

## LIST OF TABLES



## LIST OF FIGURES



## LIST OF APPENDICES

# 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. P. Bowman, Principal and Consultant with InterGroup Consultants Ltd. ("InterGroup"). This evidence is submitted in relation to the public hearing into the 2017 General Rate Application (the "Application" or "GRA") by Hydro to the Board of Commissioners of Public Utilities ("Board" or "PUB").

As a supplement to the pre-filed testimony of Mr. Bowman, Appendix D, as part of this pre-filed testimony, provides the testimony of Ms. P. Lee, associate with BCRI Inc. Ms. Lee's testimony is in relation to issues with the proposed adoption of the Equal Life Group procedure for the purposes of determining depreciation rates.

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; and
- Vale Newfoundland and Labrador Limited ("Vale").

Mr. Bowman's qualifications are set out in Appendix A. Ms. Lee's qualifications are included in Appendix D.

InterGroup was initially retained in June 2001 to assist in addressing the 2001 Hydro Rate Review, and subsequently assisted the Industrial Customers in the 2003, 2006 and 2013 rate reviews, as well as the 2009 review of the Rate Stabilization Plan ("RSP"), 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, parts of the following information was reviewed:

- The 2017 General Rate Application filed on July 28, 2017 and subsequent revisions as filed by Hydro;
- Request for Information (RFI) responses from Hydro to the requests of the IIC Group;
- A number of the RFI responses from Hydro to the requests of the other Intervenors and the Board; and
- Various regulatory filings from the PUB's website including, to a limited extent, Hydro's previous Hydro General Rate Application filings.

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

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.

## 1.1 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

The 2018 and 2019 GRA exhibits significant revenue requirement impacts on customers, totalling 19.7% in 2018, and a further 2.2% in 2019. The revenue requirement is based on the premise that the island functions as an isolated system, with any benefits of imported power accruing to an Off Island Purchases Deferral Account. This submission accepts that framework for analysis of the revenue requirement. Further comment on the approach may be provided once the details on the Off Island Purchases Deferral Account are made available.

This submission highlights a number of major drivers of the revenue requirement increase and rate proposal, some of which are advised, and others which are not advised and should not be approved:

1) **Group Accounting (Depreciation):** Hydro's depreciation study proposes to adopt group accounting methods as was advised during the 2012 Depreciation proceeding. This is an improvement to Hydro's capital asset accounting practices, and should be approved. Included in this change is the normal practice of deferring gains and losses on disposal to the group accumulated depreciation, rather than including them in revenue requirement in the year in which they occur, which is also appropriate.

2) **Depreciation Costs:** Hydro's proposals in respect of depreciation costs reflect two different types of changes: those that are driven by data and required updates, and those that are driven by policy changes that the utility has elected to propose.
    a. On the **data driven changes**, the net impacts are small (reduction in revenue requirement of $0.5 million) and should be approved. Asset lives should continue to be closely monitored.
    b. On the **policy driven changes**, these are a major driver to rates in the test years (approaching $17 million). These changes should not be approved, or should be approved on a much more constrained basis than recommended by Hydro, as follows:
        i. **Equal Life Group (ELG) procedure:** The proposal to adopt the ELG procedure (as opposed to the Average Service Life (ASL) procedure) significantly increases power rates through use of a more aggressive approach to determining depreciation expense. Not only is the approach poorly implemented by Hydro, it is incorrectly framed as a way to have more precise depreciation rates, and more fully comply with IFRS. However, the ASL procedure in itself was adopted in the 2012 Depreciation hearing expressly to comply with IFRS (driving material added depreciation expense compared to the procedure used previously, the sinking fund approach). The power industry in Canada has seen movement away from the ELG procedure. While Hydro has made superficial arguments that the ELG procedure will raise rates now in favour of lower rates in future, these arguments are overly simplistic and not supported by the facts. Similar to recent decisions

out of the Manitoba PUB, the move to an ELG procedure should be rejected. [The attached submission of P. Lee also details the history, requirements and mistaken claims regarding the ELG procedure, to illustrate why the proposal is also technically unsound.]

ii. **Net Salvage:** Hydro's proposals in respect of net salvage are to include the costs of removing assets (less disposal proceeds) into the cost of replacement assets when such replacement is being constructed (an "interim retirement"). When no replacement is being constructed, and instead an asset is being retired and a site returned to non-utility service, Hydro proposes to accrue for these costs during the life of the original asset (a "terminal retirement"). This leads to a need to establish new accruals in depreciation rates today for terminal retirements. In principle, this is an acceptable regulatory approach. However Hydro has provided no support for any expected future terminal retirement of hydraulic generation nor major transmission lines. Further, Hydro's estimated future salvage costs are upwardly biased by the short sample set of retirements to draw upon, and the skewing of the data set towards distribution and thermal generation assets. While the overall approach should be approved, no net salvage for hydraulic generation nor major transmission should be implemented today.

3) **Holyrood Fuel Conversion:** Hydro has proposed a Holyrood conversion factor (fuel efficiency) which is heavily downward biased by the historical record selected. The evidence available today shows that the approach used to set the fuel conversion factor at the previous (2013 Amended) GRA was sound, and the only reason actual performance was below forecast was that the loading of Holyrood was well below forecast levels. Continuation of this low loading condition should not be assumed for the test years given the implementation of TL267, which provides a major dependable capacity benefit to the Avalon peninsula and removes the need to operate Holyrood in a low loading condition. As a result, the Holyrood fuel conversion factor should be adjusted upwards to at least the 618 kW.h/barrel level used at the previous GRA, if not higher.

4) **Inclusion of the 2018 Revenue Deficiency in Rate Base:** Hydro has proposed, for the first time in a GRA filing, to include the test year deficiency into the rate base for that year (2018). This is unusual, is inconsistent with the premise that rate base reflects long-term assets financed by appropriate risk capital, and serves to increase costs to ratepayers. Given the timing and risk profile for the deficiency, the assumption should be that interest only accrues after the end of the test year to which it relates, that the interest is set at an appropriate short-term debt rate, and that the costs accrue to the shortfall itself, not to the base revenue requirement (e.g., similar to the RSP).

5) **Cost of Service (COS):** The COS study largely reflects existing methods, which is appropriate given the pending (COS) methodology review. However, for this GRA there are two areas where the COS errs towards excessively classifying costs as being energy-related and insufficiently reflects costs as being demand-related. This includes the rate base component of Holyrood

capital costs, and the costs to purchase wind energy. In both cases, a revision is required to properly reflect the relative demand and energy roles of the plants in the test years.

6) **Specifically-Assigned Charges (SAC):** The proposals regarding allocation of Operating and Maintenance costs to SAC (related to the Handy Whitman index) are appropriate and should be approved. Separately, the Corner Brook frequency converter being directly assigned to CBPP continues to be an issue of concern. This facility has a unique history regarding its role on the system, and the significant benefits it provides to all grid customers in terms of ensuring material 50 Hz generation is not bottled up at Deer Lake. There is a reasonable basis to conclude that the converter should not be directly assigned to CBPP.

7) **CBPP Generation Credit Pilot Agreement:** Hydro proposes to terminate a "pilot project" in respect of the way CBPP uses its own generation. The proposal should not be approved. The CBPP contract should not revert to the standard industrial contract, which results in incentives to CBPP to inefficiently manage its own generation. Such inefficiency leads to reduced flexibility to CBPP, added costs to other ratepayers, and an incentive to dispatch generation in a manner that is inconsistent with the provisions of the relevant legislation (*EPCA*, 1994).

# 2.0 THE INTERGROUP ASSIGNMENT

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

This section covers the following material:

- Overview of Island Industrial Customers; and
- Key Relevant Regulatory and Rate Making Principles.

## 2.1 OVERVIEW OF ISLAND INDUSTRIAL CUSTOMERS

The IIC Group is comprised of three customers who comprise more than 93% of the overall industrial class of customers ("industrial class" or "IC") on Hydro's Island Interconnected System ("IIS").

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 and are in full operation for the 2018 and 2019 Test Years).

There are two other Hydro industrial customers who are proposed to be part of the same industrial class (Teck and Praxair). Hydro states that 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.[2] Praxair represents about 7% of total IC load.

The customers that comprise the IIC Group have a forecast of 674 GW.h of firm electricity in 2018 and 691 GW.h in the 2019 test year (about 9.7% and 9.9%, respectively, of the total firm energy delivered by Hydro to the Island Interconnected system). The entire industrial class load (i.e. including Teck and Praxair) has a forecast firm load of 726 GW.h for 2018 and 743 GW.h for the 2019 test year,[3] with an estimated $48.1 million and $49.8 million,[4] respectively, in total allocated costs (an average unit cost of 6.63 cents/kW.h and 6.69 cents/kW.h). This amounts to an increase of 18.2%-19.4% on average unit cost per kW.h sales compared to the last GRA with an average unit cost of 5.6 cents/kW.h.[5]

Island industrial customers are engaged in capacity assistance and load curtailment agreements with Hydro that are used as a means 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. Hydro also presently has capacity assistance agreements in place with industrial customers.[6]

[2] 2017 GRA, IC-NLH-080.
[3] Sales numbers are from IC-NLH-081, Attachment 1 [2017 GRA].
[4] The allocated costs are from Hydro's 2017 GRA, Volume III, Exhibits 14 and 15 [Schedule 1.3.1, page 1 of 3].
[5] $34.8 million total allocated cost as per 2015 COS provided in IC-NLH-107 Attachment 1 divided by 621.4 GW.h total firm sales.
[6] 2017 GRA, CA-NLH-108.

Industrial Customers' 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, including a fair interpretation of the legislative limitation on industrial customer rates from funding the rural deficit;
- 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.);
- Lowest cost for power that can be achieved within the above considerations; and
- Continued reliability of power supply for Island Interconnected customers.

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.

## 2.2 KEY RELEVANT REGULATORY AND RATE-MAKING PRINCIPLES

The InterGroup assignment focuses on a review of the revenue requirement proposed by Hydro, including a detailed review of proposed depreciation parameters, the Cost of Service (including the specific components of the 2018 and 2019 COS study), and the overall rate design proposed in the 2017 General Rate Application.

**Revenue Requirement:** Hydro's revenue requirement should reflect the total necessary and prudent costs to fulfill their obligation to serve and to provide safe and reliable energy to customers. This includes many typical utility cost items, as well as items that are unique to mixed hydro/thermal utilities. In a mixed hydro-electric and thermal generation utility, the cost of fuel and water levels will drive costs in a given year in a manner that is unpredictable and not under the control of the utility. The RSP component of Hydro's rate design is intended to "protect" both Hydro and ratepayers from risks related to variances in these areas. Other costs that are more readily managed, including operating and maintenance and administrative costs and the depreciation for long-lived assets, do not provide the same instability risks to Hydro but still make up a substantial component of the overall cost structure for a given year.

**Cost of Service:** In order to fulfill normal ratemaking principles, the relative levels of rates charged to various customer classes by Hydro are to be developed based on principles of "cost of service". This involves determining a fair allocation of Hydro's costs to the various classes based on a consistent set of principles. This is the most widely accepted standard applied for regulated utilities to determine whether rates are just and reasonable. The Cost of Service concept retains the concept of used and useful – for example, if a customer class does not use a component of the system (e.g., distribution), its rates are not to include the costs of that component of the system; likewise if only one class benefits from specific assets (such as streetlights) all costs related to those assets are to be allocated to the relevant class. Also critical to the cost of service theory is the concept of the different "products" that the utility provides, most notably the distinct products of peak demand (including reliability), energy, and customer services and the appropriate ways to track the cost causation of each of these aspects of the system. Cost of

Service methods are intended to reflect primarily the revenue requirement and system configuration for the Test Year in question, but properly also consider longer-term trends or system direction to help maintain some stability in cost measures and reflect where system costs allocations are headed in relatively foreseeable future periods (during which the same rates will often apply, in between GRAs).

**Rate Design:** For the review of rate design, it is imperative that a long-term perspective is balanced with the short-term as Hydro is forecast to interconnect the island of Newfoundland to the Labrador infeed. Prior to this event, total rates in place should reflect the revenue requirement of the current level of costs, and rate designs should reflect a balanced perspective regarding long-term price signals on the island. Based on the proper allocation of costs, a rate design can be developed to recover the appropriate level of costs from the various customer classes, as well as achieve key objectives such as stability, efficiency, etc.

# 3.0 REVENUE REQUIREMENT

This section provides an overview of Hydro's proposed revenue requirements for the 2018 and 2019 Test Years in comparison to the 2015 Test Year, as well as detailed comments in respect of areas of notable concern. It consists of the following:

- Comparison to the 2015 Test Year;
- Proposed Change in Depreciation Parameters;
- Holyrood Fuel Conversion Factor; and
- Hydro's proposal to include the 2018 Revenue Deficiency in rate base.

## 3.1 COMPARISON TO THE 2015 TEST YEAR

The 2017 GRA requests approval of revenue requirements from rates of $673.1 million for 2018 Test Year and $692.8 million for 2019 Test Year.[7] For the IIS, the allocated revenue requirement is $589.9 million for the 2018 Test Year and $602.6 million for the 2019 Test Year as illustrated in Table 3.1 below. The proposed revenue requirements for the 2018 and 2019 Test Years are 19.7% and 22.3% higher, respectively, compared to the approved 2015 Test Year revenue requirement. These increases are well above the degree of IIS system load change over the same period, which remained at the same level.[8]

The most notable aspect of the current GRA is the proposed Off Island Purchases Deferral Account. This is a material consideration, in that this proposal, in effect, means that Hydro is not seeking rates that reflect the best estimates of the costs to be incurred to provide service in the 2018 and 2019 test years. The remainder of this review focuses on the Revenue Requirement as proposed, under the scenario of continued Holyrood generation. Further comments on the Off Island Purchases Deferral Account may be provided once the detailed evidence regarding the account is made available.

Table 3-1 shows that for the 2018 Test Year, Hydro is proposing a total revenue requirement at $589.9 million, which is about $97 million or 19.7% higher compared to the 2015 Test Year:

- About 53%, or $51.8 million, of the increase in 2018 over 2015 Test Year is due to fuel cost. Generally, the difference between forecast and actual fuel related expenses are recovered or refunded through the RSP, including fuel price and fuel efficiency. Consistent with normal practice, it is understood that the fuel price estimates will be updated as the proceeding progresses.
- Capital related expenses also make up a substantial portion of the change in 2018 over 2015 Test Year revenue requirement [about one third of the total change], including:
    - About 22%, or $21.1 million, of the increase in 2018 over 2015 Test Year is due to an increase in depreciation expense. However, the adoption of group accounting for

---

[7] 2017 GRA, Volume I, cover letter, page 5.

[8] Table 3-9 in 2017 GRA [Volume I, chapter 3, page 3.16] shows the total load in IIS was at 7,235.1 GW.h in 2015 Test Year compared to 7,222.5 GW.h for 2018 Test Year and 7,235.3 GW.h for 2019 Test Year.

depreciation results in a reduction in disposal gains/losses of $3.6 million, for a net depreciation related change of $17.5 million. This includes both the impact of the increased depreciable base as well as the proposed changes in depreciation parameters and methods.

- Return on debt is forecast to increase by 7.1%, or $6.9 million, from 2015 Test Year to 2018 Test Year. The information provided in the GRA shows that the increase in rate base results in an increase of about $20 million in debt return, which is offset by a decrease of about $13.1 million due to a lower rate of debt return (interest).[9]
- Return on equity is forecast to increase by 3.0% overall, or $2.9 million, from 2015 Test Year to 2018 Test Year. The information provided in GRA shows that the increase in rate base results in an increase of about $7.6 million in equity return, which is offset by a decrease of about $4.7 million reduction due to a lower weighted rate of equity return.[10]

- The fuel cost for Gas Turbines is forecast to increase by 8.7% or $8.5 million, from 2015 Test Year to 2018 Test Year.
- Operating and Maintenance expenses are forecast to increase by 6.3%, or $6.1 million, from 2015 Test Year to 2018 Test Year. In general, this is largely consistent with inflationary trends.

Hydro is also proposing a modest increase in the 2019 Test Year Revenue Requirement over the 2018 Test Year, yielding an approximately 2.2% increase in revenue requirement. The most notable increases are in the depreciation expense of $3.0 million in 2019 Test Year over 2018 Test Year, which is about 24% of total increase in 2019 Test Year over 2018 Test Year. This is followed by 22% of the total increase coming from the Number 6 fuel expense and 17% of the total increase for Operating and Maintenance expenses.

[9] Schedule 1.1 [page 2 of 2] of respective COS for 2015 and 2018 Test Years show the weighted average rate of debt return reduced from 4.801% in 2015 Test Year to 4.151% in 2018 Test Year.

[10] Schedule 1.1 [page 2 of 2] of respective COS for 2015 and 2018 Test Years show the weighted average rate of equity return reduced from 1.808% in 2015 Test Year to 1.578% in 2018 Test Year due to lower equity ratio [ROE rate for both Test Years at 8.50%].

**Table 3-1: Comparison of Hydro's Proposed 2018 and 2019 Test Year Revenue Requirements to 2015 Test Year Revenue Requirement[11]**

| | 2015 Test Year | 2018 Test Year | Change from 2015 Test Year | Increase in 2018 over 2015, % | 2019 Test Year | Change from 2018 Test Year | Increase % |
|---|---|---|---|---|---|---|---|
| | ($) | ($) | ($) | (%) | ($) | ($) | (%) |
| | A | B | C=B-A | D=B/A-1 | E | F=E-B | G=E/B-1 |
| **Expenses** | | | | | | | |
| Operating, Maintenance and Admin. | 100,888,350 | 107,033,940 | 6,145,590 | 6.1% | 109,154,478 | 2,120,538 | 2.0% |
| Fuels - No. 6 Fuel | 166,540,358 | 218,330,789 | 51,790,431 | 31.1% | 221,114,563 | 2,783,774 | 1.3% |
| Fuels - Diesel | 87,140 | 127,082 | 39,942 | 45.8% | 138,012 | 10,930 | 8.6% |
| Fuels - Gas Turbine | 3,473,690 | 11,934,765 | 8,461,075 | 243.6% | 12,632,138 | 697,373 | 5.8% |
| Power Purchases - Other | 58,109,820 | 61,065,158 | 2,955,338 | 5.1% | 62,054,740 | 989,582 | 1.6% |
| Depreciation | 55,708,988 | 76,857,538 | 21,148,550 | 38.0% | 79,898,089 | 3,040,551 | 4.0% |
| Expense Credits | (1,878,310) | (1,537,756) | 340,554 | -18.1% | (1,551,903) | (14,147) | 0.9% |
| Disposal Gain/Loss | 3,555,647 | - | (3,555,647) | -100.0% | - | - | |
| **Subtotal Rev Reqt Excl Return** | **386,485,683** | **473,811,516** | **87,325,833** | **22.6%** | **483,440,117** | **9,628,601** | **2.0%** |
| Return on Debt | 77,264,792 | 84,133,420 | 6,868,628 | 8.9% | 84,767,029 | 633,608 | 0.8% |
| Return on Equity | 29,105,451 | 31,979,563 | 2,874,112 | 9.9% | 34,428,031 | 2,448,467 | 7.7% |
| **Total Revenue Requirement** | **492,855,926** | **589,924,499** | **97,068,573** | **19.7%** | **602,635,176** | **12,710,677** | **2.2%** |

The remainder of this section focuses on three material items of concern from the 2018 and 2019 Revenue Requirement; namely, depreciation, Holyrood efficiency, and the 2018 revenue deficiency.

## 3.2 DEPRECIATION

Hydro has provided a detailed depreciation study for assets in service as of December 31, 2015, prepared by Concentric Advisors, filed as Exhibit 11 (revised). The study includes both updates related to information about the physical characteristics of Hydro's assets as well as proposed changes to depreciation methodologies and policies.

The specific approvals sought by Hydro are as follows:

1. **Transition to Group Accounting:** This is further described at Exhibit 11 (Revised), pdf pages 593-600. This change is driven in part by responding to the concerns of Intervenors raised at the 2012 Depreciation Review proceeding and is an improvement over the model now in use. The approach now proposed by Hydro is largely industry standard and provides benefits in terms of avoiding the need to include forecast gains and losses on disposal in Hydro's revenue requirement. This change should be approved by the Board.
2. **Holyrood Truncation:** A portion of the Holyrood generating station assets have been included in depreciation expense on the basis of a fixed truncation date. In principle, this is an appropriate way to deal with a group of assets across many classes that have a defined life expectancy. The specifics of the Holyrood proposals were not reviewed in detail.
3. **Group Procedure:** Hydro has proposed to adopt the Equal Life Group (ELG) group procedure, which is not advised and is further addressed in Section 3.2.1 of this submission.

[11] The table is prepared based on Hydro's 2017 GRA 2018 and 2019 COS Schedules 1.1. The revenue requirement for 2015 Test Year is based on 2015 COS as provided in response to IC-NLH-107 Attachment 1.

4. **Cost of Removal:** The costs to remove assets, less any recoveries from salvage, have previously been expensed in the year incurred. This is now proposed to be included in depreciation rates for any terminal retirements and rolled into the capital cost of the new asset for interim retirements. This approach is reasonable in principle. However, there are material concerns in the manner in which the rates are proposed for the test years to collect this cost. This proposal is further discussed in Section 3.2.2 of this submission.

Hydro's proposals in respect of depreciation in this proceeding are broad and overlapping. As a result, it is hard to fully disentangle the effects of each change. Further, the impacts are often cited in respect of the 2015 study and not the impacts as of the 2018 and 2019 test years, which can have materially different values. The proposals are also burdened by a complicated and disjointed set of facts that would apply to assets from various years, as follows:

- Assets from period **prior to 2011** are carried at a deemed cost, amortized using the Average Service Life ("ASL") group procedure and a remaining life technique. Some of these assets (hydro generation and transmission) also typically include substantial depreciation shortfalls from prior periods when they were amortized using the sinking fund approach and this shortfall is built into rates through the remaining life technique.
- Assets acquired from **2011 to 2014** are carried at original cost and amortized using the ASL group procedure, and applying a remaining life technique.
- Assets acquired in **2015** are proposed to be carried at original cost, amortized using the Equal Life Group ("ELG") group procedure, using a remaining life technique.
- Assets acquired **after 2015** are proposed to be carried at original cost, amortized using the ELG group procedure, using a whole life technique.

To make matters more difficult, the depreciation study provided effectively calculates three depreciation rates. The first is a rate that would theoretically apply to all assets prior to December 31, 2015. This first rate uses a hybrid of the ASL and ELG procedures, mixed with a remaining life collection of all calculated shortfalls (including sinking fund shortfalls), and calculated as a percentage of the original cost of all assets. This rate, while the main focus of the study, is not actually used by Hydro. The second rate is for the same vintage of assets (all 2015 and before assets) with the same characteristics as noted in the first rate, but applied to a hybrid deemed cost/original cost asset value. This second rate is the rate that is applied in the GRA revenue requirement for assets from 2015 and prior vintages. A third rate is provided for post-2015 assets. Further, for each of these 3 rates there are 2 components – the life component and the net salvage component. It is unclear how the depreciation arising due to these multiple rates will be tracked in future.

Finally, there are a large number of accounts where depreciation expense estimates provided by Hydro for the 2018 and 2019 Test Years cannot be reconciled to the requested rates and there has been insufficient opportunity to fully test the data provided to confirm the reasons for each of these accounts. This applies most notably to data provided in the response to NP-NLH-142. Some of this is now known to be errors that Hydro has indicated it plans to correct (per direct communication with Hydro staff), while others presumably relate to assumptions regarding the timing of additions and disposals during the year, leading to partial-year depreciation for a portion of the assets. Other variances remain unexplained. For this reason, precise comparisons to the test year revenue requirement are difficult. For a clear apples-to-apples comparison, this submission primarily relies on estimates tied to year-end 2018 and year-end 2019 asset values as reported in NP-NLH-142, multiplied by the relevant proposed depreciation rates. This is the same approach Hydro's depreciation study uses to characterize the year-end 2015 effects, and avoids the issue of partial year depreciation expense on new and newly retired assets.

Outside of the complexity, it is clear that, in combination, the depreciation proposals in the GRA result in a very significant and material change to the approaches previously used by Hydro. It is concerning that Concentric and Hydro suggest that the changes are largely offsetting and of little net effect on revenue requirement. The review below highlights that this is not the case and that much of the savings come from appropriate and necessary updates driven by asset data, while much of the adverse impacts come from policy decisions that are poorly supported or implemented in the test year forecasts.

Looking to the impacts of the study, the effects are set out in Table 3-2 below:

**Table 3-2: Depreciation Expense for Assets in Service as at December 31, 2015**

| | Group Accounts | Amortized Accounts | **Total Non-Holyrood** | Holyrood | Total with Holyrood |
|---|---|---|---|---|---|
| Expense at existing rates | $47,308,781 | $1,787,786 | $49,096,567 | not provided | not provided |
| apply technical update | $1,543,836 | $1,698,714 | $3,242,550 | | |
| Expense with updated rates | $48,852,617 | $3,486,500 | $52,339,117 | $8,284,465 | $60,623,582 |
| apply new lives | -$5,096,272 | $1,332,255 | -$3,764,017 | -$123,466 | -$3,887,483 |
| Expense with new lives (ASL rates) | $43,756,345 | $4,818,755 | $48,575,100 | $8,160,999 | $56,736,099 |
| | | | | | |
| apply salvage | $6,013,825 | $0 | $6,013,825 | $2,162,264 | $8,176,089 |
| Expense with added net salvage | $49,770,170 | $4,818,755 | $54,588,925 | $10,323,263 | $64,912,188 |
| apply ELG procedure | $1,489,290 | $0 | $1,489,290 | $1,159 | $1,490,449 |
| Expense with ELG | $51,259,460 | $4,818,755 | $56,078,215 | $10,324,422 | $66,402,637 |

As highlighted in Table 3-2, the study can be grouped into effects on group accounts (those accounts subject to traditional depreciation) versus amortized accounts (those accounts amortized on a straight basis over relatively short periods and retired as a vintage, like computer software and overhauls)[12] to determine the total effect excluding Holyrood truncated life assets. The Holyrood assets are also shown in the above table to yield the net effect values Concentric has tended to present[13] ($3.887 million in savings less $8.176 million in net salvage and $1.490 million for ELG).

The first 5 rows of Table 3-2 show the progression of depreciation expense from the expense that would arise if no changes were made and the previous rates retained, through 2 broad stages that arise from completing a depreciation study - the technical update stage and the imposition of new lives stage. These stages are relatively non-controversial, though there can at times be a basis to challenge some life and dispersion assumptions. The first effect, the "technical update", is a recalculation of amortization rates using the same parameters as previously approved (e.g., same life assumptions and dispersion patterns).

[12] 2017 GRA, Volume II, Exhibit 11 [Rev 4], page 45 of 633.
[13] 2017 GRA, Volume II, Exhibit 11 [Rev 4], page 9 of 633.

The technical update will capture the actual experienced effects from recent plant retirements or lack thereof (such as plant lasting longer than expected between the last study and the current study, leading to higher accrued depreciation than expected) and will determine the need to increase or decrease the depreciation rate to adjust for the actual performance (assuming the same expected life). The second effect is the review of life parameters and any needed updates (such as adjusting the rates to reflect longer life expectations).

Separately, the bottom 4 rows of Table 3-2 shows what occurs when a further 2 stages are applied representing policy changes. These steps are optional, can often be controversial and are driven by decisions of Hydro's management as opposed to a technical depreciation analysis *per se*.

Table 3-2 also highlights 2 aspects of what may be considered a less-than-complete presentation to date of the depreciation changes on the test years:

- First, in respect of the **study-driven changes**, Concentric goes to significant lengths to highlight that the study is yielding $3.887 million in savings. As noted in Table 3-2, this is the effect (including Holyrood) of changing asset lives – it does not reflect the impact of first applying the technical update. Once these 2 concurrent steps are applied, the depreciation expense savings for this given 2015 year-end plant in service (excluding Holyrood) are only approximately $0.5 million (from $49.1 million expense to $48.6 million). Note that no estimate is provided for Holyrood pre-technical update so this comparison is only using the non-Holyrood truncation assets.
- Second, in respect of the **policy-driven changes**, Concentric has tended to reference the net salvage impact at $8.176 million ($6.014 million of which is non-Holyrood truncation assets) and the ELG impact at $1.490 million focusing on the 2015 values.[14] However, as shown later in this testimony, these estimates significantly understate the full impacts of these two policy changes on rates in the test years. In fact, by 2019, the salvage change on non-Holyrood truncation assets is not $6.014 million/year, but $10.176 million[15], and the ELG impact is not $1.490 million/year, but more than $6.9 million on a full-year basis (and will be a further cost to ratepayers once implemented for the pre-2015 assets in future as Hydro suggests it will later seek).

Combined, these two policy driven changes lead to almost $17 million in revenue requirement pressure in the test year 2019, which is almost 20% of the rate increase requested,[16] significantly different than Concentric's portrayal of the depreciation impacts of being less than $1 million.[17] Part of the issue is that Concentric focuses only on effects at December 31, 2015, does not include the adverse impacts of the technical update, and includes an offset of $4.969 million "savings" from no longer booking losses on retirement to the revenue requirement. This last item is misleading as the change to exclude losses on retirement from direct impacts on revenue requirement is due to Hydro adopting (as directed) a group

[14] As illustrated in Table 3-2. Also provided in IC-NLH-035 Attachment 1.
[15] As provided by Hydro in response to NP-NLH-142 Attachment 6, page 4 of 5.
[16] 2017 GRA, Volume I [Rev 4] Table 5-1 shows shortfall of $88.6 million.
[17] 2017 GRA, Volume II, Exhibit 11 [Rev 4] page 10 of 633.

accounting approach, which has nothing to do with the calculations of the depreciation study and is not likely to be controversial in any way (in fact, it is typical utility practice).

The remainder of this submission deals in more detail with the two major policy-related changes proposed by Hydro: the change to use the ELG group procedure, and the proposals and quantification of how to address net salvage costs.

### 3.2.1 Equal Life Group Procedure

Hydro is seeking to change the group depreciation procedure it proposes to apply to all assets acquired after January 1, 2015 from the existing Average Service Life ("ASL") procedure to the Equal Life Group ("ELG") procedure. The materials suggest that Hydro expects to move all remaining assets (i.e., 2014 and prior vintages) to the ELG procedure at some future date, but does not provide a clear proposal for timing or approach to be used for the later stages of this transition.

Given the facts surrounding rates for NLH (e.g., significant rate pressures over the previous and coming few years due to capital developments, the construction of major new assets like TL267, the proposal to begin adding to costs a set of new accruals for net salvage), the proposal to transition to the ELG procedure is unexpected and problematic. This is because the ELG procedure is recognized as being among the most aggressive approaches to depreciating a group of assets, leading to the highest rates for customers. This is confirmed by the evidence of Hydro's advisors, Concentric, which notes the need for a "gradual phased in process" to implement ELG in order to "minimize the impact to current customers".[18] However as recently as 2011, Hydro was still using a sinking fund approach to depreciation of its largest asset classes (hydraulic generation and transmission), which is among the least aggressive approaches available. As a result, if Hydro were to move to ELG company-wide at the next GRA, for example, the rate impacts arising solely from depreciation <u>methodology</u> changes over the period of less than a decade (from about 2011 to the next GRA, which is expected to be filed in or about 2020) would be at the extreme end of what would ever be experienced in the industry. This increase would come at the same time as major new rate pressures are arising from inclusion of new supply facilities in rates. It is hard to imagine a worse time to implement the proposed change.

The change to ELG is also unusual in that Hydro provides effectively no company evidence as to the rationale, benefit or, most importantly, policy considerations that go into the decision to seek this approach (along with the commensurately higher rates) at this time. There is evidence provided by Concentric[19] that sets out technical rationale (often rejected by regulators) regarding the supposed "superiority" of ELG. However, the generic comments of a consultant advisor would not typically serve as prime regulatory supporting rationale for a voluntary policy decision made by company management that adversely affects the rates paid by the company's customers.

Debates over the merits or superiority of using ELG in practice can be highly technical, with significant disagreement among the depreciation community. The background related to the limited regulatory adoption of ELG in North America has been compiled by Patricia Lee, and is provided in Appendix D to

---

[18] 2017 GRA, Volume II, Exhibit 11 [Rev 4], page 13 of 633.
[19] 2017 GRA, PUB-NLH-071 and 2017 GRA, Volume II, Exhibit 11 [Rev 4], pages 13-14 of 633.

this submission. Appendix D reviews how ELG is very sensitive to good quality data and large sample sizes for the mortality groups, how the illusion of precision is often muted through blending ELG rates across vintages and with other procedures (precisely as proposed by Hydro in this application) and how ELG was originally appealing to regulatory commissions in cases where technology was driving material depreciation losses and much shorter asset lives than predicted, which is not the case for Hydro.

Beyond the concerns noted by Patricia Lee, with respect to the current proceeding, a transition to the ELG group procedure is ill-advised due to exacerbating anticipated rate effects that are projected for the coming years. Further, the proposal is, at best, curious when considered in light of the following:

- **Regulatory Precedent:** in support of the change to ELG, Concentric provides the example of Newfoundland Power transitioning to the ELG procedure in the late 1970s. Outside of this example, focusing on more recent periods, there has been limited if any significant utility industry change to adopt ELG. If anything, three relatively recent examples suggest the opposite in regard to momentum for the procedure in Canada:
    - In 2005, Yukon Energy abandoned the ELG procedure and reverted to the ASL procedure after taking over management of the assets from the private sector utility ATCO Electric and realizing the adverse rate impacts that ELG was causing;
    - In 2012 and 2015, Manitoba Hydro attempted to adopt ELG for regulatory purposes and was rejected by the Manitoba PUB after two lengthy, detailed and contentious hearings on the matter. A process is currently underway to determine how to deal with a divergence arising from the fact that, notwithstanding the Board's failure to accept ELG for rate setting purposes, Manitoba Hydro elected to adopt ELG for financial reporting purposes causing significant potential future reconciliation issues; and
    - From 2013 to 2016, the Alberta AUC convened a process to review alternatives to mitigate significant rate pressures arising from large capital investment (primarily transmission). Utilities before the AUC are among the few in Canada who routinely use the ELG procedure. Among the studies commissioned, the AUC retained Foster Associates to produce a report on depreciation alternatives.[20] Fosters noted in regards to ELG: "To the extent the objective of this investigation is to identify and evaluate depreciation methods that will delay capital recovery, it would appear counterproductive to use or retain a procedure that inherently front loads depreciation accruals."[21] While the proceeding has not led as yet to changes in depreciation procedure, the discussion has led to specific proposals regarding abandoning the ELG procedure for major utilities such as Altalink[22] and ATCO Electric,[23] and the potential for an AUC-led generic

---

[20] AUC Proceeding 2421, Exhibit X0002. Available at AUC website: https://www2.auc.ab.ca/Proceeding2421/ProceedingDocuments/Fosterreport_0151.pdf [accessed on December 1, 2017].
[21] AUC Proceeding 2421, Exhibit X0002, page 12.
[22] AUC Proceeding 3524, Decision 3524-D01-2016, paragraph 309-313. Available at AUC website: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/3524-D01-2016.pdf [accessed on December 1, 2017].
[23] AUC proceeding 20272, Decision 20272-D01-2016, paragraph 320, 340-357. Available at AUC website: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20272-D01-2016.pdf [accessed on December 1, 2017].

proceeding in the near future.[24] It should be noted that in Alberta, throughout these investigations, the utilities have typically opposed moving away from ELG.

- **Fallacy of Future Benefits:** Concentric has provided evidence that the change to ELG "will benefit future customers",[25] which is a commonly misstated characteristic of ELG provided as part of arguments in favour of the procedure. This relationship only holds at the most simplistic level. For example, the purported later life benefits of ELG only arise when assuming a steady state set of assets with no inflation, replacement or reinvestment. It is true that if there were only a single asset class with a specific vintage of investment that saw no replacement and no growth in asset base, both the ASL procedure and the ELG procedure would recover 100% of the original investment – by simple definition then, since ELG recovers more of the cost of depreciating that group in the early years of the asset, it recovers less in the later years. This, however, is not the situation for any going-concern utility like Hydro. This is because the dominant factor in depreciation expense is almost always the most recent vintages reflecting assets built at contemporary costs rather than older historic costs. Consider that Bay d'Espoir (1967) has an original cost of approximately $0.1 million/GW.h, Hinds Lake (1980) at $0.25 million/GW.h, Cat Arm (1985) at $0.41 million/GW.h and Granite Canal (2003) at $0.51 million/GW.h.[26] This means that even though the original Bay d'Espoir investment may be now into the years where the ELG rate would benefit customers (had the ELG procedure been in place all along), the higher depreciation driven by the newer investment will be a relatively more significant effect on rates (especially when noting that a significant portion of the Bay d'Espoir investment stated above will not be 1967 vintage, but in fact smaller capital upgrades and improvements that occurred since that time that will still be in the disadvantageous portion of the ELG profile – almost 1/3 of the Bay d'Espoir "original" cost noted is from 2001 or newer).[27] This effect is also noted in the seminal text prepared by the National Association of Regulatory Utility Commissioners (NARUC) on depreciation methods, as follows: "In a growing account however, a crossover point may never occur".[28] In practice, most going-concern utilities are in this situation of having a largely perpetually growing gross plant balance. In short, the promise of ELG of 'higher rates for customers now in exchange for lower rates later' has in practice become 'higher rates now followed by higher rates later' with no period where the purported benefits for customers ever arise.

Although in principle ELG is not advised for Hydro for the multiple reasons listed above, the procedure must also be noted to lead to rate impacts far beyond that portrayed by Hydro and Concentric. Appendix B provides the calculation of the ELG impact for the 2015 vintage assets (those covered in the

[24] AUC proceeding 20272, Decision 20272-D01-2016, paragraph 357. Available at AUC website: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20272-D01-2016.pdf [accessed on December 1, 2017].
[25] 2017 GRA, Volume II, Exhibit 11 [Rev 4], page 13 of 633.
[26] Bay D'Espoir at $265 million for 2,650 GW.h, Hinds Lake at $84 million for 340 GW.h, Cat Arm at $279 million for 680 GW.h and Granite Canal at $113 million for 220 GW.h. All asset values from Schedule 2.2A of the 2018 Cost of Service study, all energy values from NLH project sites [source: https://www.nlhydro.com/operations/hydroelectric-generating-stations/].
[27] Note that as of the 2002 Cost of Service study [provided by Hydro in response to NP-120 from 2001 GRA, available at http://pub.nl.ca/hyd01gra/index.htm, accessed on December 1, 2017] the Bay d'Espoir original cost was listed at $185 million, meaning $80 million of the reported Bay d'Espoir cost is in fact less than 15 years old and would likely still be in the disadvantageous part of the ELG profile were ELG applied to all assets.
[28] NARUC Public Utility Depreciation Practices, 1996, page 178.

depreciation study) while Appendix C provides the impact for the 2016-2019 assets (those proposed to use the "Whole Life ELG rate" calculated in the current depreciation study). As shown in those appendices, the annual impact for the 2015 vintage assets, by year-end 2019, is $1.334 million/year and the impact for the 2016-2019 assets is $5.642 million/year, for a total adverse impact due to the ELG procedure of $6.976 million/year as of year-end 2019.

Finally, there is the question of the timing for any change to ELG. The issue of the timing for the proposed change appears to be only explained by Concentric in PUB-NLH-071 Attachment 1. That explanation for the timing of this proposal appears justified solely on the basis of IFRS accounting. It is entirely unclear how IFRS requirements can be used to justify the need to move to ELG at this time, when Hydro has been reporting under IFRS since 2012.[29] Further, the IFRS justification was the precise rationale Hydro gave for abandoning the sinking fund method in favour of the ASL procedure in the 2012 review of the Depreciation Methodology Application, as follows:[30]

> Under IFRS, the sinking fund method of depreciation, which is used by Hydro, is no longer acceptable as a valid depreciation method. Under Canadian Generally Accepted Accounting Principles, the sinking fund method was accepted because it had regulatory approval. IFRS does not recognize regulatory accounting, thus, for financial reporting purposes, Hydro cannot use sinking fund depreciation. Group depreciation using the average service life procedure is accepted under IFRS and therefore its adoption will result in Hydro's depreciation methodology being IFRS compliant on January 1, 2012 when the new standards become effective for Hydro. Hydro recognizes that other accounting methods may be used under regulatory reporting that may not align with IFRS. Use of accounting that is not IFRS compliant however, would result in more than one set of financial records, thus, Hydro recommends utilizing a single method of depreciation for its 41,000 assets.

In short, at the time of that earlier application, regulatory accounting was not permitted under IFRS (it is now permitted within limited circumstances) and Hydro sought to have a single IFRS compliant methodology that could apply to both regulatory and IFRS statements. Hydro proposed the ASL procedure, which was ultimately accepted. Hydro now seeks to complicate depreciation by abandoning the concept of having a "single method of depreciation", to instead have differing methodologies for the post-2015 assets versus earlier vintages. Further, the method that Hydro is proposing to abandon (ASL) for post-2015 assets is being justified as being needed to best comply with IFRS, when the ASL method that is being abandoned was originally adopted precisely to comply with IFRS.

As a result, it is recommended that the Board not accept the IFRS rationale for the adoption of the ELG procedure but instead judge the proposal on its merits. It is further submitted that the merits of ELG for Hydro have not been justified in the information made available in the filed materials. Similar to Manitoba, it is recommended that the Board (i) reject the ELG procedure for ratemaking purposes, or at minimum accept that a full investigation of the proposal will take considerably more effort and detail, as

[29] Board Order No. P.U.13 (2012).
[30] Hydro's 2012 Depreciation Methodology Application Evidence, page 11 [filed on December 22, 2011].

well as proper, accurate comparative information on the merits, downsides and impacts of the proposal, than has been made available, and (ii) find that the change should not be considered at this GRA but at a later date when such information can be properly compiled and reviewed.

### 3.2.2 Inclusion of Net Salvage in Depreciation

Newfoundland Hydro is proposing to increase annual depreciation expense in order to include the cost of removal (typically termed "net salvage") in depreciation expense each year. The net impact of this proposal on depreciation expense for plant in service as of December 31, 2015 is quoted as $8.176 million,[31] which is comprised of $6.014 million for assets outside of the Holyrood accelerated depreciation assets and $2.162 million for Holyrood accelerated depreciation assets.

This section addresses the net salvage related to assets other than those covered by the Holyrood accelerated provision. Those accelerated Holyrood assets have an imminent, clear and identifiable function for the net salvage accrual and therefore, are subject to considerations that are separate and apart from the concerns noted herein regarding Hydro's net salvage proposal.

While Hydro's impact on net salvage expense is listed at $6.014 million for non-Holyrood assets, this value is for assets in service at December 31, 2015. By the 2019 Test Year, due primarily to asset additions, the annual impact of the proposal is to increase the test year revenue requirement expense for depreciation by $10.176 million[32] compared to past practice (excluding Holyrood accelerated depreciation assets). This value would grow in future.

Collection of net salvage through ongoing depreciation rates is a common, though not universal, practice in the utility industry. The reason this approach is not universally adopted is due to a number of practical issues:

- **Uncertain Scope:** There is often significant discretion or uncertainty regarding what types of expenses qualify as net salvage. For example, in most cases, the cost of removal of an asset are concurrent with costs of a replacement asset, and it can be difficult to distinguish between the costs of one component versus the other.[33] For this reason, there can be concerns about building up an accrual to address poorly defined costs. There can also be regulatory concerns about building up accrued balances that will potentially be paid out under conditions with less scrutiny than new capital expenditures (new capital expenditures are reviewed in detail as part of being added to rate base at each GRA – removal costs in contrast are no longer in the asset records at the GRA so are harder to observe and test).
- **Accounting Standards:** Many utilities adhere to accounting standards (e.g., IFRS) that are not amenable to including net salvage balances in accumulated depreciation. Similarly, accounting

[31] 2017 GRA, Volume II, Exhibit 11 [Rev 4], page IV [Page 9 of 633].
[32] 2017 GRA, NP-NLH-142 Attachment 6, page 4.
[33] In Alberta, this very issue has been the subject of extensive discussion and currently outstanding directives in the case of other regulated utilities. For example, in the AUC decision 3524-D01-2016 on Altalink's GTA, Altalink was "...directed to indicate why costs assigned to the cost of removal could not alternatively be included as a cost of the replacement asset" (page 81, paragraph 434). This directive response remains outstanding.

standards can also not permit recording liabilities associated with events far in the future, which may have significant uncertainty over whether they will actually ever occur (e.g., is there an obligation?), as well as timing for the removal and the estimate of cost associated therewith.[34] In order to record these amounts as future liabilities, these utilities typically now require special dispensation from their regulator. This is the situation for Hydro, and the reason part of Hydro's proposal is to approve a regulatory deferral (regulatory liability) for these amounts.

- **Rate Effects:** A number of regulators have not supported the inclusion of future removal costs in rates as part of depreciation,[35] due to the high degree of rate impacts early in an asset's life, when asset affordability is at its most challenging. This is particularly true for large fixed cost assets (e.g., hydraulic generation or transmission). In contrast, the rate regime can far more readily carry the costs of accruing for removal in the latter years of an asset's life, once the original price has been significantly depreciated, rate base values are lower, load may have grown, the asset may be more heavily loaded for utility service (meaning the asset is providing greater value to ratepayers, despite having a lower cost profile in revenue requirement), and inflation has helped decrease the real economic impact of asset depreciation.
- **AROs:** Net salvage concepts can overlap with required accounting recognition of Asset Retirement Obligations (AROs) which are recorded similarly as liabilities once a given asset has a confirmed obligation to remove, an expected retirement date has been set and a reliable estimate of the removal costs has been calculated. The ARO liability is recorded at the discounted value of the estimated removal cost, using a credit-adjusted risk-free rate (conceptually similar to a sinking fund method for depreciation).

In general, the trend in Canadian utility regulation has been to reduce the amount of net salvage in rates, rather than to increase it (e.g., Manitoba Hydro, BC Hydro, Yukon Energy) and further exploration is underway in some jurisdictions to extend this trend (e.g., recent Alberta Utilities Commission decisions on cases for Altalink Management Ltd and ATCO Electric).[36]

Where utilities do include net salvage in rates, there is a need to distinguish between providing for interim retirements (the net cost of removal for routine capital replacements occurring over time) versus ultimate removal (the final retirement of assets and reclamation of a site to be returned to non-utility service). Some utilities only include one of these two concepts in their depreciation studies. For example, prior to the implementation of International Financial Reporting Standards (IFRS), Manitoba Hydro only included interim retirement net salvage in its depreciation studies, and expected to include any final

---

[34] Examples include Manitoba Hydro, which asserts the IFRS accounting standard does not permit recognition of future removal costs (e.g., see page 5 of 14 [pdf page 5 of 113] Manitoba Hydro's Depreciation Study for year ending March 31, 2014, Appendix 5. 6 of the 2015/17 General Rate Application, available online: https://www.hydro.mb.ca/regulatory_affairs/electric/gra_2014_2015/pdf/appendix_5_6.pdf):
"IFRS does not permit the practice of including a provision for the future removal costs of assets in deprecation unless there is a legal or constructive obligation to remove such assets."

[35] See for example, BCUC Order No. G-96-04 regarding BC Hydro. Also see Yukon Utilities Board Order 2014-06 re: ATCO Electric Yukon which is similarly not permitted to include future removal or salvage costs in rates at this time.

[36] AUC Decision 21341-D01-2017 on AltaLink Management Ltd. 2017-2018 General Tariff Application http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21341-D01-2017.pdf
Also, AUC Decision 20272-D01-2016 on ATCO Electric Ltd. 2015-2017 Transmission General Tariff Application August 22, 2016 http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20272-D01-2016.pdf.

retirement and ultimate removal costs for the final reclamation of a site in rates as part of the recording of an Asset Retirement Obligation according to the accounting standards at that time.[37] Since that time, Manitoba Hydro transitioned to IFRS and now includes no net salvage in rates, addressing interim retirements by rolling the costs of removal of the old assets into the capital cost of putting in place the replacement asset.[38]

For those utilities that do include future removal costs and net salvage in rates, the typical practice is to include a notional percentage "adder" to the annual depreciation expense. This results in the collection of salvage costs being parallel to the straight-line nature of the depreciation. This is the approach proposed by NLH. In normal course, net salvage values would be assessed compared to the expected level of retirement costs to be faced in the future based on a variety of estimating techniques, with net salvage percentage adders varying by type of asset and specified for each account. The critical data in assessing each net salvage estimate is the utility's own data. However, in the case of NLH, there is apparently no useful account level data available,[39] and the only data provided at the corporate level is as follows:

**Table 3-3: Hydro's Cost of Removal and Disposal Proceeds (Net Salvage) ($000s)[40]**

| | 2012 Actuals | 2013 Actuals | 2014 Actuals | 2015 Actuals | 2016 Actuals | Average Actual | 2017 Forecast | Average 6 year (incl 2017 Forecast) |
|---|---|---|---|---|---|---|---|---|
| Cost of Removal | 1,182 | 991 | 1,148 | 763 | 271 | 871 | 723 | 846 |
| Disposal Proceeds | (357) | (503) | (236) | (709) | (197) | (400) | (350) | (392) |
| | 825 | 488 | 912 | 54 | 74 | 471 | 373 | 454 |

Table 3-3 highlights that the amounts recorded in Hydro's books for net salvage, as the net of removal costs less disposal proceeds, has varied between $0.054 million and $0.912 million over the actual years 2012-2016 and is forecast at $0.373 million for 2017.

Hydro also notes that in 2018 and 2019 the cost of removal estimates are $2.1 million and $1.5 million respectively, less $0.4 million in disposal proceeds each year, for a net $1.7 million and $1.1 million net salvage expense respectively for 2018 and 2019. Note, however, that Hydro's previous estimates for the 2015 Test Year were significantly above the actual level (estimate of $2.170 million removal less $0.115 million proceeds, for a net $2.055 million compared to actuals at $0.054 million) and each test year estimate (2018 and 2019) is far out of line with what has been experienced every actual year, including 2015. The difference between Hydro's forecast and actuals raises concerns regarding Hydro's forecasting in this area.

---

[37] Manitoba Hydro 2012/13 & 2013/14 General Rate Application, Transcript from hearing re: questioning by Board member Mr. Raymond Lafond and Manitoba Hydro witnesses Mr. Vince Warden and Mr. Larry Kennedy, January 14, 2013, transcript pages 3462 - 3465. Available online: http://www.pub.gov.mb.ca/pdf/transcripts/hydro/2013/hydro_jan14_3325-3590.pdf.

[38] Manitoba Public Utilities Board Order No. 73/15, Manitoba Hydro 2015/16 General Rate Application, July 24, 2015, page 43-44 of 108. Available online: http://www.pub.gov.mb.ca/pdf/15hydro/73-15.pdf.

[39] See IC-NLH-032 [2017 GRA].

[40] Per NP-NLH-153 Attachment 1. Note that the above table excludes "Loss on Disposal" which is unrelated to net salvage rates and is tied in to Hydro's proposals regarding group accounting.

Hydro's overall proposal in this area gives rise to two immediate areas of concern:

1) **Magnitude:** A clear concern is that the net salvage experienced by Hydro in the past 5 years, and forecast for a sixth year, is entirely out of line with the net salvage amounts proposed to be included in the test year rates ($10.176 million per year excluding Holyrood accelerated assets, or more than 10 times the highest year recorded).[41] Hydro has not recorded any year recently where the costs that would be charged through the net salvage provision exceed even $1 million. This means that the account would quickly grow to a large value. Further, Hydro has indicated that the corporate net cost of removal has tended to be about 10% of the original cost (gross book value) of the assets retired,[42] which means a retirement of $100 million of non-Holyrood assets would be required <u>in a given year</u> just to hold the salvage balance steady for that year, much less draw on the balance. Outside of Holyrood (which is not included in the above values), it is not clear that Hydro proposes retirements of this magnitude on any sustained basis in the future.

2) **Lack of Own Data:** Retirement costs related to cost of removal and disposal proceeds can be unique to each utility, given the service area, accounting policies and types of assets. For example, a rural utility may experience high costs of removal and low ability to achieve proceeds on disposal if the assets are expensive to move to a salvage market (e.g., from isolated sites) while an urban utility may experience high costs of site reclamation when removing assets in high valued locations with close quarters for removal activities. For this reason, it is generally understood that net salvage estimates are necessarily best derived from a utility's own data. However, in the case of NLH, effectively no useful data is available.

Beyond the above concerns, there is a significant issue arising from the Hydro proposal in respect of interim retirements versus terminal retirements.

- **Interim Retirements:** Hydro proposes that costs associated with removal for interim retirements (less any disposal proceeds received) would be rolled into the costs of the replacement asset. This would apply, for example to any rebuild of hydro generating stations, dikes, dams, transmission lines or similar assets that would be expected to be rebuilt on the same general site upon retirement. This is appropriate and, as noted above, is consistent with the practice of a number of utilities and with IFRS principles.
- **Final or Terminal Retirements:** In contrast to interim retirements, assets that will be reclaimed and the site rehabilitated and removed from utility service are known as a terminal or final retirement. Hydro proposes that only the net salvage associated with these retirements would be funded from the amounts set aside through depreciation rates during the life of the asset. In short the amounts being set aside through deprecation rates should only be targeted to these final retirements.

[41] NP-NLH-142 Attachment 6.

[42] NP-NLH-145. This purportedly relates to the 2012-2015 period. Actual 2012-2015 disposals do not appear to be available, except 2012 (CA-NLH-116 Attachment 1 Rev.1 from the 2013 Revised GRA) which showed $5.6 million in disposals, and forecast amounts varying from $4 million to $8 million per year. This is consistent with the 10% value cited by Hydro, with the exception of 2015 which showed only $54k in actual net salvage.

Going through the rationale provided by Hydro, there are a large number of accounts that are proposed to begin accruing salvage as part of depreciation rates that do not appear to be part of any credible future terminal retirement. For example:

- In respect of **hydro assets**, accounts such as D01 covering Dams, Dykes, Canals and Tunnels ($346 million deemed cost, as at 2019)[43] are representative. This is by far Hydro's largest asset account, more than 50% larger than the second largest (T04 Towers, at $222 million)[44]. The D01 account has effectively seen zero retirements[45] despite having asset data going back to 1956 and large values of assets starting in 1966.[46] Hydro has proposed a net salvage rate for D01 assets at -8% (meaning the costs for terminal retirements should be 8% of what has been set aside to depreciate the original asset). Hydro was asked to support the salvage rate (for example, in IC-NLH-038) and consistently referred to the response to NP-NLH-145. However, reviewing NP-NLH-145 shows only support of the concept that hydro assets will not face terminal retirements at any time, and only interim retirements are expected in the future (which would support a net salvage accrual of 0%). In particular, NP-NLH-145 reads: "Not hearing that there is an end of life. Will be a structure there. No anticipated replacement required for aging dams, just maintenance and capital work required", and further "no decommissioning or rebuilds of dams; no large capital programs; just usual capital maintenance and public safety work". In respect of other hydro asset accounts, such as G02 Gates, the notes also indicate: "constant maintenance to maintain rather than replacement". NP-NLH-145 also provides comparable utility depreciation rates but nothing on net salvage. For a comparison of net salvage rates at other utilities, as provided by Hydro in IC-NLH-158, noting only the salvage rates in use by Newfoundland Power and NWT Power and provided no information as to whether these utilities use the same net salvage approach as proposed by Hydro (i.e., only accrue net salvage for final retirements). Further, it is well known that Newfoundland Power's hydro assets are of an entirely different nature and scale than Hydro's assets. It is not inconceivable that small hydro assets such as those maintained by Newfoundland Power may face terminal retirements and waterway restoration at some point in the future, based on industry experience,[47] but this is a highly unlikely outcome for something such as the Bay d'Espoir complex.

- In respect of **transmission assets**, the notes provided in NP-NLH-145 similarly provide no indication that any terminal retirements would ever be expected given the configuration of the system. The notes further indicate that the same rights-of-way will be reused by new lines (as least in the case of distribution).

[43] NP-NLH-142, Attachment 6.
[44] NP-NLH-142, Attachment 6.
[45] There are very small retirements noted in IC-NLH-045, but these are insufficient to prevent the account from being reported as "100% surviving" per IC-NLH-077.
[46] Exhibit 11, page 428 or 628.
[47] For example, after interconnection the price of power from the mainland and Muskrat infeed may trend such that in the future (perhaps decades from now), when the small NP plants are otherwise due for major capital work or refurbishment, it would not be inconceivable that a decision may be made to instead close and rehabilitate the plant given the small role they play in the overall grid. Such a decision is highly unlikely for Bay d'Espoir given the capacity is critical to providing both energy and reliable capacity to the island.

Focusing only on hydraulic generation and major transmission assets,[48] there does not appear to be any justification for net salvage to be accrued based on the evidence provided. For clarity, the above assets, under the now proposed policy, would lead to zero need for accrual of net salvage as part of the depreciation rates. Further, no cost of disposal or disposal proceeds would be recorded in the test year, even in the year in which any replacement asset may be constructed. This is because the costs of removal become an effective site preparation cost for the replacement asset, a valid and appropriate cost to include in the asset site in its second generation of service. The salvage costs would therefore be recovered through depreciation of the replacement asset. This would appear to relate to the following accounts:[49]

- A01 Aircraft Landing Strips
- B03 Booms – Timber
- B04 Bridges
- B08 Buswork and Hardware
- C06 Capacitors
- C09 Circuit breakers
- C13 Conductor – Transmission
- C17 Counterpoise
- C18 Cranes
- D01 Canals
- D03 Disconnect Switches
- F04 Footings and Foundations
- G02 Gates
- G04 Generator windings
- G06 Governors
- G07 Ground Wire System
- I03 Insulators
- I04 Intake Structures
- P03 Penstocks
- P05 Pole structures – wood
- P10 Powerhouse
- R13 Roads
- S06 Spillway structures
- S10 Station service
- S15 Structure supports
- T04 Towers
- T05 Transformers Other
- T09 Turbines
- V02 Valves penstock
- W01 Water regulating structures

[48] For example, the assets previously covered by the sinking fund approach. See IC-NLH-150, pdf page 37 of 101.
[49] This list was generated by noting which accounts were dominated by sinking fund type assets as of 2012, per CA-NLH-61 from the 2012 Depreciation hearing, predominantly meaning 80% or greater.

- W02 Water supply system

In sum, the above net salvage estimates comprise $5.834 million of the $10.176 million in salvage cost proposed for the 2019 test year. There is no basis to include the above amounts in rates as there is no evidence that terminal retirements should be assumed for these asset classes. Any retirement of an asset in these accounts would coincide with the installation of a replacement asset that retains the macro-asset function providing power to future ratepayers.

Absent the above asset classes, the remaining net salvage proposed for 2019 totals $4.342 million primarily related to distribution assets and thermal generation which were not the focus on this evidence. Based on the information available in the filing, the net salvage included in rates for the Test Years should at most tie only to these distribution and thermal generation accounts.

### 3.2.3 Alternative Explanation re: 10% Ratio for Net Salvage

While Hydro has acknowledged that the data available for determining a net salvage rate by account is not available, and no data at all is available prior to 2012, Hydro has provided their interpretation that the overall net salvage rates should target 10% on a corporate level.[50] As a result, Hydro suggests that the above approach to analysis (assessing the logic by account) is inappropriate, since it misses the fact that the net salvage is, in practice, a global adjustment. More specifically, this rationale is detailed in the response to IC-NLH-160, where it is noted:

> Concentric and Hydro acknowledge that the allocation process as described in Hydro's response to IC-NLH-159 results in circumstances where, given the differences in the capitalization policies between Newfoundland Power and Hydro, a net salvage percentage is being requested in a limited number of accounts where there may not be future cost of removal expenditures. However, it is stressed that overall the procedures followed are based on the actual level of historical cost of removal expenditures in total, and will result in the collection of expected future cost of removal amounts in total. As such, while there may be some accounts that have a higher than required net negative salvage percentage, they are offset by accounts that have a lower than required net negative salvage percentage. Further, as described above, future depreciation studies will ensure that a true-up of the collected amounts are reflected in the net salvage percentages going forward. Concentric notes that the true-up as contemplated in future years is no different than the accumulated depreciation true-up that have been, and will continue to be included in depreciation studies (including Newfoundland Power) for virtually all utilities throughout North America.

First, while the response notes that this is consistent with "virtually all utilities throughout North America", Concentric's predecessor company (Gannett Fleming) assisted Manitoba Hydro in moving from a situation where net salvage was included in depreciation rates to a system where it is no longer accrued at all except in cases of a defined ARO. In addition, other utilities such as Altalink Management are being encouraged by their regulator to increasingly reduce net salvage costs from depreciation

[50] See, for example, IC-NLH-159.

expense, such as through further capitalization of salvage as part of asset rebuilding.[51] In short, the cited quotation overstates the industry status.

Second, the cited reference above hinges on the Hydro "actual level of cost of removal" despite Hydro acknowledging that it has little to no data to support this contention. The sum total net salvage cost provided (which is indicated to be the only data available) is provided earlier in this testimony in Table 3-3.

Hydro's calculation for the 10% comes from summing the "cost of removal" for the years 2012 to 2015 actuals (totalling $4.084 million) and dividing this by the total historical retirements in those years of $39.165 million. This approach is highly problematic as:

1) **It fails to include disposal proceeds:** In the calculations given, Hydro only includes the cost of removal. However, the mathematics for "net salvage" includes both the cost of removal and the offset of disposal proceeds. Had both components been properly included, the total net salvage would have been calculated at $2.279 million over the 4 years, or 5.8% instead of 10%.

2) **The dataset does not reflect many important asset classes:** The assets that make up the $39.165 million retired over the 4 year period are provided in response to IC-NLH-159. It is notable that this sample set includes almost no assets from the major hydraulic generation and transmission categories (D01 Dams, C13 conductors - transmission, P03 penstocks, R13 roads, S06 spillways, and T04 towers) which make up almost 30% of NLH's original cost of assets,[52] but make up less than 3% of the disposals.[53] In contrast, categories such as diesel engines and gas turbines (20% of the retirements,[54] but less than 5% of Hydro's original cost installed plant) are overrepresented. As a result, extending the 10% ratio to apply to all assets is not justified as it has no demonstrated relevance to hydraulic generation or transmission.

3) **The dataset is too small:** The total dataset of disposals covers 4 years actual net salvage cost of only $2.279 million. There is no evidence that over this period Hydro consistently applied the policy of including net salvage costs in the capital costs of replacement assets. Regardless, a sum total experience of $2.279 million in net salvage costs over 4 years cannot reasonably be relied upon as overwhelming evidence in support of Hydro's proposal for over $10 million per year in net salvage being required to be included in rates in each of the Test Years – the analytical basis of support is simply too small.

---

[51] AUC Decision 3524-D01-2016 paragraph 434 [available at http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/3524-D01-2016.pdf, accessed on December 1, 2017].

[52] For example, based on information provided in Table 1A of the Depreciation Study [2017 GRA, Volume II, Exhibit 11] the total original cost at December 31, 2015 for the accounts D01, C13, P03, R13, S06 and T04 about $678.5 million which is about 28% of the total of $2,458.8 million [excluding Holyrood assets with truncation date of 2021]. The information provided in response to NP-NLH-142 shows the for 2018 test year the depreciable base of those assets at $819.8 million which is about 33% of the total of $2,476.2 million [excluding Holyrood assets with truncation date of 2021].

[53] For example, based on information provided in response to IC-NLH-159 Attachment 1, the total historical retirements for the accounts D01, C13, P03, R13, S06 and T04 about $0.994 million which is about 2.5% of the total of $39.165 million.

[54] For example, based on information provided in Table 1A of the Depreciation Study [2017 GRA, Volume II, Exhibit 11] the total original cost at December 31, 2015 for the accounts D02 and G01 about $111.2 million which is about 4.5% of the total of $2,458.8 million [excluding Holyrood assets with truncation date of 2021]. This is compared to the total historical retirements for these accounts at about $7.727 million which is about 19.7% of the total of $39.165 million [IC-NLH-159 Attachment 1].

4) **The net result of proposal is far higher than 10%:** Due to the particular distribution of the net salvage percentages proposed by Hydro, by 2019 the proposed net salvage accrual (for assets other than Holyrood accelerated depreciation assets) is $10.176 million while life depreciation is only $66.930 million. This means net salvage is proposed at a rate of 15.2% of the depreciation of the asset cost, far higher than 10%.

For the above reasons, the claims of needing a benchmarking or global target of 10% should not be relied upon. At best, the data only supports 5.8% over these 4 years once the disposal proceeds are included. As the sample set includes overrepresentation of classes that may see terminal retirements (as opposed to classes like major hydro and transmission assets that should not see terminal retirements) even 5.8% is likely too high. Further, despite claiming a 10% ratio, Hydro has proposed net salvage rates that yield 15.2% accrual to net salvage compared to the amortization of the original (or deemed) cost.

As noted above, simply retaining the salvage rates proposed by Hydro for all assets, other than major hydraulic generation and transmission related assets, would yield approximately $4.342 million in net salvage in the test years. This is the maximum that should be entertained at this time, based on the evidence available.

## 3.3 HOLYROOD FUEL CONVERSION FACTOR

The current GRA proposes to continue the use of the Holyrood fuel conversion deferral account and to set the Holyrood fuel conversion factor at 616 kW.h/bbl.[55] Hydro indicates this is based on a regression of the gross unit loading, the fuel heat content and the fuel consumption rate.[56] This is a reduction from the 2015 Test Year approved efficiency of 618 kW.h/bbl (650 kW.h/bbl gross, less 32 kW.h/bbl station service or 4.9% – Hydro had proposed 650 kW.h/bbl gross efficiency less 43 kW.h/bbl station service, or 6.6%).[57]

Hydro notes that, in 2015, the actual achieved net efficiency was only 602 kW.h/bbl net of station service. Station service in 2015 is noted at 5.5%.[58] This means Hydro achieved 637 kW.h/bbl gross efficiency (less 35 kW.h/bbl station service).

The regression analysis from the 2013 Amended GRA that was relied upon to determine the 650 kW.h/bbl gross efficiency was summarized as follows[59] in Figure 3-1:

[55] 2017 GRA, Volume I, page 3.24.
[56] 2017 GRA PUB-NLH-043.
[57] Decision P.U. 49(2016).
[58] 2017 GRA PUB-NLH-042.
[59] From the pre-filed testimony of P. Bowman and H. Najmidinov, page 24 [2013 Amended GRA, June 2015].

**Figure 3-1: Holyrood Gross Fuel Conversion Rate adjusted to 2015 Test Year Heat Content vs Average Gross Unit Loading 2009-2014**[60]

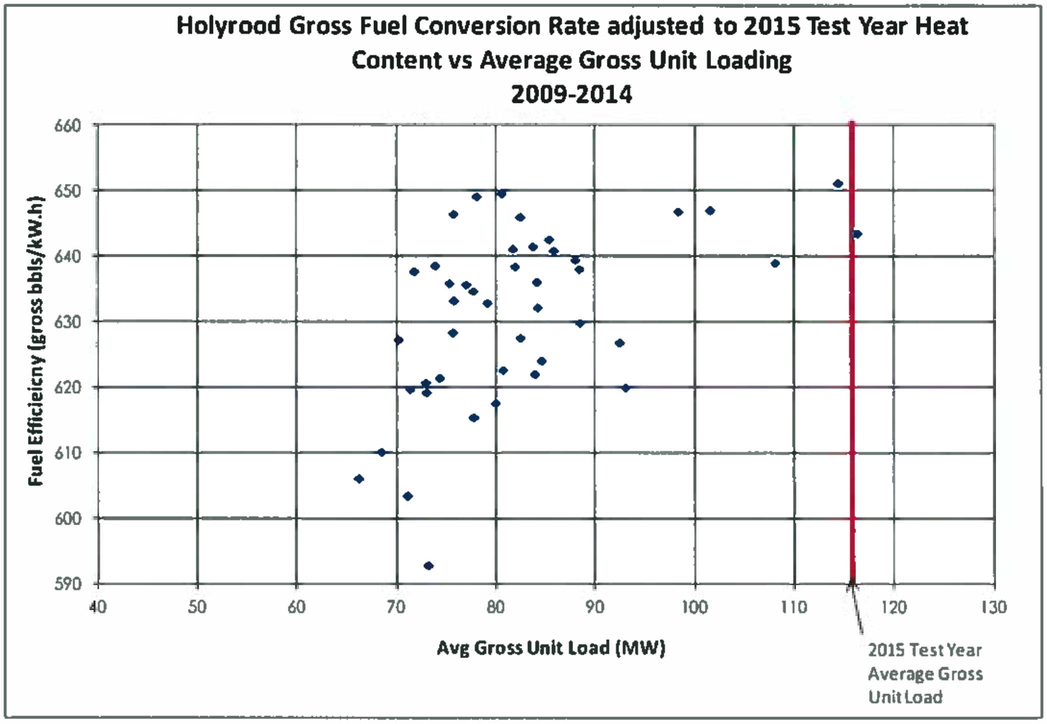


Figure 3-1 was relied upon for the purpose of confirming the reasonableness of Hydro's 650 kW.h/bbl gross efficiency. This is because the 2015 projected average unit loading was forecast at 117 MW.[61]

On the matter of the 2015 actual efficiency, it is important to note that the regression approach set out above worked as intended. Hydro achieved a gross unit efficiency of 637 kW.h/bbl[62] instead of 650 kW.h/bbl, but this is because the gross unit loading ended up at approximately 87 MW[63] rather than the 117 MW as forecast. From the above figure, 637 kW.h/bbl is fully within the range expected at an 87 MW net average loading. The reasons for the lower net loading approach relate to low level usage across many more hours than expected, particularly in summer,[64] consistent with conditions that are no longer expected to be required given the initiation of TL267. The new TL267 allows the Avalon Peninsula to receive a proper transmission based firm capacity delivery from the remainder of the island, and reduces the need for the inefficient low level Holyrood operation (which was an inferior solution to the capacity shortfalls on the Avalon Peninsula).

[60] Prepared based on data provided by Hydro in response to IC-NLH-160 from the 2013 Amended GRA [excel file]. Gross fuel efficiency is calculated based on adjusted Heat Content to 2015 Test Year value of 152,400 BTUs/gal. This is the same fuel heat content as forecast for the 2018 and 2019 test years, per PUB-NLH-043, Attachment 1 [2017 GRA].

[61] Hydro now indicates the average unit loading from 2015 Test Year was 109.6 MW per IC-NLH-119 [2017 GRA], but this does not appear to be a gross value.

[62] 602 kW.h/bbl net efficiency adjusted for 5.5% station service).

[63] Per PUB-NLH-043 [2017 GRA] the monthly average loadings are provided for 2015. 87.45 MW is the simple average of the monthly values.

[64] 2017 GRA IC-NLH-119.

For 2018 and 2019, the average gross loading (absent off-island sources) is now expected to be 130 MW.[65] Based on this operating level, and the basic confirmation from 2015 actuals that helped verify the above relationship of loading to gross efficiency, it is not clear how any gross efficiency below 650 kW.h/bbl can now be credibly proposed, particularly at the 130 MW gross average loading level.

With respect to station service, for 2015 the PUB imposed a station service estimate of 4.9%, or 32 kW.h/bbl. Hydro indicates that in 2015 it only achieved 5.5% (equivalent to 35 kW.h/bbl), but this was based on many more hours of operation than anticipated with much lower average output. Under such circumstances, station service would be expected to increase. By 2016, Hydro indicates it had achieved 5.1% station service[66] at a net average loading only slightly above the 2015 level (only 1.7 MW higher).[67] Given that the 2018 and 2019 forecast loading is over 35% higher than the 2016 level, it is reasonable to expect that the 5.1% actual 2016 station service would at minimum drop to the 4.9% previously targeted by the PUB, if not lower. Strangely, Hydro forecasts that in 2018 and 2019, a 6.2% station service should be assumed, given a simple average over the years 2011-2015,[68] years with much lower loading and before the major station service investments (such as variable speed drive fans) were made. This 6.2% station service estimate should be rejected.

In short, there would appear to be no reason at this time to consider a reduction to the Holyrood efficiency target that was used in 2015. At minimum, the 650 kW.h/bbl should be increased to reflect an even higher projected loading than the 2015 test year, and the 4.9% station service estimate should be maintained, if not lowered to reflect the higher average loading and normal continuous improvement.

Of course, the Holyrood efficiency noted for the Test Years is only notional, in that Holyrood will ideally see very little operation in 2018 and 2019 given off-island sources. However, given that the GRA revenue requirement is being set using a default baseline of Holyrood generation, the best estimate of what arises under the Holyrood scenario should be used.

With respect to the Off-Island Purchases Deferral Account, in the event that Hydro is able to secure off-island power at price lower than Holyrood, then the 618 kW.h/bbl (the 2015 test year status quo), or whatever higher efficiency the Board may set, simply becomes the basis for calculating the savings that accrue to the Off Island Purchases Deferral Account. The indications from Hydro are that material balances should accrue in this account compared to the costs of securing this same power from Holyrood. Setting an artificially low benchmark for Holyrood efficiency, as proposed by Hydro, would only serve to even further increase the balances accruing in the account at the expense of ratepayers in 2018 and 2019. The account is a sensible approach to managing the significant rate transitions pending, but it is not appropriate to artificially force even greater savings to the deferral account through using an unsupportably low Holyrood efficiency rate in test year 2018 and 2019.

For all of the above reasons, the Board should not approve the 616 kW.h/bbl efficiency as proposed by Hydro, but should at minimum retain the 618 kW.h/bbl adopted for the 2015 test year. The Board would

[65] 2017 GRA PUB-NLH-043 Attachment 1 page 2.
[66] 2017 GRA, IC-NLH-119
[67] Net average loading of 90.8 MW versus 88.9 MW.
[68] 2017 GRA, PUB-NLH-042

be justified in setting the efficiency at a level even slightly higher than this given the high unit loadings projected under the base case Holyrood scenario.

## 3.4 2018 REVENUE DEFICIENCY IN RATE BASE

Hydro in its 2017 GRA states that proposed January 1, 2018 interim rates will provide Hydro with partial recovery of costs "resulting in a shortfall in revenue requirement of $22.6 million in 2018." Hydro is proposing to defer this amount by including the balance in rate base and recover over 20 months commencing January 1, 2019, and ending August 31, 2020.[69]

As part of this collection approach, Hydro has proposed that the 2018 shortfalls that remain uncollected become part of rate base and earn a return equal to Hydro's weighted average cost of capital.

As a concept, rate base is typically understood to represent the value of a utility's property that is dedicated to long-term service to regulated ratepayers. It is primarily made up of undepreciated capital assets, with some smaller amounts of intangibles and working capital. The concept of rate base is tied to the concept of this balance being financed by a utility's long-term capital. In turn, the utility's long-term capital is made up of various forms of financial resources, at a cost commensurate with the risks that the utility experiences for its operation of the regulated business (e.g., business risks, risks of stranded assets, capital write-downs, underperformance, losses caused by weather, etc.).

The 2018 shortfall is material ($22.6 million in 2018) and does not fit with the concept of the rate base. First, there is the practical issue that the 2018 shortfall is a function of the 2018 rate base, but is itself part of the 2018 rate base, so a circular calculation approach is required to determine the revenue requirement[70] (an inferior outcome). Second, the 2018 shortfall is a short-term asset for Hydro, proposed to be collected within 20 months.[71] As such, it does not require financing by long-term bond offerings, for example. Third, Hydro is at effectively no risk of recovering the balance. It is expected that the balance should be collected within the timeframes proposed, but in the event it is not, Hydro would plan (and expect) to maintain any shortfall rider for a longer period of time as necessary. Therefore, the 2018 shortfall is not an item that requires financing by risk capital such as equity. Finally, the use of long-term capital significantly increases the net cost to ratepayers of the shortfall. Hydro suggests that financing the 2018 shortfall using an assumption of long-term capital drives $0.647 million in costs to ratepayers.[72]

A clear alternative exists, with sound regulatory precedent. Hydro can instead be directed to finance the 2018 shortfall using only short-term debt (e.g., promissory notes). No updated rates are provided for the cost of short-term debt, but the most recent estimates available indicate a cost of approximately 1%,[73]

---

[69] 2017 GRA, Volume I, Chapter 4, pages 4.11 and 4.12.
[70] 2017 GRA, IC-NLH-112.
[71] 2017 GRA, Volume I, Chapter 4, pages 4.11 and 4.12.
[72] 2017 GRA, IC-NLH-112.
[73] For example, NP-NLH-001, Attachment 1 Page 10 of 11, notes that "On October 12, 2016, Nalcor borrowed $225 MM from the Province by way of a promissory note and these funds were then loaned to Hydro. The proceeds of this loan, which matured on January 11, 2017 and carried an interest rate of 0.9%" Also, Hydro's March 31, 2017 Interim Financial Statements note that "Nalcor replaced an intercompany loan in the amount of $225.0 million to Hydro. This loan will mature on September 30, 2017 and has an interest rate of 1.112%" https://nalcorenergy.com/wp-content/uploads/2017/05/Hydro-Con-Q1-2017.pdf [accessed on December 1, 2017].

which is a significant savings compared to the 5.73% weighted average capital cost used to finance rate base. There would be no net cost to Hydro from implementing such a recommendation, but clear cost advantages to ratepayers.

Directly relevant regulatory precedent exists for this alternative. For example, in a 2002 decision from the NWT Public Utilities Board[74], the NWT PUB permitted the Northwest Territories Power Corporation (NTPC or NWTPC) to collect a shortfall related to Test Years 2001/02 over a period extending beyond the end of the test year (March 31, 2002), noting:[75]

> The Board considers it appropriate to consider granting carrying costs if there has been a significant regulatory lag and the carrying costs involved are material. Further, the regulatory lag before implementation of the rate adjustment should exceed a period of 12 months as short term situations will normally not involve amounts of material consequence. In regard to the 2001/02 deficiency, the Board is prepared to approve carrying costs for the 16 month period from April 1, 2002 to July 31, 2003 as the amounts involved are material. The Board agrees with YK/HR [the intervenor representing the City of Yellowknife and the Town of Hay River] that the shortfall should be financed at NWTPC's short term cost of debt given the relatively short period over which financing will be required.

The NWT PUB used the same principles in a decision regarding collecting 2006/07 shortfalls over a period extending beyond the end of the test year (March 31, 2007), noting:[76]

> The NTPC will be allowed to charge interest at a rate of 2.31% on the 06/07 shortfall for the period from April 1, 2007 to December 31, 2007. For the period beyond December 31, 2007 until full collection of the 06/07 shortfall, the NTPC will be allowed to apply short-term interest to the actual outstanding receivable monthly, at a level equal to 50% of the Bank of Canada Prime Business interest rate.

In that 2006/07 decision, the NWT PUB used the same short-term interest rate logic, but discounted the interest rate by one-half of the prevailing short-term interest rate as the Board had concluded that the utility contributed to the delays in recovering the test year revenue requirement.

There are three important differences between the proposals by Hydro and the approach used in NWT:

1) In NWT, the interest rate used is benchmarked off short-term rates, reflecting that the recovery occurs quite quickly;

2) The interest is accrued to the balance of the shortfall in NWT, not to the revenue requirement for the purposes of setting base rates. As such, the rate base and revenue requirement are

---

[74] NWT PUB Decision 8-2002. http://www.nwtpublicutilitiesboard.ca/sites/default/files/supporting/8-2002%20DECISION%20NTPC%20Shortfall%20Rider%20%26%20Interim%20Refundable%20Rates%20Refiling.pdf [accessed on December 1, 2017].

[75] NWT Pub Decision 8-2002 page 9.

[76] NWT PUB Decision 16-2008. Pages 14-15.

calculated focusing on costs for the year and not collections, which eliminates the issue of circularity. This is similar to how the RSP is calculated in Newfoundland and Labrador; and

3) No interest is accrued to the shortfall in NWT until the first month after the test year. This is consistent with the principle that the revenue requirement is developed on an annual unit, and can be collected on the basis of an annual period, so there is no deferral of shortfall collection to speak of until after the end of the $12^{th}$ month (amounts collected in any month of the test year, including the $12^{th}$ month, should not include interest costs).

Application of the above principles to the 2018 shortfall would materially reduce the costs to ratepayers of transitioning to the new required rate level.

# 4.0 COST OF SERVICE

Hydro's 2019 Cost of Service study (2019 COS) is prepared for Hydro's five separate systems: IIS, Island Isolated, Labrador Isolated, L'Anse au Loup and Labrador Interconnected. This is consistent with past GRAs and with standard ratemaking practice to allocate cost by each system. This submission focuses on the IIS.

The 2019 COS for IIS seeks to allocate $602.6 million in revenue requirement [77] to three major rate classes: Newfoundland Power (NP), Industrial Customers, and the Rural customer group (Rural).

For the 2019 COS, Hydro incorporated a methodology largely consistent with the 2015 COS. Updates were provided to the functionalization and classification ratios, the allocation factors based on customer load forecasts and the system load factor, to reflect the 2019 Test Year. Methodology changes are limited, reflecting the intended Cost of Service methodology proceeding which Hydro indicates it intends to initiate in 2018 [78] after the current proceeding is completed.

The challenge for 2019 is that Cost of Service methodology is usually guided by how a system is planned and operated, yet the 2019 COS study reflects neither of these considerations. For example:

- As to operating, assuming the transmission interconnections come into service as intended, the system will be largely operated in 2019 so as to minimize Holyrood fuel use through off-island sources. Absent these sources, Holyrood would be expected to generate 1,560 GW.h,[79] but this is expected to be offset by 859 GW.h from CF(L)Co recapture over the 110 MW LIL infeed [80] and a further unspecified amount over the 300 MW Maritime Link infeed. In short, Holyrood will play only a very small energy role in 2019 and in practice will function in almost entirely a reliability/capacity support role. As such, a COS based on 1,560 GW.h of Holyrood generation does not represent how the system is likely to be operated in the Test Years.
- From a planning context, the Generation Adequacy report [81] highlights that the only resource required (other than Muskrat, LIL and ML) is the new TL267 (a capacity resource to ensure full peak demand can be delivered to the Avalon Peninsula). Once these resources are in place, all planning demand and energy targets have been materially exceeded. This means the planning rationale for various smaller island resources may change from the basis on which they were originally put in place.

The issue for 2019 is determining how to reflect existing resources in the Cost of Service study pending the major methodology review. Most notably, concerns arise that costs of energy have been significantly overstated, as demonstrated in the following two areas:

[77] Hydro's 2015 COS, Schedule 1.3.1, page 1 of 3.
[78] 2017 GRA, Volume I, page 5.19.
[79] 2017 GRA Schedule 3 IV page 3.
[80] 2017 GRA, NP-NLH-015.
[81] 2017 GRA, IC-NLH-101 Attachment 1.

### 4.1 HOLYROOD CAPITAL COSTS

The Holyrood capital asset is proposed to be classified to demand and energy on the basis of its historical use pattern.[82] However, in 2019, Holyrood will not be used consistent with past experience, but rather primarily as a backup/standby plant with much lower levels of energy generation than in past years. For this reason, the capital costs of the Holyrood plant should be classified far more significantly to demand in 2019 than proposed in Hydro's COS. Hydro is already forecasting that 859 GW.h will come from CF(L)Co recapture,[83] out of 1,560 GW.h that would otherwise be expected to be generated by Holyrood (55% reduction), plus a further likely significant supply from ML sources. Given these factors, a downward adjustment of at least 50% in the energy allocation compared to past practice would be appropriate. Given the 5 year average in the COS study yields 30.44% of Holyrood capital costs classified to energy, a more appropriate classification to energy would be on the order of 15%.

### 4.2 WIND PURCHASES

Wind energy is proposed to be classified 100% to energy on the basis that this is the way Hydro's planners assess the contribution of wind (i.e., it is not thought to contribute to supply at peak times). In its submission, Hydro has excessively focused on the planning rationale as opposed to the actual contribution wind makes to the system. Note that this issue took prominence in the 2013 Amended GRA, primarily in the evidence of Mel Dean, submitted on behalf of Vale. That evidence took issue with the fact that Hydro vigorously defended a significant capacity component for wind costs in the original 2013 filing (44.6% capacity) and pivoted to vigorously defending a 0% capacity component for wind costs in the revised 2013 filing.[84] Hydro provided the following rationale in the original 2013 Cost of Service filing [85] to support a 44.6% capacity classification for wind:

> Hydro's wind purchases since 2009 have had a capacity factor in excess of 40%. Hydro uses a 40% capacity factor for wind in its planning. From the time that Hydro has been purchasing wind generation, this resource has been providing energy at the time of each of Hydro's evening system peaks, except for occasional instances in which the turbines shut down due to excessive winds. Temperature and wind speed are two principal drivers for Hydro's peak hour demand. Consideration of any changes to the current classification methodology should be in light of overall performance and wind conditions at the time of Hydro's system peak.

The above rationale is a sound description primarily of the practical <u>operating</u> contribution of wind generation, which is a valid cost of service rationale. More importantly for the present time, the operating criteria is likely the more relevant characteristic given that the <u>planning</u> perspective would have to be grounded in the question of "what characteristics of wind would be beneficial so as to lead Hydro to add wind power producers to the system?" In today's reality, presumably Hydro would not add these IPPs at all. Hydro is apparently headed into a time of significant supply surpluses and cost pressures. The only

---

[82] 2017 GRA, Volume III, Exhibit 15 [Rev 4], Schedule 4.3.
[83] 2017 GRA, NP-NLH-015 Attachment 1.
[84] Report of Mel Dean. June 4, 2015. Page 11.
[85] 2017 GRA, NP-NLH-162.

resources being added are for capacity and reliability reasons (e.g., TL267) and adding additional energy supplies to the system will no longer give cost and environmental benefits associated with offsetting Holyrood generation (since there is only minimal if any Holyrood generation planned starting in the near future). In short, as of 2019, there would not be any economic rationale for planners to want to add or value incremental wind. This means the planning context is far less informative and instructive to cost of service methods than a focus on the operating perspective and, from an operating perspective, wind normally provides useful load carrying capacity through many high load hours of the year (particularly as high loads are often, though not always, driven in part by high winds). Given wind in practice produces a hybrid demand and energy contribution, some allocation to demand and energy in the COS for 2019 is appropriate. Outside of a 100% energy classification, the lowest demand classification for wind cited in Hydro's Exhibit 13 is 9%.[86] For working purposes, pending the more thorough methodological review planned, this 9% level of allocation to capacity should be the minimum adopted.

[86] Exhibit 13, page 29.

# 5.0 SPECIFICALLY ASSIGNED CHARGES

The issue of allocating Hydro's costs to specifically assigned assets received considerable attention in the 2013 Amended GRA. However, material aspects of concern were never finalized as they were either (a) included in the negotiated settlement as part of an agreement to get through that specific GRA, pending a proper cost-of-service review in 2016 (a specific and detailed component of the settlement which has not occurred) or (b) adjudicated by the PUB as part of P.U. 49 (2016) concurrent with an expectation that Hydro would fully substantiate the issues as part of the 2017 filing. This includes the following two major items:

1) The allocation of O&M expenses to Specifically Assigned Assets; and
2) The specific assignment of the Corner Brook Frequency Converter.

Each of these is addressed below.

## 5.1 ALLOCATION OF O&M EXPENSES TO SPECIFICALLY ASSIGNED ASSETS

The 2013 Amended GRA reviewed in detail concerns over the high level of O&M charges allocated to specifically assigned assets. The Board acknowledged that there was a high degree of frustration on the part of the industrial customers on this issue [87] and specifically noted:

> The Board's concern is to ensure that all customers pay only those costs they are responsible for, and that these costs are transparent and understood by customers. While Mr. Dean's approach may reduce the O&M costs assigned to Industrial customers, there is no evidence as to whether these costs should be transferred to common costs, and hence to Newfoundland Power. The cost of service methodology review, which was to be done in 2016, would have allowed for a full review of the overall approach that should be taken to determine specifically assigned charges but this review has now been delayed to an uncertain date. This delay means there will not be an opportunity, in advance of the next general rate application, to fully assess the fairness of the proposed methodology or whether another methodology should be considered.

The most substantial weakness of the existing methodology is that it is an excessively rote calculation that leaves an image of precision even though there is little empirical support for the allocation. Hydro retained CA Energy Consulting to do a review of comparable utilities [88] (22 US and 5 Canadian) and found only three that appear to use a method similar to Hydro's approach.[89] Most of the others use approaches that avoid the issue of lack of empirical support, such as only charging for actual O&M as incurred or, more commonly, not tracking or charging the customer for ongoing O&M at all on specifically assigned assets.

---

[87] Decision P.U. 49(2016) page 98, lines 18-26.
[88] 2017 GRA, Volume II, Exhibit 13, pages 52-60.
[89] New Brunswick Power, Emera Maine and Alcorn.

Notwithstanding this review, CA Energy Consulting recommended, and Hydro has adopted, an approach to allocating specifically assigned assets based on test year indexed (Handy-Whitman) original cost values. This is effectively the same approach as was debated at the previous hearing but was found to not yet be "fully assessed".

As was stated in the previous hearing, the Handy Whitman indexed approach is preferable to the system in place today. If a system is going to be used that does not rely on tracking actual O&M time spent, the Handy-Whitman index is indisputably more appropriate than the current system, as the current system is unavoidably burdened by the impacts of differing vintages of assets and the inflation that has occurred between the dates in which they went into service. In this regard, Hydro's proposal should be approved.

Further, it should be understood that even the Handy Whitman indexed approach cannot be understood to concretely demonstrate that the allocation is fair. There can be cases where this approach still leads to allocation of O&M that is demonstrably unfair and it should be understood that in these individual cases the O&M approach could be revised. One example noted at the previous hearing was the O&M expense for Corner Brook's frequency converter more than doubling due to new investment, but that new investment was in part designed to reduce ongoing O&M in practice through such changes as improved off-site monitoring and less need for Hydro's staff to do on-site checks. In that type of situation, it should be understood that individual adjustments may be transparently justified in order to achieve a fair result. It has not been identified that any such adjustments are needed at the present time.

## 5.2 CORNER BROOK FREQUENCY CONVERTER

The Corner Brook Frequency Converter is specifically assigned to CBPP. This assignment is problematic for a number of reasons. It is important to note that the asset was first specifically assigned to CBPP in 2001 when the impact was very small – the cost made up 0.4% of the amounts CBPP paid in rates. By 2019, the frequency converter will make up 26% of the costs CBPP pays to Hydro [90] ($0.861 million/year) and potentially growing depending on further capital investment planned by Hydro (including a planned $2.944 million capital project in 2018 per IC-NLH-103). However, while the transaction has the image and financial outcome as if Hydro is a frequency conversion service provider to CBPP, in practice CBPP gets little to none of the protection, contractual commitments or flexibility that comes with being a party to a service agreement. CBPP has no ability to control the work performed by Hydro, nor the timing or level of investment. CBPP cannot engage in bipartite negotiations with Hydro in regard to what the service they are being provided is worth. And CBPP does not have other legal and logistical rights that normally come with being a party to a service agreement.

The specific assignment is further problematic given that the unit was installed not for the benefit of the customer, but for the benefit of the grid. At the time the units were cited as a "permanent" feature needed to ensure economic and efficient development of the IIS as it now exists. This same function continues to the present day, including the example of the January 2014 power outages when 22.5 MW of CBPP generation was brought through the frequency converter to aid is providing overall grid support.

[90] 2017 GRA, Volume I, Schedule 5-IV.

Further, a 1982 agreement between Hydro and Bowater confirmed that the converter would be permanently provided at Hydro's expense.[91]

While changing the assignment of the frequency converter back from specifically assigned to common would lead to rate impacts on all other customers on the system, the net effect on the Island Interconnected customers would be only 0.14% [92] (five one-thousandths of a cent per kW.h). The gross asset value of the frequency converter is quoted at $10.763 million at IC-NLH-103 Attachment 1, which is approximately equal to the amount spent to date on residential CDM, which is funded by the entire grid [93] ($10.589 million by 2019). The difference is that residential CDM benefits provincial power supply by only 11,366 MWh, while the frequency converter enables 14 times this much power (158 GW.h) to avoid being bottled up to low value uses (heat). While this comparison is not entirely apples-to-apples, it underlines that the function of the frequency converter (increased net availability of 60 Hz power to serve customers) is not different than the CDM programming, but at a far more effective investment profile for grid customers. As a component of rate base, it is hard to see how the frequency converter would be viewed to provide no value to ratepayers (other than CBPP), while CDM is of unquestioned grid value.

[91] The history of the frequency converter is provided in Attachment C to Mr. Bowman's June 4, 2015 pre-filed testimony.
[92] $0.861 million on $602 million per 2017 GRA, Volume III, Exhibit 15, page 1.
[93] 2017 GRA, Volume I, page 2.15.

## 6.0 CBPP GENERATION CREDIT PILOT AGREEMENT

Hydro has proposed to have a currently interim contract with CBPP terminated in respect of what is known as the "pilot project" component of the contract. The CBPP contract currently includes a 2009 pilot project intended to better achieve generation efficiency on the island (as required by the *Electrical Power Control Act*, 1994), and to alleviate a longstanding constraint on CBPP that incented the company to dispatch its hydro generation in an inefficient manner, and, as a consequence, to have to rely on expensive non-firm purchases from Hydro for certain core functions.

There are effectively 2 aspects to the portion of the contract known as the pilot project:

1) The contract takes away what are otherwise problematic requirements on CBPP as to how they operate their own hydraulic generation. The pilot project permits CBPP flexibility rather than forcing CBPP to follow their own load.
2) CBPP's use of this flexibility leads to a greater energy output from Deer Lake hydro plant (and the overall island generation complement, including Hydro's own hydraulic generation) than would otherwise occur. This yields net benefits to all ratepayers through avoided Holyrood generation (under the GRA working assumptions regarding Holyrood use) and generally through increased system efficiency.

As of the 2013 Amended GRA, Hydro supported continuation of the pilot project[94], noting that the agreement had, over the period 2009-2012, resulted in net savings of 21,000 barrels of oil for the island to the benefit of all customers, and with no net cost to any other customer class. The savings arise from more efficient production of power on the integrated island hydraulic generation system than would arise without the agreement. No updates have been provided regarding the savings estimate.

The Hydro evidence in this proceeding is provided in Exhibit 13, a report from CA Energy Consulting (CA). CA appears to frame the pilot project in terms of "emergency capacity assistance"[95], and recommends now terminating the pilot project based on the following:

1) Following the interconnection with the North American grid, CA suggests the economic profile of grid energy and capacity will change.
2) CA focuses on the fact that generation coordination with CBPP may be valuable, but CA provides only a series of hypothetical potential rate structures that depart significantly from any models in use in Newfoundland to date. No such model is actually proposed by Hydro in this GRA.

CA acknowledges that a desirable characteristic of a future rate design would be "eliminating the need for CBPP to use generation to follow load"[96].

[94] 2013 Amended GRA, Exhibit 4.
[95] GRA Exhibit 13, page 25.
[96] Exhibit 13, page 20.

The CA conclusions appear to be driven by considerable comment on the CBPP capacity assistance provisions (which are not related to the pilot project) and hypothetical considerations about a potential future rate. Further, the CA conclusions appear to be out-of-step with the core assumptions in this current GRA, which is that the revenue requirement is to be designed based on status quo (e.g., Holyrood) generation complement.

The CA evidence also does not address the fact that, absent the pilot project, CBPP is effectively economically incented (by way of NLH's contract and rate design) to operate its hydro generation in a manner that was inefficient, and to purchase excess quantities of power from Hydro ("non-firm" power) than was unnecessary under a properly structured rate as the pilot project provides.

The issues arise due to the standard industrial contract framework being inadequate to deal with industrial customers who own their own generation. The standard contract framework is designed such that each customer must specify a contracted peak load (a "Power on Order") and that becomes the capacity for which they pay each month. The customer is free to consume energy so long as they do not exceed this Power on Order level of capacity at any time. If the customer exceeds the Power on Order level:

a. Hydro can refuse to supply the power; and

b. If supplied, the customer will face demand charges for this new peak level for the following 12 monthly bills regardless of how often the customer uses this new peak level (or if it was only a single instance).[97]

Further, power consumed outside the normal firm Power on Order framework will be considered non-firm power. Non-firm power is an option for industrial customers to occasionally purchase energy from Hydro at a 10% premium to the full moment-to-moment marginal cost on the system. The non-firm rate is expected to be far higher than power that the customer would otherwise contract for under the firm Power on Order.

In short, under the standard contract, the incentive to the customer is to set a sufficiently high Power on Order that they will not exceed the level, but at the same time minimize the Power on Order level so that little to no load excursions will be necessary outside this range at any time over the entire upcoming year. This incentive, at its core, is to operate at a high load factor, and to operate with as "flat" a load as possible.

For a customer who owns their own generation, they are still under encouragement from Hydro to maintain a flat net load to the grid. They can achieve this by using their own hydro plant to follow their underlying load and in this manner shape their net load to Hydro into a flat pattern. Unfortunately, this does not reflect the most efficient use of the CBPP's generation. This is because each hydro unit and plant has an overall efficiency curve that is more efficient (converts each unit of water into more energy) at some loading levels, and less efficient at others. The best efficiency for a hydro plant, in terms of energy produced, is achieved by sticking to this loading optimization. The alternative of using the hydro plant to follow the load in the paper mill requires CBPP to depart from this optimization. As a result, more

[97] See CA-NLH-005 Attachment 1 from the 2013 Amended GRA in respect of section 2.02, 3.02, 3.03.

water is used to produce less energy than is necessary. By virtue of this inefficient operation, CBPP also ended up purchasing non-firm power from Hydro for some periods that would not have been required if its generation was being operated efficiently.

Along with being economically inferior, the application of the standard contract form to CBPP also appears to be contrary to public policy, by virtue of the unique provisions of the *Electrical Power Control Act*, 1994. Section 3(b)(i) of this Act states:

> 3. It is declared to be the policy of the province that ...
>
> (b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner ...
>
> (i) that would result in the most efficient production, transmission and distribution of power,

In short, industrial contracts which are structured to provide incentives to maintain a flat load, when imposed on customers who own their own hydraulic generation, lead to inefficient resource use, underproduction of hydro power, excessive use of Holyrood generation, and excessive purchases of non-firm power by the customer - all contrary to the power policy of the province.

It is acknowledged that the economics of the contract revision will be different following the Labrador infeed, and may need to be reassessed along the lines proposed by CA at a future GRA. However, any such revision would need to maintain an eye to the *EPCA*, 1994 requirement, which Hydro's proposal in this GRA does not achieve. Further, any potential for a hypothetical future revision is no reason to maintain an inappropriate contract with a self-generating customer at this time.

The pilot project continues to be needed at this time to resolve a long-standing incentive towards inefficient operation and should be retained until any new arrangement is achieved.

# APPENDIX A:
# PATRICK BOWMAN'S QUALIFICATIONS

InterGroup
CONSULTANTS

# PATRICK BOWMAN
# PRINCIPAL & 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), University of Manitoba, 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 six Canadian provinces and territories. 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, cost of service, and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor (CentraGas) 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. Appear before PUB as expert in cost of service and rate design matters.

InterGroup
CONSULTANTS

**PATRICK BOWMAN**
**PRINCIPAL & CONSULTANT**

**For Nelson Hydro (2013 - Present):** Development and updating of a Cost of Service model.

**For the Office of the Utilities Consumer Advocate of Alberta (2016 - 2017):** Analysis and strategic support of depreciation matters in the Altalink Management Ltd. 2017 – 2018 General Rate Tariff Application including support in negotiated settlement process. Preparation of expert evidence and strategic support of depreciation matters in the ATCO Pipelines 2017 – 2018 General Rate Application.

**For City of Chestermere (2013 - 2016):** Analysis of rate proposals from Chestermere Utilities Inc.

**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, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers, depreciation, as well as revenue requirements.

**For City of Swift Current (2013 - 2014):** Utility system valuation approach.

**For Municipal Customers of City of Calgary Water Utility (2012 - 2013):** Analysis of proposed new development charges and reasonableness of water and wastewater rates.

**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 the 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 - Utility Regulation Experience

| 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 Expert 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 Expert Testimony | NLPUB | Newfoundland Industrial Customers | 2003 | Yes |
| Manitoba Hydro | 2004 General Rate Application | Analysis, Preparation of Intervenor Evidence and Expert 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 Expert 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 Expert 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 Expert 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 Expert Testimony | MPUB | MIPUG | 2013 | Yes |
| Manitoba Hydro | Needs For and Alternatives To Investigation | Analysis, Preparation of Intervenor Evidence and Expert Testimony | MPUB | MIPUG | 2014 | Yes |
| Manitoba Hydro | 2015/16 General Rate Application | Analysis, Preparation of Intervenor Evidence and Expert Testimony | MPUB | MIPUG | 2015 | Yes |
| Newfoundland Hydro | Amended 2013 General Rate Application | Analysis, Preparation of Intervenor Evidence and Expert 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 Expert Testimony | NLPUB | Newfoundland Industrial Customers | 2015 | Yes |
| Manitoba Hydro | 2016 Cost of Service review | Analysis, Preparation of Intervenor Evidence and Expert Testimony | MPUB | MIPUG | 2016 | Yes |
| AltaLink Management Limited | 2017-18 General Tariff Application | Analysis, Support of Consumer Advocate during Negotiated Settlement Process | 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 | Alberta Utilities Commission (AUC) | Alberta Utilities Consumer Advocate (UCA) | 2016-17 | No - Written Process only |
| 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 |

# APPENDIX B:

# IMPACT OF THE EQUAL LIFE GROUP PROCEDURE FOR 2015 VINTAGE ASSETS, AS OF YEAR-END 2019

| Account | Account | 2019 Cost - pre 2015 assets | ASL/ELG Composite Life Rate (NP-NLH-142) | Calculated Depreciation Expense | Deemed Cost ASL Rate Accrual Rate (IC-NLH-162) | Calculated Depreciation Expense | Difference |
|---|---|---|---|---|---|---|---|
| A | B | C | D | E=C*D | F | G=C*F | H=E-G |
| A01 | Aircraft Landing Strip | 7,531 | 1.08% | 81 | 1.05% | 79 | 2 |
| A04 | Auxiliary Power Systems | 3,825,225 | 3.68% | 140,768 | 3.60% | 137,708 | 3,060 |
| B01 | Battery & Power Systems | 6,539,883 | 4.10% | 268,135 | 3.90% | 255,055 | 13,080 |
| B02 | Boiler System | 1,305,613 | 2.78% | 36,296 | 2.78% | 36,296 | 0 |
| B03 | Booms - Timber | 112,339 | 11.03% | 12,391 | 10.09% | 11,335 | 1,056 |
| B04 | Bridges | 965,004 | 2.03% | 19,590 | 2.03% | 19,590 | 0 |
| B05 | Buildings - Other | 39,694,487 | 2.37% | 940,759 | 2.21% | 877,248 | 63,511 |
| B06 | Buildings - Metal | 16,105,010 | 2.34% | 376,857 | 2.12% | 341,426 | 35,431 |
| B07 | Bus Duct Generator | 985,315 | 3.08% | 30,348 | 2.98% | 29,362 | 985 |
| B08 | Buswork & Hardware | 3,306,425 | 2.60% | 85,967 | 2.60% | 85,967 | 0 |
| C01 | Cables - Telecontrol | 393,321 | 3.42% | 13,452 | 3.42% | 13,452 | 0 |
| C02 | Cable - Submarine | 2,776,722 | 4.07% | 113,013 | 4.07% | 113,013 | 0 |
| C03 | Cables - Under Ground | 1,900,094 | 1.94% | 36,862 | 1.92% | 36,482 | 380 |
| C04 | Cables - Above Ground | 4,491,690 | 2.24% | 100,614 | 2.24% | 100,614 | 0 |
| C06 | Capictors | 684,737 | 9.28% | 63,544 | 9.28% | 63,544 | 0 |
| C07 | Chemical Feed Systems | 18,552 | 1.82% | 338 | 1.82% | 338 | 0 |
| C09 | Circuit Breakers | 31,707,682 | 2.15% | 681,715 | 1.89% | 599,275 | 82,440 |
| C10 | Compressed Air Systems | 14,194,703 | 3.55% | 503,912 | 2.49% | 353,448 | 150,464 |
| C11 | Computers | 4,027,076 | 14.38% | 579,094 | 14.38% | 579,094 | 0 |
| C12 | Condensers | 0 | 2.25% | 0 | 0.00% | 0 | 0 |
| C13 | Conductor - Transmission | 42,025,239 | 2.82% | 1,185,112 | 2.82% | 1,185,112 | 0 |
| C14 | Conductor - Distribution | 18,600,230 | 2.95% | 548,707 | 2.92% | 543,127 | 5,580 |
| C15 | Control, Meter / Relaying | 18,196,457 | 3.20% | 582,287 | 3.04% | 553,172 | 29,114 |
| C16 | Cooling Systems | 7,564,925 | 3.38% | 255,694 | 2.59% | 195,932 | 59,763 |
| C17 | Counterpoise | 2,310,209 | 2.74% | 63,300 | 2.74% | 63,300 | 0 |
| C18 | Cranes | 6,037,289 | 2.22% | 134,028 | 2.21% | 133,424 | 604 |
| D01 | Dams, Dykes, Canals & Tunnels | 340,969,691 | 1.27% | 4,330,315 | 1.27% | 4,330,315 | 0 |
| D02 | Diesel Systems & Engines | 24,611,020 | 4.36% | 1,073,040 | 4.06% | 999,207 | 73,833 |
| D03 | Disconnect Switches | 11,579,441 | 2.20% | 254,748 | 2.00% | 231,589 | 23,159 |
| D04 | Dykes and Liners | 745,693 | 2.82% | 21,029 | 2.82% | 21,029 | 0 |
| E01 | Elevators | 0 | 2.25% | 0 | 0.00% | 0 | 0 |
| E02 | EMS Equipment | 110,488 | 3.68% | 4,066 | 3.37% | 3,723 | 343 |
| E03 | Environmental Equipment | 338,053 | 3.27% | 11,054 | 3.22% | 10,885 | 169 |
| F01 | FALL ARREST EQUIPMENT | 1,919,981 | 6.13% | 117,695 | 6.09% | 116,927 | 768 |
| F02 | Fencing | 4,138,349 | 2.24% | 92,699 | 2.16% | 89,388 | 3,311 |
| F03 | Fire Fighting Equipment | 8,903,201 | 2.18% | 194,090 | 2.14% | 190,529 | 3,561 |
| F04 | Footings & Foundations | 12,240,009 | 2.15% | 263,160 | 2.08% | 254,592 | 8,568 |
| F05 | FREQ CONVERSION | 746,417 | 2.59% | 19,332 | 2.59% | 19,332 | 0 |
| F06 | Fuel Systems | 19,413,679 | 2.77% | 537,759 | 2.06% | 399,922 | 137,837 |
| G01 | Gas Turbine Systems | 45,725,326 | 2.52% | 1,152,278 | 2.24% | 1,024,247 | 128,031 |
| G02 | Gates | 16,531,113 | 1.94% | 320,704 | 1.93% | 319,050 | 1,653 |
| G03 | Generators | 78,254,751 | 2.04% | 1,596,397 | 1.99% | 1,557,270 | 39,127 |
| G04 | Generator - Windings | 16,717,821 | 1.81% | 302,593 | 1.81% | 302,593 | 0 |
| G05 | Glycol Systems | 98,436 | 4.91% | 4,833 | 4.91% | 4,833 | 0 |
| G06 | Govenors | 6,562,987 | 4.62% | 303,210 | 4.62% | 303,210 | 0 |
| G07 | Ground Wire System | 7,502,838 | 2.43% | 182,319 | 2.42% | 181,569 | 750 |
| I01 | INFORMATION DELIVERY SYS - ECC | 703,400 | 0.00% | 0 | | 0 | 0 |
| I02 | Instrumentation | 992,068 | 5.90% | 58,532 | 3.43% | 34,028 | 24,504 |
| I03 | Insulators | 25,616,142 | 3.86% | 988,783 | 3.86% | 988,783 | 0 |
| I04 | Intake Structures | 18,198,045 | 1.27% | 231,115 | 1.27% | 231,115 | 0 |
| I05 | Inverters | 176,682 | 7.07% | 12,491 | 6.81% | 12,032 | 459 |
| L02 | Land Acquisions | 5,072,678 | 0.00% | 0 | | 0 | 0 |
| L03 | Land Improvments | 323,100 | 1.57% | 5,073 | 1.66% | 5,363 | -291 |
| L04 | Lighting Systems | 465,471 | 1.85% | 8,611 | 1.85% | 8,611 | 0 |
| L05 | Lightning Arrestors | 3,973,480 | 2.12% | 84,238 | 2.09% | 83,046 | 1,192 |
| L06 | LINE COUPLING EQUIPMENT | 0 | 2.25% | 0 | 0.00% | 0 | 0 |
| M01 | Main Breakers | 288,042 | 2.73% | 7,864 | 2.73% | 7,864 | 0 |
| M02 | Marine Terminals | 860,754 | 1.12% | 9,640 | 1.12% | 9,640 | 0 |
| M03 | MetalClad Switchgear cub/Equ 4kv/600v | 669,662 | 2.21% | 14,800 | 2.13% | 14,264 | 536 |
| M04 | Meter Test Switches | 13,519 | 6.86% | 927 | 6.86% | 927 | 0 |
| M05 | Metering Tanks | 436,406 | 2.94% | 12,830 | 2.94% | 12,830 | 0 |
| M06 | METERS - DIGITAL | 4,115,377 | 6.25% | 257,211 | 6.19% | 254,742 | 2,469 |
| M07 | METERS - ANALOGUE | 76,225 | 5.56% | 4,238 | 5.56% | 4,238 | 0 |
| M08 | METERS - OTHER | 166,747 | 6.25% | 10,422 | 6.25% | 10,422 | 0 |
| M10 | Misc Units of Prop | 3,705,347 | 3.67% | 135,986 | 3.64% | 134,875 | 1,112 |
| M11 | MOBILE - A.T.V.'S & SNOWMOBILES | 1,654,719 | 8.15% | 134,860 | 7.88% | 130,392 | 4,468 |
| M12 | MOBILE - AIR COMPRESSOR,ATTACHMENT & | 131,898 | 1.00% | 1,319 | 1.00% | 1,319 | 0 |
| M13 | MOBILE - ARGO'S | 180,781 | 9.08% | 16,415 | 0.00% | 0 | 16,415 |
| M14 | MOBILE - | 7,038,321 | 4.16% | 292,794 | 4.13% | 290,683 | 2,111 |
| M16 | Multiplex Equipment | 703,901 | 6.38% | 44,909 | 6.38% | 44,909 | 0 |
| O01 | Office Equipment | 609,000 | 5.60% | 34,104 | 5.60% | 34,104 | 0 |
| O02 | Office Furniture | 743,513 | 6.10% | 45,354 | 6.10% | 45,354 | 0 |
| P01 | P.C.B. Storage Conatiner | 1,483 | 9.24% | 137 | 9.24% | 137 | 0 |
| P02 | PABX - Priv Auto Branch Exch | 277,879 | 7.64% | 21,230 | 7.64% | 21,230 | 0 |
| P03 | Penstock | 44,685,027 | 2.80% | 1,251,181 | 2.80% | 1,251,181 | 0 |
| P04 | Pole Cribs & Pole Hardware | 82,745,762 | 3.73% | 3,086,417 | 3.70% | 3,061,593 | 24,824 |
| P05 | Pole Structures - Wood | 89,051,515 | 2.44% | 2,172,857 | 2.43% | 2,163,952 | 8,905 |
| P06 | Poles - Concrete | 55,346 | 2.24% | 1,240 | 2.24% | 1,240 | 0 |
| P07 | Poles - Wood | 49,363,821 | 2.82% | 1,392,060 | 2.42% | 1,194,604 | 197,455 |
| P07 | Poles - Wood | 798,185 | 5.09% | 40,628 | 2.42% | 19,316 | 21,312 |
| P09 | Power Systems | 457,452 | 6.94% | 31,747 | 6.94% | 31,747 | 0 |
| P10 | Powerhouse | 77,546,128 | 2.09% | 1,620,714 | 2.08% | 1,612,959 | 7,755 |

| Account | Account | 2019 Cost - pre 2015 assets | ASL/ELG Composite Life Rate [NP-NLH-142] | Calculated Depreciation Expense | Deemed Cost ASL Rate Accrual Rate [IC-NLH-162] | Calculated Depreciation Expense | Difference |
|---|---|---|---|---|---|---|---|
| A | B | C | D | E=C*D | F | G=C*F | H=E-G |
| P11 | Printers | 895,786 | 5.19% | 46,491 | 5.19% | 46,491 | 0 |
| P12 | Protective Control & Relay Panels | 7,181,792 | 2.96% | 212,581 | 2.91% | 208,990 | 3,591 |
| R01 | Radio Towers (Wood or Steel) | 2,885,600 | 2.38% | 68,677 | 2.38% | 68,677 | 0 |
| R02 | Radios - Fixed Microwave Equipment | 1,160,600 | 5.37% | 62,324 | 8.59% | 99,696 | -37,371 |
| R02 | Radios - Fixed Microwave Equipment | 1,696,486 | 8.59% | 145,728 | 8.59% | 145,728 | 0 |
| R03 | Radios - Fixed UHF Equipment | 81,822 | 7.44% | 6,088 | 7.22% | 5,908 | 180 |
| R04 | Radios - Fixed VHF Equipment | 153,938 | 6.65% | 10,237 | 6.65% | 10,237 | 0 |
| R05 | Radios - Mobile VHF Base Station | 3,109,693 | 10.46% | 325,274 | 10.46% | 325,274 | 0 |
| R06 | Ramps - Yard Storage | 924,197 | 5.15% | 47,596 | 5.05% | 46,672 | 924 |
| R07 | Reactors & Resistors | 908,380 | 4.19% | 38,061 | 4.18% | 37,970 | 91 |
| R08 | Reclosers | 4,569,513 | 2.31% | 105,556 | 2.27% | 103,728 | 1,828 |
| R09 | Regulators | 3,675,861 | 2.92% | 107,335 | 2.88% | 105,865 | 1,470 |
| R11 | Revenue Metering | 831,454 | 4.21% | 35,004 | 4.03% | 33,508 | 1,497 |
| R12 | Right - of - Ways | 12,488,097 | 2.38% | 297,217 | 2.37% | 295,968 | 1,249 |
| R13 | Roads | 75,173,142 | 2.96% | 2,225,125 | 2.96% | 2,225,125 | 0 |
| R14 | Routers & Lan | 2,360,853 | 8.84% | 208,699 | 8.84% | 208,699 | 0 |
| R15 | Runner | 5,762,624 | 6.22% | 358,435 | 6.22% | 358,435 | 0 |
| S01 | Scada Equipment | 2,478,445 | 6.23% | 154,407 | 6.01% | 148,955 | 5,453 |
| S02 | Sectionalizers | 45,666 | 15.13% | 6,909 | 15.13% | 6,909 | 0 |
| S03 | Servers | 1,436,555 | 2.86% | 41,085 | 2.86% | 41,085 | 0 |
| S04 | Sewage Disposal System | 1,121,167 | 2.18% | 24,441 | 2.18% | 24,441 | 0 |
| S05 | Software | 8,948,718 | 20.34% | 1,820,169 | 20.34% | 1,820,169 | 0 |
| S06 | Spillway Structures | 26,004,636 | 1.27% | 330,259 | 1.27% | 330,259 | 0 |
| S07 | Stacks | 4,868,525 | 1.93% | 93,963 | 1.84% | 89,581 | 4,382 |
| S08 | STATIC EXCITATION SYSTEM | 5,117,789 | 11.27% | 576,775 | 11.23% | 574,728 | 2,047 |
| S09 | STATIC EXCITATION - XFORMERS | 16,538 | 2.59% | 428 | 2.59% | 428 | 0 |
| S10 | Station Service | 3,913,680 | 3.04% | 118,976 | 2.99% | 117,019 | 1,957 |
| S11 | Stop Logs | 2,643,431 | 2.73% | 72,166 | 2.72% | 71,901 | 264 |
| S12 | Storage Pallets & Rackings | 0 | 2.25% | 0 | 0.00% | 0 | 0 |
| S13 | Storm & Yard Drainage | 283,067 | 2.31% | 6,539 | 2.31% | 6,539 | 0 |
| S14 | Street Lights | 2,823,521 | 6.13% | 173,082 | 5.90% | 166,588 | 6,494 |
| S15 | Structural Supports (Wood or Steel) | 6,286,887 | 2.35% | 147,742 | 2.35% | 147,742 | 0 |
| S17 | Sump Systems | 561,992 | 5.29% | 29,729 | 5.12% | 28,774 | 955 |
| S18 | Surge Systems | 3,976,818 | 2.37% | 94,251 | 2.34% | 93,058 | 1,193 |
| S19 | Station Switching | 7,435,488 | 3.56% | 264,703 | 3.56% | 264,703 | 0 |
| S20 | Switching Systems - L.V. | 2,071,699 | 2.89% | 59,872 | 2.89% | 59,872 | 0 |
| T01 | Telecontrol System | 6,493,448 | 4.78% | 310,387 | 4.60% | 298,699 | 11,688 |
| T02 | Test Equipment | 952,613 | 5.84% | 55,633 | 5.84% | 55,633 | 0 |
| T03 | Tools & Equipment | 6,347,005 | 5.95% | 377,647 | 5.95% | 377,647 | 0 |
| T04 | Towers | 53,995,367 | 2.32% | 1,252,693 | 2.32% | 1,252,693 | 0 |
| T05 | Transformers - Other | 51,270,025 | 2.86% | 1,466,323 | 2.81% | 1,440,688 | 25,635 |
| T06 | Transformers - Pad Mount | 16,190,367 | 2.58% | 417,711 | 2.54% | 411,235 | 6,476 |
| T07 | Transformers - Pole Mounted | 29,956,008 | 3.88% | 1,162,293 | 3.71% | 1,111,368 | 50,925 |
| T09 | Turbines | 43,062,048 | 2.84% | 1,222,962 | 2.86% | 1,231,575 | -8,612 |
| V01 | Vacumm Cleaning System | 6,099 | 3.48% | 212 | 3.48% | 212 | 0 |
| V02 | Valves - Penstock | 5,430,376 | 2.31% | 125,442 | 2.30% | 124,899 | 543 |
| V03 | Vehicles - 1 ton | 51,648 | 9.77% | 5,046 | 9.77% | 5,046 | 0 |
| V04 | Vehicles - 3/4 ton and Under | 3,732,210 | 5.05% | 188,477 | 4.61% | 172,055 | 16,422 |
| V05 | Vehicles - BOOMS/BODIES/CRANES/CAB & | 10,842,171 | 7.73% | 838,100 | 7.49% | 812,079 | 26,021 |
| V06 | Vehicles - Cars, Staion Wagons & Vans | 1,151,852 | 0.18% | 2,073 | 0.18% | 2,073 | 0 |
| V07 | VEHICLES - DUMP TRUCKS | 0 | 2.25% | 0 | 0.00% | 0 | 0 |
| W01 | Water Regulating Structures | 18,454,117 | 2.25% | 415,218 | 2.25% | 415,218 | 0 |
| W02 | Water Supply System | 1,964,519 | 5.37% | 105,495 | 5.35% | 105,102 | 393 |
| W03 | Water Systems - Feed | 371,683 | 2.47% | 9,181 | 1.90% | 7,062 | 2,119 |
| W04 | Water Treatment | 6,221,345 | 2.13% | 132,515 | 1.71% | 106,385 | 26,130 |
| **Subtotal** | | **1,707,162,758** | | **45,988,158** | | **44,654,411** | **1,333,747** |

# APPENDIX C:

# IMPACT OF THE EQUAL LIFE GROUP PROCEDURE FOR 2016-2019 VINTAGE ASSETS, AS OF YEAR-END 2019

| Account | Account | 2019 Cost of post-2015 assets | ELG Whole Life Rate | Calculated Depreciation based on ELG Whole Life Rate | ASL Whole Life Rate | Calculated Depreciation based on ASL Rate | Difference |
|---|---|---|---|---|---|---|---|
| A | B | C | D | E=C*D | F | G=C*F | H=E-G |
| A01 | Aircraft Landing Strip | 51,389 | 4.27% | 2,194 | 3.03% | 1,557 | 637 |
| A04 | Auxiliary Power Systems | 5,546,573 | 3.55% | 196,903 | 3.33% | 184,886 | 12,018 |
| B01 | Battery & Power Systems | 5,528,053 | 5.37% | 296,856 | 3.85% | 212,617 | 84,239 |
| B02 | Boiler System | 14,534,020 | 2.92% | 424,393 | 2.50% | 363,351 | 61,043 |
| B04 | Bridges | 680,217 | 1.64% | 11,156 | 1.54% | 10,465 | 691 |
| B05 | Buildings - Other | 40,512,824 | 4.42% | 1,790,667 | 2.00% | 810,256 | 980,410 |
| B06 | Buildings - Metal | 5,244,100 | 2.13% | 111,699 | 1.82% | 95,347 | 16,352 |
| B07 | Bus Duct Generator | 348,798 | 2.66% | 9,278 | 2.50% | 8,720 | 558 |
| B08 | Buswork & Hardware | 501,094 | 2.13% | 10,673 | 2.00% | 10,022 | 651 |
| C02 | Cable - Submarine | 1,509,034 | 2.37% | 35,764 | 2.22% | 33,534 | 2,230 |
| C03 | Cables - Under Ground | 3,770,061 | 1.72% | 64,845 | 1.67% | 62,834 | 2,011 |
| C04 | Cables - Above Ground | 1,175,683 | 1.77% | 20,810 | 1.67% | 19,595 | 1,215 |
| C09 | Circuit Breakers | 110,138,778 | 2.21% | 2,434,067 | 1.67% | 1,835,646 | 598,421 |
| C10 | Compressed Air Systems | 363,044 | 4.00% | 14,522 | 2.44% | 8,855 | 5,667 |
| C11 | Computers | 3,586,152 | 20.00% | 717,230 | 20.00% | 717,230 | 0 |
| C13 | Conductor - Transmission | 41,953,472 | 1.96% | 822,288 | 1.67% | 699,225 | 123,064 |
| C14 | Conductor - Distribution | 929,735 | 2.60% | 24,173 | 2.22% | 20,661 | 3,512 |
| C15 | Control, Meter / Relaying | 11,218,635 | 2.92% | 327,584 | 2.50% | 280,466 | 47,118 |
| C16 | Cooling Systems | 2,238,900 | 4.10% | 91,795 | 2.50% | 55,973 | 35,822 |
| C18 | Cranes | 944,407 | 1.69% | 15,960 | 1.43% | 13,492 | 2,469 |
| D01 | Dams, Dykes, Canals & Tunnels | 4,911,881 | 0.97% | 47,645 | 0.91% | 44,653 | 2,992 |
| D02 | Diesel Systems & Engines | 35,291,140 | 6.96% | 2,456,263 | 4.00% | 1,411,646 | 1,044,618 |
| D03 | Disconnect Switches | 14,455,219 | 2.39% | 345,480 | 1.82% | 262,822 | 82,658 |
| D04 | Dykes and Liners | 1,773,600 | 3.36% | 59,593 | 2.38% | 42,229 | 17,364 |
| E02 | EMS Equipment | 66,009 | 3.37% | 2,225 | 2.86% | 1,886 | 339 |
| F01 | FALL ARREST EQUIPMENT | 445,019 | 7.09% | 31,552 | 6.67% | 29,668 | 1,884 |
| F02 | Fencing | 334,728 | 2.25% | 7,531 | 1.92% | 6,437 | 1,094 |
| F03 | Fire Fighting Equipment | 12,819,352 | 2.13% | 273,052 | 2.00% | 256,387 | 16,665 |
| F04 | Footings & Foundations | 87,345,565 | 1.81% | 1,580,955 | 1.54% | 1,343,778 | 237,177 |
| F05 | FREQ CONVERSION | 2,990,689 | 2.30% | 68,786 | 2.22% | 66,460 | 2,326 |
| F06 | Fuel Systems | 17,786,107 | 3.36% | 597,613 | 2.00% | 355,722 | 241,891 |
| G01 | Gas Turbine Systems | 23,148,315 | 2.60% | 601,856 | 2.22% | 514,407 | 87,449 |
| G02 | Gates | 744,111 | 1.33% | 9,897 | 1.25% | 9,301 | 595 |
| G03 | Generators | 10,526,163 | 1.65% | 173,682 | 1.54% | 161,941 | 11,741 |
| G04 | Generator - Windings | 2,159,822 | 2.15% | 46,436 | 2.00% | 43,196 | 3,240 |
| G06 | Govenors | 273,500 | 2.30% | 6,291 | 2.22% | 6,078 | 213 |
| G07 | Ground Wire System | 9,394,028 | 1.94% | 182,244 | 1.82% | 170,801 | 11,444 |
| I02 | Instrumentation | 774,201 | 3.43% | 26,555 | 3.33% | 25,807 | 748 |
| I03 | Insulators | 7,259,414 | 3.23% | 234,479 | 2.86% | 207,412 | 27,067 |
| I04 | Intake Structures | 288,656 | 0.97% | 2,800 | 0.91% | 2,624 | 176 |
| L03 | Land Improvments | 5,742,222 | 1.68% | 96,469 | 1.33% | 76,563 | 19,906 |
| L04 | Lighting Systems | 953,858 | 2.13% | 20,317 | 2.00% | 19,077 | 1,240 |
| L05 | Lightning Arrestors | 1,174,600 | 2.02% | 23,727 | 1.72% | 20,252 | 3,475 |
| M03 | MetalClad Switchgear cub/Equ 4kv/600v | 232,193 | 2.37% | 5,503 | 2.22% | 5,160 | 343 |
| M06 | METERS - DIGITAL | 4,131,341 | 5.66% | 233,834 | 5.00% | 206,567 | 27,267 |
| M08 | METERS - OTHER | 1,563,600 | 4.82% | 75,366 | 4.55% | 71,073 | 4,293 |
| M10 | Misc Units of Prop | 2,872,200 | 6.96% | 199,905 | 4.55% | 130,555 | 69,351 |
| M11 | MOBILE - A.T.V.'S & SNOWMOBILES | 1,515,675 | 15.02% | 227,654 | 13.33% | 202,090 | 25,564 |
| M12 | MOBILE - AIR COMPRESSOR, ATTACHMENT & | 35,882 | 7.59% | 2,723 | 4.00% | 1,435 | 1,288 |
| M14 | MOBILE - | 1,807,546 | 5.03% | 90,920 | 4.44% | 80,335 | 10,584 |
| M16 | Multiplex Equipment | 239,066 | 6.67% | 15,946 | 5.56% | 13,281 | 2,664 |
| O01 | Office Equipment | 3,063,423 | 5.00% | 153,171 | 5.00% | 153,171 | 0 |
| O02 | Office Furniture | 120,626 | 5.00% | 6,031 | 5.00% | 6,031 | 0 |
| P03 | Penstock | 18,592,511 | 1.52% | 282,606 | 1.43% | 265,607 | 16,999 |
| P04 | Pole Cribs & Pole Hardware | 8,405,634 | 3.15% | 264,777 | 2.86% | 240,161 | 24,616 |
| P05 | Pole Structures - Wood | 18,086,033 | 2.06% | 372,572 | 1.75% | 317,299 | 55,273 |
| P07 | Poles - Wood | 10,086,432 | 4.34% | 437,751 | 2.33% | 234,568 | 203,183 |
| P08 | Power Line Carrier | 1,295,300 | 4.64% | 60,102 | 4.00% | 51,812 | 8,290 |
| P10 | Powerhouse | 2,409,615 | 1.57% | 37,831 | 1.33% | 32,128 | 5,703 |
| P11 | Printers | 778,851 | 16.67% | 129,834 | 16.67% | 129,809 | 26 |
| P12 | Protective Control & Relay Panels | 12,936,057 | 3.33% | 430,771 | 2.86% | 369,602 | 61,169 |
| R01 | Radio Towers (Wood or Steel) | 1,170,500 | 2.44% | 28,560 | 2.08% | 24,385 | 4,175 |
| R06 | Ramps - Yard Storage | 1,231,800 | 4.64% | 57,156 | 4.00% | 49,272 | 7,884 |
| R08 | Reclosers | 1,170,833 | 2.44% | 28,568 | 2.08% | 24,392 | 4,176 |

| Account | Account | 2019 Cost of post-2015 assets | ELG Whole Life Rate | Calculated Depreciation based on ELG Whole Life Rate | ASL Whole Life Rate | Calculated Depreciation based on ASL Rate | Difference |
|---|---|---|---|---|---|---|---|
| A | B | C | D | E=C*D | F | G=C*F | H=E-G |
| R09 | Regulators | 450,262 | 3.56% | 16,029 | 2.50% | 11,257 | 4,773 |
| R11 | Revenue Metering | 629,314 | 3.33% | 20,956 | 2.86% | 17,980 | 2,976 |
| R12 | Right - of - Ways | 126,056 | 1.64% | 2,067 | 1.54% | 1,939 | 128 |
| R12 | Right - of - Ways | 23,895,200 | 1.64% | 391,881 | 1.54% | 367,618 | 24,263 |
| R13 | Roads | 4,462,723 | 1.77% | 78,990 | 1.67% | 74,379 | 4,611 |
| R14 | Routers & Lan | 489,441 | 20.00% | 97,888 | 20.00% | 97,888 | 0 |
| S01 | Scada Equipment | 683,898 | 5.66% | 38,709 | 5.00% | 34,195 | 4,514 |
| S03 | Servers | 1,670,463 | 14.29% | 238,709 | 14.29% | 238,638 | 72 |
| S05 | Software | 5,853,802 | 14.29% | 836,508 | 14.29% | 836,257 | 251 |
| S06 | Spillway Structures | 2,246,931 | 0.97% | 21,795 | 0.91% | 20,427 | 1,369 |
| S07 | Stacks | 48,377 | 1.94% | 939 | 1.82% | 880 | 59 |
| S08 | STATIC EXCITATION SYSTEM | 63,298 | 3.33% | 2,108 | 3.13% | 1,978 | 130 |
| S10 | Station Service | 935,137 | 2.13% | 19,918 | 2.00% | 18,703 | 1,216 |
| S14 | Street Lights | 163,658 | 6.79% | 11,112 | 5.00% | 8,183 | 2,929 |
| S15 | Structural Supports (Wood or Steel) | 9,738,166 | 1.94% | 188,920 | 1.82% | 177,058 | 11,863 |
| S16 | STUDIES | 570,706 | 15.25% | 87,033 | 0.00% | 0 | 87,033 |
| S17 | Sump Systems | 303,200 | 3.04% | 9,217 | 2.86% | 8,663 | 554 |
| S18 | Surge Systems | 6,053,280 | 1.77% | 107,143 | 1.67% | 100,888 | 6,255 |
| S19 | Station Switching | 48,894 | 3.74% | 1,829 | 2.63% | 1,287 | 542 |
| T01 | Telecontrol System | 3,443,069 | 5.58% | 192,123 | 4.00% | 137,723 | 54,400 |
| T02 | Test Equipment | 329,179 | 5.00% | 16,459 | 5.00% | 16,459 | 0 |
| T03 | Tools & Equipment | 2,342,794 | 5.00% | 117,140 | 5.00% | 117,140 | 0 |
| T04 | Towers | 168,467,315 | 1.64% | 2,762,864 | 1.54% | 2,591,805 | 171,059 |
| T05 | Transformers - Other | 50,148,763 | 2.13% | 1,068,169 | 1.82% | 911,796 | 156,373 |
| T06 | Transformers - Pad Mount | 9,570,392 | 4.10% | 392,386 | 2.50% | 239,260 | 153,126 |
| T07 | Transformers - Pole Mounted | 20,879,171 | 5.14% | 1,073,189 | 3.33% | 695,972 | 377,217 |
| T09 | Turbines | 15,286,838 | 2.39% | 365,355 | 1.82% | 277,943 | 87,413 |
| V02 | Valves - Penstock | 1,897,236 | 1.81% | 34,340 | 1.54% | 29,188 | 5,152 |
| V03 | Vehicles - 1 ton | 53,071 | 11.29% | 5,992 | 10.63% | 5,639 | 353 |
| V04 | Vehicles - 3/4 ton and Under | 8,420,282 | 13.71% | 1,154,421 | 12.14% | 1,022,463 | 131,958 |
| V05 | Vehicles - BOOMS/BODIES/CRANES/CAB & | 173,006 | 8.02% | 13,875 | 7.08% | 12,255 | 1,620 |
| V06 | Vehicles - Cars, Staion Wagons & Vans | 199,821 | 15.96% | 31,891 | 14.17% | 28,308 | 3,583 |
| W01 | Water Regulating Structures | 5,926,700 | 1.59% | 94,235 | 1.54% | 91,180 | 3,055 |
| W02 | Water Supply System | 3,609,600 | 3.53% | 127,419 | 3.33% | 120,320 | 7,099 |
| W03 | Water Systems - Feed | 1,616,800 | 2.39% | 38,642 | 1.82% | 29,396 | 9,245 |
| | **Total** | **933,975,129** | | **27,120,141** | | **21,477,674** | **5,642,468** |

# APPENDIX D:

# SUBMISSION OF P. LEE REGARDING THE EQUAL LIFE GROUP PROCEDURE

## I. BACKGROUND AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND ADDRESS

A. My name is Patricia S. Lee. My address is 116 SE Villas Court, Unit C, Tallahassee, Florida 32303.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by BCRI Inc. as a BCRI associate.

Q. PLEASE DESCRIBE BCRI.

A. BCRI is a consulting and research company founded in 1998 by Stephen Barreca. The company specializes in assessing technological change and appraising utility property.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from Appalachian State University in Boone, North Carolina in December 1970, receiving a Bachelor's degree in mathematics. I was employed as a high school mathematics teacher from 1971-1974, when I began working in the area of statistical analysis for the State of Florida. I joined the Public Service Commission staff in 1978. While my position changed over the years, my areas of primary focus were depreciation and capital recovery. I also reviewed and analyzed cost studies for the purpose of determining unbundled network element prices and universal service cost levels as well as for the purpose of determining the appropriate nuclear decommissioning and fossil dismantlement annual accrual levels. In that regard, I was responsible for depreciation issues and other issues such as determining the appropriate cost model inputs. I retired after over 30 years of service on September 30, 2011. In March 2012, I began working with BCRI Inc., d/b/a BCRI Valuation Services.

Q. WHAT WERE YOUR DUTIES AT THE FLORIDA PUBLIC SERV ICE COMMISSION?

A. I reviewed, analyzed, and presented testimony and recommendations concerning depreciation rates and the capital recovery positions of Florida regulated utilities and the valuation of assets in a competitive market. In this capacity, I investigated, analyzed, and evaluated valuation and depreciation methods, procedures, and concepts. The determination of appropriate depreciation lives and salvage values requires an understanding of the plans, needs, and pressures facing an individual company. It also requires knowledge of the various types of plant under study or review and the various factors impacting the depreciation parameters, such as competition, and technological advancements.

I also assisted in the promulgation of Florida Public Service Commission rules regarding depreciation study requirements, depreciation sub-account requirements, capitalization and expensing requirements, and dismantlement and decommissioning study requirements. Additionally, I conducted various Public Service Commission staff training sessions regarding depreciation.

Additionally, I conferred with company officials, other state and federal agency personnel, and consulting firms on capital recovery matters in both the regulated and deregulated environments. On behalf of the Commission, I participated as a faculty member of the National Association of Regulatory Utility Commissioners (NARUC) Annual Regulatory Studies Program and as a trainer for the Society of

Depreciation Professionals (SDP) in the area of depreciation. I was also a member of the NARUC Staff Subcommittee on Depreciation and Technology. In this regard, I co-authored the NARUC 1996 Public Utility Depreciation Practices manual and three NARUC papers that addressed the impact of depreciation on infrastructure development, economic depreciation, and stranded investment. Two of these papers were published in the 1996-1997 and 1998 Journals.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE?

A. Yes, I have. I proffered testimony in the 2012 depreciation application proceeding of Newfoundland and Labrador Hydro (NLH) on behalf of the Island Industrial Customers in which both a change in depreciation methodology from sinking fund to group accounting using Average Service Life (ASL) and changes in asset lives were being recommended by the company. That case was eventually settled without any ensuing hearing.[1]

I also proffered testimony in the Manitoba Hydro 2015 General Rate Application jointly retained by the Consumer's Coalition and the Manitoba Industrial Power User's Group. That proceeding reviewed proposals to, among other things, convert Manitoba Hydro's depreciation provision to the ELG procedure, and to remove any accrual for Net Salvage from Manitoba Hydro's depreciation rates. I also provided oral testimony in that contested proceeding.

Additionally, I proffered joint testimony with Patrick Bowman of InterGroup Consultants Ltd. in the 2017-2018 General Rate Application (GRA) of ATCO Pipelines Ltd. (ATCO) addressing a filed depreciation study that recommended, among other things, a change in depreciation procedures from ASL (WL, or BG) to ELG (Equal Life Group) for purposes of determining accumulated provision imbalances and amortizations thereof. The stated purpose of the study was to prepare for conversion to IFRS accounting standards for financial reporting. This case was also settled without hearing.[2]

Further, I proffered testimony in telecommunications, electric, and gas cases regarding depreciation-related issues before the Florida Public Service Commission. A complete list of all dockets in which I was assigned or in which I presented testimony is attached as Exhibit PSL-1 to this testimony.

Q. PLEASE BRIEFLY DESCRIBE THE TERMS OF THE RETAINER THAT YOU HAVE AGREED TO FOR THE PURPOSES OF THIS REVIEW.

A. I have been retained by the Island Industrial Customers of Newfoundland Hydro for the purposes of reviewing depreciation issues contained in the 2017 General Rate Application. In participation, I declare that it is my duty to provide evidence in relation to this proceeding as follows:

- To provide opinion evidence that is fair, objective and non-partisan;
- expertise; and,
- To provide such additional assistance as the Public Utilities Board may reasonably require to determine an issue.

[1] See Order No. P.U. 40(2012) issued by Newfoundland & Labrador Board of Commissioners of Public Utilities.
[2] See AUC Decision 22011-D01-2017.

Q. FROM YOUR PERSPECTIVE WHAT ARE THE MOST IMPORTANT CHARACTERISTICS FOR SELECTING AN APPROPIATE DEPRECIATION METHODOLOGY FOR USE IN RATE SETTING?

A. From my perspective, I believe the most important characteristics in selecting an appropriate depreciation methodology or technique are:

- Matching costs with benefits;
- Avoiding intergenerational equity issues;
- Transparency of the method, calculations, intentions, and resulting expenses for use in setting customer rates; and
- Quality of data in determining an appropriate retirement pattern and life.

## II. OVERVIEW AND IMPLICATIONS OF ELG

Q. CAN YOU PROVIDE AN OVERVIEW OF THE THEORY BEHIND THE EQUAL LIFE GROUP (ELG) PROCEDURE AND THE HISTORICAL IMPLEMENTATION OF ELG IN THE UNITED STATES?

A. Yes. ELG is a method of calculating depreciation expenses and resulting depreciation rates based on the life expectations of each of the equally-lived sub-groups constituting a vintage group – or composited to an account or category rate. That is, the vintage group is divided into sub – groups, or in the case of NLH, components, each of which is expected to live an equal life. Each item in any given equal life group is expected to have the same life as each other item in that group. The required depreciation expenses or accruals for the vintage is then the summation of the requirements for each contained equal life group; each individual equal life group is expected to recover its invested capital during the period that group is in service.

As an example, consider a vintage that consists of three $100 units, A, B, and C, expected to live 2, 4, and 5 years. To recover each unit during its own service life will require annual accruals of $50, $25, and $20, respectively, as shown below.

| | Table 1: Accruals in Years | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| A | $50 | $50 | | | |
| B | 25 | 25 | 25 | 25 | |
| C | 20 | 20 | 20 | 20 | 20 |
| Vintage Totals | 95 | 95 | 45 | 45 | 20 |

In its pure form, ELG is an ideal model for the proper recovery of invested capital, a major point opined by Mr. Kennedy. By separating the vintage into the equal life groups, each of those groups is assigned a rate in accord with its life. Therefore each asset (or as in the above example, each $100 unit) is recovered during its specific period of service – the epitome of the matching principle (matching expenses to consumption).

To guard against over or under recovery, the original ELG concept called for the separate monitoring of each vintage annually as to both the activity of the assets and the reserve level. If projected life patterns were not realized there would be an end-of-year correction to each vintage of the accrued depreciation expense and likewise to the reserve. Perfection was assured.

The conceptual perfection of ELG was impressed on a number of U.S. utility and regulatory personnel through the years. In the '60s-'70s the ELG controversy became a ground swell which led to acceptance by the Federal Communication Commission (FCC) in the early '80s for telecommunications companies. ELG was adopted on a going-forward basis for new additions with embedded vintages utilizing remaining life (broad group).[3] A three-year phase-in period was determined to be needed to reduce the immediate impact on depreciation expense and revenue requirements.[4] A number of state regulatory agencies soon followed. ELG was adopted for telephone companies specifically for the following reasons[5]:

> In 1980 the commission adopted major changes in the way depreciation rates were to be calculated. In response to changes in competitive and technological conditions in the market for telephone services, the FCC authorized the use of "equal life group" ("ELG") depreciation accounting for all new plant acquisitions. Amendment of Part 31, 83 F.C.C. 2d 267, 280-81 (1980), reconsideration denied, 87 F.C.C. 2d 916(1981 (hereinafter cited as Docket 20,188]. On reconsideration, the Commission emphasized that the use of ELG was necessary to bring depreciation accounting "more in line with today's technology and economic conditions" and "**to improve capital recovery promptly in light of competitive and technological conditions in the marketplace.**" [emphasis added]
>
> The FCC also adopted the "remaining life" method of accounting for correcting errors made in estimating the useful life of both embedded and new plant. Docket 20,188, 83 F.C.C. 2d at 289-90 Under the previous "whole life" method, depreciation charges were calculated each year as if the useful life of the asset had been estimated correctly from the beginning. Under the remaining life method, when new information leads to a different estimate of the asset's useful life, the remaining unrecovered depreciation is allocated over the actual remaining life, so that 100% of the asset's value is depreciated.
>
> The Commission adopted the remaining life method in recognition of depreciation reserve deficiencies which had developed under whole life accounting. Beginning in the late 1960's, asset lives had consistently turned out to be shorter than the original estimate creating depreciation reserve deficiencies which, the FCC found, would continue to grow absent corrective action. Docket 20,188, 83 F.C.C. 2d at 289-90 The Commission acknowledged that responding to these deficits by using the remaining life method

[3] See Report and Order, FCC Docket No. 20188 adopted November 6, 1980, released December 5, 1980. The FCC ordered the use of ELG for the telephone industry on new plant additions beginning in 1981 over a three-year phase-in period.

[4] NARUC Public Utility Depreciation Practices, August 1996.

[5] Regarding Docket No. 20,188; Summarized in 781 F. 2d 209 – Southern Bell Telephone and Telegraph Company v. Federal Communications Commission, United States Court of Appeals, District of Columbia Circuit No. 84-1638. Decided January 17, 1996 as amended January 7, 1986. Accessed online: http://openjurist.org/781/f2d/209/southern-bell-telephone-and-telegraph-company-v-federal-communications-commission.

> "might result in sharp increases in revenue requirements and in user charges" but concluded that such changes were necessary:

> With respect to telecommunications investment, the impact of new technology and the transition from a monopoly to a competitive environment have led to an overall shortening of life estimates. . . Absent a reversal of current trends ad without corrective action, the amount of the difference due to errors of life estimate will continue to grow, and upon ultimate retirement the reserve provisions will not be adequate.

The trend for the telecommunications industry was to shorten lives, causing reserve deficits upon asset retirements to remain competitive and widen profitability margins in the short-term. The reverse is just as plausible in different environments, with life extensions that later create a reserve surplus.

With respect to applying ELG to new additions only, the Supreme Court in US West Communications Inc. v Washington Utilities and Transportation Commission affirmed that applying ELG to the embedded investments would be inappropriate. Specifically, the Court held that to use one method or procedure of depreciation for the first part of a vintage's life and then change to a more accelerated procedure such as ELG for the later portion of life would result in recovery that would be neither straight line nor based on any measure of life and would not reasonably balance the interests of the company and the interests of ratepayers given the intergenerational inequities it would create.[6]

Almost immediately on the FCC adopting the ELG procedure, it became apparent to utilities that a mechanism must be developed that would be practicable enough to be implemented.[7] That was simple enough: the retirement pattern inherent in any standard Iowa curve was analyzed to develop the implied equal life groups; that is, if there were a decrease of 1% between ages 4 and 5, that meant that 1% of the assets would have a life of 4.5 years – and then that ELG group life went into developing the account life and rate.

A fundamental requirement for ELG was that actuarial vintage data would be maintained. Such data includes records that show the age of the retirements (and the transfers/adjustments) being experienced. The record-keeping problem of maintaining actuarial vintage data caused the dropping of the requirement for vintage asset and reserve records – a requirement of the feature of an annual vintage reserve true-up. The shortcoming of now having no reserve-sensitivity introduced the solution of coupling ELG with the Remaining Life formula[8] to provide reserve corrections.

Because ELG applied to new additions, only the survivors from the more recent vintages were used in developing an ELG service life, and the older vintages kept the traditional average service life approach.

[6] Supreme Court of Washington, En Banc. US West Communications, Inc., a Colorado corporation, Appellant, v. Washington Utilities and Transportation Commission, Respondent, No. 64821-2, Decided December 24, 1997.

[7] The initial ELG rates ordered by the FCC were individual ELG whole-life rates for each age within each plant account.

[8] The remaining life formula measures the unrecovered cost yet to be recovered (investment less reserve less net salvage) and recovers that over the remaining period the related assets will be serving the public. For example, investment of $1,000 less reserve as of the study date of $500 yields a cost yet to be recovered of $500. Assuming the remaining period of service is estimated to be 10 years results in annual remaining life expenses $50.

Then when the average service life of the entire account/category was composited, development of a remaining life for the account/category added the reserve sensitive feature. The bottom line being that the conceptual perfection of ELG was quickly abandoned to practicality – and the only result was that the new hybrid mechanism was simply one which shortened the life. That is, ELG, as brought into use, became merely a somewhat more complex remaining life rate development, using a shorter remaining life.

Q. CAN YOU PROVIDE A PRACTICAL EXAMPLE OF WHY THE EFFECT OF ELG FRONT LOADS COSTS AND SHORTENS THE REMAINING LIFE?

A. Yes. The table below compares the ELG and ASL depreciation rate in an example containing three vintages, each with a different life. As shown the ELG depreciation rate for 2010 is 45.7% compared to an ASL rate of 33.3%.

Table 2: Effect of Procedures on Depreciation Rates[9]

| Vintage | Total Amount Placed | Average Life | Depr. Rate | ELG Depreciation Rates | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| 2010 | 50,000 | 3.0 | 33.3% | 45.7% | 32.1% | 26.1% | 22.5% | 20.0% | 0.0% |
| 2011 | 80,000 | 4.5 | 22.2 | | 34.0 | 24.5 | 20.3 | 17.7 | 13.9 |
| 2012 | 100,000 | 5.5 | 18.2 | | | 29.3 | 21.4 | 17.9 | 15.7 |

Table 2A details the total depreciation expenses for all three vintages 2010-2012 calculated under the ELG procedure using the depreciation rates shown. Table 2B details the total depreciation expenses for all three vintages under the ASL procedure. A comparison of the depreciation rate and expenses for each activity year using both ELG and ASL procedures is given below. As shown, when plant is growing (activity years 2010-2012) the ELG rate and expenses will always exceed the ASL rate and expenses.

[9] NARUC Public Utility Depreciation Practices, August 1996, page 177.

Table 2A: Depreciation Expenses – ELG Method[10]

| Beginning of Year | Placements | Retirements | Depreciable Base | ELG Depr. Rate | ELG Expenses |
|---|---|---|---|---|---|
| | ($) | ($) | ($) | (%) | ($) |
| 1-1-2010 | 50,000 | | | | |
| 2010 Vintage | | 10,000 | 50,000 | 45.7 | 22,850 |
| 1-1-2011 | 80,000 | | | | |
| 2010 Vintage | | 10,000 | 40,000 | 32.1 | 12,840 |
| 2011 Vintage | | 10,000 | 80,000 | 34.0 | 27,200 |
| 2011 Composite | | | 120,000 | 33.4 | 40,040 |
| 1-1-2012 | 100,000 | | | | |
| 2010 Vintage | | 10,000 | 30,000 | 26.1 | 7,830 |
| 2011 Vintage | | 10,000 | 70,000 | 24.5 | 17,150 |
| 2012 Vintage | | 10,000 | 100,000 | 29.3 | 29,300 |
| 2012 Composite | | | 200,000 | 27.1 | 54,280 |
| 1-1-2013 | 0 | | | | |
| 2010 Vintage | | 10,000 | 20,000 | 22.5 | 4,500 |
| 2011 Vintage | | 10,000 | 60,000 | 20.3 | 12,180 |
| 2012 Vintage | | 10,000 | 90,000 | 21.4 | 19,260 |
| 2013 Composite | | | 170,000 | 21.1 | 35,940 |
| 1-1-2014 | 0 | | | | |
| 2010 Vintage | | 10,000 | 10,000 | 20.0 | 2,000 |
| 2011 Vintage | | 10,000 | 50,000 | 17.7 | 8,850 |
| 2012 Vintage | | 10,000 | 80,000 | 17.9 | 14,320 |
| 2014 Composite | | | 140,000 | 18.0 | 25,170 |
| 1-1-2015 | 0 | | | | |
| 2010 Vintage | | 0 | 0 | 0 | 0 |
| 2011 Vintage | | 10,000 | 40,000 | 15.9 | 6,360 |
| 2012 Vintage | | 10,000 | 70,000 | 15.7 | 10,990 |
| 2015 Composite | | | 110,000 | 15.8 | 17,350 |

[10] NARUC Public Utility Depreciation Practices, August 1996, page 179.

Table 2B: Depreciation Expenses – ASL Method[11]

| Beginning of Year | Placements | Retirements | Depreciable Base | ASL Depr. Rate | ASL Expenses |
|---|---|---|---|---|---|
| | ($) | ($) | ($) | (%) | ($) |
| 1-1-2010 | 50,000 | | | | |
| 2010 Vintage | | 10,000 | 50,000 | 33.3 | 16,650 |
| 1-1-2011 | 80,000 | | | | |
| 2010 Vintage | | 10,000 | 40,000 | 33.3 | 13,320 |
| 2011 Vintage | | 10,000 | 80,000 | 22.2 | 17,760 |
| 2011 Composite | | | 120,000 | 25.9 | 31,080 |
| 1-1-2012 | 100,000 | | | | |
| 2010 Vintage | | 10,000 | 30,000 | 33.3 | 9,990 |
| 2011 Vintage | | 10,000 | 70,000 | 22.2 | 15,540 |
| 2012 Vintage | | 10,000 | 100,000 | 18.2 | 18,200 |
| 2012 Composite | | | 200,000 | 21.9 | 43,730 |

Q. IN YOUR EXPERIENCE, WHAT WAS THE KEY IMPETUS FOR IMPLEMENTING ELG FOR CERTAIN UTILITIES IN THE US CONTEXT?

A. ELG was originally implemented for telecommunications companies where increased competition and technological changes were resulting in large retirements being experienced at a faster pace than perceived in the then approved life estimates. Initially, telecommunications companies proposed individual ELG whole-life rates for each age within a given account/category. The ELG depreciation rate was calculated for each age within the category in a similar manner to that shown below.

Table 3: Three Year-Life Table[12]

| Age | Amount Surviving | Amount Retired | Age of Amount Retired | Accruals: Each Group | Accruals: Total | Depreciation Rate |
|---|---|---|---|---|---|---|
| A | B | C(A)= B(A)-B(A+1) | D=A+0.5 | E=C/D | F=Sum E (A to end) | G=F/B% |
| 0.0 | 1,500 | 0 | 0.5 | 0 | 685 | |
| 0.5 | 1,500 | 300 | 1.0 | 300 | 685 | 46.0 |
| 1.5 | 1,200 | 300 | 2.0 | 150 | 385 | 32.0 |
| 2.5 | 900 | 300 | 3.0 | 100 | 235 | 26.0 |
| 3.5 | 600 | 300 | 4.0 | 75 | 135 | 23.0 |
| 4.5 | 300 | 300 | 5.0 | 60 | 60 | 20.0 |
| 5.5 | 0 | 0 | 6.0 | 0 | | |
| Total | 4,500 | 1,500 | | 685 | | |

For example, if 2015 were the first ELG year, the ELG rate in 2015 would be 46.0% for plant placed in 2015. In 2016, the ELG rate would be 46.0% for plant placed in 2016 and 32.0% for that investment remaining from the 2015 year placed, and so on. In 2017, the ELG rate would be 46.0% for plant placed

[11] NARUC Public Utility Depreciation Practices, August 1996, page 180.
[12] NARUC Public Utility Depreciation Practices, August 1996, page 181.

in that year, 32.0% for that investment remaining from 2016, and 26.0% for that investment remaining from the 2015 year placed.

One can quickly see that by 2024, this theoretically superior depreciation procedure would result in ten separate ELG rates being required for each account/category/component. In addition, a remaining life depreciation rate for the surviving investments prior to 2015 was required for each account/category/component which costly and burdensome to implement. In order to reduce the number of depreciation rates for each vintage and make the procedure simpler, a single ELG rate representing the composite of the individual ELG rates developed for each vintage within the account/category was developed.

A few years later (1985), the FCC decided to approve a composite ELG rate by prescribing a single composite remaining life rate in which the vintage group and ELG vintages were composited into a single average service life and average remaining life for each plant account. So now, back to one rate applied to each account/category/component. So the theoretically pure procedure that was touted as the most correct procedure, in reality became a hybrid mechanism that produced shorter lives and resulting higher depreciation rates.

The problem with ELG is one of practicality. As described above, the level/detail/accuracy of record-keeping required for accurate use of ELG is neither practicable nor cost-effective. The curve shapes and asset lives used in the current Hydro depreciation study should be based on and adequately supported by actual information of the company's assets. One needs only to apply a curve shape that first statistically determines the equal life groups for each vintage then depicts the retirement pattern each group will experience. However, without maintaining the necessary data, one will not know if the equal life groups are actually retiring in the manner estimated.

Major effective differences between ELG and ASL, insofar as the manner or allocation of expense/recovery for viable plant classes (accounts/components/groupings for which a separate depreciation rate is proposed), is in the timing of that recovery. This difference should only be of major consequence in plant classes experiencing appreciable early retirements or infant mortality and not in very long lived plant experiencing very few retirements, like Hydro.

An **essential requirement** for ELG (if it is to meet its alleged characteristic of being the best mechanism for matching recovery to consumption) is the ability to measure that recovery and consumption. That is, the knowledge of how many items/dollars of plant have lived the predicted age – which is to say, the knowledge of the age of the assets which have retired during any given year. To the extent the actual investment/age mix of plant retiring during a year does not equal the amount of retirements at the age-mix predicted under the ELG rates (curve), there has been an over or under recovery. As in Whole Life rates[13] (i.e. ELG rate applied from the onset of an asset coming in service), there is no provision in the ELG formula to accommodate/correct over or under recovery. This requires an annual, or other periodic, reserve true-up to match actual versus predicted activity (this was the originally proposed approach in the

[13] Whole Life depreciation rate – the whole life depreciation rate is calculated as the investment divided by the average service life in years. Whole life depreciation rates are not reserve-sensitive and so do not consider the need to recover any reserve imbalance that may exist.

telecommunications example), or reliance on a blending of ELG/Remaining Life mechanisms (which was the approach ultimately adopted by the FCC).

Q. WHAT DATA WOULD HYDRO REQUIRE IN ORDER TO PROPERLY IMPLEMENT THE ELG PROCEDURE?

A. The ELG procedure is very sensitive to retirement patterns or curve shapes. Therefore, as noted by NARUC in its Public Utility Depreciation Practices publication, detailed vintage plant mortality data must be maintained from which future retirement patterns can be estimated.[14] The amounts to be divided into equal life groups depend directly on the curve shape selected. The table below demonstrates the sensitivity of the ELG procedure.

Table 4: Effect of Curve Shape on Depreciation Expenses[15]

| Activity Year | Age | Selected Curve Shape | | | | | |
|---|---|---|---|---|---|---|---|
| | | Iowa L0 | | Iowa S1 | | Iowa R5 | |
| | | Expenses $ | Rate % | Expenses $ | Rate % | Expenses $ | Rate % |
| 1 | 0.5 | 30,632 | 31.5 | 25,099 | 25.1 | 20,491 | 20.5 |
| 2 | 1.5 | 20,475 | 23.5 | 22,201 | 22.9 | 20,491 | 20.5 |
| 3 | 2.5 | 14,372 | 19.2 | 18,188 | 20.5 | 20,491 | 20.5 |

The above three curves illustrate the difference in depreciation expenses and rates resulting from using curves with different shapes. Even when a curve shape is chosen based on informed judgment, plant generally does not retire precisely in accord with the shape selected. The resulting reserve imbalance between projected and actual retirement experience should either be addressed through recovery over the remaining life or recovery over a shorter period of time.

For ELG to be properly applicable, actuarial (aged data) vintage activity data should be available for each vintage to which the procedure is applied, as should vintage reserve activity data.

The curve shape being used tells us that, for a given service life value, a certain percent of the survivors at a given age will retire. The calculation, when completed will indicate that too many or too few retirements result from the chosen curve shape and life value. The shape and/or the life value can then be changed until the proper number of retirements are calculated. Then, from that, it can be said that if this investment experiences this many retirements in the pattern of this curve shape, there is an indication that it will live this period of time.

Consider the situation that ELG is touted as the best mechanism for accurate recovery but, lacking the proper measurement of recovery which is up to its standard of presumed perfection, ELG has come to rely on a blending with remaining life to assure correction for its under/over recovery. In which case, accept the ELG mechanism as one to produce increased cash flow, and forget the purist argument of ideally matching recovery with consumption.

[14] NARUC Public Utility Depreciation Practices, August 1996, page 165.
[15] NARUC Public Utility Depreciation Practices, August 1996, page 168.

An infirmity shared by each of these formulae is that mortals must estimate the expected lives and curve shapes of the plant. Because of the nature of the ELG formula, it is more sensitive to errors in projected lives and/or mortality dispersions (retirement patterns). To the extent a category has had miniscule retirements, fitting an appropriate Iowa curve becomes very subjective.

It is clear that for many of Hydro's accounts, there has been insufficient retirement activity from which to derive a future pattern. In many accounts, the data indicates that 90 percent or more of the curve must be estimated as there is only 10 percent actual retirement data. This leaves a considerable amount of the curve to be estimated which opens the door to much subjectivity. A limited amount of retirement experience lends itself to a wide array of possible curve shape/life combinations, one of which Mr. Kennedy has selected. The choice of curve shape can influence the life indication substantially and ultimately the depreciation expense used to set revenue rates.

When plant investment is growing the ELG rate and accruals will always exceed the vintage group ASL rate and accruals thereby causing an increase in revenue requirements. Not until the investment begins to decline will the ASL rate and accruals increase and eventually exceed the ELG rate and accruals. In an account experiencing high growth, a crossover point may never occur. The resulting effect is a higher current ratepayer cost without any corresponding increased asset use. The next generation of ratepayers, who are presumably supposed to experience lower costs, may not reap those benefits for a much longer period of time as lower costs may not occur until after the plant investment ceases. The FCC recognized that the ELG procedure results in annual depreciation expenses that are higher in the early years of a vintage's life, thereby putting pressure on customer rates. It is for this reason that when the FCC adopted the ELG procedure, it did so on a 3-year phase-in period to reduce the immediate impact on depreciation expense and revenue requirements.[16]

Q. WHAT ARE THE LASTING CONSEQUENCES OF HYDRO'S PROPOSAL ON RATEPAYERS IF ELG IS ADOPTED FOR RATEMAKING PURPOSES?

A. The lasting consequences of Hydro's proposal on ratepayers if ELG is adopted for ratemaking purposes will be higher depreciation expenses and higher revenue rates. There are also intergenerational equity and fairness issues if the Board approves Hydro's future plan to apply ELG to not only new additions but also to embedded plant.

The Average Service Life procedure applied on a remaining life technique basis as currently employed by Hydro is appropriate for ratemaking purposes. ELG is not the standard for electric, gas, or water companies across the United States. For telecommunications companies, a hybrid of ELG was implemented mainly to increase cash flow with increased competition and technological changes. As Hydro is a monopoly and technological changes do not have immediate impacts on its proven useful long-lived asset base, neither of these claims should be driving the change for the Company.

As I understand Hydro's recommendation:

- One depreciation rate is being applied to all 2015 investments. This rate consists of ASL for all investments up to December 31, 2014 and ELG for 2015 additions, thus a blended ASL/ELG rate. This implementation proposal is similar to the hybrid ELG procedure now used by the

[16] NARUC Public Utility Depreciation Practices, August 1996, page 176.

telecommunications companies in the U.S... However, to maintain the accuracy of the ELG procedure, as Mr. Kennedy proclaims to be the driver for change, one depreciation rate should be determined for the embedded (2014 and prior) account investments and then a separate ELG rate determined to only apply to 2015 additions. The rates should be separate and distinct.

- The first year ELG rate determined applicable to the 2015 additions appears to be the same rate applied to the additions in 2016 and also in 2017, so by the end of 2017 all new assets placed in service 2015 forward are being depreciated as if they were still first year ELG assets. Under no circumstances is this the intent of the ELG procedure. As indicated in the illustration above in Table 3, if 2015 were the first ELG year, the ELG rate in 2015 would be 46.0% for plant placed in 2015. In 2016, the ELG rate would be 46.0% for plant placed in 2016 and 32.0% for that investment remaining from the 2015 year placed, and so on. In 2017, the ELG rate would be 46.0% for plant placed in that year, 32.0% for that investment remaining from 2016, and 26.0% for that investment remaining from the 2015 year placed. This is not the recommendation presented by Hydro in this proceeding. In sum, Hydro's recommendations appear to only be a means to increase cash flow, not for increased precision.

Although I do not recommend that the Board approve Hydro's proposal to move to the ELG depreciation procedure for ratemaking purposes, if it does I would urge the Board to

- Adopt ELG for new additions only. In the current case, separate ELG rates would be needed for 2015 additions, 2016 additions, and 2017 additions with separate ASL(whole life) or BG remaining life rates for December 31, 2014 embedded investments . Do not adopt ELG for assets in 2015 where this requires use of a hybrid or blended ASL/ELG Remaining Life rate as is proposed.
- Calculations of reserve imbalances and amortization thereof should utilize the broad group remaining life.
- Adopt a 3-year phase in approach.
- Require Hydro to maintain the requisite actuarial data for each vintage to which an ELG rate is applied as well as vintage reserve data.
- Require a depreciation study at least once every three years to monitor the status and to address any needed adjustments.

## IV. GLOSSARY

Average Remaining Life Technique – the remaining undepreciated plant (net book value – plant investment less reserve less any salvage) in each account is depreciated over the current estimate of the remaining life of that account.

Average Service Life – all assets acquired in a given year (vintage) are grouped into a category and then the lives are averaged.

Actuarial data – requires aged data in which the age of each retirement is known. For example, $20,000 that retired in 2009 was originally placed in service in 2000, thus it was 9.5 years of age when it retired. The original placements in 2000 are reduced by the $20,000 retirement.

Capital recovery – the process of including revised resulting deprecation expenses in revenue rates.

Equal Life Group (ELG) – ELG is a procedure of calculating a depreciation rate based on this life expectations of each of the equally-lived sub-groups constituting a vintage group - or composited to an account or category rate. That is, the vintage group is divided into sub-groups, each of which is expected to live an equal life. That is to say that each item in any given equal life group is expected to have the same life as each other item in that group. The required capital recovery for the vintage is then the summation of the requirements for each contained equal life group; each individual equal life group is expected to recover its invested capital during the period that group is in service.

Survivor curve – a graphical picture of the amount of property surviving at each age through the life of the property group. The graph plots the percents surviving on the y-axis and the age on the x-axis. The survivor curve depicts the expected retirement distribution (or survival distribution) of plant in an account over time.

Vintage – year of placement of a group of property.

Whole Life Technique – the whole life technique bases the depreciation rate on the estimated average service life of the plant.

Exhibit PSL-1

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

**2011**

Docket 110233 -- Petition for approval of 2011 Depreciation Study by Sebring Gas Systems, Inc.

Docket 110207 -- 2011 depreciation study by Florida Public Utilities Company.

Docket 110131 -- Petition for approval of 2011 depreciation study and annual dismantlement accrual amounts by Tampa Electric Company.

**2010**

Docket 100461 -- Petition for approval of nuclear decommissioning cost study, by Progress Energy Florida, Inc.

Docket 100458 -- Petition for approval of 2010 nuclear decommissioning study, by Florida Power & Light Company.

Docket 100368 -- Request for approval to initiate depreciation of a Landfill Gas to Energy Facility in Escambia County by Gulf Power Company.

Docket 100136 -- Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.

**2009**

Docket 090403 -- Request for approval to begin depreciating West County Energy Center Units 1 and 2 combined cycle units using whole life depreciation rates currently approved for Martin Power Plant Unit 4, by Florida Power & Light Company.

Docket 090319 -- Depreciation and dismantlement study at December 31, 2009, by Gulf Power Company.

Docket 090144 -- Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.

Docket 090130 -- 2009 depreciation and dismantlement study by Florida Power & Light Company.

Docket 090125 -- Petition for increase in rates by Florida Division of Chesapeake Utilities Corporation.

Docket 090079 -- Petition for increase in rates by Progress Energy Florida, Inc.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

**2008**

Docket 080677 -- Petition for increase in rates by Florida Power & Light Company.

Docket 080548 -- 2008 depreciation study by Florida Public Utilities Company.

Docket 080366 -- Petition for rate increase by Florida Public Utilities Company.

Docket 080317 -- Petition for rate increase by Tampa Electric Company.

**2007**

Docket 070736 -- Petition by Intrado Communications, Inc. for arbitration of certain rates, terms, and conditions for interconnection and related arrangements with BellSouth Telecommunications, Inc. d/b/a AT&T Florida, pursuant to Section 252(b) of the Communications Act of 1934, as amended, and Sections 120.80(13), 120.57(1), 364.15, 364.16, 364.161, and 364.162, F.S., and Rule 28-106.201, F.A.C.

Docket 070699 -- Petition by Intrado Communications, Inc. for arbitration of certain rates, terms, and conditions for interconnection and related arrangements with Embarq Florida, Inc., pursuant to Section 252(b) of the Communications Act of 1934, as amended, and Section 364.162, F.S.

Docket 070671 -- Petition for approval to eliminate intraLATA toll customer contact protocols, by Verizon Florida LLC.

Docket 070646 -- Petition for approval to revise customer contact protocol by BellSouth Telecommunications, Inc. d/b/a AT&T Florida.

Docket 070552 -- Petition and complaint for expedited proceeding or, alternatively, petition and complaint or petition for declaratory statement, by MetroPCS Florida, LLC, requiring BellSouth Telecommunications, Inc. d/b/a AT&T Florida d/b/a AT&T Southeast; TDS Telecom d/b/a TDS Telecom/Quincy Telephone; Windstream Florida, Inc.; Northeast Florida Telephone Company d/b/a NEFCOM; GTC, Inc. d/b/a GT Com; Smart City Telecommunications, LLC d/b/a Smart City Telecom; ITS Telecommunications Systems, Inc.; and Frontier Communications of the South, LLC, to submit agreements for transit services provided by AT&T Florida for approval.

Docket 070408 -- Petition by Neutral Tandem, Inc. and Neutral Tandem-Florida, LLC for resolution of interconnection dispute with Level 3 Communications, LLC, and request for expedited resolution.

## UTILITY PROCEEDINGS
## IN WHICH PAT LEE PARTICIPATED OR
## PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 070295 -- Request for approval of traffic termination agreement between Neutral Tandem-Arizona, LLC, Neutral Tandem-Colorado, LLC, Neutral Tandem-Florida, LLC, Neutral Tandem-Georgia, LLC, Neutral Tandem-Maryland, LLC, Neutral Tandem-Nevada, LLC, Neutral Tandem-South Carolina, LLC, Neutral Tandem-Tennessee, LLC, Neutral Tandem-Texas, LLC, Neutral Tandem-Virginia, LLC, Neutral Tandem-Washington, D.C., LLC, and Xspedius Management Co. Switched Services, LLC, Xspedius Management Co. of D.C., LLC, and Xspedius Management Co. of Virginia, LLC.

Docket 070295 -- Request for approval of traffic termination agreement between Neutral Tandem-Arizona, LLC, Neutral Tandem-Colorado, LLC, Neutral Tandem-Florida, LLC, Neutral Tandem-Georgia, LLC, Neutral Tandem-Maryland, LLC, Neutral Tandem-Nevada, LLC, Neutral Tandem-South Carolina, LLC, Neutral Tandem-Tennessee, LLC, Neutral Tandem-Texas, LLC, Neutral Tandem-Virginia, LLC, Neutral Tandem-Washington, D.C., LLC, and Xspedius Management Co. Switched Services, LLC, Xspedius Management Co. of D.C., LLC, and Xspedius Management Co. of Virginia, LLC.

Docket 070127 -- Petition for interconnection with Level 3 Communications and request for expedited resolution, by Neutral Tandem, Inc.

**2006**

Docket 060767 -- Petition of MCImetro Access Transmission Services LLC d/b/a Verizon Access Transmission Services for arbitration of disputes arising from negotiation of interconnection agreement with Embarq Florida, Inc.

Docket 060644 -- Petition to recover 2005 tropical system related costs and expenses, by Embarq Florida, Inc.

Docket 060598 -- Petition to recover 2005 tropical system related costs and expenses, by BellSouth Telecommunications, Inc.

Docket 060479 -- Petition by Verizon Florida Inc. for resolution of dispute with XO Communications Services, Inc. concerning non-UNE transport facilities retained at UNE prices.2

Docket 060296 -- Referral by the Circuit Court of Baker County, Florida to determine whether or not Southeastern Services, Inc. is legally responsible for payment to Northeast Florida Telephone for originating intrastate access charges under Northeast Florida Telephone's Public Service Commission approved tariff for the long distance calls provided by Southeastern Services, Inc. as alleged in the Amended Complaint.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 060083 -- Complaint of Northeast Florida Telephone Company d/b/a NEFCOM against Southeastern Services, Inc. for alleged failure to pay intrastate access charges pursuant to NEFCOM's tariffs, and for alleged violation of Section 364.16(3)(a), F.S.

**2005**

Docket 050419 -- Petition by MCImetro Access Transmission Services LLC d/b/a Verizon Access Transmission Services for arbitration of certain terms and conditions of proposed interconnection agreement with BellSouth Telecommunications, Inc.

Docket 050297 -- Emergency petition by Saturn Telecom Services Inc. d/b/a STS Telecom to require BellSouth Telecommunications, Inc. to allow additional lines and locations to STS's embedded base, and for expedited relief.

Docket 050172 -- Emergency petition of Ganoco, Inc. d/b/a American Dial Tone, Inc. for Commission order directing Verizon Florida Inc. to continue to accept new unbundled network element orders pending completion of negotiations required by "change of law" provisions of interconnection agreement in order to address the FCC's recent Triennial Review Remand Order (TRRO).

Docket 050119 -- Joint petition by TDS Telecom d/b/a TDS Telecom/Quincy Telephone; ALLTEL Florida, Inc.; Northeast Florida Telephone Company d/b/a NEFCOM; GTC, Inc. d/b/a GT Com; Smart City Telecommunications, LLC d/b/a Smart City Telecom; ITS Telecommunications Systems, Inc.; and Frontier Communications of the South, LLC ["Joint Petitioners"] objecting to and requesting suspension and cancellation of proposed transit traffic service tariff filed by BellSouth Telecommunications, Inc.

Docket 050059 -- Petition to reform unbundled network element (UNE) cost of capital and depreciation inputs to comply with Federal Communications Commission's guidance in Triennial Review Order, by Verizon Florida Inc.

**2004**

Docket 041338 -- Joint petition by ITC^DeltaCom Communications, Inc. d/b/a ITC^DeltaCom d/b/a Grapevine; Birch Telecom of the South, Inc. d/b/a Birch Telecom and d/b/a Birch; DIECA Communications, Inc. d/b/a Covad Communications Company; Florida Digital Network, Inc.; LecStar Telecom, Inc.; MCI Communications, Inc.; and Network Telephone Corporation ("Joint CLECs") for generic proceeding to set rates, terms, and conditions for hot cuts and batch hot cuts for UNE-P to UNE-L conversions and for retail to UNE-L conversions in BellSouth Telecommunications, Inc. service area.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 041269 -- Petition to establish generic docket to consider amendments to interconnection agreements resulting from changes in law, by BellSouth Telecommunications, Inc.

Docket 040927 -- Complaint of Saturn Telecommunications Services, Inc. d/b/a STS Telecom against BellSouth Telecommunications, Inc. for declaratory relief regarding BellSouth's request for amendment pursuant to "change of law" provision of interconnect agreement.

Docket 040530 -- Petition for expedited ruling requiring BellSouth Telecommunications, Inc. and Verizon Florida Inc. to file for review and approval any agreements with CLECs concerning resale, interconnection, or unbundled network elements, by Florida Competitive Carriers Association, AT&T Communications of the Southern States, LLC d/b/a AT&T, MCImetro Access Transmissions Services LLC, and MCI WorldCom Communications, Inc.

Docket 040520 -- Emergency petition seeking order requiring BellSouth Telecommunications, Inc. and Verizon Florida Inc. to continue to honor existing interconnection obligations, by the Florida Competitive Carriers Association, AT&T Communications of the Southern States, LLC, MCImetro Access Transmission Services, LLC, and MCI WorldCom Communications, Inc.

Docket 040489 -- Emergency complaint seeking order requiring BellSouth Telecommunications, Inc. and Verizon Florida Inc. to continue to honor existing interconnection obligations, by XO Florida, Inc. and Allegiance Telecom of Florida, Inc. (collectively, Joint CLECs).

Docket 040156 -- Petition for arbitration of amendment to interconnection agreements with certain competitive local exchange carriers and commercial mobile radio service providers in Florida by Verizon Florida Inc.

**2003**

Docket 031125 -- Complaint against BellSouth Telecommunications, Inc. for alleged overbilling and discontinuance of service, and petition for emergency order restoring service, by IDS Telcom LLC.

Docket 031047 -- Request for approval of interconnection agreement between Sprint-Florida, Incorporated, KMC Telecom III LLC, KMC Telecom V, Inc. and KMC Data LLC.

Docket 030852 -- Implementation of requirements arising from Federal Communications Commission's triennial UNE review: Location-Specific Review for DS1, DS3 and Dark Fiber Loops, and Route-Specific Review for DS1, DS3 and Dark Fiber Transport.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 030851 -- Implementation of requirements arising from Federal Communications Commission's triennial UNE review: Local Circuit Switching for Mass Market Customers.

Docket 030715 -- Proposed amendment of Rule 25-30.140, F.A.C., Depreciation.

Docket 030714 -- Proposed adoption of Rule 25-6.04364, F.A.C., Electric Utilities Dismantlement Studies.

Docket 030558 -- Request for approval of revised fossil dismantlement studies by Florida Power & Light Company.

Docket 030512 -- Request for approval to begin depreciating Fort Myers Combustion Turbines 3A and 3B using whole life depreciation rates currently approved for Martin Power Plant, Unit No. 4, by Florida Power & Light Company.

Docket 030409 -- Petition for approval of 2003 depreciation study by Tampa Electric Company.

Docket 030222 -- Request for approval of change in depreciation rates to be implemented as of 10/1/03, by City Gas Company of Florida.

Docket 030139 -- Request for approval to begin depreciating Sanford Unit No. 4 using whole life depreciation rates currently approved for Martin Power Plant, Unit No. 4, by Florida Power & Light Company.

Docket 030048 -- 2003 depreciation study for Indiantown Gas Company.

**2002**

Docket 021014 -- Petition for approval to amortize gain on sale of property by Florida Public Utilities Company.

Docket 020943 -- Petition for approval of Agreement for Purpose of Ensuring Compliance with Ozone Ambient Air Quality Standards between Gulf Power Company and Florida Department of Environmental Protection pursuant to Section 366.8255(1)(d)7, F.S., for purposes of cost recovery of related expenditures and expenses through environmental cost recovery clause.

Docket 020853 -- 2002 depreciation filing by Florida Public Utilities Company.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 020726 -- Petition for approval of new environmental program for cost recovery through environmental cost recovery clause by Tampa Electric Company.

Docket 020648 -- Petition for approval of environmental cost recovery of St. Lucie Turtle Net Project for period of 4/15/02 through 12/31/02 by Florida Power & Light Company.

Docket 020566 -- Petition for approval of recovery schedule for two Gannon Station generating units, effective January 1, 2002, by Tampa Electric Company.

Docket 020340 -- Request by Florida Public Utilities Company for depreciation rates to reflect acquisition of Atlantic Utilities, a Florida Division of Southern Union Company d/b/a South Florida Natural Gas.

Docket 020332 -- Request for approval to begin depreciating Sanford Unit No. 5, using whole life depreciation rates currently approved for Martin Power Plant, Unit No. 4 and Common, and expand Ft. Myers depreciation rates to include heat recovery steam generators (HRSGs), effective with in-service date of unit, by Florida Power & Light Company.

Docket 020304 -- 2002 depreciation filing by Florida Division of Chesapeake Utilities Corporation.

**2001**

Docket 011595 -- Request for depreciation rates for new accounts, by Indiantown Gas Company.

Docket 010949 -- Request for rate increase by Gulf Power Company.

Docket 010906 -- Request for approval of depreciation study for five-year period 1996 through 2000 by Sebring Gas System, Inc.

Docket 010789 -- 2001 Depreciation and Dismantling Study by Gulf Power Company.

Docket 010669 -- Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities Company.

Docket 010668 -- Petition for approval of recovery schedule for three generating units, effective January 1, 2001, by Tampa Electric Company.

Docket 010383 -- Application for approval of new depreciation rates by Tampa Electric Company d/b/a Peoples Gas System.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 010261 -- Petition by Florida Power & Light Company for waiver of certain requirements of Rule 25-6.0436, F.A.C., as they apply to filing of depreciation study.

Docket 010107 -- Request for approval to begin depreciating Martin Simple Cycle Expansion Project by use of Whole Life Depreciation Rates currently approved for Martin Power Plant, Unit No. 4 and Common effective with in-service dates of units, by Florida Power & Light Company.

Docket 010031 -- 2000 Fossil Dismantlement Cost Study by Florida Power Corporation.

**2000**

Docket 001835 -- Petition for approval of revised annual accrual for nuclear decommissioning costs by Florida Power Corporation.

Docket 001608 -- Petition for approval of depreciation rates for new plant subaccounts by Florida Power Corporation.

Docket 001447 -- Request for rate increase by St. Joe Natural Gas Company, Inc.

Docket 001437 -- Request by Florida Power & Light Company for approval to begin depreciating Ft. Myers Power Plant using whole life depreciation rates currently approved for Martin Power Plant, Unit No. 4.

Docket 001148 -- Review of the retail rates of Florida Power & Light Company.

Docket 000824 -- Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.

Docket 000686 -- Revised depreciation study for Gannon Station by Tampa Electric Company.

Docket 000543 -- Proposed Rule 25-6.04365, F.A.C., Nuclear Decommissioning.

Docket 000518 -- Revised depreciation study for Sanford Site by Florida Power & Light Company.

Docket 000108 -- Request for rate increase by Florida Division of Chesapeake Utilities Corporation.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

**1999**

Docket 991931 -- Determination of appropriate method of recovery for the last core of nuclear fuel for Florida Power & Light Company and Florida Power Corporation.

Docket 990947 -- Petition for a full revenue requirements rate case for Gulf Power Company by the Citizens of the State of Florida.

Docket 990707 -- Proposed amendments to Rule 25-6.0142, F.A.C., Uniform Retirement Units for Electric Utilities.

Docket 990649B -- Investigation into pricing of unbundled network elements (Sprint/Verizon track).

Docket 990649A -- Investigation into pricing of unbundled network elements (BellSouth track).

Docket 990529 -- Petition for 1999 depreciation study by Tampa Electric Company.

Docket 990324 -- Disposition of Florida Power & Light Company's accumulated amortization pursuant to Order PSC-96-0461-FOF-EI.

Docket 990321 -- Petition of ACI Corp. d/b/a Accelerated Connections, Inc. for generic investigation to ensure that BellSouth Telecommunications, Inc., Sprint-Florida, Incorporated, and GTE Florida Incorporated comply with obligation to provide alternative local exchange carriers with flexible, timely, and cost-efficient physical collocation.

Docket 990302 -- Depreciation study by Florida Public Utilities Company.

Docket 990229 -- Depreciation study by City Gas Company of Florida.

Docket 990067 -- Petition by The Citizens of the State of Florida for a full revenue requirements rate case for Florida Power & Light Company.

**1998**

Docket 981834 -- Petition of Competitive Carriers for Commission action to support local competition in BellSouth Telecommunications, Inc.'s service territory.

Docket 981390 -- Investigation into the equity ratio and return on equity of Florida Power & Light Company.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 981246 -- Petition by Florida Power & Light Company for approval of annual accrual for Turkey Point and St. Lucie nuclear decommissioning unit costs.

Docket 981166 -- Request for approval of revised fossil dismantlement expense accruals, effective 1/1/99, by Florida Power & Light Company.

Docket 980845 -- 1998 Depreciation Study by Indiantown Gas Company.

Docket 980733 -- Discovery related to study on fair and reasonable rates and on relationships among costs and charges associated with certain telecommunications services provided by local exchange companies (LECs), as required by Chapter 98-277, Laws of Florida.

Docket 980723 -- Petition for approval of accounting methodology for Year 2000 costs by City Gas Company of Florida.

Docket 980700 -- 1997 depreciation study by Atlantic Utilities, a Florida Division of Southern Union Company d/b/a South Florida Natural Gas.

Docket 980696 -- Determination of the cost of basic local telecommunications service, pursuant to Section 364.025, Florida Statutes.

Docket 980583 -- 1998 depreciation study by Florida Public Utilities Company, Fernandina Beach Division.

Docket 980366 -- Request by Gulf Power Company for approval to initiate amortization of a cogeneration facility projected to be placed in service in April 1998.

Docket 980103 -- 1997 depreciation study by St. Joe Natural Gas Company, Inc.

Docket 980000A -- UNDOCKETED SPECIAL PROJECT: Fair and Reasonable Residential Basic Local Telecommunications Rates.

**1997**

Docket 971660 -- 1997 depreciation study by Florida Power & Light Company.

Docket 971608 -- Petition of AmeriSteel Corporation for limited proceeding to reduce Florida Power & Light Company's annual revenues by $440 million.

Docket 971570 -- 1997 depreciation study by Florida Power Corporation.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 971495 -- Request for approval of capital recovery schedules by Northeast Florida Telephone Company, Inc.

Docket 971396 -- Investigation of 1996 earnings of Northeast Florida Telephone Company, Inc.

Docket 970785 -- Depreciation studies by Florida Power & Light Company for specific (steam) generation sites.

Docket 970643 -- 1997 depreciation filing by Gulf Power Company.

Docket 970537 -- 1997 depreciation study by Florida Public Utilities Company, Marianna Division.

Docket 970428 -- 1996 depreciation filing by Florida Division of Chesapeake Utilities Corporation.

Docket 970410 -- Proposal to extend plan for recording of certain expenses for years 1998 and 1999 for Florida Power & Light Company.

**1996**

Docket 961515 -- Proposed amendment of Rule 25-6.0142, F.A.C., Uniform Retirement Units for Electric Utilities.

Docket 961230 -- Petition by MCI Telecommunications Corporation for arbitration with United Telephone Company of Florida and Central Telephone Company of Florida concerning interconnection rates, terms, and conditions, pursuant to the Federal Telecommunications Act of 1996.

Docket 960847 -- Petition by AT&T Communications of the Southern States, Inc. for arbitration of certain terms and conditions of a proposed agreement with GTE Florida Incorporated concerning interconnection and resale under the Telecommunications Act of 1996.

Docket 960833 -- Petition by AT&T Communications of the Southern States, Inc. for arbitration of certain terms and conditions of a proposed agreement with BellSouth Telecommunications, Inc. concerning interconnection and resale under the Telecommunications Act of 1996.

Docket 960797 -- 1996 depreciation study of Indiantown Telephone System, Inc.

Docket 960794 -- Request for approval of remaining life rates by Quincy Telephone Company.

Docket 960788 -- 1996 depreciation study by Frontier Communications of the South, Inc.

Docket 960775 -- 1996 depreciation filing by Sebring Gas System, Inc.

Docket 960715 -- Proposed amendment of Rules 25-4.0174, F.A.C., Uniform System and Classification of Accounts - Dep reciation, and 25-4.0175, F.A.C., Depreciation; and Repeal of Rule 25-4.176, F.A.C., Recovery Schedules.

Docket 960527 -- Request for approval of site specific depreciation studies by Florida Power & Light Company.

Docket 960409 -- Prudence review to determine regulatory treatment of Tampa Electric Company's Polk Unit.

Docket 960404 -- Application for approval of new depreciation rates by Peoples Gas System, Inc.

**1995**

Docket 951433 -- Petition for approval of special accounting treatment of expenditures related to Hurricane Erin and Hurricane Opal by Gulf Power Company.

Docket 951167 -- Petition for authorization to increase the annual storm fund accrual commencing January 1, 1995 to $20.3 million; to add approximately $51.3 million of recoveries for damage due to Hurricane Andrew and the March 1993 Storm; and to re-establish the storm reserve for the costs of Hurricane Erin by increasing the storm reserve and charging to expense approximately $5.3 million, by Florida Power & Light Company.

Docket 951069 -- Petition and complaint of Harris Corporation against BellSouth Telecommunications, Inc. concerning complex inside wiring.

Docket 950948 -- Proposed amendment of Rule 25-30.140, F.A.C., Depreciation.

Docket 950887 -- Request for approval of 1995 Depreciation Study by ALLTEL Florida, Inc.

Docket 950776 -- Request for approval of 1995 Depreciation Study by West Florida Natural Gas Company.

Docket 950696 -- Determination of Funding for Universal Service and Carrier of Last Resort Responsibilities.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 950640 -- Triennial depreciation study for approval by Northeast Florida Telephone Company, Inc.

Docket 950506 -- Application to amortize depreciation reserve imbalance and to change depreciation rates and schedules by BellSouth Telecommunications, Inc. d/b/a Southern Bell Telephone and Telegraph Company.

Docket 950499 -- Petition for approval of 1995 Depreciation Study by Tampa Electric Company.

Docket 950381 -- Request for approval of depreciation rates for newly established accounts by Sebring Gas System, Inc.

Docket 950344 -- Petition to implement triennial depreciation represcription by GTE Florida Incorporated.

Docket 950283 -- Investigation into 1994 earnings of United Telephone Company of Florida.

Docket 950270 -- Petition for approval of accounting treatment for funds expended on Lake Tarpon-Kathleen transmission line by Florida Power Corporation.

Docket 950213 -- Petition for approval of recovery schedule for energy management system by Tampa Electric Company.

Docket 950071 -- Modified Minimum Filing Requirements in compliance with Section 366.06(3)(a), F.S., by Florida Power & Light Company.

**1994**

Docket 941352 -- Petition for approval of increase in accrual for nuclear decommissioning costs by FLORIDA POWER CORPORATION.

Docket 941350 -- Petition for increase in annual accrual for Turkey Point and St. Lucie Nuclear Unit Decommissioning Costs by FLORIDA POWER & LIGHT COMPANY.

Docket 941343 -- Request for approval of Fossil Dismantlement Studies by FLORIDA POWER & LIGHT COMPANY.

Docket 941317 -- Petition for approval of 1995 depreciation rates for Martin Units 3 and 4 by FLORIDA POWER & LIGHT COMPANY.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 941229 -- Request for approval of 1994 Depreciation Study by UNITED TELEPHONE COMPANY OF FLORIDA and CENTRAL TELEPHONE COMPANY OF FLORIDA.

Docket 941023 -- Petition to recover Operator Systems investment by GTE FLORIDA INCORPORATED.

Docket 940826 -- Request for approval of capital recovery requirements by INDIANTOWN TELEPHONE SYSTEM, INC.

Docket 940580 -- Request for approval of 1993 depreciation study for Fernandina Beach Division of FLORIDA PUBLIC UTILITIES COMPANY.

Docket 940374 -- Request for approval of 1993 depreciation study by FLORIDA PUBLIC UTILITIES COMPANY.

Docket 940353 -- R equest for change in depreciation rate effective 10/1/94 by ST. JOSEPH TELEPHONE & TELEGRAPH COMPANY.

Docket 940284 -- Request to prescribe depreciation rate for the new plant account by WEST FLORIDA NATURAL GAS COMPANY.

Docket 940165 -- Request to amortize the negative depreciation reserve for the Sanderson Digital Remote Switch in 1993 by NORTHEAST FLORIDA TELEPHONE COMPANY, INC.

Docket 940161 -- 1994 Depreciation Study of CITY GAS COMPANY OF FLORIDA.

**1993**

Docket 931231 -- Request for approval of change in depreciation rates by FLORIDA POWER & LIGHT COMPANY.

Docket 931217 -- Request for approval of depreciation rates for Martin Power Plant Units 3 and 4 by FLORIDA POWER & LIGHT COMPANY.

Docket 931150 -- Petition to approve an amortization period for acquisition adjustment associated with purchase of Sebring Utilities Commission electric system by FLORIDA POWER CORPORATION.

Docket 931142 -- Request for approval of 1993 depreciation study by FLORIDA POWER CORPORATION.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 930611 -- Investigation into deferral of implementation of any change to methodology used in establishing current depreciation, dismantlement, and decommissioning rates in FLORIDA POWER & LIGHT COMPANY's next general base rate proceeding.

Docket 930566 -- Request for approval to begin depreciating Ft. Lauderdale Power Plant, Units 4 & 5, using Whole Life Depreciation Rates approved for Putnam Power Plant effective with in-service dates of units by FLORIDA POWER & LIGHT COMPANY.

Docket 930453 -- Depreciation study as of 12/31/92 for Marianna Electric Division of FLORIDA PUBLIC UTILITIES COMPANY.

Docket 930230 -- 1993 Depreciation Study of VISTA-UNITED TELECOMMUNICATIONS.

Docket 930221 -- 1993 Depreciation Study of GULF POWER COMPANY.

Docket 930170 -- 1993 Depreciation Study of GULF TELEPHONE COMPANY.

Docket 930063 -- 1992 Depreciation Study for INDIANTOWN GAS COMPANY.

**1992**

Docket 921337 -- Request for review of five-year comprehensive study of depreciable property for period ending 12/31/92 by ST. JOE NATURAL GAS COMPANY, INC.

Docket 921278 -- Review of capital recovery requirements of INDIANTOWN TELEPHONE SYSTEM, INC.

Docket 920618 -- Depreciation study for Big Bend Station and Gannon Station by TAMPA ELECTRIC COMPANY.

Docket 920589 -- Triennial depreciation study for 1989, 1990, and 1991 for NORTHEAST FLORIDA TELEPHONE COMPANY, INC.

Docket 920389 -- Request for approval of depreciation rates and a dismantlement accrual for Scherer Unit 4 by FLORIDA POWER & LIGHT COMPANY.

Docket 920385 -- Application to change depreciation rates and schedules effective 1/1/92 by BELLSOUTH TELECOMMUNICATIONS, INC. d/b/a SOUTHERN BELL TELEPHONE AND TELEGRAPH COMPANY.

Docket 920324 -- Application for a rate increase by TAMPA ELECTRIC COMPANY.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 920284 -- Petition to implement Triennial Depreciation Represcription by GTE FLORIDA INCORPORATED.

Docket 920096 -- Petition to reverse the transfer of reserve account surpluses required by Order No. 23957 and to represcribe depreciation rates based on the revised account balances, by FLORIDA POWER CORPORATION.

**1991**

Docket 911229 -- 1991 Depreciation Study of GULF POWER COMPANY.

Docket 911199 -- Petition to prescribe depreciation rates for new plant accounts by FLORIDA POWER CORPORATION.

Docket 911101 -- Request for consolidated depreciation rates by CITY GAS COMPANY OF FLORIDA.

Docket 910988 -- Petition requesting special reserve amortizations by GTE FLORIDA INCORPORATED.

Docket 910981 -- Nuclear Decommissioning Cost Studies by FLORIDA POWER CORPORATION and FLORIDA POWER & LIGHT COMPANY.

Docket 910747 -- Proposed revision to Rules 25-4.0175, 25-6.0436, and 25-7.045, F.A.C., Depreciation for Telephone, Electric, and Gas Utilities.

Docket 910725 -- 1991 Depreciation Study for UNITED TELEPHONE COMPANY OF FLORIDA.

Docket 910686 -- Petition for approval of 1991 Depreciation Study by TAMPA ELECTRIC COMPANY.

Docket 910319 -- Application for New Depreciation Rates by PEOPLES GAS SYSTEM INC.

Docket 910154 -- Petition of FLORIDA POWER CORPORATION for a limited proceed- ing to consider their request for an increase in revenues to offset any additional depreciation expense that the Commission might approve related to fossil plant dismantlement costs.

Docket 910081 -- 1991 Depreciation Study for FLORIDA POWER & LIGHT COMPANY.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

**1990**

Docket 901001 -- Request for change in depreciation rates for Putnam and St. Johns River Power Park generating stations by FLORIDA POWER & LIGHT COMPANY.

Docket 900794 -- Request for approval of change in depreciation rates for Martin and Turkey Point generating sites, to become effective 1/1/91, by FLORIDA POWER & LIGHT COMPANY.

Docket 900607 -- 1991 Depreciation Study for Fernandina Beach electric division of FLORIDA PUBLIC UTILITIES COMPANY.

Docket 900605 -- Petition for approval to implement triennial depreciation represcription by GTE FLORIDA INCORPORATED.

Docket 900600 -- 1990 Depreciation Study of FLORIDA PUBLIC UTILITIES COMPANY.

Docket 900599 -- 1990 Depreciation Study of GULF TELEPHONE COMPANY.

Docket 900597 -- 1990 Depreciation Study of WEST FLORIDA NATURAL GAS COMPANY.

Docket 900555 -- 1990 Depreciation and Decommissioning Studies for Manatee Power Plant, Riviera Power Plant and Sanford Power Plant of FLORIDA POWER & LIGHT COMPANY.

Docket 900495 -- Request for change in depreciation rates for Fort Myers Power Plant by FLORIDA POWER & LIGHT COMPANY.

Docket 900348 -- Petition for approval of depreciation rates for Energy Management System by TAMPA ELECTRIC COMPANY.

Docket 900164 -- Request for change in depreciation rates for Fort Lauderdale and Port Everglades Power Plants by FLORIDA POWER & LIGHT COMPANY.

Docket 900163 -- Request for approval to recover cost to decommission facilities at Palatka Generating Site by FLORIDA POWER & LIGHT COMPANY.

Docket 900162 -- 1990 Depreciation Study for VISTA-UNITED TELECOMMUNICATIONS.

UTILITY PROCEEDINGS
IN WHICH PAT LEE PARTICIPATED OR
PRESENTED TESTIMONY AT THE FLORIDA PUBLIC SERVICE COMMISSION

Docket 900057 -- Proposed revisions to Rule 25-6.0142, F.A.C., pertaining to Uniform Retirement Units for Electric Utilities.

**1989**

Docket 891373 -- INDIANTOWN TELEPHONE SYSTEM, INC. - 1990 Depreciation Study.

Docket 891370 -- ST. JOSEPH TELEPHONE AND TELEGRAPH COMPANY - 1990 Depreciation Study.

Docket 891154 -- Request by FLORIDA POWER & LIGHT COMPANY for approval of depreciation rates for St. Johns River Coal Terminal.

Docket 891115 -- SOUTHLAND TELEPHONE COMPANY - 1989 depreciation study.

Docket 891098 -- Request by FLORIDA POWER & LIGHT COMPANY for change in depreciation rates for Cape Canaveral generating station.

Docket 891050 -- FLORALA TELEPHONE COMPANY - 1989 depreciation study.

Docket 891026 -- Request by ALLTEL FLORIDA, INC. for new depreciation rates.

Docket 890788 -- NORTHEAST FLORIDA TELEPHONE COMPANY, INC. - 1989 Depreciation Study.

Docket 890725 -- FLORIDA PUBLIC UTILITIES COMPANY, Marianna Electric Division - 1989 Depreciation Study.

Docket 890256 -- Review of SOUTHERN BELL TELEPHONE AND TELEGRAPH COMPANY's capital recovery position.

Docket 890186 -- Investigation of the ratemaking and accounting treatment for the dismantlement of fossil-fueled generating stations.

**1988**

Docket 881543 -- CENTRAL TELEPHONE COMPANY OF FLORIDA - 1988 Depreciation Study.

# PRE-FILED TESTIMONY OF
# C.F. OSLER and P. BOWMAN
# IN REGARD TO NEWFOUNDLAND & LABRADOR HYDRO
# GENERAL RATE REVIEW

*Submitted to*

The Board of Commissioners of Public Utilities

*On behalf of*

Island Industrial Customers

*Prepared by*


InterGroup Consultants, Ltd.
604-283 Portage Avenue
Winnipeg, MB R3B 2B5


September 2, 2003

**TABLE OF CONTENTS**

# 1.0 INTRODUCTION

This testimony has been prepared for the four existing Island Industrial Customers and one potential Island Industrial Customer (collectively "IC") of Newfoundland and Labrador Hydro (Hydro) by InterGroup Consultants, Ltd. (InterGroup) by Mr. C.F. Osler and Mr. P Bowman. It is evidence for the public hearing into an Application (the "Application") by Hydro to the Board of Commissioners of Public Utilities (Board) dated May 2003.

The Island IC group includes the three large industrial companies currently operating in Newfoundland and Labrador on Hydro's Island Interconnected System and one potential industrial customer on this system. These companies are:

- Abitibi-Consolidated Company of Canada (two customer locations, at Grand Falls and Stephenville);
- Corner Brook Pulp and Paper Limited;
- North Atlantic Refining Limited; and
- Voisey's Bay Nickel Company Limited which is a potential industrial customer of Hydro.

Mr. Osler's qualifications are provided in Attachment A. Mr. Bowman's qualifications are set out in Attachment B. InterGroup was initially retained at the end of June 2001 to assist the IC in addressing the 2001 Hydro Rate Review, and subsequently assisted the Island IC in preparation for the current proceeding. Mr. Osler also submitted evidence on behalf of the IC in the 2001 proceeding.

In preparing this testimony, the following information has been reviewed:

- The Hydro Application filed May 21, 2003, including pre-filed testimony of Hydro staff and witnesses.

- The Hydro Amended Application filed August 12, 2003 reflecting the July 2003 direction from the Government of Newfoundland and Labrador with respect to rural rates, and a revised fair return on equity proposal of 9.75%.

- Most of the first round responses to Information Requests filed to Hydro from the Board, the IC, the Consumer Advocate (CA), Newfoundland Power (NP), and the Labrador Customers (LC).

- To a limited degree, the second round responses to the Information Requests filed to Hydro from the Board, the IC, the Consumer Advocate (CA), Newfoundland Power (NP), and the Labrador Customers (LC); however, given the volume of the responses and the limited amount of time that has been available for us to review them, this review has been severely restricted. Furthermore, several key responses filed to date by Hydro fail to provide sufficient information as yet to usefully answer the questions posed.

This is the second general review of Hydro's rates by the Board under the new regulatory regime established for Hydro during the mid-1990s. InterGroup has been asked to identify and evaluate issues relating to the following aspects of Hydro's filing, taking into account normal regulatory review procedures and principles appropriate for Canadian electric power utilities:

1. revenue requirements for 2004 as submitted by Hydro; and
2. cost of service and rate structures, particularly insofar as these rates affect the Island IC.

The Board's schedule for this proceeding directs that pre-filed testimony by Intervenors is to be filed by September 2, 2003. This testimony has been prepared in response to this direction and based on our review as conducted to date.

As noted, our review to date has been somewhat limited by the time available, certain availability of responses to the Information Requests filed by all parties, and the quantity of information required for a full understanding of the issues. This initial testimony focuses on summarizing the contents of the Application, identification of key issues related to the above matters, and an initial overview of these issues. Following a review and clarification as required of Hydro's responses, further analysis and testimony on these issues may be required.

## 1.1 SUMMARY

Focusing on appropriate overall rate levels in general, and the appropriate level of rates to industrial customers in particular, it is apparent that Hydro's current application, in combination with the proposed operation of the RSP, results in unacceptable short-term (test year) rate increases and medium-term (5 years) rate instability, including forecast rate decreases in subsequent years. A consistent assessment of the proposed revenue requirement in comparison to approved 2001 levels indicates a substantial increase in a number of costs that exceed expected levels of inflation and fail to reflect the Board's conclusions regarding productivity improvements. The Board would be well advised to test carefully the reasonableness of the proposed increases in light of the overall rate impacts being proposed.

The material filed by Hydro indicates substantial improvement has been made in addressing system supply shortfalls compared to the 2002 test year. Granite Canal, in particular, appears to be a useful asset that is likely to reflect long-term benefits to the system. However, a detailed review of revenue requirement, cost of service and rate design in this submission indicates an inconsistent response by Hydro to the new system configuration reflecting surplus capacity and energy.

Hydro's overall proposals reflect confirmation of appropriate cost allocations for such assets as the Great Northern Peninsula transmission. However, standards applied by Hydro in assessing other radial transmission system assets (including thermal generation assets) result in an improper allocation of costs to the IC group reflecting costs of generation and transmission assets that are proposed to be assigned as being of common benefit, despite these assets being neither used nor useful to service the Island Interconnected system. Aside from normal cost of service concerns related to Hydro's proposed approach, the Board also needs to review these proposals in the context of the legislative limitation on industrial customer rates from funding the rural subsidy.

Hydro's application reflects a limited consideration of long-term financial and system planning issues. In particular, Hydro has failed to supply a long-term financial plan along the lines required by the Board in P.U. 7 (2002-2003), and has inappropriately focused on short-term considerations in their decision not to continue the industrial Interruptible B rate despite the long-term system benefits that this type of capacity-shedding rate can provide.

The proposed rate design reflects an unreasonable (and potentially unintended) outcome as loads vary from GRA forecasts. The provisions regarding billing demands in the industrial contracts in particular are unduly onerous compared to rate designs for industrial customers in other jurisdictions, and compared to the treatment of NP load variation. The complicating factor of the Rate Stabilization Plan on load variations further detracts from any consistent or principled tracking of the costs load variations (particularly NP's) impose on the system.

In order to address the above concerns, this review in summary provides the following recommendations for the consideration of the Board:

1. The material effective increases in certain categories of revenue requirement since 2002, in particular operating and maintenance expenses, depreciation, return on debt and return on equity, reflect the need for a more thorough assessment of Hydro's operating costs and capital investment pace as they relate to rates. (Section 5)
2. There does not appear to be a reasonable basis at this time for Hydro's ratepayers to be faced with higher rates to reflect progression towards treating Hydro as equivalent to an investor-owned utility. (Section 5)
3. Assignments of the Burin Peninsula transmission assets and the GNP generation to common appears to be inappropriate, and reflect a cost allocation that is not consistent with the relative benefits that these assets provide to the various customer classes. (Section 6)
4. NP load forecasts need to be reviewed further in the proceeding to assess the extent to which NP's peak demands as currently forecast result in a reasonable allocation of demand costs, particularly in the context that the 2002 actual cost of service showed that the IC group paid more than $5 million in excess of its measured costs in 2002 and that NP paid almost $5 million below the amounts that should have been collected through rates.
5. Longer-term rate stability objectives suggest a need to assess the current application in the context of the rate adjustments forecast for the next number of years (a substantial increase in rates is forecast in the near term followed by a general reduction over the 2005 to 2007 period). (Section 6)
6. A NP two part rate should reflect Option B of Exhibit RDG-2, with a revised definition of "generation credit" to normalize hydraulic generation.
7. Industrial customer firm demand should reflect the greater of actual peak demand for the month or 80% of the peak established in the previous winter.
8. Industrial customer non-firm energy rates are reasonable as proposed, but non-firm demand should not attract any demand charges.

9. The RSP should be restructured as follows:
    a. The hydraulic component should be a separate fund with no collections or refunds until such time as a given trigger (plus or minus) is reached.
    b. The load variation component should be terminated. The residual balance should be incorporated into the fuel cost fund
    c. The fuel cost variation should be a separate fund. This fund should reflect the most timely pass-through of higher fuel costs that the Board determines is acceptable in light of concerns about rate predictability.
    d. The hydraulic and fuel cost funds should attract (or pay) interest at short-term debt rates.
    e. All riders for the fuel cost and hydraulic funds should be applied on an equal basis per kW.h to IC, NP and Rural.
10. The Interruptible B program should be continued status quo, and Hydro should be directed to study possible benefits arising from expansion of the program to other industrial customers.

Issues arising from Hydro's filing underline the relevance and role of the Board in ensuring that rates charged are fair and reasonable and consistently determined on a principled basis. The role of the Board in this regard is particularly relevant to large industrial power users who undertake substantive long term investment in the province.

## 2.0 INFORMATION ON ISLAND INDUSTRIAL CUSTOMERS

The Island IC group is comprised of large energy customers who operate with high load factors (i.e. they have relatively comparable levels of energy use throughout the day and throughout the year).

These customers are forecast to purchase over 1350 GW.h of electricity in 2004, or about 20% of the energy sold by Hydro at rates regulated by the Board, at a cost of over $65 million in 2004[1]. This represents a decrease in energy of about 2% from 2002 forecast levels, but an increase in costs of approximately 30%[2]. In each case, electricity costs make up a substantial portion of the operating costs of the customer's operation. In two cases, the customers have material hydro self-generation capability which can be from time to time used to supply surplus power to Hydro.

Industrial Customer concerns are focused around the following:

- Long-term stability and predictability in electricity rates.
- Fair allocation of costs between the various customer classes to be served, including a fair interpretation of the legislative limitation on industrial customer rates from funding the rural subsidy.
- Flexibility to tailor electrical service options to suit their operation 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.).
- Protection for customers from risky or government-initiated ventures or supply options that are not consistent with the provincial power policy objectives of efficiency and equitable power supply at the lowest possible cost.
- Lowest cost for power that can be achieved within the above considerations.
- Continued reliability of power supply for Island Interconnected customers.

Industrial customer concerns reflect the size of their capital investments in Newfoundland and Labrador, the long-term perspective essential to such investments and the major stake that these investments typically have in continued large-scale power purchases from Hydro. In addition, the industrial customer concerns reflect competitive pressures associated with selling industrial products to external markets.

[1] Includes forecast 2004 IC RSP adjustment of 1.04 cents/kW.h.

[2] The full year forecast rates for IC per Schedule D of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) yield $46.8 plus an RSP adjustment per P.U. 7 (2002-2003) of 0.28 cents/kW.h applied to firm load of 1,388.8 GW.h per Schedule G of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) yields $50.7 million on an annualized 2002 basis.

# 3.0 OVERVIEW OF HYDRO'S APPLICATION

Hydro's Application requests the Board's approval of matters in the following broad areas:

1. The rates to be charged for the supply of power and energy to Hydro's Wholesale Customer (NP), Hydro's Rural Customers and the IC as of January 1, 2004.
2. The rules and regulations applicable to the supply of electricity to Hydro's Rural Customers.

In contrast to the 2001 proceeding, Hydro apparently does not seek approvals for the contracts setting out the terms and conditions applicable to the supply of electricity to the IC[3], and has not included in the application any materials in relation to the Hydro's Capital Budget for 2004 or beyond. We are advised that a decision is pending from the Board on the 2004 Capital Budget of Hydro following a hearing recently conducted directed solely to that budget.

The Application is made pursuant to the Public Utilities Act (R.S.N. 1990, Chap P-47) the Electrical Power Control Act 1994 (EPCA, 1994) (S.N. 1994, Chap E-5.1), and the Hydro Corporation Act (R.S.N. 1990, Chap H-16).

## 3.1 CONTENTS OF THE APPLICATION

The Application filed by Hydro at May 21, 2003, as well as the Amended Application of August 12, 2003 are comparable in form and presentation to the 2001 application. The Application includes the rate schedules that Hydro proposes to apply starting in January 2004 and the rules and regulations regarding supply of power that Hydro proposes to apply starting January 2004.

Hydro has also filed pre-filed testimony of various staff and experts to address specific items which Hydro has chosen to expand upon.

Compared to the 2001 Application, Hydro's current Application reflects a number of material changes:

- ***Return on Equity:*** Hydro's August 12, 2003 revision to the current application reflects a proposal for a return on shareholder equity ("ROE") of 9.75%, equal to the return provided to the investor-owned utility Newfoundland Power (Hydro's May 2003 application had proposed a 10.75% ROE). This is a change from the 2001 application, which provided evidence that a fair Return on Equity for Hydro would be 11 to 11.5%[4] but only requested the Board to approve a Return on Equity of 3%.

- ***Price of #6 Fuel:*** Hydro's current application proposes to set rates based on a forecast 2004 price of #6 fuel of $29.20 per barrel, which is the forecast cost of #6 fuel for 2004 provided by Hydro's experts. In contrast, the 2001 application forecast a test year price of #6 fuel of $28 per

[3] Per IC-50.

[4] Wells, 2001 application, page 14.

barrel but only requested rates set based on a $20 per barrel price to mitigate short-term rate impacts, with the remaining $8 per barrel price of fuel proposed to be charged to the RSP for later recovery from customers. The Board's Decision in P.U. 7 (2002-2003) reflected the full updated forecast price of fuel in 2002 rates – the current application is consistent with that approach.

- ***System Costs Reflect Required Generation Plant:*** Hydro's current application, in the evidence of Haynes, reviews the current plant in service and its ability to service the forecast loads. The analysis indicates that the current plant is sufficient to meet all forecast loads until 2009 for energy and 2011 for capacity. In contrast, Hydro's 2001 application reflected a deficit in both capacity and energy supply for the test year, resulting in a plant in service that was calculated to be not of sufficient magnitude to properly service the test year loads.

- ***Review of Proper Cost-of-Service Assignment:*** Hydro's 2001 application reflected a proposed cost assignment of certain plant, primarily the Great Northern Peninsula ("GNP") interconnection and other radial transmission systems, that was not based on any reasonable analysis of whether the assets in fact provided any benefits to the customers to whom Hydro proposed to assign the costs. In the current application, Hydro has conducted an assessment of these radial transmission systems in an attempt to determine a proper cost allocation based on the relative benefits they provide to each customer group.

- ***Industrial Contracts:*** The 2001 application included proposed industrial contracts to govern the terms of service to the four industrial customers. The current application does not include any such contracts, and Hydro noted in IC-50 that it is not proposing any revisions to these documents from that last approved by the Board. Hydro also does not include any request to the Board to terminate the existing rate provided to Abitibi Stephenville for interruptible capacity (Interruptible B), even though Hydro proposes not to renew the rate for the winter of 2003/04[5].

- ***NP two part rate:*** The present application sets out an approach that could be used to develop a two-part (demand and energy) rate for NP, and Hydro indicates that it could implement this rate in 2004[6], even though the application does not request approval for the rate. Hydro's 2001 application indicated that, in response to the Board's repeated direction to develop an appropriate two-part rate to NP, it had reviewed the matter with NP and the two utilities had concluded that it was not appropriate.

## 3.2 ISSUES ARISING FROM THE APPLICATION

A number of key issues arising from the Application have been identified to date. These are reviewed in subsequent sections of this testimony under the following topics:

1. **Context:** The context for the Application and for review of the Application reflects a material change in Hydro's situation since the 2001 proceeding. The key contextual changes since 2001,

[5] IC-194.
[6] PUB-150.

particularly in regards to Island Interconnected system supply, are reviewed in section 4 of this evidence.

2. **Revenue Requirement and overall rate increases:** The overall revenue requirement and level of rate increases reflect materially higher costs than the approved revenue requirement for the 2002 test year. These and other matters related to regulated revenue requirements are reviewed further in section 5 of this evidence.

3. **Cost of Service:** The relative rate increases that have been requested from the various classes are calculated using a particular methodology that does not fully reflect the changes to Hydro's system supply since 2002 as well as current capacity surplus and load patterns. These matters are reviewed further in section 6 of this evidence.

4. **Rate Design and the Rate Stabilization Plan (RSP):** The collection of each customer's calculated portion of the revenue requirement reflects a certain structure for rates, which can have substantial impacts on the amounts customers end up paying under various conditions. Hydro's rate design for IC also requires an assessment of various matters in the industrial contracts, including the determination and billing for "Power on Order". In addition, the amounts customers pay is increasingly made up of material charges related to the RSP**.** Terms for operation of the RSP are included under the rate schedules included in Volume I of the Application. Matters relating to Rate Design and the RSP are reviewed further in section 7 of this evidence.

# 4.0 CONTEXT FOR REVIEW OF THE APPLICATION

This is Hydro's second review before the Board since the implementation of the new regulatory regime established for Hydro during the mid-1990s. The first review occurred in 2001, approximately 24 months ago.

The primary context for the current application, and the bulk of the issues that appear to arise from the current application, relate to the supply of bulk power on the Island Interconnected system. This reflects both Wells' assertion that the increases in costs largely arise due to new power sources coming on line, as well as major changes to the relationship between the generation plant available compared to the medium-term forecast island interconnected loads.

Newfoundland Hydro's Island Interconnected System is a mix of hydroelectric and thermal generation. Consistent with other non-interconnected hydro-thermal systems in Canada, Hydro appears to dispatch the system to maximize the energy generation from hydraulic resources and to minimize spilled water at these units. Holyrood thermal generation is dispatched as required to meet peak demand and energy requirements (based on longer-term forecasts of hydroelectric plant reservoirs and prudent water management), with a number of small and expensive peaking thermal units being available to assist in meeting critical extreme winter peaks. However the amount of energy produced by these peaking generators is to be minimized.

Correspondingly, variations in energy loads on such a system that is not interconnected to any other off-Island grid, result in easily quantifiable incremental impacts on fuel costs (particularly at Holyrood) when they occur during normal load periods, and very low incremental costs should they occur at times when surplus hydroelectricity is available (i.e. when Hydro would otherwise be spilling water as a result of other constraints, such as environmental). As a result, incremental energy sales programs, such as the industrial interruptible rate proposed by Hydro, can be priced appropriately to reflect these two conditions.

In comparison to the 2001 application, Hydro now forecasts that their current plant in service, and included in revenue requirement, is sufficient to meet all Island Interconnected loads until 2009-2011[7]. In order to ensure the system can meet the required supply under a variety of conditions, Hydro utilizes two planning criteria:

1. the energy available on the system from hydraulic sources and Holyrood, assuming a low water year, has to be sufficient to meet all forecast energy requirements, and
2. the capacity available on the system has to be sufficient to ensure a Loss-of-Load-Hours ("LOLH", a measure of system reliability) of no more than 2.8 hours per year[8].

---

[7] Hydro's application at Haynes, page 37 states that their next major plant expansion will be planned for 2010; however more recent information indicates an apparent commitment by Hydro to a large (25 MW) wind project in the near future.

[8] Haynes, page 36.

The test year system conditions reflected in Haynes, Table 8, are an energy surplus of 202 GW.h (almost the entire energy output of Granite Canal) and an LOLH of 1.1 hours. In other words, the current 2004 test year generation and transmission complement (and the 2004 test year revenue requirement) reflects a plant in service that is in excess of what is considered by Hydro to be required to properly service the 2004 loads.

In assessing Hydro's application package, and normal regulatory approaches to rate review for utilities of this nature, it is useful to consider approaches used in jurisdictions with utilities in similar overall conditions. The key characteristics of Hydro's system and corporate structure provide for identification of useful Canadian benchmarks in regards to revenue requirement issues, cost of service and rate structures. It is apparent that two Canadian jurisdictions have direct comparability to Hydro's Island Interconnected system in both physical layout (non-interconnected grid, i.e., not connected to any system for importing/exporting power, utilizing a mixture of hydraulic and thermal generation) and corporate structure (Crown-owned vertically-integrated, rate-regulated utilities primarily serving wholesale and industrial customers, but with some retail customers in smaller centres) – the Yukon Energy Corporation and the Northwest Territories Power Corporation. In addition, a second contingent of utilities share corporate structure similarities (Crown-owned vertically integrated, rate-regulated dominant utilities in their jurisdiction) but are not non-interconnected. In this case, useful comparisons for specific issues can be made to Manitoba Hydro[9], BC Hydro[10] and New Brunswick Power[11]. Where relevant, the comparable practices from a number of these other jurisdictions are highlighted within this submission.

## 4.1 FOLLOW UP TO 2001 APPLICATION

The current application is filed in part to address the requirements of P.U. 7 (2002-2003) coming out of the 2001 proceeding. That 2001 application was the first general review of Hydro's rates in nearly a decade, and the first under the new regulatory regime established for Hydro during the mid-1990s. As was to be expected given the large number of issues to be addressed, a number of issues raised in that proceeding were not fully canvassed or finalized by the time of the Board's Order. It was however, a first step in establishing "a stable regulatory environment"[12], and, as noted by the Board in P.U. 7 (2002-2003) "completes the first phase in the process to effectively regulate NLH"[13]. Specifically, the Board stated "The Board notes as well that this decision sets out several directives which are designed to lay the groundwork for the next phase on regulating NLH"[14] and noted Hydro's actions to "place the Board

[9] Manitoba Hydro until recently was more directly comparable in that it serviced both wholesale and retail customers. With the recent purchase of Winnipeg Hydro, the utility has an increased retail customer load and no wholesale customers.

[10] BC Hydro's rate regulation has been essentially suspended for much of the 1990s until very recently. It is currently undergoing a re-regulation, but there is little of relevant value from that rate review process to date.

[11] New Brunswick Power is undergoing a major re-structuring that is proposed to eliminate the vertically integrated nature of the Crown utility.

[12] P.U. 7 (2002-2003) page 161.

[13] Page 163.

[14] Page 163.

on notice that financial targets and other measures contained in the Application are temporary and will be fully addressed in the next application, scheduled for 2003"[15].

It is apparent that this 2003 proceeding is properly viewed as both a follow-up to the more interim nature of the 2001 proceeding, and at the same time a review to focus on longer-term plans and practices for Hydro. This view is consistent with the general IC inclination to focus on long-term rate stability and predictability.

Most notably, the 2003 review contrasts with the 2001 review in the following ways:

- ***Energy Policy Review:*** At the time of the 2001 proceeding, the Government of Newfoundland and Labrador had announced an intention to conduct an "Energy Policy Review" but had not released any final conclusions regarding the review. A number of material questions from the 2001 proceeding were left unaddressed pending resolution of this Energy Policy Review process. Examples from the Board's Order P.U. 7 (2002-2003) include the demand-energy rate for NP, overlap of services between Hydro and NP, a long-term plan for Hydro's financial structure, and the Rural Deficit. The Energy Policy Review process appears to have progressed since 2001[16], and although apparently not completed, the scope of the review appears to have been clarified.

- ***Financial Targets:*** Hydro's 2001 Application reflected a proposal for return on equity that was predicated on two factors. One was an assertion by Hydro that it "must and should have a normal return on equity in due course"[17] and a determination by Hydro that in assessment of this ROE "the corporation should not be viewed differently than any other utility, operated as a commercial entity, whether it be investor-owned or, as in the case of Hydro, Crown-owned", which, it asserted, would entail an ROE in the range of 11 to 11.5%. The second reflected Hydro's intent to "assist in offsetting the rate impacts resulting from increased fuel costs" by proposing a 3% ROE. In the Board's Decision from that proceeding, in regards to the request by Hydro to be treated as an investor-owned utility, it noted "NLH's request is premature in the absence of a sound plan by NLH of how it will achieve financial targets similar to an investor owned utility"[18]. In the current proceeding, Hydro has applied for a full return on equity equal to that provided by the Board to the investor-owned utility NP. Presumably, Hydro has determined it has satisfied the Board's requirement that a long-term sound financial plan be in place before ROEs of this type will be approved.

- ***Rate Stabilization Plan:*** The 2001 proceeding contained a significant quantity of review and analysis of the Rate Stabilization Plan operated by Hydro. In P.U. 7 (2002-2003), the Board noted "the concerns and issues surrounding the RSP raised by the intervenors, especially the CA and the IC, in particular concerns about the complexity of the plan and the interactions of the various components of the plan, especially the inclusion of the load variation provision". The Board

[15] Page 21.
[16] A Report on the Energy Policy Review was released in March 2002 along with a Stakeholder Consultation document, and Summary of Public Responses was provided in August 2002.
[17] Wells, 2001 Application, page 15.
[18] Page 42.

concluded that the "design and elements of the existing plan should be reviewed"[19]. At this time, the revised "new RSP" has been in operation for nearly a year and the first collection of these amounts is set to begin at January 1, 2004. It is apparent that the RSP has become an increasing source of rate instability, resulting in nearly half the 2004 rate increases to NP and more than half the increases to IC. The current proceeding will be required to review and provide confirmation of the balances in the New RSP, as well as address the appropriate means for collection of these balances in a stable way going forward.

- ***Interim Allocation of Certain Assets:*** The 2001 proceeding reviewed the cost of service allocation of a number of assets, primarily the Great Northern Peninsula transmission line (but also GNP generation, Burin Peninsula transmission, and Doyles-Port aux Basques transmission). In P.U. 7 (2002-2003), the Board concluded that it was "not prepared to confirm the change in assignment from NLH rural to common" proposed by Hydro. The Board required Hydro to undertake a study of the value of these assets to the grid in determining the proper cost of service allocation. In the present proceeding, the review by Hydro has been completed and filed, and final cost allocations for these various assets is required.

Many of the issues to be addressed in this proceeding reflect an opportunity to make incremental improvements over the 2001 approaches. As noted above, the Hydro's physical Island Interconnected infrastructure now reflects a stable plant that can service the needs of the grid beyond the short-term (until approximately 2010). Similarly, long-term and durable solutions to outstanding problems or details identified in this submission (i.e., cost of service, rate design, RSP) are required to likewise bring longer-term regulatory and rate stability to the system.

[19] Page 84. The Board's Decision notes that the Board would commission this study. We have not had the opportunity to review the results of any such study undertaken.

# 5.0 REVENUE REQUIREMENT AND OVERALL RATE INCREASES

The overall revenue requirement and level of rate increases requested are outlined by Hydro as "primarily driven by" increased costs associated with new sources of supply[20] and indicate that this will have the "largest single impact on rates for Hydro's customers arising from this application"[21]. Hydro indicates that the following factors impose material impacts on revenue requirement:

- power purchase costs, including new Power Purchase Agreements (PPAs) involving new facilities), will increase in 2004 by $18 million compared to the 2002 test year; and
- Granite Canal will increase costs by $11 million[22].

The addition of the new plant (i.e., Granite Canal and new PPAs) results in 87.3 MW of new capacity and 461.2 GW.h of new energy. Hydro also notes that other cost increases are putting upward pressure on revenue requirement in 2004, such as return on equity, interest costs and operating costs.

Looking specifically at the Island Interconnected system, there has been a material shift in revenue requirement by replacing bulk power costs that had previously been reflected primarily as #6 fuel[23] with costs that primarily arise as purchased power for the new PPAs, and return on debt, equity and depreciation for Granite Canal. As reviewed below, however, only 15% of the requested rate revenue increase for the Island Interconnected system reflects the new Granite Canal supply, the new PPAs and load growth since 2002. A further 35% of this increase reflects other increased energy generation supply costs, e.g. increased costs for fuel (primarily #6) and other purchased power costs.

It is also apparent that about 50% of the Island Interconnected rate increase requested does not relate in any way to Granite Canal, the new PPAs, the costs to supply load growth since 2002, or any other fuel cost or purchased power cost matters. As reviewed below in detail, this component of the revenue requirement increase is instead comprised of material increases in operating and maintenance expenses (7.9% over 2002), depreciation (6.7% outside of Granite Canal), interest costs (6.5% outside of Granite Canal) and return on equity (125% outside of Granite Canal). Within the context of only a two year interval since Hydro's last review, and record low inflation and debt financing rates, these increases suggest that it is relevant for the Board to assess the extent to which more rigorous cost control, capital spending restraint and productivity improvements are required within the utility.

The overall changes requested to the revenue requirement are reviewed below. Associated issues related specifically to the allocation of revenue requirements to different customer classes through cost-of service (COS) allocations, proposed rates and the RSP are addressed in subsequent sections of this testimony.

[20] Wells, page 1.
[21] Wells, page 2.
[22] Wells, page 2.
[23] See IC-204 and IC-205.

## 5.1 OVERVIEW OF PROPOSED REVENUE REQUIREMENT CHANGES

The proposed 2004 Hydro revenue requirement set out in Roberts Schedule II (1st revision) is $371.841 million. This is an increase of $54.781 million from the approved 2002 test year revenue requirement of $317.060 million (also shown in Roberts, Schedule II).

Looking specifically at the Island Interconnected system, the revenue requirement is more readily determined from the cost of service study. In particular, the respective cost of service studies and rate revenue schedules from 2002 and 2004 (1st Revision) reflect the following information for the Island Interconnected system:

**Table 5.1: Island Interconnected Revenue Requirement and Rate Increase Requirement**

| | **2002 Final** | **2004 Proposed** | ***Change*** |
|---|---|---|---|
| Revenue Requirement[24] | $277,077,901 | $327,951,968 | *$50,874,067* |
| Rural Deficit and Revenue Credit[25] | $16,137,310 | $17,317,373 | *$1,180,063* |
| Revenue to be collected through rates[26] | $293,215,211 | $345,269,341 | *$52,054,130* |
| Revenues at approved 2002 rates[27] | $293,215,211 | $305,545,600 | *$12,330,389* |
| Shortfall | $0 | $39,723,741 | *$39,723,741* |

The summary table above indicates that the requirement for higher rates to the Island Interconnected system reflects a need for $39.723 million in additional revenues compared to existing rates in place. We note that the revenue requirement above does not reflect an additional $5.97 million in costs (largely fuel) that would arise if the Board adopts SGE Acres recommendation regarding long-term normal hydraulic plant output[28].

In assessing the reasonableness of the Island Interconnected revenue requirement increases proposed by Hydro, there are three major items that are not readily isolated from the information in Roberts, Schedule II (or the cost of service study, page 1):

- ***Load growth:*** There has been a fairly material load growth on the Island Interconnected system by 2004 compared to the 2002 forecast, leading to a nearly 4.2% increase in the revenues Hydro receives at the rates currently in place (or about $12.33 million as noted in the table above).

---

[24] Page 1 of Schedule G of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) for 2002 figures. Exhibit RDG-1 (1st revision) for 2004 figures.

[25] The additional amounts to be collected from overall Island Interconnected rates to finance the non-Island Interconnected Rural Deficit (i.e. reflects net impact of higher rates for NP to finance Rural Deficit and lower rates for Rural Interconnected as a result of Rural Rates policy).

[26] Table 2 of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) for 2002 figures. Table 4 of Banfield (1st revision) for 2004 figures. Includes rural deficit allocations, and excludes wheeling revenues.

[27] Table 2 of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) for 2002 figures. Table 4 of Banfield (1st revision) for 2004 figures. Includes rural deficit allocations, and excludes wheeling revenues.

[28] Haynes, page 30.

Associated with this increased load are costs to supply the load, particularly fuel, but also other variable costs.

- ***Sources of Supply:*** Two new sources of supply have been introduced since the 2002 test year:

    1. Granite Canal and
    2. the two new Power Purchase Agreements (PPAs).

    These new bulk power sources result in a shift in Hydro's costs compared to 2002. These sources of supply represent energy that would otherwise, in all likelihood, have had to be generated by fuel at Holyrood[29]. In other words, the comparison of 2004 revenue requirement to 2002 revenue requirement will indicate a substantial shift in costs primarily from #6 fuel and interruptible capacity purchases[30], to such items as Purchase Power costs (for the PPAs), and Depreciation, Interest and Return on Equity for Granite Canal.

A review of the 2004 proposed revenue requirement is most usefully focused on assessing Hydro's 2004 costs in terms of changes from the approved 2002 revenue requirement in two areas: changes related to the three major bulk power changes noted above, as opposed to changes related to other factors.

In determining the specific impact from each of the above three major bulk power factors, it is assumed that, in the absence of Granite Canal and the new PPAs, this generation would have been provided by Holyrood. Likewise, it is assumed that had the load growth not occurred, the reduced generation requirement would have been reflected in reduced generation required from Holyrood. Each of these assumptions is consistent with the Island Interconnected system operation; that is, load growth is basically supplied by increased generation at Holyrood[31], and new sources of supply do result in comparable quantities of generation avoided at Holyrood[32].

In assessing the degree to which the Island Interconnected revenue requirement and rate increase requirement has been driven by these three major factors, the following specific impacts have been noted:

---

[29] IC-204 and IC-205.

[30] Hydro asserts in IC-194 that the acquisition of new power from Granite Canal and the PPAs eliminates the need for the Interruptible B contract, which is reflected in the proposed revenue requirement as a $1.297 million savings compared to the 2002 test year.

[31] Consider, for example, the current treatment of load in the RSP, which assume all load variations result in equal variations in the quantity of thermal generation from Holyrood.

[32] IC-204 and IC-205.

- ***Granite Canal***[33]***:*** The in-service of Granite Canal by 2004 results in 224.0 GW.h of energy being produced by hydraulic generation rather than Holyrood[34]. The construction of Granite Canal has resulted in test year costs of $11.84 million per IC-251 (depreciation, return on equity and debt, and new hydraulic O&M), but savings of $10.483 million of Holyrood fuel and $1.008 million of Holyrood variable O&M[35]. Hydro has also proposed to eliminate the Interruptible B program as a result of the new generation, which results in an additional saving of $1.297 million in purchased power costs. The net impact of Granite Canal on the 2004 test year revenue requirement is a decrease of $0.948 million.

- ***PPAs***[36]***:*** The new Power Purchase Agreements result in additional costs to Hydro of $18.367 million in the 2004 test year for 237.2 GW.h of electricity. The Holyrood fuel and variable O&M savings as a result of these PPAs $11.101 million and $1.069 million respectively. The net impact of the PPAs in the test year is an increased 2004 revenue requirement of $6.197 million.

- ***Load growth of 254.2 GW.h***[37]***:*** The growth in load since the 2002 test year has driven a material increase in the #6 fuel and variable Holyrood O&M. The 2002 final cost of service indicates MW.h at generation of 6,483,046[38] compared to a 2004 MW.h at generation of 6,737,249[39], reflecting a load growth of 254.2 GW.h. Using the variable Holyrood costs from NP-130, this equates to an increased fuel cost to the Island Interconnected system of $11.90 million for fuel plus $1.14 million for variable O&M, or a total increased cost of $13.04 million.

A calculation of the portion of the 2004 Island Interconnected revenue requirement and rate increase requirement that is driven by the above factors as opposed to other matters is provided in Table 5.2.

---

[33] Assuming the same quantity of energy had been supplied by Holyrood at the variable fuel and O&M costs outlined in NP-130. Assuming also that this would have eliminated Hydro's ability to propose an end to the Interruptible B program. We note from IC-374 that the variable O&M numbers in NP-130 are Hydro's planning estimate for costs (or savings) arising from variation in Holyrood generation for such items as system equipment maintenance and fuel additives. Hydro cautions this is not a short-term number. However, there are clearly savings from reduced Holyrood generation (or additional costs from increased Holyrood generation) and the 0.45 cents/kW.h is the best estimate available. It is also somewhat below the additional variable costs that IC face for non-firm purchases over and above the full costs of Holyrood fuel (which is a 10% premium over the Holyrood fuel costs of a forecast 4.68 cents/kW.h).

[34] IC-204 and IC-205.

[35] Using variable Holyrood fuel and O&M figures from NP-130.

[36] Assuming the same quantity of energy had been supplied by Holyrood at the variable fuel and O&M costs outlined in NP-130.

[37] Assuming all increases in quantity of bulk energy required from 2002 to 2004 were met by increases Holyrood generation at the variable fuel and O&M costs outlined in NP-130.

[38] Schedule G of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003), Schedule 3.1A column 4.

[39] Per RDG-1 (Rev.1) Schedule 3.1A column 4.

**Table 5.2: 2004 Island Interconnected Revenue Requirement versus Approved 2002 Revenue Requirement – Impact of Major Bulk Power Items versus other Factors**

| | | A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **(A-B)** | *Major Bulk Power Changes* | | | | | | **sum (D:I)** | **(C-J)** |
| | *($000)* | 2004 (Rev.1) rev. req.[40] | 2002 approved revenue req.[41] | *difference* | *Granite Canal[42]* | | *PPAs[43]* | | *load growth[44]* | | *difference – Major Items* | *difference – other* |
| | | | | | *costs* | *benefits* | *costs* | *benefits* | *costs* | *benefits* | | |
| **1** | OM&A[45] | 72,461 | 67,977 | *4,484* | *30* | *(1008)* | | *(1,069)* | *1,144* | | *(903)* | *5,387* |
| **2** | #6 Fuel | 84,820 | 81,662 | *3,158* | | *(10,483)* | | *(11,101)* | *11,897* | | *(9687)* | *12,845* |
| **3** | Diesel Fuel | 55 | 39 | *16* | | | | | | | | *16* |
| **4** | Gas Turbine Fuel | 265 | 351 | *(86)* | | | | | | | | *(86)* |
| **5** | Power Purchases | 29,928 | 11,773 | *18,155* | | *(1,297)* | *18,367* | | | | *17,070* | *1,085* |
| **6** | Depreciation | 27,885 | 25,649 | *2,236* | *510* | | | | | | *510* | *1,726* |
| **7** | Expense Credits | (1,406) | (885) | *(521)* | | | | | | | | *(521)* |
| **8** | Subtotal Expenses | 214,007 | 186,566 | *27,442* | *540* | *(12,788)* | *18,367* | *(12,170)* | *13,041* | | *6,990* | *20,452* |
| **9** | Disposal Gain/Loss | 515 | 875 | *(360)* | | | | | | | | *(360)* |
| **10** | Subtotal ex. Return | 214,523 | 187,441 | *27,082* | *540* | *(12,788)* | *18,367* | *(12,170)* | *13,041* | | *6,990* | *20,092* |
| **11** | Return on Debt | 98,968 | 83,978 | *14,990* | *9,540* | | | | | | *9,540* | *5,450* |
| **12** | Return on Equity | 14,462 | 5,659 | *8,803* | *1,760* | | | | | | *1,760* | *7,043* |
| **13** | Total Rev. Req. | 327,952 | 277,078 | *50,875* | *11,840* | *(12,788)* | *18.367* | *(12,170)* | *13,041* | | *18,290* | *32,585* |
| **14** | Rural Deficit | 17,317 | 16,137 | *1,180* | | | | | | | | *1,180* |
| **15** | Total | 345,269 | 293,215 | *52,055* | *11,840* | *(12,788)* | *18,367* | *(12,170)* | *13,041* | | *18,290* | *33,765* |
| **16** | Rev. at exist. rates | 305,546 | 293,215 | *12,331* | | | | | | *12,331* | *12,331* | |
| **17** | Rate incr. req. | 39,723 | 0 | *39,723* | | | | | | *(12,331)* | *5,959* | *33,765* |

[40] From Exhibit RDG-1 (Rev.1), Schedule 1.1.

[41] From the final 2002 cost of service, Schedule G of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003).

[42] The Granite Canal costs are per IC-251. It is not clear if the Return on Equity and Return on Debt components of IC-251 reflect RDG-1 or RDG-1 (Rev. 1). The above assumes the figures include the Revision 1 changes (the Return on Equity and Return on Debt figures in IC-251 do not exactly appear to reconcile with the $134,550,000 total capital cost applied to the WACC using either the original WACC or the Revision 1 WACC). The difference is likely to be quite small.

[43] PPA costs are per Haynes, Schedule X.

[44] Reflects 254.2 GW.h at the variable cost rates set out in NP-130.

[45] Operating Maintenance and Administration.

Table 5.2 details the $39.723 million Island Interconnected rate increase requirement from Table 5.1. This reflects a required $5.959 million rate increase to address the impact of three major bulk power supply developments: Granite Canal, the new PPAs and the load growth since 2002. The remaining $33,765 million Island Interconnected rate increase requirement reflects the following notable components:

- ***Operating, maintenance and administration expenses:*** The final approved 2002 operating, maintenance and administration expenses were $67.977 million. Proposed 2004 test year expenses are $72.461 million, an increase of $4.484 million. However, the proposed $4.484 million increase fails to reflect material savings that should arise in 2004 due to the new generations sources:
    - The in-service of Granite Canal should have increased hydraulic O&M by $0.03 million but reduced Holyrood O&M by approximately $1.008 million for reduced Holyrood output, for a net benefit to 2004 of $0.978 million.
    - The PPAs should have reduced Holyrood O&M by approximately $1.069 million
    - However, the load growth since 2002 should result in additional Holyrood O&M of approximately $1.144 million

  Net of the above amounts, the 2004 proposed operating, maintenance and administration expenses reflect an increase of $5.387 million or about 7.9% over 2002 levels.

- ***Fuel and Purchased Power:*** The 2004 test year fuel costs reflect an increase of $3.088 million over 2002 levels, primarily #6 fuel. Purchased power expense is forecast to increase $18.155 million over 2002 levels. The three major items reflect a likely saving of about $9.687 million in #6 in 2004 and account for $17.070 million of the purchased power expense increase. Absent these three items, increased costs for fuel and purchased power total $13.860 million, or 14.8%, compared to 2002.

- ***Depreciation expense:*** The 2004 depreciation expense of $27.885 million is a $2.236 million increase over 2002 levels. Granite Canal accounts for $0.510 million of the increase depreciation expense, leaving $1.726 million (a 6.7% over 2002 levels) related to other items.

- ***Return on Debt and Equity:*** The 2004 proposed revenue requirement reflects an increased cost for debt and equity of $14.990 million and $8.803 million respectively compared to 2002. Of this amount $9.540 million and $1.760 million relates to costs of debt and equity for the Granite Canal projects. Absent this one project, Hydro's costs have increased since 2002 by $5.450 million for debt and $7.043 million for equity, reflecting increases of 6.5% and 125% respectively.

- ***Rural Deficit:*** The 2002 Island Interconnected rates reflected $16.137 million in excess of measured Island Interconnected costs related to the Rural Deficit from other systems. The Rural Deficit from other systems allocated to the Island Interconnected system has increased by $1.180 million in the 2004 application compared to 2002, up to $17.317 million.

In summary, Table 5.2 indicates that $5.959 million of the requested $39.723 million Island Interconnected rate increase (15%) is due to Granite Canal, the PPAs and load growth since 2002. This is in sharp contrast to Hydro's assertion that these items are the primary drivers of the rate increase requested. An additional $13.860 million (35%) reflects effectively increased costs for fuel (primarily #6) and other purchased power costs.

The remaining 50% of the Island Interconnected rate increase requested effectively reflects increased costs for operating and maintenance expenses, depreciation (outside of Granite Canal), return on debt and equity (outside of Granite Canal) and increased allocation of the Rural Deficit, offset by some small improvement in expense credits and reduced loss on disposals. These increases are in contrast to the summary at Wells, pages 1-3.

The material effective increases in each of these categories since 2002 (excluding Granite Canal, the new PPAs and the impacts of load growth noted above), in particular operating and maintenance expenses up 7.9%, depreciation up 6.7%, return on debt up 6.5% and return on equity up 125%, reflect the need for a more thorough assessment of Hydro's operating costs and capital investment pace as they relate to rates.

## 5.2 RETURN ON EQUITY

Hydro's revised application reflects a proposed return on equity of 9.75%, down from the May application proposal of 10.75%. Per Roberts, Schedule II (Rev. 1) this reflects a total Margin of $19.384 million, down from the May application of $21.179 million. As noted above, the increase in return on equity is a material component of the requested increase to Island Interconnected customers in 2004 (over $7 million of the approximately $40 million rate increase proposed excluding impacts from Granite Canal).

Hydro has also indicated that the Margin proposed in the May 2003 application of $21.179 million results in a regulated Interest Coverage of 1.23[46]. Hydro has not calculated the interest coverage for the revised ROE proposal, but based on the same interest cost balance it would approximate 1.21[47].

In the 2002 proceeding, Hydro requested an ROE of 3%, which was consistent with a 1.08 times interest coverage ratio (Hall, page 10). This was consistent with the interest coverage ratio approved in 1992[48] of 1.08 which had not been adjusted by the Board between 1992 and 2002. During that time, Hydro had reported that they had not had any difficulty arranging debt, or to have had any negative impact on the Province's credit rating[49].

[46] Per NP-2. This is based on $21.175 million margin on an interest cost of $92.764 million.
[47] This is based on $19.384 million margin on an interest cost of $92.764 million.
[48] Board's 1992 Report on Hydro's Rate Referral, page 111.
[49] See, for example, the response to IC-65 from the 2001 Application.

Hydro's proposals to the Board in regards to the level of Margin or ROE have been notably consistent for more than the last decade, and have received a consistent response from the Board, as follows:

- ***1990 Application[50]:*** Hydro indicated a debt:equity ratio of 83:17 in 1989, and indicated a target debt:equity ratio of 75:25. Hydro also requested an interest coverage of 1.15[51]. The Board approved a 1.03 interest coverage ratio for Hydro, and recommended that Hydro move slowly towards a goal of a debt:equity ratio of 80:20.

- ***1992 Application:*** Hydro proposed an interest coverage ratio of 1.10[52], but requested long-term guidance in excess of the interest coverage target proposed for that year, to confirm the long-term target of 1.15 to 1.25. Hydro also presented financial experts to support a debt:equity goal of 80:20, and ***indicated*** that its debt:equity had deteriorated since 1990 from 82:18 to 84:16. The Board allowed a 1.08 interest coverage and denied the request for further guidance[53]. Specifically, the Board again directed Hydro to move slowly towards attainment of the 80:20 debt:equity target.

- ***2001 Application:*** Hydro proposed a 3% ROE, which was equal to a 1.08 interest ***coverage***. Hydro's Application requested guidance that a "normal return on equity" similar to an investor-owned utility would be applied by the Board "in due course"[54]. The reported test year debt:equity ratio was 83:17[55].

  The Board, in P.U. 7 (2002-2003) confirmed the 3% ROE (1.08 interest coverage) for the 2002 test year. The Board also stated that "a determination on full return on rate base can be made based on a future request and in light of economic and capital market conditions prevailing at the time"[56]. Further, the Board concluded that "there is no statutory or evidentiary foundation for regulating NLH similar to an investor owned utility"[57] and concluded that "NLH's request is premature in the absence of a sound plan by NLH of how it will achieve financial targets similar to an investor owned utility"[58]. The Board re-confirmed the short-term target debt:equity ratio of 80:20.

---

[50] Board's 1990 Report on Hydro's Rate Referral, pages 54-69.
[51] Board's 1990 Report on Hydro's Rate Referral, page 61.
[52] Board's 1992 Report on Hydro's Rate Referral, page 74.
[53] Board's 1992 Report on Hydro's Rate Referral, page 111.
[54] Wells, 2001 Application, page 15.
[55] Hall, 2001 Application, page 12.
[56] P.U. 7 (2002-2003), page 44.
[57] P.U. 7 (2002-2003), page 41.
[58] P.U. 7 (2002-2003), page 42. A more specific reference at pages 161-162 of the Decision indicates:

> "Until such time as NLH brings forward its comprehensive financial goals in an application, the Board is not in a position to deal with them. As demonstrated following the review of the evidence in relation to NLH's debt/equity ratio, … the Board notes Government's guarantee remains in place which will ensure NLH the same access to the capital markets that it has traditionally maintained.

The most notable conclusion of the Board in P.U. 7 (2002-2003) in regards to this issue arises at page 40, where the Board notes:

> NLH's position on this issue, however, is developed primarily as a consequence of the evidence and its interpretation of *EPCA*, Section 3(a)(iii) wherein it is the policy of the province … to enable NLH *'to earn a just and reasonable rate of return as constituted under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world'.*
>
> The Board notes NLH's credit rating, as attested to earlier, is dependent on the standing provincial policy which currently guarantees NLH's debt. (P.U. 7 (2002-2003) page 40)

Accordingly, it is not readily apparent how one draws a conclusion that the legislation leads to any required change in debt/equity ratio targets or in required margin/ROE - if anything, Hydro's current Application as well as other available evidence suggest the adequacy of the targets used for Hydro since 1990[59]. We also note that the current application maintains the requirement to collect via rates $14.453 million related to the debt guarantee fee to the Government of Newfoundland and Labrador[60].

In the current filing, there is no evidence that Hydro has addressed the Board's requirements that, prior to treatment as an investor-owned utility (including receiving a Return on Equity comparable to an investor-owned utility), Hydro must present to the Board a sound plan of how it will achieve suitable financial targets[61]. Notably, the 2001 proceeding included evidence that Hydro's 5 year plan was to

---

> NLH's future intention to operate on a standalone basis similar to an investor-owned utility is entirely within the hands of NLH's management."

[59] Addressing the credit rating issue directly, the response to IC-65 from the 2001 Application states:

> "It is impossible to conclude with any degree of precision at what level Hydro's debt ratio would negatively impact on the Province's credit rating. Based on the experience of other Crown Corporations, debt ratios of up to 90% in the short-term have been maintained without negative impact on the Province's credit rating. The debt rating agencies would tend to focus on the utility's ability to fully recover its debt service costs without running the risk of having to turn to the Provincial government for assistance. Stated alternatively, as long as Hydro's debt is guaranteed by the Province, the debt rating agencies' concerns are with assurance that Hydro is self-sufficient, i.e. Hydro will cover its total out-of-pocket costs, including interest expenses, from its own revenues, without risk of a short-fall."

[60] Roberts, Schedule VII.

[61] We also note that there remain a number of sections in the legislation that provide for terms that are otherwise inconsistent with the regulatory framework for investor-owned utilities in the Province and which reduce the discretion of the Board with respect to material matters, including: restriction on the Board in setting Hydro's rate base in section 17(2) of the Hydro Act; restriction on the Board regarding review the liabilities of the Corporation under the Hydro Pension Plan and determining whether such expenses are reasonable and prudent; restrictions on the Board regarding review of foreign currency losses and determining whether such expenses are reasonable and prudent; restrictions on the Board regarding review of ongoing amounts paid under contracts to non-utility generators (from Hydro's Request for Proposals 92-195) and determining whether such expenses are reasonable and

achieve an 82:18 debt:equity ratio by 2005[62]. In contrast, the current five year plan filed in CA-3 indicates a projected 2005 debt:equity of 85:15 progressing to 84:16 by 2007.

Hydro has filed evidence in Wells, Schedule II that maintaining a 75% payout ratio reflecting the current Hydro policy (and as assumed in the application per PUB-87) will not allow it to achieve a debt:equity ratio below 84:16 by 2008 *even if the 10.75% ROE was approved*. As a result, Hydro has proposed a 50% payout ratio to the Government of Newfoundland and Labrador[63]; however, this payout level, combined with a 10.75% ROE, will only achieve an 81:19 debt:equity by 2008. Finally, we note that continuation of a 3% ROE will make no material difference to Hydro's ability to progress on debt:equity levels by 2008 if the 75% payout is maintained (if a 50% payout were adopted, the increase to a 10.75% ROE would allow Hydro to progress to 81:19 by 2008, compared to 83:17 were the current 3% level to be maintained – it is not apparent what a 9.75% ROE would do to these calculations[64]).

Finally, all of the above analysis fails to reflect that Hydro's system planning notes a requirement for 600 GW.h of new energy supply by 2012 (nearly three times the size of Granite Canal)[65]. Capital spending to address the required additions will in all likelihood require substantial new debt issuances, which will only further deteriorate Hydro's debt equity ratio in the period beyond 2008[66]. Hydro has refused to comment on matters related to major capital spending commitments in the 6-10 year timeframe[67].

It is apparent that Hydro and the Board have similarly determined that progress towards an 80:20 debt:equity ratio has been merited since at least 1990. However, the record indicates that all efforts to date by Hydro and the Board have not allowed Hydro to make progress on this matter, and in fact Hydro's debt ratio has deteriorated from the 1990 levels of 83%. Even the most optimistic plans of Hydro (a 10.75% ROE and a reduced payout ratio of 50%) only reflect progress to an 81:19 level by 2008, just prior to a period of expected cash requirements for major investment in generation infrastructure, which would likely lead to deterioration in this ratio.

There does not appear to be a reasonable basis at this time for Hydro's ratepayers to be faced with higher rates to reflect progression towards treating Hydro as equivalent to an investor-owned utility. Progression in other areas such as a sound plan for financial targets, as required by the Board, does not

---

prudent; restrictions on the Board from setting amortization periods in regards to the Hydro Pension Plan expenses and the foreign exchange losses; and, substantial utility operations of Hydro remain "non-regulated" even those directly connected to transmission systems servicing regulated customers.

[62] This is quoted at P.U. 7 (2002-2003), page 42.

[63] Wells, Schedule II, discussion paper page 6 of 7.

[64] The material filed by Hydro on this matter has not been updated to reflect the revised 9.75% ROE proposal.

[65] Hydro's five-year capital plans also reflect no capital expenditures on gas turbines, for example (IC-280) despite a lengthy discussion at Haynes, page 8-9 about the age and condition of these units.

[66] The exception is if these projects are either funded by others (Hydro has declined to comment, for example, on any role for the Government of Canada in transmission interconnections to Labrador (IC-255)) or are solely served by purchased power arrangements, with all developments being undertaken by parties other than Hydro.

[67] See, for example, IC-373, IC-387, IC-388, and IC-389.

appear to have been addressed. In addition, the continued provision of the government guarantee, along with the continued payment by ratepayers of nearly $15 million for this fee, appears to satisfy the requirements of the legislation that the Board provide Hydro with the ability to maintain a sound credit rating.

# 6.0 COST OF SERVICE

Hydro has applied for primary firm rates based on an embedded cost/cost of service based approach, consistent with previous practice in Newfoundland and most other Canadian jurisdictions with regulated power rates. Hydro has also applied for certain non-firm industrial power rates which are based on incremental cost principles.

As noted by Greneman (page 1), the application of normal utility cost and rate principles to the Newfoundland Hydro system has followed the industry standard embedded cost of service approach. In developing the overall revenue requirement that is being sought from each group of customers, Hydro has used a cost-of-service (COS) study with the output provided in Exhibit RDG-1. This study seeks to allocate among the various customer classes Hydro's full revenue requirement.

With a few material exceptions, the overall COS study methodology filed by Hydro appears to be generally consistent with accepted utility regulatory practice in other jurisdictions and the directions of the Board in P.U. 7 (2002-2003), and to accurately track the costs of Hydro's system and the customer classes to which these costs relate.

Concerns arise because Hydro's cost of service study, and the calculation of the revenue requirements to be allocated to each customer class, insufficiently recognizes the current Island Interconnected overall peak capacity supply and configuration in determining which customers benefit from various capacity resources. The current treatment results in two notable issues:

1. **Assignment of certain radial transmission and generation assets as being of benefit to all Island Interconnected customers:** Hydro provides three radial transmission lines (non-230 kV) which service both customer loads and interconnect relatively small generation plant. Hydro now proposes to assign the costs of diesel generation on one such system (the GNP) to all customers and to assign the transmission line itself on another of the systems (the Burin Peninsula) as similarly of common benefit. Each of these assignments appears to be inappropriate, and reflect a cost allocation that is not consistent with the relative benefits that these assets provide to the various customer classes.

2. **The provision of a "generation credit" to Newfoundland Power:** Hydro's cost of service study proposes to provide Newfoundland Power with a "credit" for the thermal generation capacity that Newfoundland Power maintains on the Island Interconnected system. This treatment results in two material changes that shift costs away from NP. One is to reduce NP's forecast peak to in essence give them credit for generation that they do not expect to use. The other is to artificially adjust downward the properly measured and forecast system load factor that Hydro is required to supply to reflect the same factor. Based on normal cost of service

practice in Newfoundland, there is no proper basis to make such an adjustment for either NP's peak demand or the system load factor.

This section reviews the relative changes in rates proposed for each group of customers, the impact of the current Island Interconnected supply situation on the proper application of cost of service principles, and the resulting costs of demand to various customers on the Island Interconnected system. A review of the specific issues with respect to radial transmission systems, the Newfoundland Power generation credit, and NP's Load Forecast and Load Factor follows.

## 6.1 RELATIVE CHANGES IN RATES

A summary of the proposed 2004 test year average rate increases as presented in the Application, in percentage terms, for each of the customer classes is provided in Table 6.1 below:

**Table 6.1 – Base Rate and RSP Changes Proposed in the August 12 Application**

| Customer Class | Firm Base Rates | RSP[68] | Overall Increase |
|---|---|---|---|
| NP[69] | 12.8% | 11.3%[70] | 24.1% |
| IC[71] | 12.0%[72] | 16.4%[73] | 28.4% |
| Rural Island Interconnected[74] | 7.4%[75] | NA | NA |
| Labrador Interconnected | 7.2%[76] | NA | NA |
| Isolated Systems | 7.4%[77] | NA | NA |

[68] RSP rate increases are projected based on 2004 forecast balances in the RSP. NP rate increases at July 1, 2004, IC at January 1 , 2004 per Banfield, 1st revision, page 15-16.

[69] All increases are measured on an annualized basis as a percentage of total existing firm power rates. For NP the amount for 2004 at existing rates is $227,065,646 from Banfield Table 4 (1st revision) plus NP projected RSP at December 31, 2003 at 0.324 cents/kW.h times 4,741 GW.h yields a total annualized revenue of $242,427,782.

[70] July 1, 2004 projected NP RSP rate of 0.902 cents/kW.h compared to December 31, 2003 RSP rate of 0.324 cents/kW.h is an increase of 0.578 cents/kW.h (per Banfield, Table 6 (1st revision). On a total forecast 2004 firm sales to NP of 4,741,400 MW.h yields an annualized increased of $27,405,292.

[71] All increases are measured on an annualized basis as a percentage of total firm power rates. For IC the amount is $45,823,492 from Banfield Table 4 (1st revision) plus IC RSP of 0.423 cents/kW.h times 1,367 GW.h yields a total annualized revenue of $51,609,286.

[72] The IC base rates for wheeling service are forecast to decrease by 4.7%.

[73] January 1, 2004 projected IC RSP rate of 1.04 cents/kW.h compared to December 31, 2003 RSP rate of 0.423 cents/kW.h is an increase of 0.617 cents/kW.h. On a total forecast 2004 firm sales of 1,367,800 MW.h yields an annualized increased of $8,439,326.

[74] Firm rate increases are measured on an annualized basis as a percentage of existing rates.

[75] The 7.4% increase is based on the calculated NP increase to retail customers, as rural interconnected customers pay the same rates as NP customers.

[76] The Labrador interconnected rate changes vary considerably by customer class and location.

[77] Rates for government customers are requested to decrease by 12.6% on the isolated systems.

The rate increases requested by Hydro reflect an onerous impact on customers[78]. It is also notable that, based on the figures above, about half of the increase for NP, and in excess of half for IC, are coming from the RSP increases. In addition, the increases reflect a cost of service analysis that fails to incorporate at least two additional proposals Hydro has put forward: to lower the average hydraulic generation estimate (and raise the total fuel cost in the 2004 revenue requirement) to reflect "the longest reliable reference inflow sequence"[79], and to assign the GNP generation assets as being of common benefit to all Island Interconnected customers, not just Hydro Rural. Adoption of these two proposals would increase the rate increases required from IC and NP.

Rate stability and 'smoothing' objectives indicate the need to assess the Application in the context of its implications for future years. Hydro has provided information extending the NP and IC rate increases beyond 2004 to 2007, based on current forecasts and the impacts flowing from ongoing annual RSP adjustments, as follows (in cents/kW.h)[80].

**Table 6.2 – Average Energy Rates (including RSP) from CA-3 (cents/kW.h)**

| Customer Class | 2003 | 2004 | % | 2005 | % | 2006 | % | 2007 | % |
|---|---|---|---|---|---|---|---|---|---|
| NP | 5.04 | 6.03 | *19.6%*[81] | 6.36 | *5.5%* | 6.29 | *(1.1%)* | 6.07 | *(3.5%)* |
| IC | 3.80 | 4.85 | *27.6%*[82] | 4.98 | *2.7%* | 4.44 | *(10.8%)* | 4.60 | *3.6%* |

It is apparent that rates over the period to 2007 reflect a substantial increase in collections from customers in the near term, followed by a general reduction over the 2005 to 2007 period. The same table in CA-3 indicates the projected change in base rates is very smooth (generally less than 2% annually) and slowly upward trending following the 2004 run-up. The rate instability over this period is clearly being introduced by the Rate Stabilization Plan itself. In this regard, a complete review of the rate impacts stemming from the application need to consider both base rate and RSP impacts.

Specific COS and rate design issues related to the 2002 test year are noted below, focusing on matters relevant to Island IC ratepayers.

---

[78] The rate increases calculated above reflect Hydro's filed cost of service study – Hydro also endorses SGE Acres recommendation to use a revised long-term hydraulic plant output average, which would increase the revenue requirement a further $5.97 million, and result in an additional 2.1% rate increase for NP and 2.7% for IC, per Haynes, page 30.

[79] Haynes, page 28.

[80] See response to CA-3.

[81] This appears to reflect an average rate throughout the year, using a blended RSP adjustment to reflect the July 1 rate change.

[82] The 4.85 cents/kW.h for 2004 appears to reflect the numbers from Banfield, Table 4. This equates to the sum of $52,018,920 firm plus $14,225,120 RSP for a total $66,244,040. On a load of 1,367,800 MW.h, this yields an average rate of 4.843 cents/kW.h. However, the 2003 value appears slightly high using the same approach (the approach would yield an average rate of 3.773 cents/kW.h). The difference may relate in some way to non-firm power.

## 6.2 IMPACT OF CURRENT SUPPLY CONDITIONS ON COST OF SERVICE APPROACH

The relative rate increases that have been requested from the various classes are calculated using a cost-of-service methodology that is very similar to the approved approach from the 2001 application. Hydro has proposed a number of minor variations, such as:

1. Hydro Place[83] is now charged to all systems, rather than just the Island Interconnected system.
2. General Plant is now charged based largely on labour ratios, rather than plant, which more accurately reflects the role and function of general plant.
3. Municipal taxes are directly recognized as being revenue related for all retail customers.
4. PUB costs are directly recognized as being revenue related for all customers.

The impact of the above four changes is summarized in CA-130. Each of the changes appears to be reasonable and consistent with normal cost of service principles.

Consideration of issues related to cost of service requires attention to the material changes that have occurred in the Island Interconnected System since Hydro's Cost of Service was last reviewed. In particular, we note the following comparison of the system capabilities:

**Table 6.3 – 2002 and 2004 Capacity and Energy Availability (LOLH and Energy Balance)**

| | **Test year[84]** | | **Number of years to next plant required[85]** |
|---|---|---|---|
| | LOLH | Energy Balance | |
| **2002 Test Year** (Budgell, Schedule X from the 2001 application) | 3.97 | (36) GW.h | 5 years[86] |
| **2004 Test Year** (Haynes, Table 8 from the current application) | 1.1 | 202 GW.h | 6 years[87] |

The LOLH is a measure of the generating capacity in place on the Island Interconnected system compared to the loads to be served. Hydro's planning criteria requires the Island Interconnected LOLH

[83] We understand this to be Hydro's head office building.
[84] Budgell reflects 2002 test year, Haynes reflects 2004.
[85] Next plant not yet approved or next purchased power contract not yet negotiated.
[86] Budgell, page 11 indicates a requirement for additional plant in 2007 on top of Granite Canal and the two new purchased power arrangements that were already committed at that time.
[87] Haynes, page 37 indicates a requirement for additional plant in 2010.

(measured in hours) not be above 2.8[88]. In other words, the current 2004 test year generating complement represents a plant in excess of that determined to be required by Hydro to service the Island Interconnected load[89]. This is distinct from the 2001 cost of service, where the costs for plant-in-service, based on Hydro's measures, did not reflect a generating complement technically capable of supplying the Island Interconnected load (demand or energy) to the acceptable reliability standard.

The current situation allows for a serious review of the Island Interconnected generating plant in service, what role each unit plays in providing the system with appropriate levels of reliability, and whether a portion of the generating complement is not in fact required for service to the entire grid (as opposed to perhaps being simply of local benefit to radial loads for the purposes of voltage control, supply during outages, etc.).

Clearly, Hydro has already begun their assessment of the Island Interconnected system from this perspective. The most notable example is the decision by Hydro to not renew the 'Interruptible B' contract with Abitibi Stephenville. This contract had been in place since 1993 and provided the ability for Hydro to interrupt, on short notice, up to 46 MW of load at Stephenville during the critical winter months. IC-194 sets out Hydro's reasoning in not renewing the contract as being based on the fact that the Island Interconnected System had sufficient capacity in place to meet the LOLH target until 2011. However, Hydro's review does not yet appear to have extended to an assessment, on a comparable basis, as to whether the Great Northern Peninsula backup diesel generation or NP backup thermal generation is likewise required to meet LOLH targets, and whether there is any basis for other customers on the Island Interconnected system to pay rates that reflect costs associated with these peaking plants.

## 6.3 COMPARISON OF COSTS OF CAPACITY

On the Island Interconnected system, Hydro proposes a particular combination of cost allocation and program offerings to address the requirements for capacity to meet peak supply. However, given the current situation of excess capacity until 2011, three matters merit review in this regard:

1. The allocation of GNP Generation as being of common benefit to the Island Interconnected system.
2. The allocation of Burin Peninsula transmission as being of common benefit to the Island Interconnected system, primarily as a result of the line servicing both NP and Rural ("under the guideline associated with the connection of two or more customers to the grid"[90]) but also as a result of connecting what is determined by Hydro to be significant generation to the grid.

---

[88] Haynes, page 36.

[89] Hydro's planning criteria ignore any energy capability of the peaking plant maintained by Hydro (i.e., gas turbines) and ignore the capability for Hydro to request capacity interruptions from industrial customers under a suitable interruptible demand program. Hydro has previously maintained 46 MW of interruptible demand with Abitibi Stephenville but has since determined they no longer intend to offer the rate.

[90] Exhibit JRH-3 page 21.

3. The provision to NP of a "generation credit" to recognize their thermal generation plant.

Each of these capacity-related matters is reviewed in more detail in the following sections and in Attachment H. The related decision by Hydro not to renew the Interruptible B offering is reviewed in Section 7.3 as well as in Attachment H.

A useful comparison to assess these three matters can be based on the amounts that are proposed to be paid by IC and NP (or would be paid by IC and NP) for various sources of system capacity to service peak demand. As none of the NP or Hydro thermal generation (other than Holyrood) is cited as providing any energy benefit to the grid, all benefits from GNP generation, Burin peninsula generation (outside of Paradise River), other NP thermal generation and IC Interruptible B relate only to their contribution to supplying peak winter demands[91].

Table 6.4 illustrates the comparative costs to the industrial customer group and NP related to various sources of capacity, in comparison to the costs of Hydro's gas turbines (which are used as a benchmark).

[91] The LOLH for summer months is basically zero and minimal for spring and autumn per IC-301. Each of these sources is available for the critical winter months. Interruptible B was available for December to March of each year.

**Table 6.4 – Costs of Island Interconnected Peaking Capacity to NP and IC**

| | kW made available[92] | Cost to IC | Costs to NP[93] | Details |
|---|---|---|---|---|
| **Hydro's Gas Turbines[94]** | **128,000** | **$280,613 or $2.19/kW made available** | **$1,789,356 or $13.97/kW made available** | **Hydro's primary peaking capacity – first dispatched peaking units.** |
| GNP Generation[95] | 14,700 | $191,136[96] or $13.00/kW made available | $1,202,115 or $81.77/kW made available | Transmission assigned rural, but Hydro proposes to assign generation as common. |
| Burin Generation[97] | 25,000 | $231,709 for TL 219 as common[98] *plus* $332,910 for NP generation credit[99] *Total* – $564,619 or $22.58/kW made available | N/A | Hydro proposes to assign TL219[100] as common, plus pay additional amounts to NP via "generation credit" than if the capacity was not in service. |
| NP Generation Credit (thermal)[101] | 45,500[102] | $738,386 or $16.23/kW made available | NP receives a net credit of $841,388 | Hydro proposes to credit NP (charge IC) to reflect NP's thermal generation. |
| Interruptible B[103] | 46,000 | $163,913 or $3.60/kW made available | $1,045,600 or $22.73/kW made available | Hydro does not propose to offer during the test year. |

[92] Ignores hydraulic – small hydraulic generation on radial systems are primarily in service for energy reasons, so are of common benefit to the grid and should be assigned as common.

[93] Prior to allocation of rural deficit. Costs to NP per kW are much higher than to IC as NP makes up 80.60% of the system peak, while IC make up 12.64%.

[94] The full cost of Hydro's gas turbines is set out at IC-13 (Rev.) at row 15. This cost is allocated 100% on demand, which results in 80.60% of the costs to NP, 12.64% of the costs to IC, and 6.76% of the costs to Rural per RDG-1 (Rev.1) Schedule 3.1A.

[95] This is only intended to reflect thermal generation – Roddickton mini-hydro should be assigned as common due to energy benefits to the system. Not clear if figures include the costs of mini-hydro, but the total revenue requirement of this unit, at $46,218 (IC-13 (Rev.)) makes up approx. 3% of the GNP generation revenue requirement.

[96] Per JRH-3, Appendix B

[97] This excludes Paradise River – TL 212 is assigned common as it interconnects the 8 MW hydro plant at Paradise River. There are also apparently three small (total 1.7 MW) NP hydro plants on the Burin peninsula – these assets are inconsequential to considerations of the appropriate assignment of the transmission line costs.

[98] Per IC-228

[99] Per IC-312

[100] Hydro also proposes to assign TL 212, but as that line is required to service the Paradise River hydro plant, the allocation of it to common appears reasonable.

[101] The information in this row is derived from IC-190 and IC-191. In those examples, NP is provided with a generation credit for their hydraulic generation equal to 77.5 MW compared to 79.3 MW in the cost of service, a difference of 1.7 MW. In other words, essentially all of the changes reflect in IC-190 and IC-191 compared to RDG-1 reflect the difference in the NP thermal generation. A portion of these amounts is also reflected in the row entitled "Burin Peninsula" – the amounts in the table rows are not additive.

[102] This is shown in Exhibit RDG-2 at Appendix 3, and is net of capacity reserves. The gross NP thermal generation is 53.9 MW per the same exhibit.

[103] Per IC-224

It is also of note that assigning the GNP generation to common results in an increased revenue requirement to Hydro of $44,986 as these assets are allowed a return on equity (there is no return on equity if the assets are specifically assigned to Rural)[104].

The table above illustrates the inconsistent impact on IC and NP from the various sources of peaking capacity. It is apparent that reliable and essential peaking capacity in the form of Hydro's gas turbines[105] (or the readily available Interruptible B capacity) results in less costs per kW to IC and NP than the costs proposed to be assigned to reflect so-called benefits from other peaking sources, despite these other sources being less useful as they are not on the backbone 230 kV transmission grid, are lower in the dispatch sequence[106], have longer startup times (in the case of NP's thermal generation)[107] and are smaller sources of capacity than Hydro's gas turbines[108].

Even the cost of brand new capacity additions to Hydro's system, quoted at $100/kW/year[109], would only result in $12.64 per installed kW being charged to the industrial customers, and that would reflect units under Hydro's complete control and dispatch. There is simply no basis to try to assign to IC $13.00 in costs per kW installed on the GNP, or $22.58 in costs as a result of each kW NP has installed on the Burin peninsula. There is also simply no basis to assign IC higher costs of $16.23 for each kW of thermal generation that NP has installed around the island, especially given NP is collecting the costs of this generation from its customers (via NP's revenue requirement[110]) who are the ones that primarily benefit from its presence (and given that this generation is not required to provide service improvement benefits to the reliability of the Island Interconnected grid).

## 6.4 ASSIGNMENT OF RADIAL TRANSMISSION AND GENERATION

### 6.4.1 Background on GNP Prudence and Cost Assignment

In the 2001 proceeding, Hydro proposed that any radial transmission line that had generation in place, as well as the costs of the generation itself, should be allocated to all Island Interconnected customers as being of common benefit so long as the generation could, even under light load conditions, exceed the radial load[111]. The Industrial customers disagreed with this cost-of-service approach for two reasons:

---

[104] IC-234

[105] See, for example, IC- 396 indicating a 17.2 hours LOLH in 2004 (compared to target maximum of 2.8 hours) if the gas turbines were removed from service.

[106] See below, and Appendix A of Exhibit JRH-3.

[107] The exception is St. Anthony and Hawke's Bay diesels, their start-up time is 3 minutes compared to 8 minutes for the gas turbines; however, this difference is not likely to be material.

[108] See IC-295.

[109] Per IC-289.

[110] Per IC-187 NP.

[111] This is summarized in P.U. 7 (2002-2003) at page 112.

1. there was no basis to assign a transmission line as being of common benefit if the generation could only exceed the radial load under light (i.e., summer) conditions when that generation was simply not required on the main grid; and
2. the GNP transmission line in particular had not yet been demonstrated to be a prudent investment in the first place (the Board had decided in the previous hearing in 1995 that it did not have sufficient information to determine if the line was a prudent investment, and deferred that matter to Hydro's next rate hearing "for the purpose of determining recoverable costs"[112] – in this case the 2001 proceeding).

The Industrial customers called evidence in the 2001 proceeding indicating that a proper project review prior to construction would have demonstrated that the GNP project was marginal at best based on Hydro's financial and cost tests. Contrary to Hydro's assertion at IC-96 that the prudence of GNP costs was dealt with in the 2001 proceeding, or that the questions of prudence are no longer material to the current proceeding, the Board did not provide clear comment on the prudence of GNP interconnection costs in P.U. 7 (2002-2003). The Board did determine that Hydro's proposal to classify the GNP transmission and generation as being of common benefit was not acceptable.

In the present proceeding, Hydro has re-assessed the issue of GNP assignment[113] in exhibit JRH-3. In that exhibit, Hydro confirms, with respect to the GNP assets, that the GNP transmission is not of any common benefit to the Island Interconnected grid, so has determined it is appropriate to retain the transmission line as specifically assigned Rural. However, Hydro has now concluded that the GNP generation is of common benefit to the grid, and that all customers should share in the costs of this generation based primarily on their relative CP at generation[114].

Based on a review of the evidence in 2001 and the new evidence filed with the current proceeding, there appear to remain material questions outstanding as to whether the GNP interconnection, and the associated costs, was a prudent project for Hydro to undertake. However, so long as the costs of the transmission line remain assigned specifically to rural customers, this is not a matter that requires further consideration to protect the interests of industrial customers located elsewhere on the grid.

To the extent that Hydro now proposes to assign costs for generation that is located on the GNP, and that provides service almost entirely to GNP customers, as being of common benefit to the Island Interconnected grid including the industrial customers, the question of GNP prudence cannot be ignored.

As an example of the issues that must be addressed, the material in IC-399 is instructive. In particular, this response indicates the Island Interconnected system LOLH and Energy Balance that would arise if the GNP were not interconnected to the Island Interconnected grid. Comparing these results to Haynes,

[112] See Board's report filed in response to CA-2 from the 2001 proceeding, page 189 (R11).
[113] Hydro has not filed any material in this proceeding to attempt to conclusively address the matter of whether the GNP interconnection reflects a prudent investment of $26.4 million in the first place.
[114] The bulk of the GNP generation is peaking plant classified to demand – CP at generation.

Table 8 indicates that, on a net basis, the GNP radial transmission line, including both loads and generation, has a net adverse impact on the Island Interconnected system. But for this radial line being interconnected, the Island LOLH would improve to 0.7 hours/year in the test year from 1.1 hours per year in Haynes, Table 8 and the Energy balance likewise would improve. Also notable, the requirement for future generation additions to the Island Interconnected grid would be delayed to 2012 from the currently forecast 2010. On balance, this type of information indicates a reason for concern, from the IC perspective, that costs for GNP assets will be assigned to the IC cost-of-service, even though these costs only arise as a result of a project that has a net adverse impact on the IC service quality.

The material below reviews the cost allocation of the GNP generation and illustrates, even if the GNP transmission was a prudent investment to undertake, that there is no credible basis to assign the costs of the GNP generation as being of common benefit. However, the question of who should pay for the GNP generation matter is even more conclusively determined if it is determined that the GNP interconnection project is an uneconomic venture that ought not to have its costs recovered automatically through rates.

### 6.4.2 Assessment of Radial Transmission and Generation in the Current Application

Hydro has undertaken a reassessment of certain generation and transmission costs on radial systems, included in the filing at Exhibit JRH-3. The exhibit reviews the generation and transmission configuration of three radial systems that have generation assets installed, and determines the following:

1. Great Northern Peninsula ("GNP") transmission should be assigned to rural customers, but the generation should be assigned common
2. Burin peninsula transmission should be assigned common
3. Doyles-Port aux Basques should be specifically assigned to Newfoundland Power.

Specific details regarding the GNP generation and the Burin Peninsula transmission are set out in Attachment H.

The review in exhibit JRH-3 appears to be incomplete in its analysis of the relative benefits and costs of the radial transmission and generation. The exhibit reviews, from both a system planning and a system operation perspective, the role of the generation assets, but it does not consider the relative benefits obtained in comparison to the cost implications for the various customer groups. It also appears to assume that the thermal generation in place, for example, in the GNP (14.7 MW of thermal[115]) would have to be replaced at a cost of $100/kW/year if it were not available to customers in its current form. This reasoning raises two serious concerns. First, there is no basis to suggest that any cost would have to be incurred to replace this generation in 2004 (if it were not already in service). Absent the GNP generation, the Island Interconnected LOLH only increases from 1.1 hours/year to 1.4 hours/year. This is

[115] It is not relevant in this sense to discuss the Roddickton mini-hydro. That unit provides energy benefits and so is readily considered to be of benefit of the Island Interconnected system and assigned to 'common'.

still well below the target maximum of 2.8 hours/year. Second, the assertion that the 14.7 MW of capacity would have to be replaced at a cost of $1.47 million to the system is incorrect. Hydro has previously contracted with Abitibi Stephenville for 46 MW or capacity (over three times the capacity made available by the GNP generation) for a cost of less than $1.47 million per year for essentially the same function[116].

In addition, the analysis fails to reflect the differential impact on IC versus other customer groups in regards to the radial plant assignment. With the current approach to financing the Rural Deficit, Newfoundland Power is basically indifferent to most issues of radial plant assignment, as they either pay the costs as common plant, or pay the costs as their share of the Rural Deficit[117]. However, under the provisions of the EPCA, 1994, Industrial Customer are prohibited from paying costs that are properly part of the costs of providing service to Rural customers. In this regard, assignment of radial plant is an issue that must be carefully considered to ensure that improper cost of service procedures are not resulting in cost allocations that are in contrary to the provisions of the legislation.

Based on a review of the evidence filed in this proceeding, and as set out in Attachment H, there appears to be no reasonable basis to assign any costs associated with the GNP thermal generation to any customers other than Hydro Rural. The proposed 'common' allocation results in assets that are properly providing service to rural customers being assigned to NP and IC. These assets have on occasion, prior to the major plant additions of Granite Canal and the two new PPAs (and during a period where the system had generation capacity shortages compared to Hydro's planning targets), been operated for one brief period in support of the entire grid[118]; however, this operation makes up less than one percent of the role that these units have played in providing service to Rural customers. Given that a common allocation results in over 90% of the costs of this plant being assigned to customers other than Rural, there is a clear disconnect between the customers who benefit and the customers who Hydro proposes should pay for the plant. In addition, there is a clear inconsistent cost impact from assigning GNP thermal generation to common, given that a greater quantity of capacity can be acquired at a lesser cost to IC and NP via such measures as the Interruptible B program.

There is also little basis to suggest that the Burin Peninsula transmission assets, outside of that portion required to interconnect Hydro's Paradise River generation to the grid, reflect sufficient benefit to the grid in the test year to assign them as common. As reviewed in Attachment H, the NP generation on the Burin peninsula is not required to meet the Island Interconnected peak demands in the test year, and therefore does not reflect any material benefit to the Island Interconnected customers outside the Burin Peninsula area. Hydro's own assessment from the 2001 proceeding was that the Burin transmission assets should be addressed in the same fashion as the GNP transmission and Doyles-Port aux Basques transmission

[116] IC-216 indicates annual costs of $1.297 million to $1.354 million over the 1994 to 2002 period- it is presumed that 1993 reflects only a partial year of the program, costing $335,000.

[117] For example, the GNP generation allocation to common versus specifically assigned rural (a movement of approximately $1.4 million in costs per IC- 277) results in only an $11,830 impact on NP (per JRH-3, Appendix B).

[118] Per JRH-3 page 15, this occurred on January 30, 2003.

(both of which are proposed by Hydro to be specifically assigned and not considered to be of common benefit[119]). In addition, there seems to be no merit in Hydro's assessment that the transmission should be assigned to NP, IC and Rural simply because it serves both NP and Rural[120].

## 6.5 NP GENERATION CREDIT

A key item of complication in the cost of service is Newfoundland Power's own generation. In order to consider an appropriate treatment of the NP generation, it is important to recognize that there are two types of generating plant that NP maintains on the Island Interconnected system:

- ***NP Hydraulic generation:*** Comparable to Hydro's small hydraulic generation, NP's plants provide energy to the grid, and play some role in meeting demand peaks[121]. The hydraulic generation is presumably dispatched in almost all cases to maximize energy output, which would be consistent with the normal practices for economic dispatch of small hydro plants.

  As a result of their hydro generation being available to service a portion of their load from both an energy and capacity perspective, NP imposes a smaller burden on Hydro's network (and likely on Hydro's costs) than if NP did not possess the hydraulic generation and Hydro had to serve NP's full native load. Within a cost-of-service perspective it would be the normal practice to net the hydraulic energy off of the forecast total native energy NP required in determining the energy they require from Hydro's system. In addition, it would be normal practice to net the capacity that NP's hydraulic plant can reasonably provide off of NP's native peak to determine their peak demand for the purposes of cost allocation.

- ***NP Thermal generation:*** In contrast to hydraulic generation, NP's thermal generation plays no role in meeting the system energy requirements. The NP thermal generation is considered in determining the Island Interconnected capacity requirements, reflecting its ability to be operated at peak times. However, as noted above, the system is presently in a state of capacity surplus having recently added 87.3 MW of capacity at Granite Canal and the PPAs. In addition, the NP thermal generation is clearly located on the grid primarily to service radial loads in order to increase their local reliability[122], similar to the GNP generation that Hydro maintains. In addition,

[119] IC-267 from 2001 proceeding.

[120] Assets that serve NP and IC but not rural are assigned to a separate "NP-IC" category and not charged to Rural customers so long as they have an original cost of at least 2% of Hydro total transmission and terminal station cost. The TL219 original cost is $14.199 million per IC-334, which is 3.3% of the total Island Interconnected transmission and terminal station Plant in Service of $430.697 million per RDG-1 (Rev. 1) Schedule 2.2A. Hydro was asked about this potential allocation for COS purposes, but declined to answer as the response claims the matter is "not relevant" (IC-337 and IC-338).

[121] Per Haynes, Schedule II, NP hydraulic generation has a normal output of 424 GW.h and a firm generation of 323 GW.h. with a maximum peak capacity of 93.2 MW.

[122] The NP Greenhill 25 MW gas turbine is located on the radial transmission line on the Burin Peninsula, the Wesleyville 15 MW gas turbine is located well off the main 230 kV grid on a long 69 kV radial line, and the "mobile" 7

IC-295 indicates that NP's thermal generation is very far down the list of available resources at times of system constraints, and is only dispatched after all Hydro's gas turbines, the St. Anthony diesel plant and the Hawke's Bay diesel plant have been brought on-line.

The cost-of-service approach used to date in Newfoundland is not designed to reflect peaks net of load shedding that only occurs on an infrequent basis. In particular, the System Operating Instruction in Appendix A of Exhibit JRH-3 indicates the following measures that are to be applied in the sequence set out below in times of system constraints:

1. Approach maximum on Hydro's hydraulic and steam generation
2. Request NP to maximize their hydraulic generation
3. Request Deer Lake Power and NUGS to maximize production
4. Notify industrial customers that non-firm power rates will start to be based on gas or diesel costs (higher cost than Holyrood). Ask NP to curtail their interruptible loads.
5. Start using standby generation[123]
    a. Hardwoods gas turbine (54 MW)
    b. Stephenville gas turbine (54 MW)
    c. Curtail Interruptible B load (46 MW)[124]
    d. Holyrood gas turbine (10 MW)
    e. Hawke's Bay diesel and St. Anthony diesel (13 MW)
    f. Two NP gas turbines (25 MW and 40 MW)
    g. Roddickton diesel (1.7 MW), NP mobile gas turbine (7 MW), various NP diesels (6.9 MW)
6. Interrupt non-firm industrial energy
7. Re-confirm steps 1-6
8. Reduce voltage at Hardwoods and Oxen Pond
9. Request industrial customers to shed non-essential loads
10. Request industrial customers to shed additional load
11. Request NP to start rotating feeders and start rotating Hydro rural feeders.

The above sequence beyond step 4 reflects activities that are infrequent at best. For example, exhibit JRH-3 notes that St. Anthony and Hawke's Bay diesels (step 5e) have been dispatched only once since the 1996 interconnection[125]. In addition, PUB-176 notes that on one occasion in the last ten years, two

MW gas turbine appears to be located on the Doyles-Port aux Basques radial line. The NP diesel appears to be located at Port aux Basques (2.5 MW), Port Union (0.5 MW) on the long Bonavista radial transmission line, with then remaining 4 MW located in St. John's or as portable units.

[123] Standby generation sequence per IC-295, sequencing of interruptible B reflects terms of contract.

[124] Interruptible B contract is not proposed to be in place for winter 2003/04 or beyond. The interruptible B terms provided that an interruption would occur after Hydro had dispatched 2 of its gas turbines and prior to dispatching the third.

[125] In contrast, IC-188 and IC-192 seem to indicate a more frequent operation of NP's thermal generation, which is lower on the dispatch sequence than St. Anthony and Hawke's Bay diesels. These requests seem to primarily reflect

industrial customers were requested to drop firm loads (step 9) of 15 MW each. The evidence on this matter indicates very little practical difference between the amount of dispatch beyond step 5(e) through to step 9.

Comparing the items on this list, the cost of service does not propose to in any way credit the peak loads forecast for the industrial customers to reflect effective capacity reduction that would occur in step 3[126] (as Corner Brook reduces their net load on the system by maximizing production from Deer Lake hydro), and in the 2001 application did not propose to credit the industrial peak loads to reflect step 5(c) or step 9. However, with respect to NP, Hydro does propose to net off of the NP loads a quantity of capacity sufficient to reflect the implementation of steps 2, 5(f) and 5(g) despite these being lower on the dispatch sequence than the IC load shedding at steps 3 and 5(c). In addition, in terms of the practical amount that each of these devices would be used, there is little difference between the items through much of the range from step 5(e) to step 9. Clearly the approach proposed by Hydro in regard to NP's generation reflects an inconsistent treatment of NP and IC loads.

The most striking comparison regarding NP's generation is shown in IC-187. As noted in that response, the thermal generation that NP maintains reflects a total annual cost (revenue requirement to NP's customers, as reviewed by the Board in NP's 2003 GRA) of $1,691,000. However, as shown in IC-190, this generation results in a credit to NP (a cost to IC and Rural[127]) of $995,488 in the test year. In other words, the cost of service approach proposed by Hydro results in IC and Rural effectively paying 59% of the costs of NP's peaking generation[128]. Even Hydro's own peaking generation, such as the gas turbines which are clearly of benefit to the entire grid, only result in 19.4% of the costs being paid for by IC and Rural customers[129].

In summary, there are only two potential rationales that could be offered as to why NP's thermal generation is considered as a credit to NP in the cost of service study:

- ***If NP's thermal generation could realistically be needed for dispatch/interruption at peak:*** One rationale for netting certain loads off of cost of service peaks is that they are not firm load that the utility has to supply at critical peak times. For example, the CFB Goose Bay secondary power is properly not included in the Labrador Interconnected cost of service capacity

---

non-peak voltage support (i.e. occasions in April, October, etc,), rather than proper peak load shedding consistent with the normal rationales for CP adjustments in the cost-of-service.

[126] Industrial customer peak loads for the purpose of the cost-of-service analysis are based only on Power on Order less normal diversity, as set out in IC-265. These calculations reflect the peak that the customer would expect to impose if running both their operation and any of their own generation at 'business as usual' levels.

[127] Prior to reallocation of the Rural Deficit.

[128] In addition, Hydro pays to NP all costs of fuel consumed when the units are actually run for system peaking support.

[129] Per RDG-1 (Rev. 1) Schedule 3.1A, IC pays 12.64% and Rural pays 6.76% of peaking capacity costs, which are based on Production Demand allocators.

allocations[130] as secondary power does not place any firm demand peaks on the system (it is readily interrupted at the time of system peak). Applying this rationale to the NP thermal generation, however, does not indicate that they should be netted off of NP's firm loads based on overall assumptions adopted for the cost of service. First, the NP thermal generation units are well down in the capacity shortage dispatch sequence (below other capacity sources that are not netted off in the cost of service, such as increased Deer Lake Power output and the Interruptible B capacity). In addition these units are not dispatched until after St. Anthony and Hawke's Bay diesels have been put into service. Hydro has confirmed that the St. Anthony and Hawke's Bay diesels have only been used once in support of the Island Interconnected grid[131] (in contrast to 112 times for local transmission outages[132]), and that was before Granite Canal and the new PPAs were in service. In addition, a portion of NP's thermal generation is very small and of limited benefit to the system[133]. In summary, there is little credible basis to suggest that these units provide any material benefit to the Island Interconnected grid or would likely be needed for dispatch or interruption at this system's peak.

- ***If considering NP's thermal generation as a credit in the cost of service study prevents uneconomic dispatch or peak shaving by NP:*** The more common response from Hydro is that giving NP a full generation credit as if all their thermal capacity was operating at peak is necessary to prevent NP from needing to run these units to peak shave[134]. In other words, Hydro is asserting that if NP is already provided with the benefit reflecting 100% of the output of these units, there is no additional need for NP to actually run them at peak in order to reduce their own costs charged by Hydro – and that running them at peak would be less advantageous for all customers since it represents an uneconomic dispatch of the system generation. This rationale ignores the legislative framework for regulation by the Board. Any consideration of NP's generation, and any reduced rates or reduced bills that might arise as a result of this generation plant, need to first recognize the clear power policy of Newfoundland, as outlined in the EPCA, 1994 at section 3(b). Specifically, the Board must ensure all utility generation is operated in such a way as to "result in the most efficient production, transmission and distribution of power"[135] and "result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service"[136]. In other words, the provision of a "generation credit" for NP in order to prevent them from dispatching their generation in a way that lowers the overall system efficiency (and increases overall system costs) is simply unnecessary and inappropriate. The legislative direction to the Board already appears to ensure the Board will not allow NP to profit (at the expense of others) from reducing the efficiency of power generation in the Province.

[130] Per RDG-1 (Rev.1) Schedule 3.1E, row 1.
[131] JRH-3 page 15.
[132] Since 1996, per IC-235.
[133] For example, all of NP's diesel generation is 2.5 MW or less.
[134] Greneman, page 17.
[135] EPCA, 1994 section 3(b)(i).
[136] EPCA, 1994 section 3(b)(iii).

On balance, using the approach to cost-of-service as it has been generally applied in Newfoundland, there does not appear to be any credible basis to provide NP with any generation credit to reflect the thermal generation plant they have in service. It remains appropriate to provide such a credit for NP's hydraulic generation, but only to reflect the peak capacity that NP would provide to the system based on economic dispatch to maximize energy output (not full dispatch that is reflective of system capacity shortage conditions). In this regard, it appears from IC-306 that the NP hydraulic generation would be expected to be running at 77.5 MW of output, but Hydro is proposing to provide 81.6 MW of capacity credit reflecting peak output[137]. The 77.5 MW figure should be the only amount applied to NP's native peak in allocating capacity-related costs in the cost of service.

## 6.6 NP LOAD FACTOR

The 2002 actual cost of service filed in IC-1(c) compared to the test year cost of service in IC-1(a) reflects a materially different result for NP and IC. In particular, the results in IC-1(c) indicate that the IC group paid more than $5 million *in excess* of its measured costs in 2002 (including RSP adjustments)[138]. In contrast, NP's actual payments to Hydro were almost $5 million *below* the amounts that should have been collected via rates (including the Rural Deficit)[139]. This divergence reflects a number of different factors, and it is not a simple exercise to itemize and quantify the various factors. However, one factor that appears to be material relates to the NP actual load factor compared to the 2002 forecast that NP submitted to Hydro[140].

In allocating the costs of the Island Interconnected system, the primary factors that distinguish the portion of costs that are assigned to IC versus NP or Rural are the forecast peak demand and energy

[137] An additional update that further exacerbates the problems noted above is in regard to the calculated "capacity reserve" required on NP's generation. Hydro has recently determined (IC-306) that since Granite Canal and the PPAs are now in service, there is a reduced need for capacity reserve on the overall Island Interconnected system. In the 2001 GRA, and in the May 2003 application filed by Hydro, NP's total generation output was de-rated by 18.5% to reflect the need for maintaining capacity reserves. As a result, NP's total generation plant of 147.4 MW was only given a generation credit of 124.8 MW. However, with the increased capacity available, the system reserve has been reduced to 16%. The net effect is to increase the NP generation credit provided. In other words, although there is more reliable baseload system capacity available, which makes the NP generation *less likely* to actually be of any benefit, Hydro is proposing to *increase* the generation credit it provides to NP. This result is not consistent with reasonable cost allocations reflecting the physical system in place.

[138] IC-1(c) Schedule 1.2 reflects total revenues from IC of $55,855,978 including RSP adjustments in comparison to measured costs of $49,479,727.

[139] IC-1(c) Schedule 1.2 indicates NP's total revenues of $245,524,223 including RSP adjustments compared to target revenue of $250,294,459.

[140] We have not attempted to quantify the impact, however NP's share of peak demand increased from a forecast 78.57% of the Island Interconnected system to an actual 82.46%. The revenue requirement to be collected based on demand peak allocators is $91.7 million in the forecast 2002 cost of service and $95.8 million in the actual 2002 cost of service. In other words, this revised peak demand may account for $3.6 to $3.7 million of the shift in costs from NP to IC (about 70-75% of the approximately $5 million noted above).

values[141]. These values reflect Hydro's short-term load forecasts as set out in PUB-3, and appear to be simply Hydro's compilation of the demand and energy forecasts that each of the four ICs and NP provides to Hydro.

In determining the level of rates to be paid by each customer group, Hydro's cost of service determines the total costs to be assigned to each group (Schedule 1.2 of the Cost-of-Service, Exhibit RDG-1), and then divides these costs by the number of units which Hydro forecasts it will bill in the test year (Schedule 1.3 of the Cost-of-Service, Exhibit RDG-1). The source of data for both cost allocation and billing units is the load forecasts provided by the customers.

As an example, if the IC customer group revises their load forecast to Hydro by increasing their energy sales by, for example, 100 MW.h, then there will be two cost of service changes:

1. a revision to Hydro's revenue requirement (primarily Holyrood) to supply the extra load, and
2. more of the energy-related costs allocated to the IC group, as they will now make up a larger percentage share of the total system energy.

However, there will also be more billing units to divide this total cost into in determining the IC energy rate, so the net effect, in all likelihood, will be a slight increase in the energy rate to be charged to the IC customers. Likewise, a slight reduction in the energy consumption would affect the three variables noted above and result in a slight difference in the end energy rate.

With respect to demand units, there are very few incremental costs to affect the revenue requirement related to increased or decreased consumption. In this case, a higher forecast demand peak by IC will result in a greater share of the demand related costs being assigned to the IC group, but a higher number of billing units, such that in all likelihood the rate impact will likely be slightly upward.

The situation with respect to NP is somewhat different as a result of the energy-only rate. Since NP does not have a demand rate based on the number of billing demand units that they forecast to require, NP's demand forecast is only relevant to determining their share of the demand costs. In this case, a higher peak demand forecast by NP would lead to a higher energy rate (all else being equal), and a lower peak demand forecast by NP would lead to a lower energy rate.

In the case of IC, there is a strong incentive to provide accurate forecasts to Hydro, particularly for demand, as the Power on Order clause in their Industrial Contracts ensures:

- the customer is only assured of firm power for the amount of demand they specify in advance, any usage above this level can be interrupted and is priced on a variable basis

[141] RDG-1 (Rev. 1) indicates at Schedule 2.1 A that 88% of the Island Interconnected revenue requirement is allocated based on Production Demand, Transmission Demand or Production and Transmission Energy, with most of the remainder reflecting Rural specific assets.

such that the unit costs are very high at certain times (see Section 7 below)

- the customers actually pay for all demand that they forecast they will require, regardless of whether they actually use that level of demand or not (an effective take-or-pay provision).

As a result, there is little benefit to IC of providing forecasts that vary from actuals.

In the case on NP, the demand forecasts submitted do not in any way commit the utility to any given level of costs or take-or-pay provisions. In this case, the rate NP is to be charged would be reduced to the extent that a lower demand forecast is submitted.

During the 2001 proceeding, the cost of service originally filed was updated during the hearing to reflect a new NP load forecast. In that case, NP's peak demand forecasts, as they relate to the cost-of-service filed early in the proceeding, reflected a forecast peak of 953,251 kW at Transmission[142]. A later revision submitted by NP reflected a reduction in this peak demand forecast to 923,476 kW[143]. The final 2002 cost of service filed in IC-1(a) to the current proceeding retained this 923,476 kW peak value. However, the actual peak recorded by the actual 2002 cost of service study filed in IC-1(c) was 1,047,534 kW[144]. In each case the variability in the energy consumed was within a tight margin[145].

There has been insufficient time to review in detail the NP load forecasts filed in this proceeding compared to long-term NP load characteristics, the various 2002 NP load forecasts filed in the 2001 proceeding, and the more recent information regarding increased penetration of electric heat in the Newfoundland market. It is apparent that revisions to the NP load factor can have significant impacts on the cost of service allocations, and that NP has not been driven by the same considerations as the IC group in regards to ensuring peak demand forecasts are as accurate as possible. It is possible that the two part rate for NP will ensure incentives for more detailed NP peak demand forecasts. To the extent that this is not the case, the review of load forecasts within the proceeding will be required to assess the extent to which NP's peak demands result in a reasonable allocation of demand costs.

[142] Per Schedule 3.1A exhibit JAB-1 Rev. 1 from the 2002 proceeding.
[143] Per Schedule 3.1A exhibit JAB-1 Rev. 2 from the 2002 proceeding.
[144] Per Schedule 3.1A, IC-1(c).
[145] From a low of 4,602 GW.h in JAB-1 Rev.1 to a high of 4,692 GW.h in the IC-1(c) final cost of service study.

# 7.0 RATE DESIGN

Following the determination, via a properly conducted cost of service study, of the amounts to be paid by each customer class, it is necessary to design rates to recover these costs. In addition, a fundamental overall ratemaking concern relates to cost tracking, or ensuring that customers are charged rates that reflect the overall costs that their use of electricity imposes on the system under various potential load variations that may occur as the test year unfolds. Efficiency objectives related to sending effective price signals to ratepayers are also important - particularly when addressing variable cost items

The rate design reflected in Hydro's application contains a number of components, many of which are unchanged from the 2001 application. Key components of the Island Interconnected rate design include:

- the base firm power rates applied under the Newfoundland Power and Industrial Customer Rate Schedules;
- the Interruptible energy rates applied to IC for loads that exceed their high load factor firm base load requirement; and
- the Rate Stabilization Plan.

In terms of achieving a fair allocation of costs between IC, NP and Rural Interconnected customers, not only under GRA forecast loads but under variations that may reasonably arise from GRA loads, the current rate design is clearly inadequate. The following deficiencies in the proposed rate design are reviewed in detail in the section below:

- The NP energy only rate combined with the RSP load variation provision result in NP failing to cover costs associated with their load growth in the same fashion as IC. In addition, NP load growth results in charges to other customers (IC and Rural) via the RSP even if the other customers' loads came in at exactly GRA forecast levels. The net cost to NP from load growth is well below the costs to produce the incremental power to serve the load (shown to be at 3.37 cents/kW.h per section 7.2.4.1 below).
- The NP energy only rate results in NP receiving no rate impact from increasing the demand peaks they impose on the system.
- In addition to the NP generation credit reviewed in section 6[146], the tentatively proposed "Option A" two-part rate for NP[147] results in NP also receiving an additional billing demand benefit based on assuming all their generation is in operation at the time of the system peak.

[146] As noted in section 6, the cost of service treatment of the NP Generation Credit results in an inappropriate costing benefit to NP based on an assumption that all their generation is in operation at the time of the system peak, including thermal generation that is uneconomic to operate, as well as assuming all NP hydro is operating at full output, which is inconsistent with the provisions of the EPCA, 1994 3(b)(i) and 3(b)(iii).

- The industrial rate structure (unlike NP's energy-only or proposed two part rate structure) requires industrial customers to forecast their demand requirements and then face an effective take-or-pay provision on their forecasts.
- The industrial interruptible rate structure means that, unlike Newfoundland Power, the industrial customers have to pay the full incremental costs to service any load growth, plus additional energy and demand charges. There is no cost to NP from IC load growth above their pre-specified Power on Order levels (as this load growth is priced at incremental rates and is not included in the RSP), unlike the costs imposed on IC (via the RSP) for all NP load growth.
- The IC group faces substantial charges via the RSP when they reduce their load compared to forecast. This results in the group saving less than 1 cent/kW.h for each kW.h that they are able to reduce their load compared to the last GRA forecast. Almost 80% of the cost savings from reduced IC load are passed on to NP.
- The IC also face substantial additional burdens if one customer is to close, as the RSP will continue to charge the remaining IC customers for all of the firm energy revenue forecast in the previous GRA to be collected from that closed operation, but only credit the IC with about 21%[148] of the savings that arise from not serving this load[149].
- The inconsistent treatment of firming-up service and wheeling service results in the firming-up service being provided to NP at no cost whatsoever; in contrast, the wheeling service provided to IC is credited back to all customers for the test year forecast amounts, and any additional wheeling sales appear to be simply credited to Hydro's net income.

The net impact of the proposed combination results in a materially different and inconsistent approach to addressing ongoing load variation among the IC and NP. Far more preferential terms are proposed by Hydro to be provided to NP than IC.

In order to address the above noted inconsistencies and inappropriate price signals, the following rate design changes are merited:

---

[147] As outlined in Exhibit RDG-2.

[148] See, for example, RDG-1 (Rev. 1) Schedule 3.1A, which shows that IC firm sales make up 20.99% of the forecast Island Interconnected sales for the 2004 test year.

[149] This is confirmed at IC-363 and shown in detail at IC-364, where the pro forma closure of Abitibi Stephenville in May 2003 results in the monthly RSP charging the remaining IC customers $870,897 (which is the total lost revenue to Hydro compared to forecast as a result of Abitibi-Stephenville closing) and crediting the RSP in total with $1.504 million related to fuel savings as a result of this closure, of which only $305,164 is allocated to the IC (20.29%, with $1.1 million or 73.33% being credited to NP). In other words, were Abitibi Stephenville to close, the IC RSP would be charged with over $500,000 a month, for each month until the next GRA ($870,897 less $305,164), wile the NP RSP would receive credits of over $1.1 million a month until the next GRA.

- NP should face a two-part rate similar to Option B in Exhibit RDG-2; however, the "generation credit" should only reflect expected hydraulic output using normal hydraulic conditions and economic dispatch of generation (it should not reflect any thermal output).
- Industrial customer billing demands should be based on the actual highest firm demand in the billing month, or 80% of the highest demand from the previous winter, whichever is higher. This would eliminate the practice of billing customers based on forecast Power on Order demand levels.
- Industrial Interruptible energy charges should reflect the energy charge proposed by Hydro, but no demand charges.
- The Load Variation provision of the New RSP should be eliminated, and any current balances amalgamated into the Fuel component.
- The hydraulic component of the RSP should be treated separately, with a well-defined trigger set perhaps in the order of $35 million to $70 million. To the extent that the hydraulic component remains within this trigger (plus or minus), there is no basis for any charges/refunds to customers.

A separate rate design issue for the 2004 test year is the Interruptible B rate that Hydro proposes to terminate. For the past ten years, Hydro has provided a rate offering that allows one industrial customer to service a portion of their load using interruptible capacity. This means that the customer could have their otherwise firm power supply reduced by a substantial margin (46 MW) on short notice in order to assist Hydro in meeting key winter system peaks for the overall benefit of the Island Interconnected system. This type of rate is typically offered by utilities focused on the long-term benefits of this dispatchable capacity reduction resource. Hydro's intention to terminate the offering effective the 2003/04 winter season is not consistent with the longer-term view that is appropriate for this type of rate. Recognizing the important long-term benefits from this type of rate, it should be retained for the existing 46 MW subscribed to the rate, along with an investigation of the potential for further system benefits from expansion of the rate offering to other industrial customers.

## 7.1 THE PROPOSED NP AND IC RATE SCHEDULES

### 7.1.1 Newfoundland Power two part rate

The topic of a two-part rate (demand and energy components) for Newfoundland Power has been discussed for a considerable period of time, as noted in various materials filed, including Exhibit RDG-2. There does not appear to be any inconsistency in the Board's direction on this matter going back to before 1990 (and including the Board's reports on Hydro's 1990 GRA, 1992 GRA and the Board's Decision in Hydro's 2001 GRA) that a proper rate structure for NP should include demand and energy components.

In the current proceeding, Hydro has requested continuation of the energy-only rate in the proposed rate schedules. However, in response to PUB-150, Hydro has noted that outside of a number of limited issues (discussed in PUB-149), a two part rate along the lines of that discussed in Exhibit RDG-2 (Option A) could be applied to NP.

In particular, Exhibit RDG-2 summarizes a number of aspects of the two part rate that require examination and review in order to determine the proper rate form, as follows:

1. **Price Signal:** A two part rate for NP, similar to the existing multi-part rates for IC, can be used to send a correct price signal to NP regarding the costs of its consumption. This price signal can then be reflected in the retail rates designed by NP. This price signal is also addressed in RDG-2 as an incentive to minimize the island interconnected peak for the benefit of the entire system, as increased peak loads will result in higher demand charges to NP. The existing single part (energy-only) rate provides price signals to NP in regards to energy (kW.h) consumption, but no specific price signal in regards to peak (kW) consumption and the increased costs that arise from increased peak consumption. In contrast, as noted below, industrial customers pay demand charges for basically all "Power on Order" that they forecast they will require, plus increased demand costs either related to interruptible or maximum demands in excess of Power on Order when they exceed this level. To the extent that these industrial rates are appropriate and track valid incremental costs on the system, a similar rate structure seems appropriate for NP.

2. **Revenue stability and neutrality:** Exhibit RDG-2 expresses a concern that with a demand charge component of the NP rate, a certain level of new volatility will be introduced into Hydro's revenues. This is because, unlike energy charges, demand charges are not addressed by the load provision of Hydro's RSP. However, as noted in Section 7.2, there appears to be no proper basis for maintaining any load variation component of Hydro's RSP (demand or energy). To the extent that Hydro seeks to stabilize revenues related to weather-specific variables (specifically colder or warmer than normal winter peak conditions), there are a number of models that can be contemplated to accomplish this, based on such concepts as NP's own Weather Normalization Reserve. This normalization can either be applied to costing (i.e., charge NP for a weather-normalized peak) or to revenue-recognition (i.e., charge NP for actual peak, but credit a new Hydro "weather normalization provision" with any above or below normal revenues received, so that the provision balances out to zero over time with no riders to customers – to the extent that this gives rise to revenue/cost volatility to NP, the problem can be addressed via NP's own stabilization mechanism). The preferred method does appear to be the former; that is, a weather normalized peak demand charge to NP.

3. **Address NP Generation:** In measuring the demand costs and rates that are to be applied to NP, there is a need to consider an appropriate treatment NP's generation (both hydro, which is normally operated throughout the year, and peaking thermal, which rarely operates at all) in order to forecast the net load to be supplied by Hydro. Otherwise, as noted by Hydro in Exhibit RDG-2 section 4, an improper rate design might result in an ability for NP to profit from dispatching its generation in an economically inefficient manner. However, any

consideration of NP's generation, and any reduced rates or reduced bills that might arise as a result of this generation plant, needs to first recognize the clear power policy of Newfoundland, as outlined in the EPCA, 1994 at section 3(b). Specifically, the Board must ensure all utility generation is operated in such a way as to "result in the most efficient production, transmission and distribution of power"[150] and "result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service"[151]. In other words, the oft-repeated concerns that a poorly designed rate or generation credit for NP will result in NP dispatching their generation in a way that lowers the overall system efficiency (and increases overall system costs), in order to simply minimize Hydro's charges to NP, can be addressed. The Board not only appears to retain authority to price and set rates so as to ensure NP is not rewarded for such inefficiency-inducing behaviour, the Board appears to in fact be required to ensure such behaviour is not rewarded[152].

As a result of the above, Exhibit RDG-2 proposes that a two-part rate could be developed for NP incorporating the following key factors:

- Use the single winter peak to determine the demand charges during the year. To the extent that other months are lower than the winter peak, the demand charge would be based on the previous winter peak (i.e., a 100% ratchet on prior winter's peak).
- Normalize the winter peak for weather[153].
- Reflect a minimum demand equal to 98% of the test year loads, to ensure that load reductions do not result in material lost revenue to Hydro.

Our review and consideration of the above matters suggests that these three methodological approaches to demand billing for NP appear to be reasonable.

---

[150] EPCA, 1994 section 3(b)(i)

[151] EPCA, 1994 section 3(b)(iii)

[152] Another example arises at Exhibit RDG-2 page 11, where there is a concern that if the demand rate is too high, it may "encouraged NP to add gas turbines for the sole purpose of shaving peak" which, the exhibit asserts, may result in adverse impacts in Hydro's revenues and "non-economic island based resource management". However, as noted above, this type of action by NP appears to be contrary to the EPCA, 1994, and as a result, it would seem imperative that the Board not only reject any opportunity for NP to lower its costs via this introduction of inefficiency, but also ensure that NP is not allowed to recover any costs associated with such generation at the time of an NP rate application. In this way, the Board both ensures the legislation is implemented and also solves the problems highlighted by this exhibit.

[153] The mathematical intent appears to be to ensure that NP pays for 12 months at the weather-adjusted system peak; however to accomplish this a complicated demand-charge calculation is set out in Exhibit RDG-2 page 15 which effectively charges for actual peak in January, February and March, charges for weather adjusted peak in April-December, and credits back during the April-December period all revenues arising in the January-March period relating to actuals peaks higher than the weather-adjusted peak.

The main concern that arises with respect to the proposed approaches to NP billing demand is comparable to the concern that arises with respect to the treatment of NP's generation in the cost of service as noted above. That is, the generation credit should not provide any benefit to NP related to any of their generation that is not properly dispatched at peak times (based on proper economic dispatch principles). Regardless of whether NP operated their thermal plant at peak or not, or whether they ramp up their hydro production at peak, if this additional generation is contrary to proper economic dispatch, they should not see a benefit from such gaming actions.

Exhibit RDG-2 sets out three possible approaches to addressing NP's generation (entitled Options A through C). Without specifically reviewing the details of each option, both Option A and C appear to reflect providing NP with credit for their hydraulic and thermal generation in both the cost of service and the rate design[154]. Option B isolates and does not provide credit for NP's thermal generation in the measurement of billing demands, but does for the cost of service. Option B also provides credit for NP's hydraulic generation in both billing demand and cost of service[155].

At present, none of Options A through C in Exhibit RDG-2 pages 7-9 appear to optimally address this issue. With respect to Billing Demand calculations set out at Exhibit RDG-2 page 25, Option B appears closest to a proper rate calculation and price signal for determining billing demand, in that it isolates and excludes NP's thermal generation from the calculation of their peak demands.

Option B reflects charging NP for a billing demand calculated as their highest Non-Coincident Peak imposed on Hydro's system, but adding back any thermal generation operating at the time of system peak. In other words, NP would not be able to operate their thermal generation to reduce their bills. However, at page 8 of the exhibit, Stone and Webster note concerns that Option B provides incentives to ineffectively operate (or game) NP's hydraulic generation.

This issue appears to be solved by simple recognition of the principles (and the Board's requirements) under EPCA, 1994 section 3(b)(i) and (iii) and the considerations outlined below. Specifically, there appears to be no basis to credit NP with generation (regardless of whether it was running at peak times) if that generation is not properly part of the least-cost economic dispatch to service the Island

[154] Option A provides the Generation Credit based on the total installed NP thermal generation for both cost of service and measurement of billing demands, so there is no need for NP to run the generation to get the credit. Option C appears from Appendix 3 of RDG-2 to provide NP with a substantial generation credit in the cost of service (reflecting a 1038.5 MW peak, or the NP native load of 1161.5 MW less 77.5 hydraulic and 45.5 thermal generation) and use a billing demand based on their net load to Hydro (so there is an incentive for NP to run the thermal generation at peak to reduce its net load to Hydro, even though this would be an uneconomic dispatch of the system). However, this does not appear consistent with the text of the exhibit which states at page 8 "No generation credit would be applied to NP's demand for either costing or billing demands". In both cases, it appears from Appendix 3 of RDG-2 that NP is given some form of credit to reduce its costs as a result of having installed generation that properly should not be credited in the Newfoundland cost of service or rate design process.

[155] For cost of service, Option B uses full potential hydraulic output less reserves, and for billing demands it uses actual hydraulic output at the time of system peak.

Interconnected load. NP's peak for billing purposes should reflect the native peak[156] less the *normal* NP hydraulic plant output[157] at peak times, which appears to be reflected in the COS at 77.5 MW[158]. Regardless of whether 77.5 MW is the right figure, a fixed value for the normal winter NP hydraulic generation, reflecting normal hydraulic conditions and optimum economic dispatch for these units, should be the *only* amount credited back to the NP native peak in determining the billing demands. Any NP hydraulic generation in excess of this amount either reflects a) weather (i.e. precipitation or other relevant weather values) outside of normal, or b) operation varying from optimum economic dispatch, and should not be properly reflected in the NP demand charge[159].

The end result is that no NP thermal generation (regardless of actual operation), and no NP hydraulic generation above principled analysis of economic dispatch, should be reflected in determining the NP billing demand. This would remove all concerns with respect to NP failing to operate consistent with economic dispatch, and would ensure NP is not given credit for generation that is not properly operated for this purpose.

In terms of the NP two part rate, the rate schedule proposed in Exhibit RDG-2 pages 15 to 16 appears to be sufficient to address the above concerns. The only addition required is to add the definition of "Generation Credit" which reflects the following:

> Generation Credit: "xxx MW[160], reflecting the forecast generation from NP's hydraulic generation at the time of winter system peak (using normal hydraulic conditions and economic dispatch of generation to maximize NP's annual hydraulic energy output)"

The specific number of MW could possibly be fixed at 77.5 MW for this proceeding, so long as it is reviewed and set in future proceedings based on an analysis of the proper peak-hour output of NP's

[156] Defined in Exhibit RDG-2 at page 15 as "the load supplied by Hydro to Newfoundland Power in any hour, plus the total generation by Newfoundland Power during that hour".

[157] Haynes, Schedule II notes that NP hydraulic generation has an installed capacity of 93.2 MW, and Exhibit RDG-2 at page 25 notes an apparent reserve capacity of 18.5% (consistent with NP-126 from the 2001 proceeding). This equates to a total available capacity of 79.3 MW. Haynes Schedule II notes a average annual generation of 424 GW.h, which reflects an average annual capacity of 48.3 MW, and the COS appears (per Exhibit RDG-2 page 25) to reflect a credit of 77.5 MW. We assume that the 77.5 MW is the expected NP generation at the time of system peak, reflecting normal hydraulic conditions and economic NP hydraulic dispatch to maximize hydraulic energy generation over the course of the year.

[158] This may in fact be higher than normal winter economic dispatch for the NP hydraulic generation. Regardless, a fixed value for the normal winter NP hydraulic generation, reflecting normal hydraulic conditions and optimum economic dispatch for these units, should be the only amounts credited back to the NP native peak in determining the billing demands.

[159] Isolating the variation outside of normal due to precipitation is consistent with the weather normalization principles addressed above for winter temperatures, and variation due to uneconomic dispatch should not be properly credited back as any form of savings to NP.

[160] This is to be determined via hydraulic modeling; in the interim, 77.5 MW appears to be the only estimate currently available.

hydraulic generation assuming economic dispatch of the Island Interconnected generation, and subject to review and approval by the Board.

### 7.1.2 Industrial Customer demand and energy rate form

The Island Interconnected industrial customers are high load factor operations. This means that the IC group generally has a very limited ability to consume additional energy without setting new (higher) demand peaks. In other words, for the IC group, the access to power to address load growth is tied to the availability of power (as firm or interruptible service) and the demand and energy charges that would be applied. This area of service is governed by the industrial contracts, and the determination of "Power on Order" in particular.

The Industrial contracts currently in place are not proposed by Hydro to be revised or updated[161]. As a result, the existing terms regarding demand and energy consumption, billing, etc. are apparently proposed by Hydro to remain as per the final contracts from the 2001 proceeding.

A detailed review of the existing contract provisions is set out in Attachment F.

In summary, industrial customers are provided with firm power up to the peak (kW) level specified in their annual Power on Order. The industrial customer must forecast this amount by October of the year prior to service (and this amount has to be confirmed by Hydro, who has the opportunity to reject the amount of firm Power on Order requested by November of the year prior to service). Throughout the calendar year, the prevailing Power on Order represents both the maximum firm supply (at firm rates) that the customer can rely on from Hydro, and also represents the amount that the customer will have to pay for via demand charges, whether they use that power or not. In other words, so long as a customer remains below their declared Power on Order for the year, there is no cost impact to the industrial customer of incremental demand consumption or increased peak loads.

The effective rates paid by an industrial customer on their firm service average between 3.758 and 3.956 cents/kW.h exclusive of RSP charges (see Attachment F).

If a customer's requirements during the year exceed the Power on Order, the customer will be supplied by Interruptible Power, but only if it is available from Hydro at the time requested. This Interruptible Power is supplied at higher variable energy rates than firm power, based on the customer paying rates in excess of the full incremental cost to supply the power at the time it is delivered. The forecast rates for Interruptible Power reflect approximately 6.219 cents/kW.h if supplied from Holyrood[162], and are forecast to be higher than 13 cents/kW.h[163] when diesel units are operating on the Island Interconnected System.

---

[161] Per IC-50.

[162] Includes demand charges, and reflects the forecast Interruptible consumption of Corner Brook Pulp and Paper in the 2004 test year.

[163] Per IC-175, the forecast Holyrood-based non-firm energy rate is between 5.150 cents/kW.h and 5.267 cents/kW.h, the forecast gas turbine based non-firm energy rate is between 10.684 cents/kW.h and 11.143

The access to Interruptible Power is limited by a Maximum Interruptible Demand peak. If the customer has need to exceed the Maximum Interruptible Demand peak for a temporary load excursion, they face rates under the contract for such temporary use of power that are extremely high (reflects the so-called Maximum Demand provision). The example noted in Attachment F results in an effective rate of 25.66 cents/kW.h.

#### 7.1.2.1 Power on Order

In regards to Power on Order (i.e., the firm power provided by Hydro) the specific approach to industrial customer demand billing used by Hydro appears onerous compared to some other jurisdictions in Canada and contrary to normal price signal considerations. In particular, we note the following:

- ***Manitoba Hydro's*** billing demands to their industrial customers (General Service Large) only reflect the greater of the actual peak of the current month or 80% of the highest peak achieved in the previous December, January and February[164]. Where a customer is taking surplus power under the Surplus Energy Program ("SEP"), the demand charges for firm power are not applied to loads above the specified "Reference Demand" cut-off for SEP.

- ***Nova Scotia Power's*** Large Industrial Rate provides for demand charges on the maximum demand in the current month or the maximum actual demand of the previous December, January and February occurring in the previous 11 months[165].

- ***BC Hydro's*** industrial customers billing demands reflect the highest current period demand, or 75% of the highest peak in the previous winter, or 50% of the contract demand[166].

- In ***Yukon*** and ***Northwest Territories***, billing demands to industrial customers are based on either the highest current month firm peak or the highest firm peak of the previous twelve months, whichever is greater[167]. However, in this case, there is limited applicability of the Yukon

---

cents/kW.h and the forecast diesel based non-firm energy rate is 11.982 cents/kW.h. In addition, the interruptible energy rate proposed by Hydro includes an additional 10% premium over these thermal generation costs plus $1.50 per kW of demand.

[164] There are also rarely used provisions that the billing demand cannot be less than 25% of contract demand, or 25% of the highest measured demand in any of the previous 12 months. Per Manitoba PUB Order 53/96.

[165] Per NS Power Large Industrial Rate Schedule.

[166] BC Hydro Electric Tariff, Schedule 1821

[167] This is per Rate Schedule 39 for Yukon Energy and the Giant Mine rate tariff for NWT (in addition in Yukon, there is a contract minimum demand for industrial customers which is not normally relevant). A comparable 100% ratchet provision in Newfoundland would ensure that a customer's demand charges are not as high as the Power on Order if their usage has been below that level for 12 months. In this case, depending on the specific load profile, a comparative analysis would show that there can be months where the demand charges are higher under the Newfoundland approach and likewise months that may lead to higher demand charges under the Yukon and NWT approach. However, the Yukon and NWT approach would remove the requirement for the customer to specify a Power on Order under the current effective take-or-pay system in Newfoundland.

and Northwest Territories approaches as these jurisdictions do not offer an interruptible power program and so there is no need to clarify the cut-off between firm demand and interruptible demand (such as accomplished by the Manitoba Hydro Reference Demand noted above).

The above jurisdictions, by relying on maximum monthly demand peaks to a significant extent, ensure there are consistent and appropriate price signals to the industrial customers of the costs that result from demand consumption. For example, in Manitoba so long as a customer is above the 80% ratchet level, each extra kW peak they impose on the system results in additional charges on their bill. However, the customer is only responsible for paying for demand peaks they actually impose on the system, not peaks they forecast up to 14 months earlier[168]. This approach to demand billing appears to reflect more consistent cost causation principles than the Power on Order take-or-pay demand billing approach adopted by Hydro to date.

#### 7.1.2.2 Interruptible Power

The interruptible power provisions under the industrial contracts are more onerous than those usually encountered for industrial interruptible energy programs in other jurisdictions. It is important to note that Interruptible industrial rate offerings are not unique to Newfoundland Hydro. A number of these programs, including those provided by Hydro in IC-222, are summarized in Attachment G.

In the interruptible energy programs noted in Attachment G, the energy rates for interruptible power are typically higher than the specific incremental costs to supply the power[169]. These energy rates are generally comparable to Newfoundland Hydro's proposed 10% premium over the incremental fuel costs incurred.

However, Newfoundland Hydro is the only utility that includes a demand charge component in their program. There does not appear to be any sensible basis for charging a customer for demands that, by definition, will not impose new peak demand costs on the system (as these loads will be interrupted at times of constrained system peak demands). To the extent that these loads are expected to cover in excess of the incremental costs they impose on the system (to reflect some contribution towards the fixed costs of the system), this is already covered in the 10% premium charged on the energy rate, similar to the other three utilities reviewed.

---

[168] For example, in reference to the 80% ratchet mechanism, Manitoba Hydro has objected to removal of the ratchet otherwise customers may lose an incentive for discipline regarding the peaks they impose on the system.

[169] For example, 3% plus .12 cents/kW.h in Nova Scotia, 0.9 cents/kW.h on-peak and 0.3 cents/kW.h off-peak in New Brunswick, and 10% plus transmission losses and plus 0.06 cents/kW.h in Manitoba. In the case of Manitoba, this is the relevant provision of the Manitoba Hydro Surplus Energy Program when supplied from Manitoba Hydro generation (as opposed to purchased power or foregone export sales, which are not relevant in Newfoundland). Manitoba Hydro also charges $100 per month to customers who take surplus energy.

With the 10% premium included, the rates paid for interruptible energy are higher on a per kW.h basis than the costs for high-load factor firm power. However, the loads to be served by interruptible power are considerably different than the loads that a customer would seek to serve with firm power:

- the availability of the interruptible power is riskier,
- the price for the interruptible power can change both quickly and dramatically, and
- the uses reflect opportunistic loads that are capable of being interrupted on short notice.

As a result, the interruptible power loads are likely to have a very low annual load factor. A customer would not be likely to have such loads served by firm power, as the low load factors would result in very high effective rates (due to annual demand charge ratchets, and the limitations of the Power on Order approach).

It is clear that interruptible power is an essential part of the rate offering to industrial customers. The provision of this power, at an energy rate 10% above the incremental costs, provides benefits to both the industrial customer using the power, and to the rest of the system (and likewise the rates paid by the other customers on the system). There does not appear to be any basis to levy a demand charge for this service.

#### 7.1.2.3 Industrial Customer Summary

The Industrial Customer rate provisions in Newfoundland reflect an onerous combination of demand and energy charges. In order to ensure that the bills paid by industrial customers fairly reflect the costs they impose on the system, the following adjustments to the industrial contracts are merited:

- The customer's demand charges in any given month should reflect the greater of actual peak for that month, or 80% of the peak the customer established in the previous winter (December, January and February[170]). This is the same provision as currently used in Manitoba (80% winter ratchet), which also a winter peaking load[171], and above the firm demand provisions in BC (75% winter ratchet) and above the 70% ratchet that is to apply to industrial service in Manitoba as a result of recent Manitoba PUB ruling.
- The rate for Interruptible Power above the Power on Order should retain the proposed energy charges, but should not be subject to demand charges. This is comparable to the approach to interruptible billing in Manitoba and New Brunswick.

The customer would still be required to set a Power on Order, and this figure would continue to be the cut-off between firm power (on which the customer pays firm demand and energy rates) and

[170] This reflects the fact that the Newfoundland system can peak in any one of these three months, and approximately 95% of the LOLH arises in these three months in 2004 per IC-301.

[171] The most recent Board Order in Manitoba (Order 7/03) determined it was appropriate to reduce the ratchet to 70% on April 1, 2003 and eliminate the ratchet on April 1, 2004; however, this order has been stayed pending a Review and Variance application by Manitoba Hydro.

interruptible power (on which the customer only pays interruptible energy rates). The customer would have incentive to set the Power on Order at the level that reflects full supply of their mission-critical high-load factor operations, but below the opportunistic, interruptible low load factor operations.

The interruptible power would continue to cover all variable costs of generation plus a margin, so it would be appropriate to continue to account for all fuel used to supply the interruptible load outside of the RSP.

## 7.2 RATE STABILIZATION PLAN

As reviewed in the 2001 Hydro Rate Review, the RSP has formed a substantial portion of customer's bills since its inception. More recently, at May 2003, the RSP charge comprised 15% of the total IC energy rate[172] and based on the rates proposed by Hydro in the application, this is projected to increase to more than 27% of the total IC energy rate at January 1, 2004[173]. Clearly, the RSP is an important element of Hydro's overall rate structure that is before the Board in the Application.

The RSP is included as a specific rate schedule in Volume I of Hydro's Application.

Based on the information reviewed below, as well as in Attachments C and D to this testimony, it is apparent that the new RSP and all balances therein (deriving from September 2002 forward) are best viewed as an interim mechanism pending the Board's decision in this rate case proceeding[174]. This allows for a sensible and coherent review of the new RSP charges to date, the balances included therein and the optimum approaches to addressing the future operation as well as existing balances.

Concerns identified at this time that appear to have a material impact on the revenues Hydro proposes to collect and the charges imposed on the IC group relate primarily to five areas:

1. The ***'Load Variation'*** component of the RSP continues to be inappropriate in regards to normal prospective rate-setting practice.

2. The ***'Hydraulic Production Variation'*** component is a long-term stabilization mechanism that should not be collected and/or refunded on a two-year cycle, but rather focus on staying within a sensible operating range over the long-term.

3. The ***'Fuel Cost Variation'*** component is a short-term deferral that should be addressed in the most expeditious way tolerable to ensure timely price signals and minimum inequities. There also

---

[172] The IC RSP charge at May 2003 was 0.423 cents per kW.h per the May 2003 RSP report. The IC base energy rate was 2.388 cents/kW.h, for a total IC energy rate of 2.811 cents/kW.h.

[173] The IC RSP rate forecast for January 1, 2004 is 1.04 cents/kW.h per Banfield page 20. The IC base energy rate proposed for January 1, 2004 is 2.765 cents/ kW.h for a total forecast IC energy rate of 3.805 cents/kW.h.

[174] This would ideally include consideration of any conclusions available from the study discussed by the Board in P.U.7 (2002-2003) as well as evidence called by various parties to the current proceeding.

does not appear to be any benefit from the complexities associated with using differing monthly fuel price forecasts as opposed to simple annual averages.

4. The ***mechanism for collection*** need not include a complicated NP/IC breakdown.

5. The ***interest rate*** charged/paid by Hydro should reflect the short-term nature of the RSP asset/liability to Hydro.

This evidence provides an overview of the RSP as it was reviewed in the 2001 proceeding, reviews the creation of the 'Old RSP' and 'New RSP' accounts per P.U. 7 (2002-2003), followed by a detailed review of the New RSP operation to date. This is followed by discussion on the five concerns noted above.

On balance, our review indicates that the new RSP maintained by Hydro should be adjusted as follows:

- The ***hydraulic component*** of the new RSP, comprising somewhere on the order of $11 million as of the end of May, 2003, should be isolated into a hydro stabilization fund. The hydro stabilization fund should continue to operate in basically the same way as the existing RSP hydraulic provision. No collections or refunds should be undertaken on this fund until such time as an adequate trigger, likely in the $50 to $100 million dollar range (positive or negative), is reached. Interest on the balances should be charged or credited at an appropriate short-term rate.

- The ***fuel cost component*** of the RSP, comprising nearly $45 million at May 2003, should be isolated in a fuel price stabilization fund. This fuel price stabilization fund should ***continue*** to operate in basically the same manner as the existing fuel cost variation component of the RSP. Balances that accrue in this fund should be charged and/or refunded to customers using an equal per kW.h rider for IC and NP[175] in an expeditious manner, recognizing the need for rate predictability and smoothing. Interest on the balances should be charged or credited at an appropriate short-term rate.

- The ***load portion*** of the new RSP should be terminated. The small existing balance (about $2.7 million owing to customers) should be rolled into the overall fuel cost stabilization fund noted above to assist in mitigating the impact of the substantial existing balance in that account.

The end result of applying this approach would be somewhere on the order of $42 million owing from customers as of the end of May, 2003 for the fuel price stabilization fund, which should be pursued from customers on an equal NP/IC rider basis going forward before the balance grows larger with further fuel use and interest charged by Hydro.

[175] Rural riders would reflect the retail riders put in place by NP to pass through the Hydro-NP rider.

### 7.2.1 Overview from 2001 Proceeding and Creation of New RSP

The RSP was a major topic of review at the 2001 Hydro rate proceeding, comprising a substantial number of Information Requests, a considerable amount of evidence from intervenors, and many days worth of testimony. The evidence of Mr. Osler regarding the RSP in the 2001 Hydro rate proceeding focused on 3 primary considerations:

1. that the balances in the RSP deriving from operation of the Plan since 1985 be restated from 1992 onwards in part to reflect elimination of the Average and Excess Demand approach, and the elimination of the two disconnected industrial customers (Albright and Wilson and Royal Oak mines)[176];

2. that the fuel price used for rate setting purposes and for calculating the RSP fuel price variance component target more regular review and adjustment than had been the case since 1992, and that it be designed to reasonably reflect current market conditions[177]; and,

3. the elimination of load component of the RSP for all customers[178].

In its Decision P.U. 7 (2002-2003), the Board rejected point 1 above. The Board utilized the then best available forecast price of fuel for the purpose of setting rates and ordered Hydro to submit its next General Rate Application no later than December 31, 2003, which fully addresses point 2 above. On point 3 above (the elimination of the load variation provision), the Board noted as follows:

> "The Board does however note the concerns and issues surrounding the RSP raised by the intervenors, especially the CA and the IC, in particular concerns about the complexity of the plan and the interactions of the various components of the plan, especially the inclusion of the load variation provision. The Board also agrees that the existing RSP and its operation is difficult to understand.
>
> The Board is convinced, based on the evidence and issues raised at the hearing, that the design and elements of the existing plan should be reviewed. To that end the Board will commission a study of the RSP, which will include a review of the plan since its implementation, together with the operational issues raised by the intervenors at the hearing. The Board will decide based on the results of that study what action should be taken."[179]

[176] Pre-filed 2nd Supplementary Testimony of C.F. Osler (2001 Hydro Rate Review), page 8.
[177] Pre-filed Supplementary Testimony of C.F. Osler (2001 Hydro Rate Review), page 36.
[178] NLH-99.
[179] Decision P.U. 7 (2002-2003), page 84.

The above-mentioned study, to the extent it may have been completed, has not yet been made available for review in preparing this testimony.

The Board's Decision basically divides the RSP into two components – the "old RSP" comprising the balance as at August 31, 2002 and the "new RSP" comprising all activity from September 1, 2002 onwards. The old RSP, as reviewed below, is currently being collected by a rider from each of NP and IC on a straight-line basis over five years. To date, we are not aware of any initiation of riders or recollection of the new RSP balances reported by Hydro.

As a result of the above, the 'new RSP' balances are currently comprised solely of amounts Hydro calculates to be properly charged to the Plan, including interest, with no charges or riders having been assessed on customers to date. All justification for these charges derive from the Board's decision in P.U.7 (2002-2003) which recognized the lack of finality in regards to the optimum long-term structure and operation of the RSP at page 84, where it noted "The Board is convinced, based on the evidence and issues raised at the hearing, that the design and elements of the existing plan should be reviewed". As a result, it is apparent that the new RSP and all balances therein (deriving from September 2002 forward) are best viewed as an interim mechanism pending the Board's decision in this rate case proceeding[180]. This allows for a sensible and coherent review of the new RSP charges to date, the balances included therein and the optimum approaches to addressing the balances that have arisen.

### 7.2.2 Old RSP Versus New RSP

The Board's Decision in P.U. 7 (2002-2003) effectively divides the RSP into two components – the "old RSP" comprising the balance as at August 31, 2002 and the "new RSP" comprising all activity from September 1, 2002 onwards:

- ***Old RSP:*** The old RSP balances are carried forward in two portions, one for NP and one for IC. The Board's Decisions sets out that these balances are designed to be recovered over five years using a straight-line recovery method. The Old RSP balance was locked in at $105.838 million181 comprising $28.638 million for the IC and $77.200 million for NP. The initial rate set by the Board in P.U. 7 (2002-2003) for recovery of the Old RSP balance was 0.177 cents/kW.h for NP and 0.280 cents/kW.h for IC182. However, the rates set in P.U. 7 (2002-2003) were insufficient to recover the Old RSP balance within the directed five year timeframe. As a result, the IC rate was adjusted at December 31, 2002 to 0.423 cents/kW.h183 (an increase of 51% on the RSP portion of the IC energy rate, or 5.4% on the overall IC energy rate184). The NP rate remained at 0.177

[180] This would ideally include consideration of any conclusions available from the study discussed by the Board in P.U.7 (2002-2003) as well as evidence called by various parties to the current proceeding.
[181] August 2002 RSP Report page 16.
[182] September 2002 RSP Report page 19.
[183] January 2003 RSP Report page 19.
[184] The IC base energy rate at December 31, 2002 was 2.388 cents/kW.h. The effect of the RSP rate change was to increase the IC overall energy rate from 2.668 cents/kW.h to 2.811 cents/kW.h.

cents/kW.h until July 1, 2003 when it increased to 0.324 cents/kW.h185 (an increase of 83%, or a wholesale energy rate increase of 3.0%186).

It is not apparent how the "straight-line" recovery method is being applied by Hydro. A normally applied straight-line method would be expected to result in setting an RSP rider measured in cents/kW.h that would be equal for the five year period. It appears from Banfield page 20 to 21 that the IC "old RSP" rate is forecast to rise from 0.423 cents/kW.h to 0.43 cents/kW.h (presumably at December 31, 2003) and the NP "old RSP" rate is to rise from 0.324 cents/kW.h to 0.344 cents/kW.h at July 1, 2004. There also seems to be an unexplained adjustment included in the old RSP balance from December 2001 which purportedly relates to a Deer Lake power purchase that increases the balance in the fund by $179,000, $110,000 from IC and $69,000 from NP[187] that would seem to merit addition review.

- ***New RSP***: At September 1, 2002, Hydro initiated a new RSP to address all amounts from that point forward. Up to the end of May 2003, that new RSP had resulted in charges of $54.020 million including all RSP components plus interest. No collections had yet begun by that time on the new RSP. A detailed analysis of the balances in the new RSP is set out below.

  Hydro now forecasts that the new RSP will give rise to a requirement for an additional 0.61 cents/kW.h "new RSP" charge for the IC effective December 31, 2003 in addition to the 0.43 cents/kW.h old RSP charge. For NP, the projected new RSP charge effective July 1, 2004 is 0.558 cents/kW.h in addition to the 0.344 cents/kW.h old RSP charge[188]. By December 31, 2003, the projected new RSP balance is $67.0 million comprised of $16.8 million for IC and $50.2 million NP[189].

There has been insufficient time to review the materials filed in respect of the old RSP balances and the collection to date, including the extent to which it reflects the Board's direction to collect the outstanding balance over five years on a straight-line basis. The new RSP is reviewed below in some detail, as well as in Attachment C.

### 7.2.3 Operation of the New RSP

The concept of a rate stabilization mechanism as it is applied in other similar jurisdictions (i.e. non-interconnected grids that generate electricity with a mix of hydro and petroleum, such as Yukon or the Northwest Territories) is to provide protection for both ratepayers and the utility from variations in such uncontrollable variables as water availability and petroleum prices. In each case, the utility and the

---

185 per Banfield, page 21.

186 The NP base energy rate at July 1, 2003 was 4.789 cents/kW.h. The effect of the RSP rate change was to increase the NP overall energy rate from 4.966 cents/kW.h to 5.113 cents/kW.h.

187 For example, see footnote 2 from January 2002 RSP report.

188 Banfield, pages 20 and 21.

189 Banfield, page 20.

regulatory body normally set rates based on their best estimation of the costs to provide service over the test year, and the rate stabilization mechanism adjusts for any difference that occurs in utility revenues or costs due solely to these uncontrollable variables. From our understanding of the RSP, this is generally the way it was designed to work when the Board created it in 1985[190].

In this regard, the new RSP operates similarly to the RSP that existed from about 1985 up to August 2002 with a few notable exceptions[191]:

- The hydraulic and fuel price components operate basically the same as the previous RSP except that the variables assumed for fuel prices, long-term average hydraulic generation and fuel efficiency at Holyrood have been updated to reflect P.U. 7 (2002-2003) and P.U. 21 (2002-2003).
- The load provision reflects updated test year load forecasts and rates per P.U. 7 (2002-2003) and P.U. 21 (2002-2003).
- There is no longer an RSP cap of $50 million for the NP balance owing.
- The fuel-related amounts are now divided based on 12 months-to-date energy sales, with no Average and Excess Demand reallocation or demand-related cost rebalancing.

The net result is a material simplification of the operation of the RSP. However, the fund continues to be more complicated than seems necessary given the ability of other similar jurisdictions to operate without this level of analysis or tracing being required (see Attachment D regarding sample stabilization mechanisms from other jurisdictions).

The materials made available to date show the new RSP operation from its initiation at September 2002 to May 2003, a period of 9 months. This operation is summarized in detail in Attachment C and in the table below.

[190] However, a number of additional details in the Newfoundland and Labrador Hydro RSP set it apart from the types of mechanisms seen elsewhere, as discussed in Attachment D to this testimony.

[191] Other minor changes include inserting the mini-hydro plants in the RSP, excluding any interruptible energy sales or fuel used for that purpose, and establish RSP collection energy rates based on 12 month-to-date sales.

**Table 7.1: Operation of the New RSP from September, 2002 to May 2003**

| *$ millions* | **Hydro** | **%** | **NP** | **%** | **IC** | **%** |
|---|---|---|---|---|---|---|
| Hydraulic | **$11.316** | ***21.23%*** | $8.249 | *23.52%* | $2.344 | *16.39%* |
| Load | **($2.689)** | ***(5.04)%*** | ($5.848) | *(16.67)%* | $2.800 | *19.57%* |
| Fuel Price | **$44.677** | ***83.82%*** | $32.667 | *93.15%* | $9.160 | *64.03%* |
| Total | **$53.304** | ***100%*** | $35.068 | *100%* | $14.305 | *100%* |
| | | | | | | |
| *Rural Reallocation* | ***$(0.507)*** | | *$3.422* | | *$0* | |
| *Interest* | ***$1.244*** | | *$0.939* | | *$0.305* | |
| *Other Adjustments* | ***$(0.021)*** | | *$(0.015)* | | *$(0.004)* | |
| *Revised Total* | ***$54.020*** | | *$39.415* | | *$14.605* | |

Key observations in regards to the above are as follows:

- ***Fuel Price:*** The Fuel Price variation component makes up the largest part of the overall Hydro new RSP balance to date (at about 84%). This provision has been climbing at between $1.1 million and $8.4 million per month (plus interest accruing on the balances).

- ***Hydraulic:*** Hydraulic variation is a material component of the new RSP balance to date (at about 21%); however this hydraulic variance is well below the types of triggers or thresholds that are normally considered for hydro stabilization funds, including the previous (pre-1985) $36 million trigger applied for Newfoundland and Labrador Hydro[192] (with no adjustment to this figure for inflation or load growth since that time).

- ***Load Variation:*** The load variation provision is a small part of Hydro's overall RSP, but comprises nearly one-fifth of the amounts owning from IC, and credits NP with about one-sixth of the RSP that would otherwise be owing from that customer in the absence of this provision.

- ***Collection from Customers:*** No recollection of these balances has been initiated, and none is proposed for IC until January 1, 2004 and for NP until July 1, 2004[193]. As this balance reflects nine months of operation of the new RSP to the end of May 2003, this means that an additional seven months of operation will occur before IC is assessed a charge for the new RSP, and an additional 13 months until NP is assessed any 'new RSP' rate.

[192] This is referenced in Board Decision P.U. 7 (2002-2003) at page 79. Likewise, the Northwest Territories Power Corporation maintains a hydro stabilization fund with a trigger of $3 million on a total long-term average annual hydro generation of 177.5 GW.h, and Yukon Energy's comparable "Diesel Contingency Fund" uses a trigger of $4.04 million on annual hydro generation of 351 GW.h – on a comparable basis, Newfoundland Hydro's trigger (on 4,582 GW.h long-term average per Haynes Schedule II) would approximate $77 million and $53 million respectively.
[193] Reflects Banfield, page 20 and 21.

- ***Interest:*** The nine month period has resulted in about $1.24 million in interest to Hydro at a 7.157% cost of capital – a further seven to thirteen months until the first 'new RSP' riders are implemented will result in a drastic increase in this interest provision, including a proposal from Hydro to increase the effective interest rate to 8.440%[194] effective the date of rate implementation currently proposed for January 1, 2004 (despite short-term interest rates being at record low levels).

### 7.2.4 Concerns with the New RSP

Based on the above review, it is apparent that a number of aspects of the new RSP raise concerns that merit attention.

#### 7.2.4.1 Load Variation

The 'Load Variation' component of the RSP is an anomaly among Canadian utilities that we are aware of, and is not the normal practice for assignment of the load risk. Our review of Canadian electrical utilities, particularly focused on integrated Crown utilities, indicates that in almost all cases (7 of 8 Crown utilities) all risks with respect to load reside with the utility[195]. This is in part illustrated by the fact that none of these utilities maintain any form of account or trust that accumulates amounts related to variations in annual or monthly sales from the load forecast[196]. More importantly, for the one utility that does have a Rate Stabilization Account that in any way addresses load variation (BC Hydro), as well as two utilities which previously operated as Crown utilities with similar accounts (Ontario Hydro and Nova Scotia Power), none appears to have applied any differential collection to individual customer groups related to the accounts (i.e. would suggest no difference in application to NP versus IC).

The load variation mechanism used by Newfoundland Hydro results in three major problems:

1. it removes Hydro's risks with respect to its load forecast;
2. it results in inappropriate price signals and cost allocations to customers; and,
3. it necessitates complicated IC versus NP accounting and collection.

---

[194] This arises from Greneman, Exhibit RDG-1, Schedule 1.1, page 2, row 17.

[195] This includes SaskPower, Manitoba Hydro, New Brunswick Power, Hydro Quebec, Northwest Territories Power Corporation, Yukon Energy Corporation, and Nunavut Power Corporation. The one exception (BC Hydro) involves a special Rate Stabilization Account that is not at all comparable to the RSP approach (see next footnote).

[196] In one case (BC Hydro) a special Rate Stabilization Account is established by Provincial Government direction which is effectively an *earnings and dividend* stabilization mechanism. In this way, it does implicitly stabilize BC Hydro's earnings for load variation among other factors, but unlike the Newfoundland Hydro RSP, it does not lead to charges and/or refunds to customers. Certain of the Crown utilities have at various times in the past had similar stabilization accounts, such as the Ontario Hydro Account for Stabilization of Rates and Contingencies, or the Nova Scotia Power Corporation Rate Stabilization Reserve. However, similar to BC Hydro's Rate Stabilization Account, each of these reserves was intended to stabilize overall earnings for the Corporation from all factors (neither specifically addressed load variation in the format of the Newfoundland Hydro RSP), to our knowledge neither account ever resulted in charges or refunds to customers, and neither of these two mechanisms continues to exist.

Each of these major problems is elaborated on below. To address these problems, and to conform with normal COS and rate design principles, is recommended that the load variation provision be deleted from the RSP.

#### *7.2.4.1.1 The Load Variation provision removes all of Hydro's risks associated with its load forecast*

- ***Assigns risks onto customers rather than Hydro:*** The load variation provision ensures that any variation in Hydro's net income related to variations in load is charged back to customers – that is Hydro's earnings are completely insulated from any variation due to load developments. This is inconsistent with normal regulatory practice in a jurisdiction where rates are set on a prospective basis[197]. As reviewed in NLH-99 from the 2001 proceeding, the overall load provision resulted in $18.816 million in additional income to Hydro from 1992 to 2000. In contrast, the new RSP operating over the nine month period from September 2002 to May 2003 has resulted in $2.689 million being credited back to customers (reduced net earnings to Hydro) related to the load provision[198].

- ***Assigns costs of load variation to specific customer groups:*** In addition to the removal of any load-related risk related to Hydro's own load forecast, the load variation provision of the RSP as it is practiced by Newfoundland Hydro takes the total amounts derived from insulating Hydro from load risks, and specifically assigns these amounts to individual customer groups. Using the September 2002 to May 2003 period as an example, Hydro's net credit to customers of $2.689 million via the RSP Load provision results in $5.848 million being provided to NP, and $2.800 million being charged to IC.

#### *7.2.4.1.2 The Load Variation provision results in inappropriate price signals and cost allocations*

As reviewed in detail in Attachment C, the operation of the load variation provision in the RSP means that rates paid by customers for incremental increases or decreases in consumption compared to the load forecast are counter-intuitive and without any reasonable foundation:

- ***NP load growth:*** The 207.9 GW.h increase in NP's load compared to forecast over the nine months of the new RSP has resulted in an effective rate to NP on this new load of 2.97 cents/kW.h[199], while also effectively charging IC 0.83 cents/kW.h[200] for each kW.h that NP used

[197] The prospective method of regulation is the norm for fully regulated utilities. An alternative is retrospective regulation based on actual performance of the utility achieved in a given year, but we are not aware of any jurisdictions that regulate their Crown electric utilities (or any other type of utility) on this basis.
[198] See Table 7.1 above.
[199] See Attachment C. This excludes the rural deficit reallocation and excludes the fuel price variance portion arising from increased NP use.

over forecast. The effective rate to NP is well below the approved NP firm energy rate of 4.789 cents/kW.h and below the average cost of Holyrood fuel to supply this load (using GRA approved fuel prices) of 4.062 cents/kW.h[201]. Further, over this period the true cost of Holyrood fuel has been as high as 80% above this GRA fuel price[202]. As a result, there is a inappropriate price signal to NP (or the eventual retail customers) with respect to increasing consumption.

- ***IC load reduction:*** The 69.1 GW.h load reduction for IC compared to load forecast over the nine months of the new RSP has resulted in an effective savings to the IC group of only 0.829 cents per kW.h that the load was reduced. This is well below the normal IC approved rate of 2.388 cents/kW.h[203] that one would normally expect the customers to save by reducing their load. Further, this 0.829 cents/kW.h[204] is then spread across all four customers in the IC group, so the individual customer that actually reduces their load saves costs *well below* this level. In contrast, the load reductions by industrial customers result in savings to NP of 3.00 cents/kW.h for each kW.h saved. Given that the cost of fuel saved as a result of this load reduction is 4.091 cents/kW.h[205] based on 2001 GRA forecast fuel prices, and that actual fuel prices have been as high as 80% above this level, this is clearly an inappropriate price signal to the industrial customers for reducing their load during this period.

A further complication of the price signal in the RSP is that NP's existing rate is an energy-only structure. This results in a portion of the rate NP pays for each kW.h they consume being properly related to the demand peaks (kW) they impose on the system rather than the costs of supplying energy (kW.h). The load provision of the RSP, however, credits back to NP all revenues paid on the incremental load growth, with no attempt to isolate what portion of the rates paid are properly designed to compensate Hydro for incremental costs of supplied increased demand. This is inconsistent with IC, whose rate includes a demand and energy portion.

The clearest example of the inappropriate price signals arising from the load component is illustrated in IC-327, the forecast RSP accounting for 2005-2007. The response indicates that over the three year

[200] See Attachment C. This excludes the rural deficit reallocation and excludes the fuel price variance portion arising from increased NP use.

[201] The cost of Holyrood fuel to supply the NP 207.9 GW.h load growth is calculated from Table C2 of this testimony, dividing the sum of $1.596 million (column H row 4) plus $6.849 million (column H row 9) divided by the 207.9 GW.h figure.

[202] In February 2003 the actual fuel price was $44.44 per barrel per the February RSP report, compared to a GRA forecast fuel price of $24.64.

[203] See Attachment C. This excludes the rural deficit reallocation and excludes the fuel price variance portion arising from increased NP use.

[204] See Attachment C. This excludes the rural deficit reallocation and excludes the fuel price variance portion arising from increased NP use.

[205] The cost of Holyrood fuel saved as a result of the IC 69.1 GW.h load reduction is calculated from Table C2 of this testimony, dividing the sum of $0.053 million (column H row 18) plus negative $2.880 million (column H row 23) divided by the 69.1 GW.h figure.

period, NP is projected to exceed their overall GRA test year forecast energy by a total 274.1 GW.h[206] while IC is forecast to vary only a small amount from GRA forecast (6.1 GW.h, with the majority of this due solely to 2004 forecasts being based on a 366 day year).

In the detailed set of tables provided in IC-327, the key conclusion is that, based on the long-term load forecast currently in place, Hydro proposes to operate the load component of the RSP to give rise to the following impacts solely related to the NP load growth over the period:

**Table 7.2 Impact on Forecast NP Load Growth in 2005-2007 on RSP ($millions)**

| | **Refund credit to NP RSP** | **Charge to RSP for fuel to serve increased NP load** | | | **Total Credit (Charge) NP RSP** | **Total Credit (Charge) IC RSP** |
|---|---|---|---|---|---|---|
| | | **Total[207]** | ***Allocation to NP[208]*** | ***Allocation to IC*** | | |
| 2005 | $1.376 | ($1.128) | *($0.822[209])* | *($0.236[210])* | $0.554 | ($0.236) |
| 2006 | $4.799 | ($3.948) | *($2.893[211])* | *($0.817[212])* | $1.906 | ($0.817) |
| 2007 | $8.791 | ($7.518) | *($5.527[213])* | *($1.541[214])* | $3.264 | ($1.541) |
| Total | $14.966 | ($12.594) | *($9.242)* | *($2.594)* | $5.724 | ($2.594) |

In other words, the above indicates a net credit to NP of $5.7 million via the RSP (2.09 cents/kW.h for each unit of load growth for the full 274.1 GW.h growth), while charging IC $2.6 million (0.95 cents/kW.h for each extra kW.h that NP consumes). Given that the above RSP forecast reflects an energy-only NP rate of 5.46 cents/kW.h[215], the net effect of the RSP adjustment is to reduce NP's incremental costs for the additional 274.1 GW.h they are forecast to consume to 3.37 cents/kW.h and require IC customers to pay an incremental cost of NP's consumption of 0.95 cents/kW.h. This results is clearly not consistent with normal rate structure operation, and is contrary to the implied structure of Hydro's rates, which, per the proposed Rate Schedule for NP and IC, reflect a fixed per-unit cost for all firm energy consumption, including incremental load growth.

#### *7.2.4.1.3 The Load Variation provision gives rise to complicated IC versus NP accounting*

For utilities that maintain either fuel price and/or hydraulic stabilization accounts, such as Yukon Energy or the Northwest Territories Power Corporation reviewed in Attachment D, there is no accounting

[206] 25.2 GW.h in 2005, 87.9 GW.h in 2006 and 161.0 GW.h in 2007 per IC-327 pages 8, 19 and 31 respectively.
[207] The IC component of load variation makes up about 1.2% of this amount.
[208] Excludes rural deficit allocation.
[209] 72.89% to NP in 2005 per IC-327 page 10.
[210] 20.90% to IC in 2005 per IC-327 page 10.
[211] 73.28% to NP in 2006 per IC-327 page 22.
[212] 20.69% to IC in 2006 per IC-327 page 22.
[213] 73.52% to NP in 2007 per IC-327 page 34.
[214] 20.50% to IC in 2007 per IC-327 page 34.
[215] See, for example, page 8 of IC-327

required to separate the charges to any particular group of customers. The amounts deferred in the various stabilization accounts are allowed to proceed until such time as a refund/collection is required (generally on a prompt basis for fuel price deferrals, and very infrequently, if ever, for hydraulic stabilization accounts). At that time the adjustment is applied equally to all kW.h sold without distinction between customer groups, as the charges relate to an energy-related cost.

In the Newfoundland Hydro system, this would entail determining the total forecast kW.h sales to IC and NP over the period that an outstanding balance is projected to be collected. The total balance to be collected would be divided by this kW.h sales to IC and NP to determine a single rider. Using the above example, Hydro's Fuel Cost RSP at May 2003 totalled $44.677 million excluding interest to date[216]. If using a 24 month collection period (to be consistent with P.U. 7 (2002-2003)), the IC and NP sales would be about double the 12 month totals from the May 2003 RSP report, or about 11,984 GW.h. The result of the division is an example of a 0.372 cents/kW.h rider for 24 months. As a result of 0.372 cents/kW.h being applied to all wholesale sales to NP, there would be a corresponding retail rider (likely slightly higher than this level, to account for distribution losses) that would likewise be applied to Hydro's rural customers[217]. As a result, Hydro's collections to be used in paying down the RSP balance would include 0.372 cents/kW.h on all kW.h sold to IC and NP, plus a slightly higher rider on Hydro's rural customers.

##### *7.2.4.1.4 The Load Variation provision results in inconsistent treatment of special rates to NP and IC (wheeling and firming-up)*

A very small portion of Hydro's revenue requirement is made up of two special purposes charges – one available to industrial customers who seek to "wheel" power across Hydro's transmission lines, and one available to NP, who on occasion purchases power from Hydro which Hydro has purchased from an industrial customer on an interruptible basis and seeks to have Hydro "firm-up" this supply. In each case, Hydro develops a rate that reflects the embedded cost of Hydro's plant that is required to provide the service (gas turbines, transmission and terminal stations for firming up, transmission and terminal stations for wheeling).

The cost of service and rate treatment for revenues derived from these two rates is substantially different. For wheeling service, Hydro credits the Island Interconnected revenue requirement with the full forecast revenues[218], and any amounts charged in excess of this amount appears to be simply a credit to Hydro's net income. The revenues derived from wheeling rates in the past 5 years are set out in CA-

---

[216] Ideally the amount to be collected would target the full current balance, plus the forecast RSP fuel-related charges for some next number of months, plus the expected interest that would accrue on that balance during the collection period, such that at some point in the future the Fuel Price RSP would be projected to come back down to zero.

[217] This is to reflect the normal practice of changing Hydro's rural customer rates at the same rates implemented for NP's customers.

[218] $70,964 per RDG-1 Schedule 1.1 line 14.

151[219] reflecting revenues as high as $414,522 in 2002. This compares to a forecast of $6,950 in the original 2001 application, and a forecast $0 in the final cost-of-service from the 2001 application[220].

In contrast, although firming up revenues are forecast at $0 in the cost of service, any revenues actually received are credited in full to the NP RSP[221]. In other words, any and all amounts paid by NP for the firming-up service are credited directly back to NP such that the firming up service is provided to them at a net cost of zero. Other customers likewise see no benefit from the firming up revenues, despite the fact that the other customers are paying for the assets that allow this service to be provided.

In each case, the revenues from these special rates are quite minimal on a forecast basis. Actual wheeling revenues can be substantial, as noted above, but it appears actual firming-up revenues are typically very small. Despite the dollar impact, the different treatment in the two rates is an additional indication of the distinct and preferential treatment of NP compared to IC.

On balance, there is no basis to address load variation from wheeling revenues or firming up revenues as a specific credit to any group of customers. The inconsistent impact of the RSP Load Variation provision in regards to these two rates would also be properly addressed by eliminating the RSP load variation component.

#### 7.2.4.2 Hydraulic Production Variation

The hydraulic variation component of the RSP is a long-term stabilization mechanism that should not be collected and/or refunded on a two-year cycle, but rather focus on staying within a sensible operating range over the long-term. With proper long-term hydro generation forecasts, it would be expected that the hydro production component would *never* lead to additional charges or refunds to customers.

Despite this theoretical basis, the hydraulic component of Hydro's RSP, over the period 1992 to 2000, refunded to customers somewhere on the order of $78 million[222] (due to high water), but the nine-month period from September 2002 to May 2003 has resulted in about negative $11.3 million (due to low water) that Hydro proposes to start charging to customers starting December 2003 (for IC, July 2004 for NP).

During the early part of the 1980's, Hydro maintained a separate provision for hydraulic variation (a 'Water Equalization Provision'). According to Board Decision P.U. 7 (2002-2003) "The water equalization account had a maximum provision of $36,000,000 which was considered sufficient to absorb the adverse

---

219 The amounts in CA-151 reflect $137,243 in 1998, $230,012 in 1999, $185,367 in 2000, $350,957 in 2001 and $414,552 in 2002.

220 The final cost of service reflecting P.U. 7 (2002-2003) and P.U. 16 (2002-2003) dated August 2002 at Schedule 1.1 line 14.

221 Also see CA-67 which notes that no firming-up revenue is forecast, and all actual revenues are refunded via the RSP.

222 This figure comes from the sum of the December RSP reports from the nine-year period, but was summarized in NLH-99 from the 2001 proceeding.

affects of a reoccurrence of the three consecutive driest years on record"[223]. Hydro's current evidence at Haynes, Schedule II indicates that the difference between average hydro conditions (4582.2 GW.h) and firm energy availability (presumably the measure of energy available in the driest year contemplated, at 3846.0 GW.h) is 736.2 GW.h per year. Using the 'three dry years' approach noted above, this would result in somewhere on the order of 2208.6 GW.h in variation over 3 years[224]. Using current fuel price forecasts[225] and Holyrood efficiency estimates[226], this would equate to a modern trigger of about $103 million.

Comparable hydro stabilization accounts in other non-interconnected jurisdictions suggest triggers on the order of $43 million to $77 million[227]. Using any of the approaches, the current $11.3 million balance owing from customers is well within the normal expectations of hydro variability and does not appear to merit any collections from customers in the near term (and ideally no collections until such time as water conditions return to normal or above normal levels).

In terms of price signals, refunds or collections of hydraulic production variances are not a particularly useful part of sending appropriate price signals to customers on the Newfoundland system. This is because in both low water conditions and high water conditions, the incremental generation on the system is basically Holyrood. In other words, a customer reducing their consumption during lower than average flow conditions is not saving the system any more costs than a person reducing their consumption during higher than average flows. This is in contrast to the fuel cost variation component, which should be properly viewed in part as a means to send an important and timely price signal to customers.

#### 7.2.4.3 Fuel Cost Variation

Completely in contrast to the hydraulic variation component notes above, the fuel cost variation is a short-term deferral account that should properly result in some 'smoothing' of the costs of fuel, but still lead to adjustments in the most expeditious way tolerable to ensure timely price signals and minimum inequities.

The record in Newfoundland seems to indicate a basis for concern over smoothing versus deferral. The concept of smoothing fuel cost variations is a requirement to prevent massive and routine rate revisions that are intolerable to customers and difficult to manage for the utility. The pre-1985 Fuel Adjustment

[223] P.U. 7 (2002-2003) page 79.

[224] The level might reasonably be somewhat below this, as the "three driest years on record" does not necessarily need presume three consecutive repeats of the driest year on record.

[225] $29.20 per barrel for 2004 per Haynes Schedule VIII.

[226] 624 kW.h per barrel for 2004 per Haynes Schedule VII

[227] The Northwest Territories Power Corporation maintains a hydro stabilization fund with a trigger of $3 million on a total long-term average annual hydro generation of 177.5 GW.h, and Yukon Energy's comparable "Diesel Contingency Fund" uses a trigger of $4.04 million on annual hydro generation of 351 GW.h – on a comparable basis, Newfoundland Hydro's trigger (on 4,582 GW.h long-term average per Haynes Schedule II) would approximate $77 million and $53 million respectively.

Clause in Newfoundland appears to be a prime example of inadequate smoothing, as fuel price changes appear to have been flowed through monthly resulting in, among other things, a complete inability for customers to plan for or project their electricity costs. In contrast, the extreme response to inadequate smoothing is continual deferral of fuel cost increases in order to ensure rates only rise on an overly-smoothed basis. The present new RSP appears to err somewhat in this fashion.

The new RSP has accumulated about $44 million related to fuel cost variation in nine months (to May 2003), and Hydro appears to propose no implementation of riders to recollect this amount (along with interest on the outstanding balance) until at least December 2003 for IC and July 2004 for NP (a further seven months and thirteen months respectively). This means that for NP customers, the rider that is started in July 2004 is only at that time starting to address the actual costs of fuel from as early as September 2002, and the two-year proposed collection means that this balance will not be fully addressed until June 2006.

A properly administered fuel cost variation account needs to be isolated from proper long-term stabilization accounts (such as the hydraulic variation provision) and ensure that higher costs for fuel get passed through to customers in a timely way consistent with normal rate design objectives that rates are change predictably and gradually to the extent possible. Within the context of the other cost changes arising in the present proceeding, it will be essential to assess the degree to which the deferred fuel cost balances amounts can be discharged in a more timely fashion than that proposed by Hydro to date.

#### 7.2.4.4 Mechanism for Collection

As noted above, with the elimination of the load provision, there is no need or advantage to maintaining any form of separate NP/IC accounting for the RSP components. In the two other non-interconnected jurisdictions in Canada that utilize hydro (each of which has a mixture of Crown and investor-owned utilities, with the Crown utility both selling directly to customers and having wholesale sales to an investor-owned utility retailer), separate hydraulic and fuel stabilization accounts are used for stabilization, and each account is designed to be managed as a single balance for all customers, such that once a trigger is reached, an equal rider is applied to all sales.

#### 7.2.4.5 Interest Rate

The RSP asset/liability to Hydro is not consistent with a long-term investment of the type normally considered to be part of ratebase, or assets that are financed by long-term capital (long-term debt and/or equity). In this regard, it is not apparent that Hydro's weighted average cost of capital is the appropriate interest rate to be charged on outstanding balances.

Looking at the comparable fuel and water stabilization funds maintained by other utilities, it is apparent that there are a number of other approaches that have been utilized by regulators:

- ***Yukon Energy Diesel Contingency Fund:*** This fund which is primarily a hydraulic variance stabilization fund, is managed as a trust outside of rate base, and earns or charges interest based on the prevailing investment/borrowing rate appropriate for short-term investments.

- ***Yukon Energy's Fuel Adjustment account:*** The Fuel Adjustment account maintained by Yukon Energy (as well as the separate fuel adjustment account maintained by the private utility The Yukon Electrical Company Limited) does not earn or pay interest at all[228]. Each Yukon utility is directed to implement fuel rider adjustments on a co-ordinated and timely periodic basis, as required to ensure that balances in these fuel accounts are adjusted periodically to maintain the balance at as low a level as is reasonable.

- ***Northwest Territories Power Corporation Diesel Stabilization Fund:*** NTPC's diesel price stabilization funds charge or credit interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points.

- ***Northwest Territories Power Corporation Hydro Stabilization Fund:*** NTPC's hydraulic ***stabilization*** fund charges or credits interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points.

- ***Nunavut Diesel Stabilization Fund:*** Nunavut Power maintains a diesel price stabilization fund that was broken out of NTPC's consolidated NWT/Nunavut account at the time of the division of the two companies. The Nunavut Utilities Board has reviewed the operation of this fund and approved riders to collect outstanding balances. The Board did not change the previous NTPC approach of charging or crediting interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points.

- ***Centra Gas Manitoba's Purchased Gas Variance Account:*** The Centra Gas Manitoba gas price variance account uses a short-term carrying cost rate to accrue interest.

- ***Idaho Power's Power Cost Adjustment:*** Idaho Power's operation in Idaho maintains a Power Cost adjustment mechanism to address hydraulic and power acquisition price stabilization[229]. This account accrues interest at a rate tied to short-term rates while amounts are being charged to the account, and accrues no interest during periods where the account is being re-collected back from customers.

In summary, we have not been able to identify any such funds outside of Newfoundland that use a full weighted average cost of capital, or any long-term debt or equity cost rate, in calculating interest on the balance.

[228] As another example, the BC Hydro Rate Stabilization Account does not earn interest of any sort. However, as noted above this account is not comparable to the Newfoundland Hydro RSP.
[229] Both fuel costs and purchased power costs. The mechanism specifically excludes load changes from the calculation.

## 7.3 INTERRUPTIBLE B

The Interruptible B program previously offered by Hydro up to 2003 is outlined in Attachment H. Hydro now proposes to no longer offer this component of its industrial rates.

The specific details of the Interruptible B rate program are set out in Attachment H. Briefly, this program was in place under a contract from December, 1993 to March, 2003, and provided Hydro with the ability to call upon Abitibi Stephenville, at any time during the four winter months between the hours of 0800 and 2200, to reduce their power consumption by up to 46 MW for up to 10 hours. The interruption could be initiated on one hour's notice. This type of program is similar to interruptible capacity rate offerings by other utilities, as outlined in Attachment G to this submission.

Use of a curtailable program by large industrial customers requires a portion of their load to be served by this lower quality power (defined to be of lower quality than firm power since it can be interrupted on short notice). In order to enable their operations to utilize this low quality power, there can be substantial required investment in capital, development of operating procedures, and staff training. The quantities of power in question (46 MW) form a substantial part of the capacity that is normally consumed by the customer. Subscription to Interruptible B can require changes to many facets of a large organization in order to optimally respond to the requirement for a curtailment. This type of program cannot be easily implemented on short notice (i.e., changing program availability from year to year).

In the case of Manitoba's Curtailable Service program discussed in Attachment G, this rate offering is reviewed and approved by Public Utilities Board, and is made available to all qualified industrial participants[230] (up to a maximum subscription limit). A recent review by the Manitoba Public Utilities Board regarding renewal of the program concluded that the program was to be renewed on a permanent basis[231]. The Manitoba PUB had previously concluded that the program would benefit both Manitoba Hydro and its overall ratepayers[232] (not just the industrial customers who subscribe to the program). Manitoba Hydro, in a submission to the PUB regarding the Curtailable program, specifically noted that the program benefits arise from the long-term participation of the loads, and as such the program had to be viewed in terms of retaining the loads and the program participants over the long-term. Specifically, Manitoba Hydro's rebuttal evidence filed in the 2002 Status Update Filing before the Manitoba PUB notes, at page 35:

> "It is a fact that Manitoba Hydro's curtailable rate offerings have always relied, to a certain extent, on the longer term benefits, even where current program duration may not be sufficient to capture these benefits and, in fact, even during the period that the program was experimental. However, Manitoba Hydro's experience is also that most curtailable load can be expected to be available in the longer term, provided that some

[230] Customers must have a minimum of 5 MW of curtailable load.
[231] Manitoba PUB Order 7/03.
[232] Manitoba PUB Order 148/93.

> recognition is given to the longer term benefits in the early years to justify the necessary customer investment to be able to participate. "

In contrast, Newfoundland Hydro appears to have determined that it will ignore long-term benefits from curtailable load. Hydro has confirmed that a program such as Interruptible B would be among the items considered to address future capacity shortages[233].

It is apparent that Hydro is not in a capacity constrained situation at the current time. To the extent that Hydro has determined it is appropriate to retain all currently installed peaking generation plant in revenue requirement as used and useful assets, there is a clear recognition that although these assets are not required to retain the LOLH below the target maximum of 2.8 hours in the short-term, they may reflect a longer-term benefit to the Island Interconnected system. The same rationale supports continuation of the Interruptible B program on an uninterrupted basis.

The response to CA-156-IC indicates that Abitibi Stephenville has approached Hydro to renew the Interruptible B program for another 10 years, at the same terms and conditions as the ten-year contract from 1993 to 2003. This proposal reflects a discount to Abitibi on the power costs they would otherwise pay, and results in the discount remaining constant for 20 years (with no provision for inflation or other escalation). Recognizing the long-term benefits of a rate of this type, it is apparent that the Board should ensure Hydro offers the Interruptible B rate to Abitibi Stephenville as proposed (i.e., on the same terms and conditions as for the previous agreement)[234]. It is also apparent that Hydro should be directed to study the long term avoided cost benefits arising from expanding the rate program to other industrial customers, and consider the maximum additional Interruptible B that it could make available to other industrial customers in the future[235].

---

[233] NP-138.

[234] This does not specifically address whether the rate would be required to be offered to all industrial customers on the same basis. If that were determined to be the case, the 46 MW of subscription should be made available, and allocated to all industrial customers that are interested using some reasonable approach to apportionment. The rest of the proposal as it reflects expansion beyond 46 MW is valid in either case.

[235] Hydro has confirmed that it has not investigated the expansion of the program in NP-139.

# ATTACHMENT A – RESUME - CAMERON F. OSLER

## PRESIDENT AND SENIOR CONSULTANT

**EDUCATION:**

Simon Fraser University
M.A. (Economics) 1968

University of Toronto Law School
1964-1965

University of Manitoba
B.A. (Philosophy) 1964

**PROFESSIONAL HISTORY:**

1974 - Present

Founding partner and President of InterGroup Consultants Ltd. (formerly InterGroup Consulting Economists Ltd.). Director, CBT Energy Inc. (2000 - Present)

Strategic planning and multi-disciplinary project team management experience, based on resource and regional economics expertise relating to mining, energy (particularly hydro-electric generation and renewable liquid energy fuels), and downtown tri-government urban development projects.

Detailed project experience is outlined below separately under each of the following headings:

- Utility Regulation – Expert Analysis and Testimony at Hearings
- Strategic Planning & Multi-disciplinary Project Team Management - Resource, Regional and Urban Development Projects
- Socio-Economic and Environmental Assessment & Related Public Consultation – Mining, Hydro-electric, Forestry and Other Major Projects
- Compensation & Monitoring Related to Resource Project Impacts
- Resource Rent, Royalty and Tax Policy – Related Expert Evidence
- Other Strategic Planning and Assessment

***Utility Regulation – Expert Analysis and Testimony at Hearings***

- **For the Island Industrial Customers of Newfoundland Hydro (2001),** expert testimony before the Board of Commissioners of Public Utilities of Newfoundland and Labrador regarding the Newfoundland and Labrador Hydro 2001 General Rate Application.

- **For the Manitoba Industrial Power Users Group (1987-1999),** expert testimony before the Manitoba Public Utilities Board in Manitoba Hydro electricity rate hearings, including rate applications in 1987/88, 1989, 1990, 1991, 1992, 1994, 1995, and 1998, and the Manitoba Hydro Major Capital Projects hearing in 1990. Represented MIPUG at hearings before the Board in 1999 to approve the purchase of Centra Gas by Manitoba Hydro.

- **For the Yukon Energy Corporation (1989-2002)**, expert testimony before the Yukon Utilities Board on planning major capital projects (1992) and on electricity costing and rates related to rate applications by Yukon Energy Corporation (1989, 1991, 1993, 1996, 1997, 1998). Also, expert testimony before the Yukon Territorial Water Board in regards a renewal water licence for the Aishihik Generation Station (2001/02)

- **For the Bruce Municipal Telephone System in the early 1990s,** expert economic evidence to the Ontario Telephone Service Commission related to the cost of equity capital.

- **For Government of Yukon, expert testimony before the National Energy Board in 1985**, expert testimony on costs and rates pertaining to the Northern Canada Power Commission.

- **For IPSCO during the 1980s**, expert testimony before Saskatchewan Utilities Regulatory Commission hearing on the first and second rate applications by Saskatchewan Power Commission.

- **For Stelco, INCO and the Motor Vehicle Manufacturers' Association of Canada, in the 1977-1979 Ontario Energy Board hearings HR5,** examining Ontario Hydro's electricity costing and pricing principles; provided consulting advice and expert testimony on the issues and options pertaining to that hearing.

- **For a consortium (The Consumers' Gas Company, Union Gas, Northern and Central Gas and the Ontario Ministry of Energy), a 1974 report on natural gas requirements throughout Canada;** provided expert testimony before the National Energy Board on this report.

***Strategic Planning & Multi-disciplinary Project Team Management - Resource, Regional and Urban Development Projects***

- **For the City of Winnipeg and Neeginan Development Corporation (1998),** project director responsible for preparation of the Development Plan for the Thunderbird House project on Main Street.

- **For Spirit of Manitoba Inc. and Manitoba Entertainment Complex Inc. (1994-1995),** responsible for management of all aspects of a project to develop a new downtown entertainment complex and to retain the Winnipeg Jets Hockey Club in Winnipeg; managed the multi-disciplinary team carrying out negotiations, siting, design, costs, feasibility planning, environmental assessments, and other work required to secure approvals under tight deadlines specifically for the new arena component of the project.

- **For The Forks Renewal Corporation (a corporation owned by Canada, Manitoba and Winnipeg) during the late 1980's and early 1990's,** Development Coordinator responsible for planning and directing initial development and financial activities (1987-1993), including negotiation of land exchange agreements, preparation of a Phase I Concept and Financial Plan, site planning and Stage One projects, roads and services; ongoing financial and strategic planning counsel.

- **For Government of Yukon (Department of Economic Development, Mines & Small Business) (1985-1987),** management of multi-disciplinary team carrying out financial, economic, legal and strategic planning work relating to the devolution and transfer to Yukon of the Northern Canada Power Commission assets and operations in Yukon; participation in all related negotiations.

- **For the East Yard Task Force (comprised of the governments of Canada, Manitoba and Winnipeg) (1985-1986),** general advisor and manager for all consultant work (planning and architectural, engineering, financial and legal) related to the redevelopment of a major rail yard area in downtown Winnipeg.

- **For North Portage Development Corporation (1984-1987),** economics and financial counsel during the initial development phase; coordinator for work relating to corporate financial plans, selection of major developers (retail, housing and office projects), and negotiation of long-term agreements (land lease, development and other related agreements) with each of the selected developers.

- **For Canadian Methanol Canadien during the 1980s**, participation in an executive capacity in a partnership venture involving Inter-City Gas Corporation and The M100 Group to develop methanol vehicle fuel [management of multidisciplinary project team involving engineers, planners, financial, legal, and other professionals to demonstrate and develop hybrid (natural gas and wood feedstock) methanol production facilities as well as different market uses for methanol (including use in flexible fuel passenger vehicles)].

- **For the Government of Canada in the late 1970s,** project director of a major multi-disciplinary study to examine the feasibility of producing liquid fuels (including methanol) from biomass feedstock resources throughout Canada; this study included examination of liquid fuel production options involving the joint use of either electricity or natural gas along with biomass feedstock. The multi-disciplinary consulting team included firms with chemical engineering and forestry expertise.

***Socio-Economic and Environmental Assessment & Related Public Consultation – Mining, Hydro-electric, Forestry and Other Major Projects***

- **For Manitoba Hydro (1999 – Present),** Study Leader responsible for socio-economic assessment and planning work as well as public involvement activities in a multi-disciplinary Consultant Management Team retained to assist Manitoba Hydro in the conduct of the environmental assessment programs associated with future planning for three potential hydroelectric generating stations in northern Manitoba, including site selection and environmental assessments for the associated transmission facilities.

- **For uranium mining companies in northern Saskatchewan during the 1990s**, project director for consultants regarding socio-economic impact assessment, economic impact and cost-benefit assessments, and public consultation design and implementation for the Rabbit Lake expansions (Cameco Corporation, 1991-1993), the McArthur River developments (Cameco Corporation, 1993-1996), the Cigar Lake developments (Cigar Lake Mining Corporation, 1993-1996), and the Rabbit Lake extension (Cameco Corporation, 1999-); provided related evidence and expert witness testimony for the Rabbit Lake federal environmental review panel hearing and the McArthur River developments federal-provincial environmental review panel hearings. Provided advisory review for InterGroup's similar socio-economic and economic impact assessments, and public consultation work for COGEMA related to Cluff Lake mine projects during this period.

- **For Yukon Energy Corporation (1992-1996**), advisory reviews of environmental impact assessment work for re-licensing of the Aishihik hydro-generation facility.

- **For Cameco, Cigar Lake Mining Corporation and COGEMA (1993-1994),** facilitation of an agreement in principle for an impact management agreement involving seven Athabaska communities (this was one element of the socio-economic/public consultation EIS work related to the McArthur River and CLMC projects).

- **For Repap Manitoba, Inc. (1989-1991)**, project management of the socio-economic impact assessment, and design and implementation of an extensive public consultation program, for the proposed Phase 1 Manitoba expansion.

- **For aggregate producers in Ontario during the 1980's and early 1990s,** socio-economic impact and resource policy evaluations relating to proposed aggregate developments in southern Ontario (Puslinch, Milton and Niagara Escarpment Planning Area); provision of resource economics expert testimony before the Ontario Municipal Board on behalf of TCG Materials Limited and on behalf of Armbro Aggregate.

- **For the City of Winnipeg in the 1990s**, socio-economic impact assessment for the new Charleswood and Main/Norwood bridge developments (two separate assignments; provided advisory review for other InterGroup principals who directed this work, as well as assistance in coordination of hearing testimony for the regulatory review of the Charleswood bridge project.

- **For the Moosonee Development Area Board (early 1990s),** socio-economic counsel in an intervention relating to potential impacts of Ontario Hydro's proposed hydro generation development of the Moose River Basin.

- **For Manitoba Hydro in the late 1980s and 1990s,** senior advisory review as required by other InterGroup principals carrying out the following assignments: socio-economic impact assessment and public consultation program for the Conawapa hydro generating station EIS (1989-1993); socio-economic impact assessment and public consultation program for the Split Lake transmission line project (joint study with the First Nation, early 1990's); socio-economic impact assessment and public consultation program for the siting and the EIS related to the Winnipeg-Brandon transmission line and Neepawa substation projects (1995-1997); study to review environmental externality and compensation cost modeling for hydro-generation and related transmission line projects (1996-1997). Deputy

Project Director for initial environmental assessments study for third Bipole Transmission Lines (1986-1987).

- **For Manitoba Hydro in the early-to-mid 1980s,** various investigations with respect to the environmental and socio-economic impacts related to planning of new power generation projects in northern Manitoba, including deputy project director for the Burntwood River Environmental Overview Study (1980-1984), and review of InterGroup's work (carried out by senior staff) to prepare the socio-economic assessment and conduct public consultation for the Limestone hydro-electric generating station EIS.

- **For Alcan in the early 1980s,** management of investigations with respect to the socio-economic impacts of a proposed aluminum smelter in Manitoba.

- **For Key Lake Mining Corporation in the early 1980s,** expert testimony before the Commission of Enquiry on socio-economic impacts associated with the uranium project at Key Lake.

- **For Amok Ltd., in the 1977 Saskatchewan hearings on uranium developments,** provided expert testimony before the Bayda Commission of Enquiry on socio-economic impacts associated with the Amok mining project at Cluff Lake.

***Compensation & Monitoring Related to Resource Project Impacts***

- **For Tsay Keh Dene Treaty Society (2001-2003),** negotiation of framework agreement to address flooding impacts of the BC Hydro Williston Lake/Bennett Dam project.

- **For Kwadacha First Nation (2001-2003),** expert utility economics and socio-economics assistance in respect of negotiation of framework agreement to address flooding impacts of the BC Hydro Williston Lake/Bennett Dam project.

- **For Manitoba Hydro in the 1990s,** expert socio-economic and resource economics assistance with respect to claims by the community of South Indian Lake (early 1990's) and by Northern Flood Agreement communities, including the Cross Lake First Nation (1999 - Present), related to post-project development impacts from hydroelectric power development.

- **For uranium mining companies (1999),** project director for the preparation of a draft work plan for a community vitality monitoring program for northern communities in Saskatchewan affected by uranium mining development; the work plan requirement arose out of federal-provincial environmental impact panel hearings on the McArthur River and Cigar Lake mining projects; the work plan was prepared for a working committee with representatives from the three uranium mining companies (Cameco Corporation, COGEMA, and Cigar Lake Mining Corporation0, the Saskatchewan Northern Mines Monitoring Secretariat, and the northern Saskatchewan Health Districts.

- **For BC Hydro (early 1990s),** evaluation of a trust fund proposed to compensate five Lillooet Nation Bands for damages from hydroelectric generation and transmission activities.

- **For the Beaufort Sea Steering Committee (early 1990s),** review of wildlife compensation program options in the event of an oil spill in the Beaufort Sea.

- **For Manitoba Hydro (1989-1990),** project management of an independent post-project evaluation of the Grand Rapids Project impacts on Aboriginal communities, including direction of the socio-economic component of the evaluation.

***Resource Rent, Royalty and Tax Policy – Related Expert Evidence***

- **For Regional Municipality of Ottawa Carleton (RMOC) in the mid-1990's,** expert resource and regulatory economist evidence before the Ontario Municipal Board on By-Law 234/92, which imposed compensation payments on private landfill operators in the Region.

- **For a group of pipeline companies in Ontario (1989-1992),** assistance with coordination of expert evidence in an arbitration, and provision of expert evidence on methodology to determine annual rent for pipeline use of a transmission corridor owned by Ontario Hydro.

- **For Sun Oil in the 1970s,** counsel on preparation of a brief to the Government of Canada on the proposed Federal Land Regulations for Oil and Gas Lands.

- **For the Canadian Potash Producers' Association in the 1970s and early 1980s,** expert assistance with taxation discussions with Saskatchewan authorities, analysis of the proposed government takeover of the potash industry, and liaison with legal counsel.

- **For the Uranerz-Inexco joint venture in the 1970s,** participation in discussions between the Saskatchewan Government and the uranium industry concerning uranium taxation revisions; provided economic counsel for these discussions.

- **For the Mining Association of British Columbia in the 1970s**, expert testimony before the Commission of Enquiry into property taxation in that province.

- **For the Mining Association of Canada in the 1970s**, preparation of analytical models for comparison of different mineral taxation structures.

- **For Canadian Industrial Oil and Gas Ltd. In the 1970s**, analysis of the public policy aspects of Saskatchewan Bill 42 relating to taxation (advice to legal counsel related to a court case).

***Other Strategic Planning and Assessment***

- **For Manitoba Hydro (1999 – Present),** assistance on various matters, including policy reviews related to debris management programs and planning related to US market consultations.

- **For the Yukon Energy Corporation and the Yukon Development Corporation (1987-ongoing),** financial and strategic planning counsel on major issues, including rate policy planning (see also Utility Regulation), major capital planning issues (see also Environmental Assessment), management agreement arrangements, and negotiations between YEC and various owners of the Faro mine.

- **For the Northern Manitoba Economic Development Commission (1991-1992),** participation in the preparation of two reports, contributing to the Commission's Sustainable Economic Development Plan for Northern Manitoba for the 1990s.

- **For Regional Municipality of Ottawa Carleton (RMOC) during the 1990s,** economic assessments of options to extend the life of the Trail Road Landfill site.

- **For Metropolitan Toronto (late 1980s),** economic analysis of the best available technology for the utilization of the landfill gas resources at the Keele Valley Landfill site.

- **For a western energy company (early 1990s),** preparation of a Cost-Benefit Analysis of a 160 MW co-generation project, assessment of the implications of the project for Manitoba Hydro, and participation in the discussions between the company and Manitoba Hydro.

- **For Western Economic Diversification (late 1980s),** assessment of Winnipeg tri-government development corporation cash flow scenarios.

- **For the Government of Manitoba during the late 1980s and early 1990s,** advice and assistance in the preparation of proposal calls for the redevelopment of a historically significant site in Winnipeg, as well as participation in the developer selection and negotiation process.

- **For the Canadian Electrical Association in the late 1970s,** management of interdisciplinary team investigations with respect to the impacts of proposed federal atmospheric emission control guidelines on Canadian electrical generating industry thermal power stations.

1968 - 1974 MANAGER AND SENIOR CONSULTANT, Hedlin Menzies/Acres Consulting Services (Winnipeg)

RESEARCH ECONOMIST, Hedlin Menzies & Associates Ltd. (Winnipeg)

Project manager of major studies involving regional resource and cost-benefit impact policy issues relating to prairie manufacturing, prairie elevator and transportation rationalization, Manitoba Hydro northern development activities, Canadian energy requirements and research and development priorities, alternative export policies for natural gas, Canadian Merchant Marine development options, alternative rail route options in the Yukon and northern British Columbia, and various mineral resource policy options pertaining to mining development and taxation.

Sessional lecturer on mineral economics for one year at the University of Manitoba's Natural Resources Institute.

**RESEARCH PAPERS:**

"The Process of Urbanization in Canada, 1600-1961." Simon Fraser University (M.A.) Thesis. 1968.

"Technological Change and the Economics of Agricultural Development." Simon Fraser University (M.A.) Thesis. 1968.

"Economic Analysis of Short-Term Alternatives Regarding Southern Indian Lake in Manitoba" (joint work with Dr. A.M. Lansdown, P.Eng., 1969).

"A New National Development Policy for Canada: The Relevance of Western Canada." Prepared for the Liberal Conference on Western Objectives. 1973.

"Canada's Gains and Losses from Oil Export Taxes" (joint work with Dr. R.W. Fenton, 1973).

"Resource Management Factors Influencing Mineral Development in North Central Canada." Paper presented to the annual western meeting of the Canadian Institute of Mining and Metallurgy, Winnipeg, October 7, 1974.

"Energy, Provincial Rights and Canadian Unity." 1973.

"An Evaluation of 'An Energy Policy for Canada' " (joint work with Dr. R.W. Fenton, 1973).

"Resource Management Factors Influencing Manitoba Mining." Natural Resources Institute, University of Manitoba. 1974.

"Liquid Fuels from Renewable Resources in Canada: Systems Economic Studies." Paper presented to the Institute of Gas Technology Symposium on Energy from Biomass and Wastes, Washington, DC. August 1978.

"Canadian Scenario for Methanol Fuel." Paper presented to the Alcohol Fuels Technology Third International Symposium, California, January 1979.

"Socio-Economic Impacts from Potential Canadian Methanol Fuel Development." Paper presented to the IV International Symposium on Alcohol Fuels Technology, Brazil. October 1980.

"Canadian Methanol Development Using Natural Gas and Wood Feedstocks." Paper presented to the First IEA Conference on New Energy Conservation Technologies and their Commercialization, Berlin. April 1981.

"Methanol as an Alternative Automotive Fuel: CMC's Approach and Experience." Paper presented to the West Coast International Meeting of the Society of Automotive Engineering, Vancouver, BC. August 1983.

"Status of CMC Fuel Methanol Production and Market Development Programs." Paper presented to the VI International Symposium on Alcohol Fuels Technology, Ottawa. May 21-25, 1984.

# ATTACHMENT B – RESUME – PATRICK BOWMAN

## CONSULTANT

**EDUCATION:** MNRM (Natural Resource Management), University of Manitoba, 1998. Specialized in Resource Economics and Land-Use Policy

BA (Human Development and Outdoor Education), Prescott College, 1994.

**PROFESSIONAL HISTORY:**

**InterGroup Consultants Ltd., Winnipeg, MB**

1998 – Present *Research Analyst/Consultant*

Regulatory economic analysis and socio-economic impact assessment experience, primarily in the energy field.

***Utility Regulation***

Conducted research and analysis for regulatory reviews of electrical and gas utilities in four Canadian provinces. Prepare evidence and review testimony for regulatory hearings. Assist in utility capital and operations planning to assess impact on rates and long-term rate stability.

- **For Yukon Energy Corporation (1998-present)**, analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Prepare analysis of major transmission line project and design flexible financing mechanism to reduce "rate shock" to ratepayers.

- **For Yukon Development Corporation (1998-present)**, prepare analysis and submission on energy matters to Government round table on competitiveness of Yukon economy. Coordinate development of options for government rate subsidy program.

- **For Northwest Territories Power Corporation (2000-present)**, provide technical analysis and counsel regarding General Rate Application. Assist in preparation of evidence, filings before the Northwest Territories' Public Utilities Board, appearance to provide expert testimony, and related issues.

- **For Manitoba Industrial Power Users Group (1998-present)**, prepare analysis, evidence and argument for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Submission of expert testimony and appear before commission. Assist in regulatory analysis of the purchase of local gas distributor by Manitoba Hydro. Assist industrial power users in dealings with Manitoba Hydro regarding alternative rate structures and surplus energy rates.

- **For Nexen Chemicals, Inc. (2000)**, review options for subscribing to curtailable service rates.

- **For Columbia Power Corporation/Columbia Basin Trust and Municipal Interveners (2000),** review evidence and prepare analysis on major transmission line project for Public Convenience and Necessity hearing before the British Columbia Utilities Commission.

- **For the City of Yellowknife (1999)**, prepare preliminary analysis of policy options and planning process for development of a municipal piped propane distribution system.

- **For the Government of the Northwest Territories (1999)**, prepare analysis of policy alternatives to facilitate supply of natural gas to local communities in the event of a Mackenzie Valley pipeline being constructed.

- **For INCO Manitoba Division (1998-present)**, prepare analysis of energy costs under various alternative industrial rate options. Provide recommendations on preferred energy rate options.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-02),** prepare analysis and assist in preparation of evidence for Newfoundland Hydro GRA before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users.

***Socio-Economic Impact Assessment and Mitigation***

Primarily involved in socio-economic planning and assessment work for new northern hydroelectric generation and transmission projects in Manitoba, forestry harvest planning in Manitoba and Saskatchewan, and impact mitigation programs in northern Manitoba. Also conducted assessment of socio-economic impacts of policy options for floodplain management, and strategic planning for resource management board.

- **For Manitoba Hydro Power Major Projects Planning Department (1999-present)**, review and analysis of socio-economic impacts of proposed new northern generation stations and associated transmission. Assist Manitoba Hydro and northern First Nations in impact assessment and management options, including mitigation and compensation mechanisms.

- **For Manitoba Hydro Mitigation Department (1999-present)**, provide analysis and process support to implementation of mitigation programs related to past northern generation projects. Assist in preparation of materials for independent inquiry into northern hydro developments. Provide analysis and support to Manitoba Hydro in addressing compensation claims.

- **For International Joint Commission (1998)**, analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of other floodplain management policies.

- **For Nelson River Sturgeon Co-Management Board (1998)**, an assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

- **For two separate forestry harvest proposals and one uranium mining operation**, identification and analysis of expected socio-economic impacts of various forest/deposit management plans. Preparation of socio-economic portions of submissions to regulatory authorities.

**Government of the Northwest Territories, Yellowknife, NT**

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.

**Natural Resources Institute, Winnipeg, MB**

1996 - 1998 *Researcher*

Conducted research on surface rights allocation and access for mining, with particular emphasis on implications of government actions undermining mineral rights tenures.

Undertook analysis of Manitoba's Registered Trapline System and implications for Aboriginal trappers; also, an economic assessment of the property rights system inherent in the provincial Registered Trapline System policy and its implications on efficiency in allocation of the furbearer resource.

**PUBLICATIONS:** G*overnment Withdrawals of Mining Interests* in Great Plains Natural Resources Journal. University of South Dakota School of Law. Spring 1997.

*Legal Framework for the Registered Trapline System* in Aboriginal Trappers and Manitoba's Registered Trapline System: Assessing the Constraints and Opportunities. Natural Resources Institute. 1997

*Land Use and Protected Areas Policy in Manitoba: An evaluation of multiple-use approaches.* Natural Resources Institute. (Masters Thesis). 1998

*Electrical Rates in Yukon.* Submission by Yukon Development Corporation to Yukon "Government Leader's Economic Forum Series" on Tax Reform and Competitiveness. 1999.

*Review of Red River Basin Floodplain Management Policies and Programs.* Prepared for Red River Basin Task Force of the International Joint Commission. 1998.

# ATTACHMENT C – DETAILED ANALYSIS OF 'NEW' RATE STABILIZATION PLAN

To date, the RSP monthly reports from September 2002 to May 2003 have been made available for analysis. This covers the first nine months of Hydro's operation of the 'new RSP' as established by P.U. 7 (2002-2003).

## HYDRAULIC VARIATION COMPONENT

The hydraulic variation component requires three variables to calculate the monthly values – the cost of service long-term forecast hydro generation, the actual monthly hydro generation and the forecast price of #6 fuel. The variation in hydro, defined as the difference between long-term forecast hydro generation and actual hydro generation, is translated in a quantity of fuel (using the approved Holyrood efficiency of 615 kW.h/barrel). Using the approved price of #6 fuel, the cost of the hydraulic generation variance from forecast can be determined.

For the months of September 2002 to May 2003, this is set out in the top portion of Table C1 attached (rows 1 to 12). Column A is the forecast long-term average generation, column B is the actual generation and column C is the variance (calculated as column B minus column A). The approved cost of fuel is shown in column D which yields the cost of the hydraulic variance in column E. The nine months in question indicate seven with below forecast generation and two above forecast (March 2003 and May 2003). The net impact on Hydro is $7.02 million in 2002 and $4.29 million in 2003. The RSP is charged with these amounts as an appropriation to Hydro's income.

Columns G to I show the allocation of these amounts among NP, IC and Rural based on the December, 2002 12 months-to-date sales for those portions arising in 2002, and the May, 2003 12 months-to-date sales for those portions arising in 2003[236].

The net result of the hydro variance is $8.25 million charged to NP's RSP account, $2.34 million to the IC RSP, and $0.72 million to Rural (which is then re-allocated back to NP and Labrador based on a calculated rural deficit ratio)[237]. Rural amounts allocated to Labrador appear to be written off while rural amounts allocated back to NP are added to the NP RSP balance to be collected.

The hydraulic component of the RSP has no need for an NP/IC distinction.

## FUEL COST VARIATION COMPONENT

The fuel cost variation component for the nine months of available data is similarly set out in Table C1 (rows 13 to 24). The fuel variation likewise require only three variables to calculate the RSP amounts –

[236] These ratios will be re-calculated monthly until December 2003, when the year-to-date total will be locked in as an allocation to each of the customer groups.
[237] We have not specifically reviewed the rural deficit re-allocation ratios.

the approved forecast cost of fuel (column A), the actual cost of fuel (column B) and the actual barrels consumed (column D). Column C sets out the difference between forecast and actual price of fuel, and column E is the total fuel cost variance (the variance in price per barrel times the number of barrels). In this case, all nine months had actual prices of fuel above the forecast cost (by as much as $19.80 per barrel in February 2003).

Similar to the hydraulic variation component, the fuel variation is allocated among the customer groups using 12 months-to-date sales at columns G to I.

The hydraulic component of the RSP has no need for an NP/IC distinction.

## LOAD VARIATION COMPONENT

The Load variation component is set out at Table C2. In this case, the RSP is required to be calculated separately for IC and NP.

- ***Newfoundland Power:*** The top of the Table (rows 1 to 14) sets out the NP calculation based on the NP COS sales (column A) compared to the actual NP sales (column B) to determine the monthly variance (column C). This variance gives rise to a revenue variance (columns D and E) and a fuel cost variance (columns F and G) predicated on the simple assumption that all incremental sales growth or reductions result in additions or savings to the quantity of fuel that would otherwise be burned at Holyrood on a one-to-one basis.

  The sum of the values shown in column E and column G are the changes in Hydro's earnings that arise as a result of the NP load variation. For example, in this case NP's extra load growth of about 207.9 GW.h (the sum of column C, rows 1 to 9) gives rise to $9.936 million in additional revenue to Hydro[238] and $8.445 million in extra costs to Hydro at Holyrood[239]. The net impact on Hydro is $1.511 million in additional net revenues during this nine month period.

  The allocations of these amounts are set out in row 10-14 and columns I-K. In simple terms, the full revenue that arises from the extra sales to NP ($9.956 million) is credited directly back to this customer. Then the $8.445 million in extra fuel costs to serve this load is allocated among NP, IC and Rural using the ratios reflected in columns I to K, such that NP is charged with only $6.182 million of the extra fuel consumed to serve their load growth, IC is charged $1.725 million as a result of NP's load growth, and Rural is charged $0.539 million[240].

  On an overall basis, NP's extra loads cause three impacts on NP – an extra cost of $9.956 million in the rates they pay during the year, an RSP credit equal to the full and exact $9.936 million that

[238] Table C2, Column E row 10.

[239] Table C2, column H rows 4 and 9. The RSP Load Variation provision reflects the 2001 GRA forecast prices of #6 fuel

[240] Most of this amount is assigned to the NP RSP, although a portion is assigned to Labrador and apparently written off by Hydro

they paid in their rates, and an RSP charge of only $6.182 million[241]. On the 207.9 GW.h, this represents a net cost of NP's increased consumption of 2.97 cents/kW.h[242]. For the IC, the net impact of NP's increased consumption is a cost of $1.725 million, or a *cost* of 0.83 cents/kW.h for every extra kW.h that NP consumes[243].

- ***Industrial Customers:*** For the IC loads, the results are set out in rows 15 to 28. The IC load variation over this nine month period is a load *decrease* compared to forecast of about 69.1 GW.h[244] which gives rise to a lost revenue to Hydro of $1.649 million compared to forecast[245]. This load reduction also gives rise to a fuel savings (using the 2001 GRA prices of #6 fuel) of $2.827 million[246] for a net impact on Hydro of a $1.178 million savings.

  The allocation of these amounts at columns I to K illustrate that the fuel cost savings of $2.827 million is credited $2.073 million to NP, $0.573 million to IC and $0.180 million to Rural.

  The net effect of the IC load variation on the IC group is, similar to the NP case noted above, threefold. First the IC reduce their energy costs by $1.649 million during the year as a result of the decreased sales. Second, the IC are charged the full and complete $1.649 million that they saved during the year via their RSP account. Finally, as a result of the $2.827 million fuel savings arising from the reduced load, the IC is credited with $0.573 million[247]. For NP, the IC load reduction results in no revenue-related impact, but a credit is provided related to the fuel saved totalling $2.073 million[248].

  The net result is that IC customers pay the full normal rate for the load that they *did not consume*, less only the $0.573 million credited back via the RSP fuel portion. This equates to a cost savings to the IC customers of only 0.83 cents for each kW.h that they avoided consuming[249]. NP, on the other hand, saves 3.00 cents for each kW.h that the IC do not consume compared to forecast[250]. The problem is further compounded when considering that the 0.829 cents/kW.h that the IC group saves is spread out over 4 customers – for the customer that is able to implement (or forced to implement) load reductions, the savings that they see is likely

---

241 Prior to Rural RSP reallocation.
242 $6.182 million divided by 207.9 GW.h.
243 $1.725 million divided by 207.9 GW.h. All of the above NP load discussion ignores the fuel cost variation component of the RSP – once those are considered, NP's load growth will have also caused additional costs to the IC and Rural customers via the RSP, as the fuel consumed to supply this load growth will result in charges to the fuel cost component of the RSP as well.
244 The sum of Table C2 column C rows 15 to 23
245 Table C2, column E row 24
246 Table C2, column H rows 18 and 23.
247 Table C2, column J row 26.
248 Table C2, column I row 26.
249 $0.573 million divided by 69.1 GW.h.
250 $2.073 million divided by 69.1 GW.h.

well below one-half of one-cent per kW.h (or perhaps on the order of one-tenth the benefits that NP receives as a result of the industrial customer load reduction)[251].

On a net "overall Hydro" basis, the total revenue variation arising as a result of load changes during this nine month period is only $2.689 million in total for NP and IC (this reflects a positive variance, i.e., a net benefit to Hydro). Instead, the fuel cost variation component of the RSP seeks to credit back to NP $5.848 million[252] while charging IC $2.800 million[253] and charging Rural $0.359 million[254].

## TOTAL NEW RSP RESULTS

Due to the complexities that remain in the RSP, it is difficult to illustrate the full required level of detail on a single sheet. However, to ensure these values reported in this Attachment reconcile back to the May 2003 RSP report, Table C3 combines the above reporting in a slightly less detailed fashion.

- Rows 1 to 6 of Table C3 illustrate the total RSP impacts on Hydro. The hydraulic impacts are as noted in Table C1 totalling $11.316 million[255]. Likewise the load impacts are summarized at $2.689 million[256] consistent with Table C2, and the fuel cost impacts are at $44.677 million[257] equal to the reported value in Table C1. The sum of the three components totals $53.304 million at column N row 1. In order to reconcile with the May 2003 RSP report, Column N shows that an additional $1.244 million in interest is added[258], $0.507 million is assigned to Labrador and written off[259], $0.021 million in Rural adjustment is applied[260] and a minimal amount of firming sales revenue is credited[261]. The total RSP balance then equals $54.020 million, consistent with the May, 2003 RSP report.

---

[251] Additionally, this result is prior to considering the fuel variation component of the RSP. Once included, the actual fuel cost savings to Hydro (and credited back to the RSP) arising from the IC load reduction are well above the $2.827 million noted in Table C2; however, only a very small portion of this additional savings will arise to the industrial customer that was able to reduce their load.

[252] The sum of Table C2 column I row 14 of $3.775 million and column I row 28 of $2.073 million

[253] The sum of Table C2 column J row 14 of $1.725 million and column J row 28 of $1.076 million.

[254] The sum of Table C2 column K row 14 of $0.539 million less column K row 28 of $0.180 million. This amount is subsequently reallocated to Labrador and NP.

[255] Table C3, column A row 1.

[256] Table C3, column I row 1.

[257] Table C3, column L row 1.

[258] This interest value is calculated by applying the monthly equivalent of 7.157% to the previous month's closing balance.

[259] The sum of the December, 2002 YTD Labrador assignment of $184,516 reported in the December 2002 RSP report plus the May, 2003 YTD assignment of $322,822 from the May 2003 RSP report.

[260] This entirely arises in September 2002 ($19,552 per the September 2002 RSP report) and October 2002 ($1,066 per the October 2002 RSP report).

[261] The sum total of firming sales revenue appears to be $374. It appears this is the sum total of revenues arising from the application of this rate. If this is correct, it is apparent that Hydro receives zero net revenues from providing this service, but instead credits all revenues received from NP back to NP's RSP account, meaning that the service is provided to NP at no cost. If so, it is not apparent why there is any calculation of the firming rate necessary or approvals requested within the 2003 Rates Application.

- Rows 7 to 22 derive the respective NP and IC balances. Specifically rows 7 to 12 calculate the NP balance of $35.068 million prior to assignment of $0.939 million in interest, $3.422 million in rural deficit, and a credit of $0.015 million in Rural Adjustment and a minimal amount for firming revenues, to result in a new RSP balance for NP of $39.415 million consistent with the May 2003 RSP report.
- Rows 13 to 17 set out the IC RSP reflecting only the three RSP components reviewed above totalling $14.305 million, plus interest of $0.305 million and an unexplained Rural Adjustment credit of $0.004 million to arrive at $14.605 million consistent with the May 2003 RSP report.
- Rows 18 to 22 address the comparable aspects of the Rural RSP. The balance from the three components (with the revenue component of the load variance not being applied to Rural) yields $3.931 million (less a Rural Adjustment of $0.001 million), of which $3.422 million is assigned to NP and $0.507 million is assigned to Labrador.

## Table C1: New RSP September 2002 to May 2003 by component

### Hydraulic Component

| | | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Cost of Service generation (GW.h) | Actual generation (GW.h) | Hydro Variance (GW.h) (B-A) | COS Fuel Cost ($/bbl) | Charge to (credit to) RSP ($millions) (C / 615 x D) | Annual Total ($millions) | | | |
| 1 | September, 2002 | 307.54 | 268.00 | 39.54 | 25.94 | 1.67 | | **Allocation Ratios** | | |
| 2 | October, 2002 | 302.08 | 276.73 | 25.35 | 26.27 | 1.08 | | *NP* | *IC* | *Rural* |
| 3 | November, 2002 | 301.90 | 260.51 | 41.39 | 26.47 | 1.78 | | *72.64%* | *20.98%* | *6.39%* |
| 4 | December, 2002 | 436.40 | 379.21 | 57.19 | 26.80 | 2.49 | 7.02 | 5.10 | 1.47 | 0.45 |
| 5 | January, 2003 | 429.30 | 377.75 | 51.55 | 24.11 | 2.02 | | | | |
| 6 | February, 2003 | 405.21 | 385.96 | 19.25 | 24.64 | 0.77 | | | | |
| 7 | March, 2003 | 399.21 | 410.37 | (11.16) | 24.80 | (0.45) | | *NP* | *IC* | *Rural* |
| 8 | April, 2003 | 366.43 | 311.57 | 54.86 | 25.12 | 2.24 | | *73.33%* | *20.29%* | *6.38%* |
| 9 | May, 2003 | 348.04 | 355.10 | (7.06) | 25.36 | (0.29) | 4.29 | 3.15 | 0.87 | 0.27 |
| 10 | | | | | | | | **Total Allocation** | | |
| 11 | | | | | | | | *NP* | *IC* | *Rural* |
| 12 | | | | | | | | 8.25 | 2.34 | 0.72 |

### Fuel Cost Component

| | | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Cost of Service fuel cost ($/bbl) | Actual fuel cost ($/bbl) | Cost Variance ($/bbl) (B-A) | Actual Barrels (000's) | Charge to (credit to) RSP ($millions) (C x D) | Annual Total ($millions) | | | |
| 13 | September, 2002 | 25.94 | 33.80 | 7.86 | 213 | 1.68 | | **Allocation Ratios** | | |
| 14 | October, 2002 | 26.27 | 36.44 | 10.17 | 356 | 3.62 | | *NP* | *IC* | *Rural* |
| 15 | November, 2002 | 26.47 | 36.02 | 9.55 | 460 | 4.39 | | *72.64%* | *20.98%* | *6.39%* |
| 16 | December, 2002 | 26.80 | 35.98 | 9.18 | 440 | 4.04 | 13.73 | 9.97 | 2.88 | 0.88 |
| 17 | January, 2003 | 24.11 | 39.63 | 15.52 | 513 | 7.96 | | | | |
| 18 | February, 2003 | 24.64 | 44.44 | 19.80 | 426 | 8.44 | | | | |
| 19 | March, 2003 | 24.80 | 43.56 | 18.76 | 445 | 8.35 | | *NP* | *IC* | *Rural* |
| 20 | April, 2003 | 25.12 | 41.95 | 16.83 | 302 | 5.08 | | *73.33%* | *20.29%* | *6.38%* |
| 21 | May, 2003 | 25.36 | 31.76 | 6.40 | 175 | 1.12 | 30.95 | 22.69 | 6.28 | 1.97 |
| 22 | | | | | | | | **Total Allocation** | | |
| 23 | | | | | | | | *NP* | *IC* | *Rural* |
| 24 | | | | | | | | 32.67 | 9.16 | 2.85 |

# Table C2: New RSP September 2002 to May 2003 by component (con't)

## Load Component - NP

| | | A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | NP Forecast Load (GW.h) | NP Actual Load (GW.h) | NP Variance (GW.h) | NP energy rate (cents/kW.h ) | NP Revenue Charge to (credit to) RSP ($millions) | Forecast Price of Holyrood (cents/kW.h) | NP Fuel Charge to (credit to) RSP ($millions) | Annual total fuel cost ($millions) | | | |
| | | | | (B-A) | | (C x D) | | (C x F) | | | | |
| 1 | September, 2002 | 259.10 | 272.20 | 13.10 | (4.789) | (0.627) | 4.22 | 0.553 | | **Allocation Ratios** | | |
| 2 | October, 2002 | 330.00 | 351.48 | 21.48 | (4.789) | (1.029) | 4.27 | 0.917 | | *NP* | *IC* | *Rural* |
| 3 | November, 2002 | 382.80 | 412.85 | 30.05 | (4.789) | (1.439) | 4.30 | 1.293 | | *72.64%* | *20.98%* | *6.39%* |
| 4 | December, 2002 | 535.00 | 508.21 | (26.79) | (4.789) | 1.283 | 4.36 | (1.167) | 1.596 | 1.159 | 0.335 | 0.102 |
| 5 | January, 2003 | 522.60 | 548.66 | 26.06 | (4.789) | (1.248) | 3.92 | 1.022 | | | | |
| 6 | February, 2003 | 484.10 | 515.31 | 31.21 | (4.789) | (1.495) | 4.01 | 1.251 | | | | |
| 7 | March, 2003 | 473.90 | 541.03 | 67.13 | (4.789) | (3.215) | 4.03 | 2.707 | | *NP* | *IC* | *Rural* |
| 8 | April, 2003 | 379.30 | 413.42 | 34.12 | (4.789) | (1.634) | 4.08 | 1.393 | | *73.33%* | *20.29%* | *6.38%* |
| 9 | May, 2003 | 326.20 | 337.73 | 11.53 | (4.789) | (0.552) | 4.12 | 0.476 | 6.849 | 5.022 | 1.390 | 0.437 |
| 10 | | | *total revenue variation ($millions)* | | | *(9.956)* | | | | **Total Allocation** | | |
| 11 | | | | | | | | | | *NP* | *IC* | *Rural* |
| 12 | | | | | | | | | | 6.182 | 1.725 | 0.539 |
| 13 | | | | | | | | | plus: revenue | (9.956) | - | - |
| 14 | | | | | | | | | net impact | (3.775) | 1.725 | 0.539 |

## Load Component - IC

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | IC Forecast Load (GW.h) | IC Actual Load (GW.h) | IC Variance (GW.h) | IC energy rate (cents/kW.h ) | IC Revenue Charge to (credit to) RSP ($millions) | Forecast Price of Holyrood (cents/kW.h) | IC Fuel Charge to (credit to) RSP ($millions) | Annual total fuel cost ($millions) | | | |
| | | | | (B-A) | | (C x D) | | (C x F) | | | | |
| 15 | September, 2002 | 104.55 | 108.67 | 4.11 | (2.388) | (0.098) | 4.22 | 0.173 | | **Allocation Ratios** | | |
| 16 | October, 2002 | 114.28 | 123.45 | 9.17 | (2.388) | (0.219) | 4.27 | 0.392 | | *NP* | *IC* | *Rural* |
| 17 | November, 2002 | 116.00 | 110.13 | (5.87) | (2.388) | 0.140 | 4.30 | (0.253) | | *72.64%* | *20.98%* | *6.39%* |
| 18 | December, 2002 | 117.79 | 111.83 | (5.96) | (2.388) | 0.142 | 4.36 | (0.260) | 0.053 | 0.0382 | 0.0110 | 0.0034 |
| 19 | January, 2003 | 118.93 | 115.49 | (3.44) | (2.388) | 0.082 | 3.92 | (0.135) | | | | |
| 20 | February, 2003 | 109.24 | 107.20 | (2.04) | (2.388) | 0.049 | 4.01 | (0.082) | | | | |
| 21 | March, 2003 | 120.69 | 118.07 | (2.61) | (2.388) | 0.062 | 4.03 | (0.105) | | *NP* | *IC* | *Rural* |
| 22 | April, 2003 | 116.89 | 76.12 | (40.77) | (2.388) | 0.974 | 4.08 | (1.665) | | *73.33%* | *20.29%* | *6.38%* |
| 23 | May, 2003 | 117.69 | 96.04 | (21.65) | (2.388) | 0.517 | 4.12 | (0.893) | (2.880) | (2.112) | (0.584) | (0.184) |
| 24 | | | *total revenue variation ($millions)* | | | *1.649* | | | | **Total Allocation** | | |
| 25 | | | | | | | | | | *NP* | *IC* | *Rural* |
| 26 | | | | | | | | | | (2.073) | (0.573) | (0.180) |
| 27 | | | | | | | | | plus: revenue | - | 1.649 | - |
| 28 | | | | | | | | | net impact | (2.073) | 1.076 | (0.180) |

## Table C3: New RSP September 2002 to May 2003 by NP, IC and Rural

### Total RSP

| | A | B | C | | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ***Hydraulic RSP*** | | | ***Load RSP*** | | | | | | | ***Fuel Price RSP*** | | | ***Total RSP*** | |
| | Variance (GW.h) | Average Fuel Cost ($/kW.h) | Hydraulic variance ($) | | Load Variance (GW.h) | Average price of Fuel ($/kW.h) | Fuel Variance ($) | Average Revenues ($/kW.h) | Revenue Variance ($) | Total Load Variance ($) | Average Variance ($/bbl) | # of barrels | Fuel Price Variance ($) | | Net RSP |
| 1 | (271) | 0.04177 | (11,316,035) | | 139 | 0.04046 | (5,617,998) | 0.05983 | 8,307,044 | 2,689,046 | (13.41) | 3,330,447 | (44,677,444) | | (53,304,433) |
| 2 | | | | | | | | | | | | | | Interest | (1,243,840) |
| 3 | | | | | | | | | | | | | | W/O labrador | 507,338 |
| 4 | | | | | | | | | | | | | | Rural Adjustment | 20,618 |
| 5 | | | | | | | | | | | | | | Secondary (firming) | 374 |
| 6 | | | | | | | | | | | | | | Total RSP | (54,019,943) |

### NP RSP Share

| | A | B | C | | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ***Hydraulic RSP*** | | | ***Load RSP*** | | | | | | | ***Fuel Price RSP*** | | | ***Total NP RSP*** | |
| | Variance (GW.h) | Average Fuel Cost ($/kW.h) | Hydraulic variance ($) | | Load Variance (GW.h) | Average price of Fuel ($/kW.h) | Fuel Variance ($) | Average Revenues ($/kW.h) | Revenue Variance ($) | Total Load Variance ($) | Average Variance ($/bbl) | # of barrels | Fuel Price Variance ($) | | Net RSP |
| 7 | (198) | 0.04176 | (8,249,424) | | | | | | | 5,847,925 | (13.43) | 2,432,033 | (32,666,638) | | (35,068,137) |
| 8 | | | | | | | | | | | | | | Interest | (939,287) |
| 9 | | | | *NP load variance* | *208* | | | *0.04789* | *9,956,152* | *9,956,152* | | | | Reassign Rural | (3,422,469) |
| 10 | | | | *NP Share of system load variance* | *102* | *0.04046* | *(4,108,227)* | | | *(4,108,227)* | | | | Rural Adjustment | 14,977 |
| 11 | | | | | | | | | | | | | | Secondary (firming) | 374 |
| 12 | | | | | | | | | | | | | | Total RSP | (39,414,543) |

### IC RSP Share

| | A | B | C | | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ***Hydraulic RSP*** | | | ***Load RSP*** | | | | | | | ***Fuel Price RSP*** | | | ***Total IC RSP*** | |
| | Variance (GW.h) | Average Fuel Cost ($/kW.h) | Hydraulic variance ($) | | Load Variance (GW.h) | Average price of Fuel ($/kW.h) | Fuel Variance ($) | Average Revenues ($/kW.h) | Revenue Variance ($) | Total Load Variance ($) | Average Variance ($/bbl) | # of barrels | Fuel Price Variance ($) | | Net RSP |
| 13 | (56) | 0.04179 | (2,344,350) | | | | | | | (2,800,455) | (13.36) | 685,893 | (9,160,368) | | (14,305,172) |
| 14 | | | | | | | | | | | | | | Interest | (304,553) |
| 15 | | | | *IC load variance* | *(69)* | | | *0.02388* | *######* | *(1,649,108)* | | | | Rural Adjustment | 4,325 |
| 16 | | | | *IC Share of system load variance* | *28* | *0.04048* | *(1,151,347)* | | | *(1,151,347)* | | | | Total RSP | (14,605,401) |
| 17 | | | | | | | | | | | | | | | |

### Rural RSP Share

| | A | B | C | | D | E | F | G | H | I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ***Hydraulic RSP*** | | | ***Load RSP*** | | | | | | | ***Fuel Price RSP*** | | | ***Total Rural RSP*** | |
| | Variance (GW.h) | Average Fuel Cost ($/kW.h) | Hydraulic variance ($) | | Load Variance (GW.h) | Average price of Fuel ($/kW.h) | Fuel Variance ($) | Average Revenues ($/kW.h) | Revenue Variance ($) | Total Load Variance ($) | Average Variance ($/bbl) | # of barrels | Fuel Price Variance ($) | | Net RSP |
| 18 | (17) | 0.04177 | (722,261) | | | | | | | (358,424) | (13.41) | 212,521 | (2,850,439) | | (3,931,124) |
| 19 | | | | | | | | | | | | | | Reassign Rural NP | 3,422,469 |
| 20 | | | | *Rural load variance* | *N/A* | | | *N/A* | *N/A* | *N/A* | | | | Reassign Labrador | 507,338 |
| 21 | | | | *Rural Share of system load variance* | *9* | *0.04046* | *(358,424)* | | | *(358,424)* | | | | Rural Adjustment | 1,317 |
| 22 | | | | | | | | | | | | | | | 0 |

# ATTACHMENT D – REVIEW OF RATE STABILIZATION MECHANISMS IN SIMILAR JURISDICTIONS

A brief review of other jurisdictions highlighted the following rate stabilization approaches aimed at addressing similar concerns to the Newfoundland RSP. The list proceeds from the utilities/jurisdictions most comparable with Hydro to those least comparable with Hydro.

## CANADIAN JURISDICTIONS WITH CROWN ELECTRIC UTILITIES, NON-INTERCONNECTED GRIDS AND A MIXTURE OF HYDRO AND DIESEL GENERATION

- ***Yukon Energy Diesel Contingency Fund:*** This fund, which is primarily a hydraulic variance stabilization fund, addresses water flow variances from the average annual levels (based on long-term modelling) to the extent that such variances affect Yukon Energy diesel generation costs. The fund is managed as a trust outside of rate base, and earns or charges interest based on the prevailing investment/borrowing rate appropriate for Yukon Energy short-term investments. Once a trigger of $4.04 million (positive or negative) is hit, the fund is expected to trigger refunds or charges to customers on an equal per kW.h basis. The fund has not previously hit the trigger.

- ***Yukon Energy's Fuel Adjustment account:*** The Fuel Adjustment account maintained by Yukon Energy addresses diesel price variation from the last GRA forecast. A similar account is maintained by The Yukon Electrical Company Limited, the primary local retailer of power (with some small installed diesel generation). These accounts do not earn or pay interest at all. Each Yukon utility is directed to implement fuel rider adjustments on a co-ordinated and timely periodic basis, as required to ensure that balances in these fuel accounts are adjusted periodically to maintain the balance at as low a level as reasonable. Charges (or refunds) to customers are addressed on an equal cents per kW.h basis for all consumption throughout Yukon.

- ***Northwest Territories Power Corporation Diesel Stabilization Funds:*** NTPC's diesel price stabilization funds address variances in fuel price from the last GRA forecast. One fund is maintained for each of the larger grids and a single conglomerated fund is maintained for the group of non-interconnected communities. The funds charge or credit interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points. Refunds or collections to customers are addressed on an equal per kW.h charge.

- ***Northwest Territories Power Corporation Hydro Stabilization Fund:*** NTPC's hydraulic stabilization fund addresses water flow variances from long-term forecast. The fund charges or credits interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points. The fund has a trigger of $3 million (positive or negative) at which point an equal charge/rebate in cents per kW.h is expected to all customers on the grid. The fund has not previously hit the established trigger.

## CANADIAN JURISDICTION WITH CROWN ELECTRIC UTILITIES, RELYING ON FUEL FOR GENERATION

- ***Nunavut Diesel Stabilization Fund:*** Nunavut Power has maintained a diesel price stabilization fund that was broken out of NTPC's consolidated NWT/Nunavut account at the time of the division of the two companies. The Nunavut Utilities Board has reviewed the operation of this fund and approved riders to collect outstanding balances. The Board did not change the previous NTPC approach of charging or crediting interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points. Any amounts collected from or refunded to customers are addressed on an equal cents/kW.h rider/refund for all sales.

## CANADIAN JURISDICTION WITH CROWN GAS DISTRIBUTOR

- ***Centra Gas Manitoba's Purchased Gas Variance Account:*** The Centra Gas Manitoba purchased gas variance account (PGVA) is not directly comparable to any aspect of the Hydro RSP except for the purposes of considering carrying costs. The PGVA uses a short-term carrying cost rate to accrue interest.

## AMERICAN JURISDICTION RELYING ON MIX OF HYDRO AND FOSSIL FUEL GENERATION (SELF-GENERATED OR PURCHASED POWER)

- ***Idaho Power's Power Cost Adjustment:*** Idaho Power's operation in Idaho maintain a Power Cost adjustment mechanism to address hydraulic and power acquisition price stabilization[262]. This account accrues interest at a rate tied to short-term rates while amounts are being charged to the account, and accrues no interest during periods where the account is being re-collected back from customers. Charges or refunds to customers are done on an equal cents/kW.h basis.

[262] Both fuel costs and purchased power costs. The mechanism specifically excludes load changes from the calculation.

# ATTACHMENT E – REVIEW OF LOAD STABILIZATION APPROACHES IN OTHER JURISDICTIONS

There appear to be only two regulatory mechanisms that seem in any way related to the Newfoundland Hydro RSP load variation provision, but both have material differences that clarify they are not comparable.

- ***Weather Normalization:*** Certain utilities (primarily gas utilities, however apparently also Newfoundland Power) maintain weather normalization provisions that adjust the utility earnings for load variation related solely to actual weather conditions being different than the long-term average. There are two material reasons how this differs from the Newfoundland Hydro RSP load provision. The first is that the use of these provisions is conceptually limited to one variable which, like hydraulic generation fluctuates annually up or down, but over the long-term achieves a certain stable mean[263]. Second, these provisions do not appear to result in charges or refunds to customers but rather a long-term balancing of inflows and outflows, and in particular do not result in differential charges to various groups of customers.

- ***Revenue Decoupling:*** A technique that has been used in various jurisdictions that is mechanically similar to the load variance provision is something called 'revenue decoupling'. In order to ensure utilities' earnings are not adversely affected by DSM and conservation activities (due to decreased sales), certain jurisdictions have experimented with ensuring utility revenue is held whole for any reductions due to this one single factor (DSM load reductions). However, we are not aware of any such mechanism ever being applied to a Crown electric utility in Canada, and in addition the entire basis for this approach is to encourage conservation – as reviewed in Section 7, the effective incremental rates faced by Hydro's customers as a result of the Load Variation provision in fact achieve the opposite, they strongly discourage conservation and load reductions (particularly for the IC group).

[263] In the case of Newfoundland Power the measure is degree-days.

# ATTACHMENT F – INDUSTRIAL CUSTOMER FIRM SERVICE

Industrial customer service contracts basically reflect four components to the service, each comprising different rates and terms:

- *Power on Order*, or the portion of the customer's load served by firm power at firm rates
- *Interruptible Power*, or the portion of the customer's load above the specified Power on Order, resulting in non-firm service and rates
- any *Maximum Demands* in excess of the contract limits on Interruptible Power, effectively representing short-term load excursions that are not firm service, but are charged at very high effective rates for the power received
- for those customers with their own generation, a separate *Generation Outage Power.*

This material reviews Power on Order, Interruptible Power and Maximum Demands. We have not specifically focused on Generation Outage Power, as this is a unique term available to only two customers.

**"Power on Order"**

The existing Industrial contracts provide a requirement for each industrial customer to specify a value called Power on Order for each year. This Power on Order value is measured in kW at peak, and operates roughly in the following way:

- ***Customer's own forecast:*** The Power on Order is each industrial customer's forecast of the firm demand peak it expects to impose on the system in the coming year.

- ***Specified in advance:*** The Power on Order value must be specified, in writing, by October 1 of each year for application to the following calendar year.

- ***Cannot decrease during year:*** The Power on Order value specified in October does not have to be the same during the calendar year – it can change at specified times during the year, but these intra-year changes may only be increases, not decreases[264].

- ***Subject to maximum:*** Each industrial customer has an absolute maximum Power on Order it is allowed to specify[265] without providing "adequate notice in order that Hydro may make suitable extensions or additions to the system"; the period of such notice is not specifically quantified in the contracts.

[264] An exception is if the customer installs new generation, and provides Hydro with 36 months written notice, it can reduce its Power on Order during the calendar year.

[265] This maximum value is 90 MW for Abitibi Stephenville, 45 MW for North Atlantic Refining, 70 MW for Corner Brook, and 40 MW for Grand Falls.

- ***Subject to confirmation from Hydro:*** Even if the customer's specified Power on Order submitted in October is below the specified contract maximum level, Hydro can notify the customer by November 1 of the year before service is to be provided that it cannot meet the full customer-specified Power on Order266.

- ***Exceeding the Power on Order:*** If a customer has a requirement to consume more power than the Power on Order provides, they must have agreement from Hydro[267] and Hydro is not obliged to provide that additional power and may interrupt it at any time. If the additional power is made available, the customer will pay the non-firm rate for all consumption above the Power on Order up to the interruptible demand maximum[268]. The non-firm rate and terms for this service are addressed in the section below. If the customer's requirement is in excess of the Interruptible Demand maximum, these additional amounts become part of the Maximum Demand measurement, which is also addressed below.

- ***Customer billed for at least the Power on Order each month:*** For each month of service during the year, and regardless of actual use, the industrial customer will pay their demand rate based on the full amount of the Power on Order, unless one of the following is higher:
  - ***Ratchet Provision:*** If the customer's Power on Order in a given month is lower than 75% of the prior year's Power on Order (or 15,000 kW below the prior year's Power on Order, whichever is lower), the customer instead pays their demand charge on this higher ratcheted billing demand. This effectively prevents reductions in the Power on Order from being too large from year to year.
  - ***Actual Maximum Firm Demand:*** As addressed below, if the customer's actual monthly demand is in excess of the Power on Order plus Maximum Interruptible Demand available (which requires agreement from Hydro, and Hydro is not obliged to provide that additional power), then the customer pays additional demand charges based on the amounts in excess of the Power on Order for that month and all subsequent months in the year.

- ***Special Circumstances:*** There is a provision in the contracts that generally provides that energy supply (on the part of Hydro) and/or requirement to purchase energy (on the part of the customer) is suspended if the works of either party is suspended "in whole or in part by reason of war, rebellion, civil disturbances, strikes, serious epidemics, fire or other fortuitous events". If it is the customer that is prevented from taking power, the billing demand will be reduced to reflect this interruption, but billing demand will not be lower than 85% of Power on Order. If it

[266] The specific text states that "if Hydro cannot fully comply…" with the Power on Order declared by the customer "it will, as soon as practical and in any event not later than November 1 of the year in which the declaration was made, advise the Customer of the extent to which it can comply."

[267] The contracts provide for a request from the customer to Hydro prior to consumption, if practicable, otherwise notification to Hydro as soon as practicable after initiation of consumption. Hydro will advise the customer if such interruptible power will be made available.

[268] The Interruptible Demand maximum is 25% of the Power on Order if the Power on Order is less than 20000 kW, 5000 kW if the Power on Order is 20001 kW to 50000 kW, and 10% of the Power on Order if the Power on Order is greater than 50000 kW.

Hydro that is prevented from delivering power, then there is no such lower limit on billing demand reductions.

The net effect on the monthly bill (i.e., ignoring deferred amounts in the RSP for now) is that industrial customers who decrease their loads from forecast save the energy rate on the kW.h not consumed (proposed at 2.765 cents/kW.h) but save nothing on demand charges. Even if the customer is able to forecast a reduction in energy requirements by October 1 of the year prior to the reduced requirement, the ability to save the demand charges associated with the reduced use is limited to ratchet provisions on the reduced Power on Order. In addition, the customer is not able to save any demand charges whatsoever (even if forecast at October 1 of the prior year) if they, at any time in the calendar year prior to the load reduction, have exceeded their Power on Order above the available Interruptible Demand.

In situations where load is reduced due to special circumstances facing the industrial customer (i.e., strikes or fire), there is a limited ability to save on demand charges due to the 85% downside limit on reductions below Power on Order.

The resulting average costs per kW.h to IC for firm power service (i.e., loads up to the Power on Order) depends on the load factor of the loads to be served. Using the proposed rates in the May 21, 2003 application (ignoring the RSP adjustment) and the forecast load factors, the average costs per kW.h range as follows:

- Load Factor of 90%[269]: 3.758 cents/kW.h[270]
- Load Factor of 75%[271]: 3.956 cents/kW.h[272]

To use an example, Corner Brook Pulp and Paper has a Power on Order forecast for the test year of 56 MW. This compares to a contract maximum Power on Order of 70 MW, so there is room for Corner Brook to increase their Power on Order in future years if there is a requirement for more power. In the test year, Corner Brook will be provided with a Maximum Interruptible Power of 5.6 MW. In the event that Corner Brook's peak in any given month exceeds 61.6 MW[273] (the sum of Power on Order and Maximum Interruptible Power), the additional power above 61.6 MW is served as Maximum Demand.

### Interruptible Power

When an industrial customer has a requirement for an increased load compared to Power on Order, the initial block of increased load is required to be served at the interruptible rate. This rate operates outside the RSP, and ensures that the industrial customer pays:

---

[269] Per PUB-3, each of Abitibi Stephenville, North Atlantic Refining and Corner Brook Pulp and Paper are very close to a 90% annual load factor compared to Power on Order peak demands.

[270] Each kW of Power on Order results in $78.48 in demand costs, and reflects 7906 kW.h at a 90% load factor for an energy cost of $218.59. The total cost of $297.07 reflects an average energy rate of 3.758 cents/kW.h

[271] Per PUB-3, Abitibi Grand Falls is very close to a 75% annual load factor compared to Power on Order peak demand.

[272] Each kW of Power on Order results in $78.48 in demand costs, and reflects 6588 kW.h at a 75% load factor for an energy cost of $182.16. The total cost of $260.64 reflects an average energy rate of 3.956 cents/kW.h

[273] Ignoring peaks caused by outages at Corner Brook's own generation.

- 100% of the incremental costs of supplying the energy (no lower than a forecast 5.510 cents/kW.h at Holyrood, but as high as a forecast 11.982 cents/kW.h for Diesel[274])
- plus 10% over the incremental energy supply costs to reflect "an allowance for incidental operating costs of staff and facilities involved in dealing with the request and subsequent processing of the bill, an allowance for non-fuel items such as lube oil and fuel additives, and transmission losses"[275]
- plus $1.50 per kW to reflect "some value of the assets in place to provide the non-firm service"[276]

In the previous application (IC-44) Hydro also noted the specific requirement for interruptible rates to be higher than incremental costs in order to provide "an allowance for profit".

Compared to high load factor firm service at a rate approximating 3.758 to 3.956 cents/kW.h, the interruptible rates are costly on a per kW.h basis. There is only one customer forecast to consume interruptible power in Hydro's GRA load forecast[277]; Corner Brook Pulp and Paper is forecast (in the month of August) to consume 800 MW.h and use 5.6 MW of demand. The cost of service in Exhibit RDG-1 (Schedule 1.2 page 2 of 6) reflects a forecast cost for this power of $49,752, or an average cost per kW.h of 6.219 cents/kW.h. However, given the approach to Power on Order used in Newfoundland, were there no interruptible power available, Corner Brook would be required to serve this load with firm power by specifying a higher Power on Order or Maximum Demand, which would result in costs of between $205,240 and $461,608[278] or between 25.65 and 57.70 cents/kW.h.

**Maximum Demands**

Any power required in excess of the Maximum Interruptible Power available remains available to be interrupted at Hydro's discretion, but is served at Hydro's firm IC rates including billing demand ratchets. As such load excursions above the maximum interruptible power are likely to be rare (and therefore at a very low load factor), the resulting demand charge peaks they cause for the customer can result in the power being extremely expensive. The extreme example is if a customer exceeds their maximum interruptible demand by 1 kW for 1 hour in January for a total consumption of 1 kW.h – the resulting cost would be 1 kW.h apparently charged at the firm energy rate (2.765 cents) plus 12 months of demand for the extra kW ($6.54 times 12, or $78.48) for a total $78.51 for a single kW.h of power.

A more practical example is the one-time requirement of Corner Brook Pulp and Paper (forecast for August 2004) currently forecast to be served by Interruptible Power – if a similar type of one-time load

---

[274] Per IC-175, the forecast Holyrood-based non-firm energy rate is between 5.150 cents/kW.h and 5.267 cents/kW.h, the forecast gas turbine based non-firm energy rate is between 10.684 cents/kW.h and 11.143 cents/kW.h and the forecast diesel based non-firm energy rate is 11.982 cents/kW.h.

[275] IC-59

[276] CA-68

[277] PUB-3

[278] The 5.6 MW load in August to service 800 MW.h would likely have to be part of Power on Order for either all 12 months, or if a Power on Order increase were allowed in August for a total of 5 months. This would result in a demand charge of between $183,120 and $439,488 as well as energy charges of $22,120, for a total cost of between $205,240 and $461,608.

peak requirement were to arise in excess of the Maximum Interruptible Demand (i.e., in the test year, if a 5.6 MW peak were required above the 61.6 MW level), this power would be served by firm IC rates. As noted above, the cost would be in the effective range of 25.66 cents/kW.h[279]. This represents a load with an annual load factor of 1.63%, which is very low, but likely representative of the types of short-term load excursions that might arise on this type of service.

The net effect is that, in practical terms, the industrial customers must remain well below their Maximum Interruptible Demand cut-off, otherwise they risk having relatively minor and short-lived load excursions into Maximum Demand that result in very costly bill impacts.

[279] Assuming the power is used in August – if used in January the average cost would be 57.70 cents/kW.h as noted above.

# ATTACHMENT G - REVIEW OF INDUSTRIAL INTERRUPTIBLE RATE OFFERINGS FROM OTHER UTILITIES

Many jurisdictions in Canada maintain interruptible rate programs available to industrial customers. These rates tend to generally fall into three categories:

1. **Interruptible Energy:** This type of rate offering is similar to the current Newfoundland Hydro Interruptible Demand/Energy component of the IC contracts discussed in Attachment F. Other examples provided in response to IC-222 are the Nova Scotia Power Industrial Expansion Interruptible Rate[280], the New Brunswick Power Surplus Energy Charge, and the Manitoba Hydro Surplus Energy Program. These three utilities offering an interruptible energy service do not charge any demand rate for this service. Energy rates are typically higher than the specific incremental costs to supply the power (3% plus .12 cents/kW.h in Nova Scotia, 0.9 cents/kW.h on-peak and 0.3 cents/kW.h off-peak in New Brunswick, and 10% plus transmission losses and plus 0.06 cents/kW.h in Manitoba[281]), but are comparable to Newfoundland Hydro's proposed 10% premium.

   A separate category of interruptible rates, often referred to as secondary energy, reflects power that is made available to general service or industrial customers from hydraulic generation that would otherwise be spilled. Newfoundland Hydro appears to offer such a secondary rate, as noted in the industrial contracts, but there is little reference to this rate in the materials filed. In other jurisdictions, surplus hydro is typically made available on an interruptible basis at rates that comprise only an energy component (no demand charge), for example, Rate Schedule 32 in Yukon and the Taltson excess power rate in NWT.

2. **Interruptible Capacity:** This type of offering would apply to rates that operate similarly to Newfoundland Hydro's now terminated Interruptible B rate. These rates offer a demand charges discount for a customer who offers a portion of their capacity that can be interrupted on short notice for limited periods of time to address system constraints. Examples provided in response to IC-222 include the Nova Scotia Power Interruptible Rider (rate code 25) or the Manitoba Hydro Curtailable Rate Program.

3. **Special Purpose:** This type of offering would be comparable to the Generation Outage Demand provided to two IC customers by Newfoundland Hydro, and also BC Hydro Schedule 1880 service provided in response to IC-222.

---

[280] Rate code 18; however, there are significant restrictions on the application of this rate, such as the load served has to be "new" or "expanded" load as approved by the regulator.

[281] This is relevant provision of the Manitoba Hydro Surplus Energy Program when supplied from Manitoba Hydro generation (as opposed to purchased power or foregone export sales, which are not relevant in Newfoundland). Manitoba Hydro also charges $100 per month to customers who take surplus energy.

# ATTACHMENT H – COMPARISON OF ISLAND INTERCONNECTED CAPACITY SOURCES

## GREAT NORTHERN PENINSULA DIESEL GENERATION

The Great Northern Peninsula diesel plant comprises 14.7 MW at three sites – 8 MW at St. Anthony, 5 MW at Hawke's Bay and 1.7 MW at Roddickton[282]. These units primarily service the local loads at time of transmission system outages. This is reflected in the response to IC-235, which notes that the Hawke's Bay and St. Anthony diesel units have operated 112 times since 1996 to support local loads. In contrast, since the interconnection, the units have only operated once in support of the Island Interconnected system (January 30, 2003)[283] and that was prior to the in-service of Granite Canal or the new PPAs, which have added 87.3 MW capacity to the system[284] (almost 6 times the thermal generation on the GNP).

In addition, Table 3-3 from Exhibit JRH-3 indicates that absent the GNP generation, the Island Interconnected LOLH only increases from 1.1 hours/year to 1.4 hours/year in 2004, and the requirement for capacity additions is only advanced from 2011 to 2009 (also note that this 2009 result of 3.0 hours LOLH is barely above the 2.8 hours target maximum LOLH, and Hydro plans to add additional capacity in 2010 regardless due to energy balance shortfalls, per Haynes, page 37).

The issue of GNP generation, and whether to retain a specific amount of generation versus decommissioning the various units appears to have been reviewed in detail during the late 1990's. In particular, we note the response to IC-104 provides a copy of Hydro's application to the Board dated November, 1999 to decommission the Roddickton Woodchip plant and Roddickton Diesel plant, both sources of generation that existed on the GNP. In that application (page 2) Hydro specifically notes: "Normally, upon interconnection, Hydro decommissions all diesel generating capacity which supported the formerly isolated area. The St. Anthony/Roddickton area electrical load is situated at the end of a long radial transmission line. In this case, Hydro has decided to retain the 8800 kW diesel generation at St. Anthony as backup generation for this area"[285]. In addition, a detailed analysis was conducted by Acres International[286] regarding the backup diesel generating plant in the GNP area, which concluded that the existing generating plant was providing reduced total outage durations for St. Anthony (in particular) but also Roddickton and to some degree Hawke's Bay[287]. In contrast, there is no basis to support a

---

[282] Per JRH-3 Table 2-1.

[283] Per JRH-3, page 15.

[284] Per JRH-1, Schedule II. Hydro has not specifically addressed how this system constraint would have been addressed had Granite Canal and the PPAs been in service, but it is apparent that on a normal basis, the requirement for operating the diesel generation on the GNP has been reduced by the addition of this new capacity.

[285] It appears the difference between the 8800 kW cited here as the St. Anthony diesel capacity and the 8000 kW cited in JRH-3 is a mobile diesel generation unit that is now situated at Roddickton.

[286] filed in IC-231.

[287] "System Performance Review for Great Northern Peninsula" by Aces International, page v. Filed in IC-231.

conclusion that the units would be of any material benefits to non-GNP customers in 2004 now that Granite Canal and the two new PPAs are in service.

The cost of service treatment of common assets versus those specifically assigned is a key aspect in considering the allocation of these GNP generation costs. The GNP diesel assets appear to account for $1.402 million of the 2004 Island Interconnected revenue requirement. As these costs would presumably be classified 100% to demand, the resulting costs (prior to Rural Deficit reallocation) of the generation is as follows:

| **($millions)** | **Assigned to Common**[288] | **Specifically Assigned Rural** |
|---|---|---|
| NP | $1.165 | $0 |
| IC | $0.182 | $0 |
| Rural | $0.098 | $1.403 |
| Total[289] | $1.445 | $1.403 |

The most striking impact of the common allocation is the reduction in costs assigned to the rural customers from 1.4 million (100% of the cost) to $98,000 (6.8% of the cost). This is clearly not consistent with the relative benefits received from these assets.

## INTERRUPTIBLE B

The Interruptible B rate program with Abitibi Stephenville was in place from December, 1993 to March, 2003. This program provided Hydro with the ability to call upon Abitibi Stephenville, at any time during the four winter months between the hours of 0800 and 2200, to reduce their power consumption by up to 46 MW for up to 10 hours. The interruption could be initiated on one hour's notice.

The ability to interrupt capacity at times of peak offers a number of clear benefits to the operation of the grid:

- ***The capacity is guaranteed to be available.*** With standby generation plant, there is the potential for the plant to be out-of-service or to break-down when required for service.

- ***The capacity is made available on the high voltage backbone transmission grid.*** In comparison, radial generation is more typically located at the end of long and isolated transmission systems, which themselves may be problematic at times of system constraints.

- ***The capacity interrupted in fact frees up the full capacity subscribed plus the transmission losses that had been associated with serving this power.*** In the case of Abitibi Stephenville's Interruptible B load, 46 MW plus the associated transmission losses was

[288] Allocated based on the production demand allocation ratios in column 3, exhibit RDG-1, Schedule 3.1A.
[289] The $1.403 million cost when assigned Rural is outlined in IC-13 (Rev.) line 20. The $1.445 million cost when assigned common is the total cost when assigned rural plus $44,986 for return on equity per IC-234.

made available by the customer interrupting their load. In contrast, additional grid generation, such as the gas turbines only supply their net capacity to the grid.

## BURIN PENINSULA TRANSMISSION ALLOCATION

The Burin Peninsula is a long radial system serving primarily NP load, as well as a small quantity of Hydro rural customers. The loads are set out in IC-339 as 246,770 MW.h for NP (99.5% of the load) and 1,309 MW.h for Hydro rural (0.5% of the load). There are no IC loads on the Burin Peninsula. The system is made up of two roughly parallel transmission lines that are connected at the southern terminus to form a loop.

Hydro has proposed in Exhibit JRH-3 that the Burin Peninsula be assigned common, the same as in P.U. 7 (2002-2003). However, the primary basis for this recommended allocation appears to be that the line services both NP and Rural customers. However, based on other tests for NP-IC Sub-transmission assets, given that the system makes up a material asset value, it would appear that this factor would only lead to a joint NP-Rural allocation, with no basis to assign any costs to IC[290]. As an apparent secondary basis, Hydro asserts that the Burin Peninsula has been assigned common in the past due to "significant generation" being interconnected, but since that time 15 MW of NP generation has been removed and 8 MW of Hydro hydraulic (Paradise River) has been added.

The matter of the Burin Peninsula allocation was considered in brief in the 2001 proceeding. Specifically, Hydro noted in IC-267: "In addition to the assets requested in IC-88[291], the assets on the Burin Peninsula are currently assigned Common by virtue of connecting remote generation on a radial system that reaches the 230 kV grid. Hydro's proposed plan allocation now treats the GNP and the Doyles-Bottom Brook assets consistently with those assets. If the principle of plant assignment related to 'connecting remote generation on a radial system that reaches the 230 kV grid' is modified, the Burin Peninsula assets should receive similar treatment to the GNP and the Doyles-Bottom Brook assets."

The two transmission lines on the Burin peninsula do not necessarily provide the same function. Specifically, we note that the first line, TL212, is the line that connects the Paradise River hydro plant, and continues to the Linton Lake Terminal Station (per IC-332) well past the Paradise River plant. The other radial line, TL219 does not play any material role in connecting Paradise River to the Island Interconnected grid, except during transmission outages of TL212[292]. TL 219 accounts for the bulk of the costs on the Burin Peninsula.

Outside of the Paradise River plant, the only material generation on the Burin Peninsula is NP's 25 MW gas turbine. In past Hydro GRAs there had been 40 MW of NP thermal generation on the Burin peninsula,

[290] Specifically, Exhibit JRH-3 notes that transmission assets comprising more than 2% of Hydro's plant in service that only service NP and IC are assigned only to those two customer groups, not to Rural customers. By a comparable test, the Burin assets would properly be assigned NP-Rural and not IC. Hydro was asked about this possibility in IC-337 and IC-338, but declined to answer as the response claims the matter is "not relevant".
[291] That IR refers to the Doyles-Port aux Basques system.
[292] IC-333.

but the other 15 MW has since been relocated. As reviewed above, and within the GNP assessment from the 2001 proceeding (including the Board's direction in P.U. 7 (2002-2003) to assign the GNP transmission assets to Rural), radial peaking generation in this range does not result in an automatic assignment of transmission to common.

To the extent that there is any basis for arguing that interconnection of generation is a credible rationale for assigning the Burin transmission assets to common, this only appears to have any merit in relation to TL212. There is no real need for a TL219 backup transmission line to interconnect an 8 MW plant (Granite Canal, which is 40 MW, is not backed up by a second line). In addition, the Paradise River plant reflects $21 million in plant in service located only a small distance down the Burin Peninsula[293] - this does not provide a basis for assigning an additional $19 million of transmission plant[294] ranging the full length of the Burin Peninsula as being of common benefit. Even the TL212 assets at best only merit assignment of the portion north of Paradise River as common; however, Hydro appears to suggest this is not possible in their accounting system, and the impact on cost allocation is likely to be small.

In summary, there is no credible basis to assign any assets on the Burin Peninsula outside of TL212 as being of common benefit.

[293] See Haynes Schedule III and Reeves, Schedule II.
[294] Per IC-334.