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]

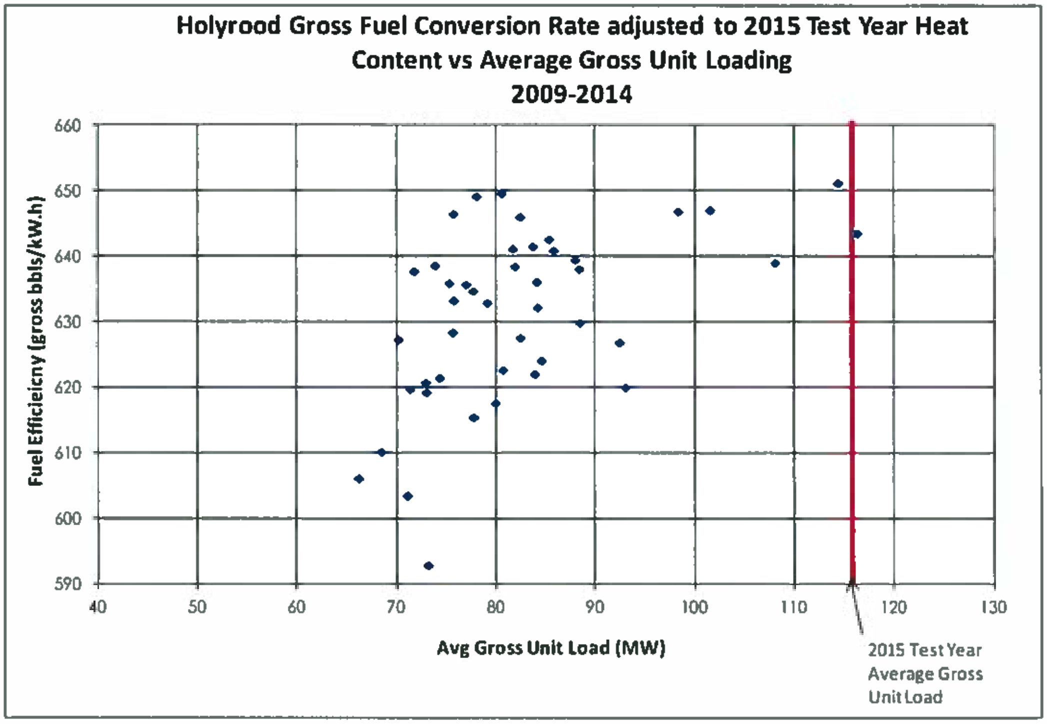

Figure 3-1 was relied upon for the purpose of confirming the reasonableness of Hydro's 650 kW.h/bbl gross efficiency. This is because the 2015 projected average unit loading was forecast at 117 MW.[61]

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.

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	Analyses and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analyses, 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	Analyses and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analyses and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analyses and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analyses 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	Analyses and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analyses and Case Preparation	NWTPUB	NTPC	2000-02	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analyses, 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	Analyses, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analyses and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analyses and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analyses and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analyses, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analyses, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analyses, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analyses, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analyses, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analyses, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analyses, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analyses, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006-08	Yes
Manitoba Hydro	2008 General Rate Application	Analyses, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analyses, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008-09	Yes
FortisBC	2009 Rate Design and Cost of Service	Analyses and Case Preparation	BCUC	BC Municipal Electrical Utilities	2009-10	No
Yukon Energy	Mayo B Part III Application	Analyses, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analyses, 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	Analyses, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010-11	Yes
NTPC	Bluefish Dam Replacement Project	Analyses, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
NTPC	2012/14 General Rate Application	Analyses, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2015	Yes
Newfoundland Hydro	Amended 2013 General Rate Application	Analyses, 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	Analyses, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analyses, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	Yes
AltaLink Management Limited	2017-18 General Tariff Application	Analyses, 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	Analyses, 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	Analyses, 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.

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.

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

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.