June 4, 2015

VIA COURIER and ELECTRONIC MAIL

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

Dear Ms. Blundon:

RE: 2013 Amended General Rate Application of Newfoundland and Labrador Hydro

Enclosed are the original and twelve (12) copies of the report of Vale's expert, Mel Dean, in respect of the above-noted Application.

We have provided a copy of this correspondence together with enclosures to all concerned parties.

We trust you will find the enclosed satisfactory.

Yours faithfully,

Thomas J. O'Reilly, Q.C.

TJOR/js
Encl.

c.c. Geoffrey P. Young, Newfoundland & Labrador Hydro
Gerard Hayes, Newfoundland Power
Thomas J. Johnson, O'Dea, Earle
Paul Coxworthy, Stewart McKelvey
Dennis Browne, Q.C., Browne Fitzgerald Morgan & Avis
Nancy Kleer, Olthuis, Leer, Townshend LLP
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Genevieve M. Dawson, Benson Buffett

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IN THE MATTER OF the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47 (the "Act"), and

IN THE MATTER OF a General Rate Application (the Amended Application) by Newfoundland and Labrador Hydro for approvals of, under Sections 70 and 75 of the Act, changes in the rates to be charged for the supply of power and energy to Newfoundland Power, Rural Customers and Industrial Customers; and under Section 71 of the Act, changes in the Rules and Regulations applicable to the supply of electricity to Rural Customers.

EXPERT'S REPORT ON NEWFOUNDLAND AND LABRADOR HYDRO'S AMENDED 2013 GENERAL RATE APPLICATION

Prepared by Mel Dean
June 4, 2015

Forward

This report replaces the "Expert's Report on Newfoundland and Labrador Hydro's 2013 General Rate Application, Prepared by Mel Dean, April 25, 2014" in its entirety.

Introduction

My name is Melvin Dean and I reside in Stephenville, NL. I am a professional electrical engineer. Over the past 45 years, I have been responsible for or managed a variety of engineering, maintenance and project activities relating to electrical power supply. During my career, I have served in a variety of management positions covering areas such as supply management, strategic projects, continuous improvement management and on-site shutdown management. I also managed a 50 megawatt generating station from 1985-1987.

I have been involved in power rates in Newfoundland and Labrador since January 1987. From 1987 to 2011, I was employed by one of the Island's industrial customers and, for the majority of that time, was tasked with reducing power costs. As part of my role with this company, I led the negotiations that resulted in the December 1, 1993 implementation of the first interruptible B power contract on the Island Interconnected System.

In 1992, I was instrumental in forming the Island Industrial Customer Power user group and served as chair of that group from 1992 to 2006. During the 1990's, industrial customers met regularly with Government officials, including Ministers and the Premier. As chair of the user group, I was responsible for most or all of the presentations made to Government. In 2003-2004, I served as the company representative for Abitibi-Consolidated on a working group formed by the Government and Abitibi to explore, among other things, opportunities to reduce power costs at the paper mill located in Stephenville. In addition, from 2004-2006, I was the Newfoundland and Labrador representative on the Canadian Major Power Consumer Group.

I have provided advice to industrial customers on a number of Applications before the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "PUB") including Newfoundland and Labrador Hydro's (Hydro) 1990, 1992, 2001 and 2003 general rate applications (GRA). During my career, I have given expert evidence before the PUB in four GRAs (1992, 2001, 2003 and April 2014). I was also actively involved in the 1992-1993 cost of service methodology hearing as well as the rural rate hearing that was held in or around 1994-1995.

Since 2007, I have been one of four directors and principals of a small wind energy company located in Stephenville, NL. As part of my role with this company, I have researched various aspects of rates and regulations in several other Canadian jurisdictions including British Columbia, Manitoba, Ontario, New Brunswick, Nova Scotia and Prince Edward Island. In particular, my research has been focused on demand and energy rates, marginal generation costs, open access transmission tariffs, feed-in tariffs, net metering and the requirements for connecting a wind turbine to the grid.

In August 2013, I was retained by Vale Newfoundland & Labrador Limited ("Vale") to assist it in the 2013 rate stabilization plan (RSP) application, the 2014 capital budget application and the 2013 GRA. The following are my submissions on the Amended 2013 GRA. The areas covered in this evidence are:

1. Methodology Used to Calculate the Operating, Maintenance and Administration Charges
2. Classification of Wind Energy
3. Holyrood Classification
4. Industrial Customer Second Block Energy Rate
5. 2014 Revenue Requirement

1. Methodology Used to Calculate the Operating, Maintenance and Administrative Charges

The Amended 2013 GRA Rate Schedule, page 6 of 46 and the 2015 COS (Amended 2013 GRA 2015 cost of service, page 40 of 109, line 21, col. 2) shows that Vale's specifically assigned charge is $499,522 per annum. See Table 1 for the components of the total specific assigned charge. As Vale paid for most of the transmission line and terminal station[1] serving the Vale plant, the depreciation and return on debt and equity is low.

Table 1: Vale's Annual Specific Assigned Charges ($)

Operating, Maintenance and Administration expense	436,715
Depreciation	37,553
Return on debt (interest)	19,281
Return on equity	7,339
Other	(1,367)
Total	**499,522**

Reference: Amended 2013 GRA, Exhibit 13, 2015 COS, page 40 of 109, line 21

The assets specifically assigned to Vale are about 20 kilometers of transmission line and a terminal station consisting of two transformers and the related switchgear.

[1] According to IN-NLH-114 Attachment 2 (Rev 1, Dec 4-15), page 5 of 5, the average net book value is $346,327 whereas the average original cost is $11,063,917.

However, the specifically assigned operating, maintenance and administration (OM&A) expense is $436,715 each year, or 87% of the total specific assigned charge. Table 2 shows the breakdown of the OM&A charge.

Table 2: Vale's Annual Specific Assigned OM&A Charge ($)

Lines	74,839
Terminals	104,837
Other	44,050
<u>Subtotal LTO</u>*	<u>223,726</u>
Administrative and General	212,989
Total	**436,715**

Reference: Amended 2013 GRA, Exhibit 13, 2015 COS, page 40 of 109, line 21
* LTO is lines, terminals and other

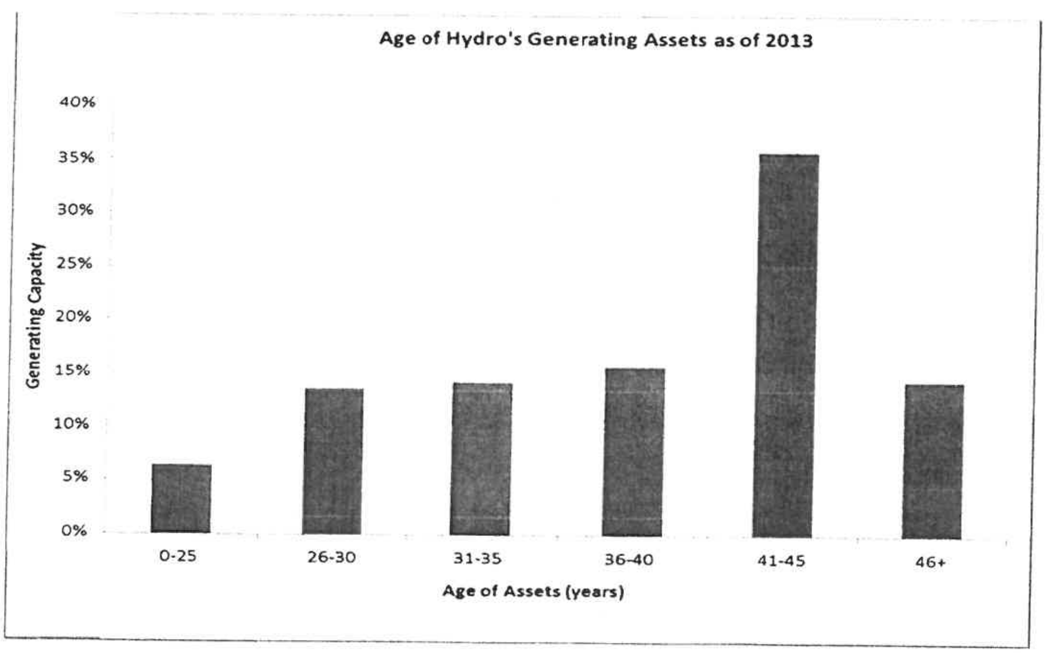
The 'other' expense include costs that are related to both transmission and terminals such as vegetation control, helicopter use and fleet vehicle use (see V-NLH-069 revision 1). The administrative and general charge is the portion of Hydro's overall administrative and general expense that Hydro allocates to Vale. The specific assigned operating and maintenance (O&M) for lines, terminals and other is determined by prorating the OM&A expense on the basis of the <u>original cost</u> of plant in service (see V-NLH-066 rev. 1, V-NLH-067 rev. 1 and V-NLH-069 rev. 1). The specific assigned charge for administrative and general is largely determined by the same method (see V-NLH-068 rev. 1).

The prorating of O&M costs using plant in service without accounting for the time value of money has the potential to achieve inequitable results. This possibility is heightened with an electrical system consisting of new and old assets as one is comparing vastly different original costs. The current island system is comprised of "more than 40,000 assets with in-service years ranging back to the 1960's" (see V- NHL-083). As such, the total of Vale's plant in service measured in 2012 dollars is being prorated against plant in service values that are based on 1960's dollars.

The gravity of this situation is emphasized in Hydro's evidence for the Amended GRA[2] where they state *"As Shown in Chart 1.1, most of Hydro's generating assets are over 40 years old. The hydraulic generating assets, which form a large part of Hydro's Island Interconnected generating capacity, are now a high value, low cost source of clean renewable energy as their original cost represents a fraction of the replacement cost of hydraulic assets today"*. Hydro's Chart 1.1[3] is included for completeness.

Hydro acknowledges that much of the transmission plant is also very old. They state *"The majority of Hydro's transmission system was constructed at the same time as the Bay d'Espoir facility in the late 1960s to connect generation to load centers across the province. As shown in Chart 1.2, many of Hydro's transmission lines are now greater than 40 years old and many components are reaching the end of their service lives."* [4] Again, Hydro's chart 1.2[5] is included for convenience.

Chart 1.1



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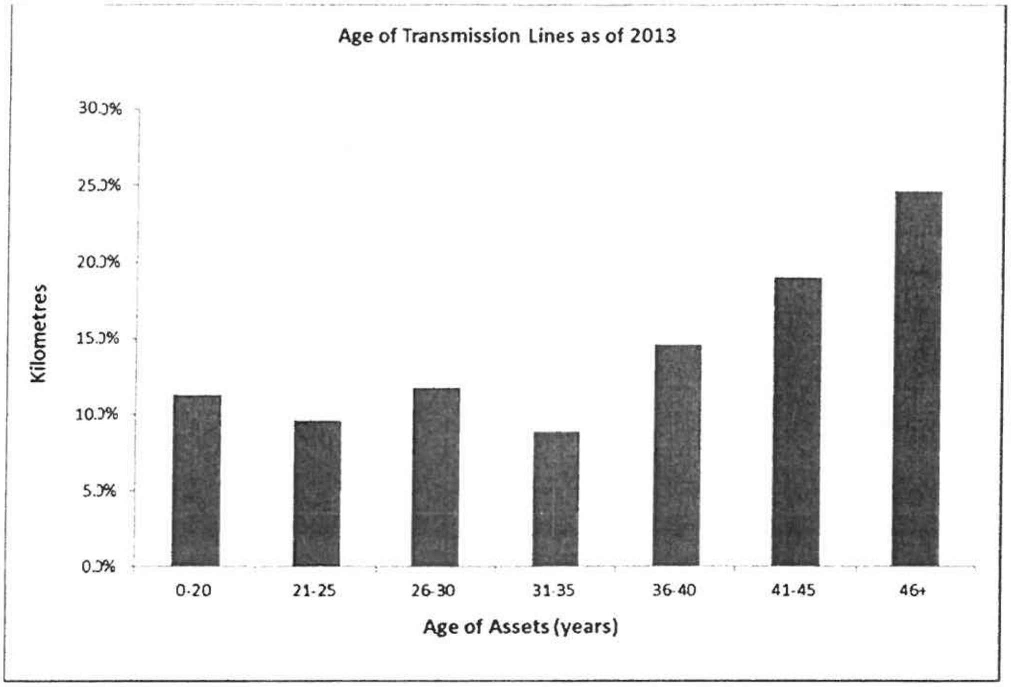
[2] (Reference: Hydro's Amended GRA evidence, Section 1: Introduction, page1.7, line 15 to page 1.8, line 15)
[3] Ibid: page 1.8
[4] Ibid: page 1.9, lines 9 to 12
[5] Ibid, page 1.9

Chart 1.2



In order to understand the methodology used in calculating the specific allocated charges and resolve the inequity, Vale submitted 22 separate requests for information (RFI) in five separate rounds. In each case, we drilled down deeper into the detail. The RFI and the request dates are as follows:

V-NLH-001 (requested on 2013-09-23)
V-NLH-060 to V-NLH-069 (requested on 2013-10-28)
V-NLH-083 (requested on 2013-12-28)
V-NLH-106 to V-NLH-111 (requested on 2015-02-25)
V-NLH-112 to V-NLH-115 (requested on 2015-04-15)

The responses to V-NLH-112 to V-NLH-115 were intended to gather enough information so that we could calculate an equitable OM&A allocation. The information provided by Hydro was inadequate and Vale has filed an Application with the PUB to obtain full and complete responses.

It is important to note that Hydro's expert, Mr. Robert Greneman, agreed with Vale that the current methodology achieves an inequitable result. In particular, Mr. Greneman wrote " .... it is acknowledged that an inequitable allocation of O&M can result due to significant newer plant additions associated with certain IC."[6] Also, in the response to V-NLH-110, Hydro acknowledges the inequity.

Hydro's expert, Mr. Greneman proposed a solution that he said could be characterized *"as an initial attempt at recognizing the impact of inflation in the O&M allocation methodology, but could open the way to discussion among the parties relative to refinements and steps that could be towards a more comprehensive analysis"*[7]. Mr. Greneman's alternate proposal is to take the specifically assigned plant additions since the 2007 GRA and deescalate back to 2007 dollars.

Vale appreciates the attempt to find a simple way to move towards a fair and equitable allocation of specific assigned expenses. The procedure described below is to move toward a method which will come much closer to removing the inequity. The prime concern with Mr. Greneman's initial proposal is that the deescalation only goes back eight years to 2007. When the Handy-Whitman index for transmission plant is set with the base year of 2015 = 100, the index for 2007 is 78 whereas the index for 1968 is 10[8]. Combined with the large amount of plant that was installed prior to 2007, this proposal falls far short of reaching an equitable allocation.

A Procedure for Restating the Plant in Service in 2015 Dollars:

Using the partial responses to V-NLH-112 to V-NLH-114, the specifically assigned OM&A expense can be recalculated by restating the plant in service in 2015 dollars instead of in original dollars. This methodology comes much closer to removing the inequity. For example, the results demonstrate that Vale is being charged approximately $350,000 a year in excess of the fair and equity amount.

[6] Reference: Hydro's Rebuttal Evidence May 30, 2014, appendix A, page A-3, lines 10 - 11
[7] Reference: Ibid, lines 16 - 20
[8] Reference: "The Handy-Whitman Index of Public Utility Construction Costs", Bulletin 180, 1912 to July 1, 2014, North Atlantic region

The overall concept is to use a method that will result in an equitable classification and allocation of OM&A specific assigned charges. The ideal method would be to restate the original plant in service costs to constant year dollars. Hydro is reluctant to restate the costs of each of the more than 40,000 assets on its system. An alternative approach, however, is to restate the function or sub-function original costs in constant year dollars. This proposed option is to list, by function or sub-function, the original cost each year since the earliest in-service date, calculate the annual change, and restate each annual change in 2015 dollars. The next step is to add the restated annual changes in order to obtain the plant in service costs in 2015 dollars for each function or sub-function. The classification and allocation of specifically allocated plant and in turn specific allocated charges are then calculated using the restated costs. Although some assumptions are required, the end result is expected to be very close to that which would be obtained by individually escalating the cost of each of the more than 40,000 assets.

The steps involved are:

a. Use the Handy-Whitman electrical utility index for the North Atlantic region[9]. For convenience, rebase the required index numbers so that 2015 equals 100. From 1912 to 2000, there is one index listed for each year. Since 2001, there is an index published on January 1 and July 1. The July 1 index was chosen as the most representative for the year. In 2015, the January 1 index is used as it is the only one available.
b. List the original plant costs for each year, subdivided by hydraulic production, Holyrood production, subtotal production, subtotal terminal stations, subtotal transmission plant, subtotal distribution, and total plant. The other required sub-functions are calculated using this information. The starting year is when the first plant-in-service cost was incurred, say 1968.
c. Calculate the annual increase for each function or sub-function (example: transmission lines, terminal stations)
d. Restate the annual increase using the appropriate Handy-Whitman index.

[9] Hydro's expert, Mr. Greneman recommended this index in his proposal as outlined above. In the response V-NLH-108, Hydro agreed that this is the proper index.

e. Add the annual increases to arrive at the plant in service cost in 2015 dollars. Appendix A shows an example of steps (b) to (e) for terminal stations.

f. Repeat steps (b) to (e) for the <u>system</u> specifically allocated plant in service for the sub-total terminal stations, subtotal transmission plant and total plant. Note that transmission lines and the general plant sub-total can be calculated using these categories.

g. Repeat step (f) for each customer that has specifically assigned charges.

h. Use the restated plant in service dollars to re-calculate the specific assigned amount in the Functional Classification of Plant in Service for the Allocation of OM&A Expenses and the Functional Classification of Operating and Maintenance Expense (See column 18 on schedules 2.2A and 2.4A, pages 26 and 29 of 109, 2015 COS). Refer to the spreadsheets in Appendix B and Appendix C.

i. Use the restated plant in service dollars and the amounts calculated in step (h) to re-calculate the specific assigned OM&A charges to each customer as shown on the Allocation of Specifically Assigned Amounts to Classes of Service (2015 COS, schedule 3.3A, page 40 of 109, columns 2 to 6) (See Appendix D).

As noted above, certain assumptions are required in order to use this procedure. The first assumption is that the Handy-Whitman Index® of Public Utility Costs™ was the proper index to use. Hydro agrees that they are the most appropriate and in the response to V-NLH-108, they state "*While other general construction cost indexes are published, the Handy Whitman Indexes are unique because they are specifically tailored to the utility industry and report construction costs by FERC account and region. The publications are used by regulatory bodies, operating bodies, operating utilities, service companies, valuation engineers, insurance companies, and equipment industry. Handy-Whitman Index values are widely used to trend earlier valuations and original cost records to estimate reproduction cost at prices prevailing at a certain date.*"

The Handy-Whitman index does not have a single index for transmission lines. Instead it has individual indexes for components such as overhead conductors, poles and fixtures. The total transmission plant index is used to represent all Hydro transmission plant. Likewise, there is no Handy-Whitman index for general plant. It is assumed that the transmission index is a close approximation. Choosing the distribution index would yield similar results.

No information was provided for the years prior to 1997 in the responses for V-NLH-112 to V-NLH-114. Consequently, for this report, estimates were required. The best available source is Hydro's charts 1.1 and 1.2 above. The percentages of production capacity and transmission lines were scaled off these charts and then used to help determine when the equipment was installed. As shown in Appendix E, the estimate is that by the year 1971, 50% of the generation asset was installed and by 1972, 50% of the transmission plant was in service. It is recognized that a degree of inaccuracy is involved with this estimate, but until the complete data is obtained, it is a reasonable approach. One has to note that it is much more accurate than the current method which does not account for the time value of money at all.

The start of the plant in service dates were not provided for Hydro or for the customers except for Teck and Vale which both have started up since 1997. Estimates were used instead of the actual.

To summarize, I recommend that the Board adopt this procedure in order to restate the original plant in service costs to 2015 dollars and then use the restated cost to allocate the specifically assigned expense. While it may not be as precise as individually restating the cost of each asset in current or constant year dollars, it would however go a long way to eliminate the inequity in the current methodology employed by Hydro. As mentioned above, Hydro has specifically allocated $436,715 of OM&A expense to Vale. Taking into account the ten-fold escalation in construction costs, as this procedure does, the appropriate OM&A charge to Vale is $87,742. The current methodology is inequitable and overcharges Vale almost $350,000 each and every year.

2. Classification of Wind Energy

In the original 2013 GRA (July 30, 2013), Hydro classified purchased wind power according to the load factor,[10] that is the percentage classified to energy being the same as the load factor. At that time the demand/energy split was 44.61% / 55.39%[11]. Hydro rigorously defended this position in the response to NP-NLH-162, stating that "*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 of the principal drivers for Hydro's peak hour demand. Consideration of any changes to the current classification methodology should be in light of overall system performance and wind conditions at the time of Hydro's system peak.*"

In the amended GRA, Hydro has fundamentally changed its position and are suggesting that wind energy be classified as 100% energy[12]. Hydro's position is not based on a study but rather on a planning decision that "*from a system planning perspective, Hydro no longer assumes that wind generation will be available to supply system capacity requirements. Therefore, Hydro is proposing that the purchased power costs related to wind be classified as 100% energy related.*"

This a change that shifts $200,000[13] a year to the Industrial Customers, which is significant when one considers the limited number of customers in this class. In the "Pre-filed Evidence of C. Douglas Bowman" dated April 25, 2014 (page 27, lines 16-18), Mr. Bowman recommends that "*Hydro file a study for the Board's consideration on the appropriate capacity/energy classification of purchases from wind generation on the Island Interconnected system for use in the cost of service study.*" Hydro did not base their decision on a study.

[10] Reference: Amended 2013 GRA filing: Reconciliation to original GRA filing, page 1.5R, lines 9-10

[11] Reference: Original GRA, exhibit 13, 2013 COS, page 107 of 109, schedule 4.2. line 5, column 2

[12] Reference: Amended 2013 GRA (Nov 2014), section 4: rates and regulations, section 4.3.2, page 4.15

[13] Reference: Response to V-NLH-099

In the response to NP-NLH-280, Hydro lists a number of North American utilities and their practices regarding classification of wind generation. Two of these utilities, SaskPower and Colorado base their classifications on studies. After the study, SaskPower assigned a 20% capacity value to its wind turbines in the cost of service. Colorado, attributes a demand component of around 12% to its wind generation. Without a study, it is difficult to determine the proper demand/energy split. However based upon the Canadian Wind Atlas[14], it is easy to see that the wind resource in Newfoundland and Labrador is much greater than in Saskatchewan. As well as visual observations of the wind resource in each province, the interactive wind map provides detailed wind information for specific locations. As an example, for St. John's, the annual mean wind speed at a tower height of 80 meters is 10.02 metres per second (about 36 kilometers per hour) whereas in Regina and Saskatoon the annual mean wind speed is 6.7 m/s (24.2 km/h) and 6.15 m/s (22.1 km/h) respectively. Clearly, the wind resource in Newfoundland is greater than in Saskatchewan, yet Saskatchewan, after a study, found that a 20% capacity value should be used for wind turbines whereas Hydro proposes to use zero. Natural Resources Canada publishes a Canadian Wind Map which shows on one page that our Province has greater wind resource than the other Canadian provinces. The map can be found on-line[15] at https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/pdf/fichier/81770/windtrm_resource_map.pdf.

In the response to NP-NLH-280, Hydro lists the wind generation practices for numerous utilities across Canada. For the first six (Page 1, line 9 to page 2, line 17), the demand/energy classification is listed but not the capacity used for planning purposes. The rest of the utilities listed in the response all attribute a certain percentage of the wind turbine nameplate capacity for planning purposes. As can be seen in Table 3, all but one assign 30 - 35% for planning purposes. The list includes the Canadian utilities in Alberta, Ontario, Hydro-Quebec and the Maritimes. Clearly,

[14] Reference: http://www.windatlas.ca/en/index.php
[15] Due to copyright, it cannot be included as an appendix.

Hydro's decision to assign a value of zero to wind turbines for planning purposes is outside the norm.

Table 3: Wind Generation – Classification and Capacity Value

Jurisdiction	Capacity Factor (%)	Wind Capacity for Planning Purposes (% of name plate capacity)
Maritimes	37.0	35.0
Hydro Quebec	35.0	35.0
Texas	33.7	8.7
South Carolina	30.0	35.0
South Carolina	30.0	35.0
Kentucky	30.0	30.0
Maryland	29.8	35.0
Alberta	29.7	35.0
Florida	28.5	30.0
Maine	27.6	35.0
Ontario	27.0	35.0
Pennsylvania	24.9	35.0
California	24.9	35.0
New York	23.6	35.0
Massachusetts	22.8	35.0
Vermont	20.6	35.0
Arizona	20.2	35.0
New Jersey	16.0	35.0

Capacity factor is another important consideration. As discussed above, Hydro acknowledges that the capacity factor for the two wind farms is in excess of 40%. Tables 3 and 4 list the capacity factors[16] of the same utilities discussed in the response to NP-NLH-280. Only two other utilities report capacity factors in the same range as the wind farms on the Island. They are Austin Energy (Texas) at 40% and

[16] Reference: Amended 2013 GRA, response to V-NLH-118

SaskPower in excess of 40%. The lower capacity factors of the utilities listed in Tables 3 and 4 are similar to the forecast in *"The Global Wind Energy Outlook 2012"*[17] which uses a capacity factor of 28%. Again, Hydro has chosen a zero value for wind capacity for planning and cost of service purposes even though Hydro has experienced a higher capacity factor than is experienced globally.

The six utilities listed in NP-NLH-280 that specify the demand/energy ratio for wind generators are all shown in Table 4. Four of the six have a demand component and three of these four have a capacity factor lower than the wind generation in Newfoundland. Saskatchewan has a capacity factor the same as Newfoundland and they classify 20% to demand. BC Hydro has the lowest capacity factor of the group and has classified the wind generation to 100% energy.

Table 4: Wind Generation –Capacity Factor and Classification

Jurisdiction	Capacity Factor (%)	Classification to Demand (%)	Classification to Energy (%)
Demand Allocation > Zero			
SaskPower*	> 40	20	80
Colorado*	33.7	12	88
MidAmerican (Iowa)**	33.3	1 - LF	LF
Nova Scotia**	30.0	9	91
Energy = 100%			
BC Hydro**	20 – 30	0	100
Austin Energy (Texas)	40	0	100

* Demand component based on studies showing contribution to peak in these jurisdictions
** The classification is under review in these jurisdictions

Austin Energy (Texas) appears to be unique in this listing as they use the base-intermediate-peaking (BIP) allocation methodology. They classify wind generation as

[17] Reference: www.gwec.net/wp-content/uploads/2012/11/GWEO_2012_lowRes.pdf, section 2 "The Global Wind Energy Outlook Scenarios", page 14, top of page

base load which, in turn, is classified as 100% energy. Note that nuclear, hydraulic and sometimes thermal generation are base load which means that they also would be classified as 100% energy. This is a classification methodology which is very different than what has been and is being used in this province. Consequently, I submit, that the Board should not give the Austin Energy (Texas) allocation much weight.

In the response to PUB-NLH-390 Hydro argues that wind farms cannot be depended on to be available during the time of the system peak. However, NP-NLH-043 revision 1 shows that since installation, the wind farms have contributed capacity at the time of the system peak each and every year. In the majority of the years, the total output of the wind farms was between 48% and 64 %. 2013 was the year with the lowest output and it was still over 9% of the total island wind generation. It needs to be noted that in a presentation to the Board[18], Hydro says that a new system peak of 1501 megawatts (mW) was set on December 14, 2013 (slide 8). This presentation also states that wind generation was 49 megawatts which is over 90% of the 54 mW nameplate capacity. Meanwhile, 75 mW of the 100 mW of gas turbine generation was unavailable, that is to say, 25% availability (reference: slide 7 of same presentation). This shows that even the generators dedicated to peak load conditions are not always reliable.

I recommend that the Board maintain the current classification of wind generation until a full study is completed. In the alternate, the Board could look at the current practices in North America as outlined above and assign a percentage to demand. I believe that the Saskatchewan situation is instructive and that the percentage allocated to wind should be at least 20%.

3. Holyrood Classification

Since 1992, the classification of non-fuel Holyrood cost has been based on the average plant capacity factor over the previous five years. The choice of using the previous five years is beneficial for balancing out annual fluctuations in water flows.

[18] Reference: Island Interconnected System Supply Disruptions - January 2 to 6, 2014, Public Utilities Board Briefing, January 8, 2014

However, this method does not take into account significant load changes. When there is a long period between GRAs, the method does not have a chance to correct itself in a timely fashion. Since the last GRA, the actual Holyrood capacity factors have varied between a low of 20% to a high of 31%[19], giving an average of 24%. During this seven year period, the capacity factor used in the cost of service was 41%[20], which clearly did not reflect the actual demand / energy split. The variances between the actual and COS capacity factor were due to unexpected industrial load reductions and the same could occur in the future. Following so many years with no update to the capacity factor, I submit that there is no requirement to change the existing methodology for the remaining two year life of the Holyrood plant.

The change proposed by Hydro and the information that NP requested in NP-NLH-356 would classify a higher percentage of the non-fuel Holyrood costs to energy than at the current time. This comes at a time when Holyrood will be operated during the summer for Avalon transmission support. Hydro clearly states that this is not for energy requirements, it is strictly for capacity reasons[21]. The current demand / energy split does not take in to account the new role for the increased capacity requirement at Holyrood. This further supports the recommendation to maintain the status quo for the remaining two year life of the Holyrood plant.

4. Industrial Customer Second Block Energy Rate

The use of a second block energy rate where the second block is set near the marginal cost of energy sends a price signal to the customer to conserve electrical energy. When industrial customers, such as Vale and Praxair, are constructing and commissioning their plants and routinely adding load until they get into full and stable production, the benefit of an energy price signal as recommended by the Board's expert, Mr. Wilson (April 25, 2014 evidence, page 19, first paragraph) is highly questionable. During a typical industrial start-up, the total focus is on the construction,

[19] Reference: Amended 2013 GRA evidence, section 4: rates and regulation, page 4.16, Table 4.4.
[20] Ibid, page 4.17, line 2
[21] Reference: Amended 2013 GRA, response to V-NLH-120

commissioning, operator training, maintenance procedures, procuring spare parts and optimizing the production at a full and stable level. During this stage, energy consumption and conservation of energy is a low priority. We agree with Hydro's proposal that a second block not be implemented for industrial customers while Vale's load is ramping up. Mr. Patrick Bowman[22] and Mr. Douglas Bowman[23] both agree.

5. 2014 Revenue Requirement

In the amended 2013 GRA, Hydro is requesting to recover a 2014 Revenue Deficiency of $45.9 million[24].This is in addition to the $10 million of supply costs that Hydro has requested in a separate application[25]. On November 28, 2014, Hydro submitted a 2014 Cost Recovery Application to the Board which, among other things, proposed to establish a 2014 revenue deficiency deferral account and to segregate $45.9 million in the Hydraulic Variation Account by customer group. In P.U. 58(2014), dated December 24, 2014, the Board approved the creation of the deferral account and the segregation of $45.9 million. Recovery of this amount, or any part of it, was not approved and the proposed transfer from the RSP Hydraulic Variation Account to the deferral account was not approved. This issue has been brought forward to the GRA and I recommend that the Board consider several issues.

The OM&A expenditure in 2014 increased by $12.3 million over 2013[26]. I recommend that the Board examine this increase in expenditure carefully. In particular, I point out the following:

- The response to V-NLH-088 indicates that an extra $2.9 million (line 14) was spent on activities related to the power outages in January 2014. This amount does not include the regular labour and benefits (lines 12-13).

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[22] Source: Evidence - P. Bowman and H. Najmidinov, April 28, 2014, page 37, lines 18 to 27
[23] Source: Evidence - C. Douglas Bowman, April 25, 2014, page 16, lines 17 to 19
[24] Reference: Amended 2013GRA evidence, Section 1: Introduction, page 1.4, lines 10 to 11
[25] Ibid, footnote 7
[26] Reference: Amended 2013 GRA, RFI V-NLH-030 revision 1. (99,765,512 - 87,496,557 = 12,268,955)

- In 2014, there was a lot of catch-up maintenance done on transformers[27]. A six-year maintenance program was started in 2010 and the plan was to maintain 17 or 18 transformers a year. Four years later, at the end of 2013, only 50 out of the scheduled 69 transformers had been completed. In 2014, Hydro maintained the 19 transformers that they were behind plus the 18 scheduled for the year. The 2014 expenditure was $805,907, whereas the expenditure for the previous 4 years averaged $145,797. The catch-up maintenance resulted in an overtime expenditure of $318,816 (see V-NLH-116).

- In 2014, there was a lot of catch-up maintenance done on breakers[28]. A six-year maintenance program was started in 2010 and was to maintain 31 to 35 breakers a year. Four years later, at the end of 2013, only 83 out of the scheduled 128 breakers were completed. In 2014, Hydro maintained a total of 65 breakers for an expenditure of $621,924. The average expenditure for the previous 4 years was $68,269. The catch-up maintenance resulted in an overtime expenditure of $205,721 (see V-NLH-117).

- In the response to V-NLH-095, Hydro explains the reasons for the increase in professional services of $6.3 million between 2013 and 2014. The reasons (lines 7 to 15) include increased Board related costs, outage inquiry consulting cost, increased condition assessments and environmental remediation at the Sunnyside Terminal Station.

- The response to V-NLH-124 indicates that an extra $292,306 of costs resulted from work by the President and Chief Executive Officer, Vice-President Finance and the Vice-president Corporate Communication as a result of the January 2014 power outages.

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[27] Reference: Amended 2013 GRA, RFI V-NLH-089, page 1 of 2
[28] Ibid, page 2 of 2

These are costs that are included in the 2014 Cost Recovery Application. I believe that the Liberty Prudence Report will be instructive in determining the appropriateness of these OM&A expenses.

The increase in the return on equity (ROE) from the current 4.465% to 8.8% and the inclusion of the rural portion of the rate base in the 2014 Cost Recovery Application results in an increase of $20,123,005[29]. This is nearly half of the $45.9 million of recovery that Hydro is proposing. In P.U. 58(2014), the Board states

> *"Newfoundland Power notes that Hydro's current return on equity for rate making purposes, effectively approved by the Board in the 2007 general rate application, is 4.47%. Newfoundland Power states that the assumption of an 8.8% return on equity where the Board is not approving new rates does not conform with the direction provided by the Government in OC2009-063."* (page 5, lines 18-22).

Vale's submission on the 2014 Forecast Revenue Deficiency Application also raises a concern about the appropriate ROE. Vale stated that

> *"To support an entitlement to a rate of return on equity of 8.8%, Hydro has previously relied on OC2009-063, which directed the Board '<u>for all future General Rate Applications</u>' to calculate Hydro's return on equity based on the same target most recently set for Newfoundland Power. Vale submits that Hydro's Application to recover its stated 2014 revenue deficiency is brought coincident with its 2013 Amended General Rate Application but is not itself a general rate application."*

In view of the $20.1 million involved, I recommend that the Board consider the appropriateness of the ROE.

A further consideration, is the method of recovery of any amount that the Board may deem appropriate. I recommend that the amount to be recovered be transferred from the existing balance in the RSP Hydraulic Variation Account or other RSP account which has a balance owing to customers. A recovery method that uses an existing balance is recommended over methods such as a rate rider that would affect future

[29] Reference: amended 2013 GRA, RFI V-NLH-087

years. A rate rider would worsen the rate impact that the Industrial Customers are experiencing and would cause intergenerational inequity due to the changing dynamics within the Industrial Customer class.

Mel Dean

Appendix A: Restatement of Transmission Terminal Plant in Service

Subtotal Terminal Stations Original Costs in 2015 Dollars

Year	Original* Cost ($)	Increase ($)	Index** (2015 Base)	Average Index*** During Increase	Increase (2015$) (C / D * 100)
1967	0		10		
1968		0	10		0
1969		0	11		0
1970		0	11		0
1971		0	12		0
1972		0	13		0
1973		0	14		0
1974		0	17		0
1975		0	19		0
1976		0	20		0
1977		0	22		0
1978		0	22		0
1979		0	24		0
1980		0	27		0
1981		0	29		0
1982		0	31		0
1983		0	32		0
1984		0	32		0
1985		0	33		0
1986		0	34		0
1987		0	34		0
1988		0	38		0
1989		0	40		0
1990		0	42		0
1991		0	43		0
1992		0	44		0
1993		0	45		0
1994		0	47		0
1995		0	49		0
1996		0	50		0
1997	134,222,632	134,222,632	51	13	1,053,355,873
1998			52		0
1999	135,520,324	1,297,692	52	52	2,478,661
2000	137,545,775	2,025,451	55		3,692,867
2001	139,530,508	1,984,733	57		3,512,199
2002	138,844,286	(686,223)	58		(1,190,992)
2003	142,432,904	3,588,618	58		6,228,323
2004	145,407,141	2,974,238	63		4,719,559
2005	143,721,129	(1,686,012)	67		(2,504,735)
2006	143,002,085	(719,044)	72		(992,638)
2007	144,999,000	1,996,915	78		2,556,335
2008	147,212,774	2,213,773	87		2,541,088
2009	152,720,844	5,508,070	84		6,519,388
2010	157,118,178	4,397,334	88		4,976,294
2011	160,515,918	3,397,740	93		3,666,918
2012	168,247,275	7,731,357	94		8,184,809
2013	175,702,612	7,455,337	96		7,744,969
2014	188,903,974	13,201,362	99		13,386,775
2015	219,509,093	30,605,119	100		30,605,119
Original Cost	219,509,093				**1,149,480,812**

* Source: NLH amended GRA 2013, RFI V-NLH-112, attachment 1, column 5

** Reference: "The Handy-Whitman Index of Public Utility Construction Costs", Bulletin 180, 1912 to July 1, 2014, North Atlantic Region

*** The 1972 index was chosen as described in Appendix E

Island interconnected Plant In Service - By Customer & Component (2015 $)

	System	Specifc Assigned	NP	IC	Vale	CBPP	NARL	Teck
Subtotal - hydraulic	4,749,456,113							
Holyrood	1,419,384,381							
Subtotal - hydraulic & Holyrood	**6,168,840,494**							
Production - other	590,144,033							
Subtotal - production	6,758,984,527							
Trans. Lines - all	1,893,058,785	71,305,833	58,400,264	12,905,569	6,873,418	0	0	6,032,151
Subtotal - terminals	1,149,480,812	103,046,534	78,510,053	24,536,482	4,730,441	9,702,244	8,897,814	1,205,983
Subtotal - trans	3,042,539,597	174,352,368	136,910,317	37,442,051	11,603,859	9,702,244	8,897,814	7,238,134
Subtotal - dist.	772,386,650							
Subtotal - prod'n, trans & dist.	10,573,910,774	174,352,368	136,910,317	37,442,051	11,603,859	9,702,244	8,897,814	7,238,134
Subtotal PTD excl. hydr. & Holyrood	4,405,070,281	174,352,368	136,910,317		11,603,859	9,702,244	8,897,814	7,238,134
Subtotal general plt	959,482,798	16,331,037						
Subtotal-production, transmission & general	10,761,006,922	190,683,404						
Total Plant	**11,533,393,572**	**190,683,404**						

Appendix C: Restatement of Specifically Assigned OM&A Expense

Island Interconnected & Specifically Assigned OMA Expense (2015 $)

	System* OM&A Expense	System Plant** In Service	Spec. Assigned Plant In Service	Spec. Assigned*** OM&A Expense
Subtotal - production	40,564,546	6,758,984,527	0	0
Transmission				
Subtotal - transmission lines	3,910,236	1,893,058,785	71,305,833	147,287
Terminal stations	5,102,709	1,149,480,812	103,046,534	457,438
Transmission - other	2,237,357	3,042,539,597	174,352,368	128,211
Subtotal - transmission	11,250,302	3,042,539,597	174,352,368	732,937
Subtotal - distribution	8,059,497	772,386,650	0	0
Subtotal - prod, trans & dist'n	59,874,345			732,937
Customer accounting	2,135,554			0
Subtotal - prod, trans, custustomer acct & dist'n	**62,009,899**			**732,937**
Administrative & General				
Plant-Related:				
Transmission	5,300,429	3,042,539,597	174,352,368	303,740
Prod, trans, dist'n & gen plt	343,528	11,533,393,572	190,683,404	5,680
Prod, trans & dist'n excl hydraulic & Holyrood	1,425,303	4,405,070,281	174,352,368	56,413
Property insurance****	1,595,772	7,908,465,339	103,046,534	20,793
Revenue-Related:				
All expense-related	21,809,014	62,009,899	732,937	257,775
Prod, trans, dist'n expense-related	1,380,404	59,874,345	732,937	16,898
Admin and gen. expenses not spec. assigned	12,188,434			0
Subtotal admin and general	**44,042,884**			**661,299**
Total OM&A expenses	**106,052,783**			**1,394,236**

* Source: 2013Amended GRA, Exhibit 13, 2015 COS, Sch 2.4A, column 2

** Reference: amended 2013 GRA, V-NLH-066 to V-NLH-069 revision 1

*** Spec. assigned OM&A expense = system OM&A expense * spec. assigned plant in service / system spec. assigned plant in service

**** Hydro's calculation for plant in service is the sum of lines 13, 21, 23, 35 and 36 from COS schedule 2.2A. For simplification, these calculations use lines 13 & 21 only. This simplification results in an insignificant loss of accuracy on the OM&A specifically assigned expense.

Appendix D: Restatement of OM&A Amounts to Customers

Allocation of OM&A Specifically Assigned Amounts to Classes of Service (2015 $)

	Total OM&A Amount ($)	Lines ($) (Plant)	Terminals ($) (Plant)	Admin & Gen ($) (col C + col D)	Other ($) (col C + col D)
Basis of Allocations - Amounts					
Newfoundland Power		58,400,264	78,510,053	136,910,317	136,910,317
Industrial					
Vale		6,873,418	4,730,441	11,603,859	11,603,859
Corner Brook Pulp & Paper		0	9,702,244	9,702,244	9,702,244
North Atlantic Refining Limited		0	8,897,814	8,897,814	8,897,814
Teck Resources		6,032,151	1,205,983	7,238,134	7,238,134
Subtotal Industrial		**12,905,569**	**24,536,482**	**37,442,051**	**37,442,051**
Total		**71,305,833**	**103,046,534**	**174,352,368**	**174,352,368**
Amounts Allocated					
Newfoundland Power	1,089,111	120,630	348,517	519,286	100,678
Industrial					
Vale	87,742	14,197	20,999	44,012	8,533
Corner Brook Pulp & Paper	87,004	0	43,070	36,800	7,135
North Atlantic Refining Limited	79,790	0	39,499	33,748	6,543
Teck Resources	50,589	12,460	5,354	27,453	5,323
Subtotal Industrial	**305,125**	**26,657**	**108,921**	**142,014**	**27,533**
Total	**1,394,236**	**147,287**	**457,438**	**661,299**	**128,211**

Appendix E: Estimated Average 1967 – 1997 for Generation and Transmission

Generation Plant In-Service Dates from 1967 - 1997

Context: To date, data has not been obtained for plant in service original costs for the years prior to 1997. Thus weighted average in service dates have to be estimated.

Table 1: Approximate In-Service Date for Generation Plant

Chart Year*	Age Range**	Year Range (A - B)	Assumed in*** Service Date	Generating** Capacity (%)	Accumulative Generating Capacity (%)
2013	46+	1967 or earlier	1968	14%	14%
2013	41 - 45	1968 - 1972	1970	36%	50%
2013	36 - 40	1973 - 1977	1975	15%	65%
2013	31 - 35	1978 - 1982	1980	15%	80%
2013	26 - 30	1983 - 1987	1985	14%	94%
2013	0 - 25	1988 - 2013	1997 - 2015	6%	100%

* Source: Amended GRA 2013 evidence, section 1, Chart 1.1, page 1.8. The age range is relative to 2013

** Source: Ibid, Chart 1.1, page 1.8. The % of generation capacity was scaled off the chart

*** Assume 1968 is the earliest plant in service date. 1970, 1975, 1980 & 1985 are the midpoints of the year range. 1997-2015 are the years with data available and hence an estimate is not required.

Analysis:

* Assume that the first plant in service is 1968

* By 1997, in excess of 94% of the generation capacity was installed.

* The year when 47% (i.e. 94% / 2) of the generation plant was installed would represent the weighted average between 1967 and 1997

* By 1972, 50% of the generation capacity was installed.

*** Therefore, the 1971 index is representative of generation plant installed between 1967-1997**

Plant In-Service Dates from 1967 - 1997

Context: To date, data has not been obtained for plant in service original costs for the years prior to 1997. Thus weighted average in service dates have to be estimated.

Table 2: Approximate In-Service Date for Transmission Lines					
Chart Year	Age Range	Year Range (A - B)	Assumed in Service Date	Transmission Lines (%)	Accumulative Transmission Lines (%)
2013	46+	1967 or earlier	1968	25%	25%
2013	41 - 45	1968 - 1972	1970	19%	44%
2013	36 - 40	1973 - 1977	1975	14%	58%
2013	31 - 35	1978 - 1982	1980	9%	67%
2013	26 - 30	1983 - 1987	1985	12%	79%
2013	21 - 25	1988 - 1992	1990	10%	89%
2013	0-20	1993 - 2013	1997 - 2015	11%	100%

* Source: Amended GRA 2013 evidence, section 1, Chart 1.2, page 1.9. The age range is relative to 2013

** Source: Ibid, Chart 1.2, page 1.9. The % of transmission lines was scaled off the chart

*** Assume 1968 is the earliest plant in service date. 1970, 1975, 1980, 1985 & 1990 are the midpoints of the year range. 1997-2015 are the years with data available and hence an estimate is not required.

Analysis:

* Assume that the first plant in service is 1968

* As terminals stations are installed with transmission lines, it is assumed that Table 2 represents all transmission plant.

* By 1997, in excess of 89% of the transmission lines were installed.

* The year when 44.5% (i.e. 89% / 2) of the transmission lines were installed would represent the weighted average between 1967 and 1997

* By 1972, 44% of the transmission lines were installed.

* **Therefore, the 1972 index is representative of transmission plant installed between 1967-1997**