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April 25, 2014

VIA COURIER and ELECTRONIC MAIL

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

Attention: **Ms. G. Cheryl Blundon**
Board Secretary

Dear Ms. Blundon:

RE: 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. Newfoundland & Labrador Hydro
P. O. Box 12400
500 Columbus Drive
St. John's, NL A1B 4K7
Attention: Geoffrey P. Young
Senior Legal Counsel

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and Teck Resources Limited
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Attention: Paul Coxworthy

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Attention: Edward M. Hearn, Q.C.

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Attention: Stephanie Kearns

House of Commons
Confederation Building
Room 682
Ottawa, ON K1A 0A6
Attention: Yvonne Jones, MP Labrador

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

IN THE MATTER OF a General Rate Application (the Application) by Newfoundland and Labrador Hydro for approvals of, under Section 70 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 2013 GENERAL RATE APPLICATION

Prepared by Mel Dean
April 25, 2014

Introduction

My name is Melvin Dean and I reside in Stephenville, NL. I am a professional electrical engineer. Over the past 44 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 with electrical 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 company and Government to explore, among other things, opportunities to reduce power costs at the paper mill located in Stephenville. In addition, from 2004 to 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 evidence before the PUB in three GRAs (1992, 2001 and 2003). 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, 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 2013 GRA. The areas covered in this evidence are:

1. Demand Allocation
2. The Calculation of O&M Costs in Specifically Assigned Charges
3. Conservation and Demand Management
4. The RSP

1. <u>Demand Allocation</u>

In Hydro's 2013 GRA, the PUB is being asked to set demand rates based on a test year that is characterized by an unstable period for demand. In particular, the fact that two of the five island industrial customers are in the pre-production stage of their respective operations has resulted in an inequitable distribution of demand costs. An examination of why the demand allocation proposed by Hydro is inequitable requires an examination of (i) the historical treatment of pre-production industrial customers, (ii) the historical differences between the demand rates charged to industrial customers and Newfoundland Power ("NP") and (iii) the demand allocation method used to apportion demand costs between industrial customers and NP.

<u>(i) Pre-production Industrial Customers</u>

Industrial customers are customers that purchase power from Hydro at voltages of 66,000 volts or higher. There are currently 5 industrial customers on the island system, two of which are in the pre-production stage. In addition to being unique with respect to the voltage at which power is taken and their annual usage, the manner in which a new industrial customer's demand ramps up before maintaining a relatively stable state make ICs different from Newfoundland Power's customer group.

An operating industrial customer in stable operation typically has a nearly constant load throughout the year and, therefore, a high load factor. However, from the time that a new industrial customer starts purchasing power until the customer reaches stable production, referred to as the pre-production stage, an industrial customer generally has a low load factor. During this time period, the new industrial customer is building and commissioning their plant causing load to build up gradually month after month. Even within a month, the demand will likely change from the start of the month until the end. As a result, whether you consider the annual load factor or the monthly load factor, the pre-production industrial customer's load factor will be lower due to this "ramping up" effect.

The PUB began regulating industrial customers following the enactment of the *Electrical Power Control Act*, 1994, c. E-5.1. Since that time, three industrial customers have been added to the system. In all three cases, the PUB ordered that the new industrial customer were to use the existing industrial customer basic energy[1] and demand rates. The difference approved by the PUB was that the pre-production industrial customer was to be charged based on a monthly peak rather than an annual peak until they entered the stable production stage. The three customers and the corresponding PUB orders approving the use of a monthly peak are:

- Aur Resources (now Teck Resources) – P.U. 1 (2007)
- Vale - P.U. 6 (2012)
- Praxair - P.U. 9 (2013)

The PUB Order for Vale, P.U. 6 (2012) states in part that:

> The Board is satisfied that the service agreement for Vale should be approved as proposed. Other than the temporary suspension of the annual demand charge during startup, which is reasonable in the view of the Board, the service agreement is consistent with those in place for other Industrial Customers. (page 6, lines 4 -7)

[1] In all cases the basic energy rate was the same as the existing IC customers. The RSP rate for Aur Resources was different as they were excluded from paying the historic RSP charge. This resulted in the total energy rate being lower for Aur Resources.

Clause 2.06 (e) of the service agreement attached to P.U.6 (2012) clarifies the temporary suspension,

> During the Ramp-Up Period, the Customer's Billing Demand for Firm Power shall be the greater of the Customer's Maximum Demand in that Month less its maximum Interruptible Demand in that Month, and the Amount of Power on Order declared under paragraph (d) of this Clause.....

The above referenced PUB orders for Aur Resources and Praxair are similar to the one for Vale.

The key point is that the PUB has ordered that, while all new customers were to the have the same basic energy and demand rates as the existing industrial customers, the fact that the new customer was gradually increasing its load had to be recognized. To recognize this situation, the PUB ordered that the new industrial customer's demand rate charge be based on monthly peaks rather than annual peaks during the pre-production stage. In no case did the PUB order a higher demand rate.

(ii) 2013 Test Year Demand Rate in Context with Historical Rates

Historically, the demand rate charged to NP customers has been higher than the demand rate charged to industrial customers. The year by year demand rates for each of these customer classes from the 2007 test year rate to the 2014 forecast rate are:

Table 1: Demand Rates for IC and NP

Year*	IC Demand ($/kW)	NP Demand ($/kW)	Source (GRA RFI IC-NLH-002 unless otherwise noted)
2007T	6.69	7.49	2007 forecast COS, page 11 of 109, lines 1 & 2, col 2
2007A	6.62	7.22	2007 actual COS, page 11 of 109, lines 1 & 2, col 2
2008A	5.74	7.84	2008 actual COS, page 11 of 109, lines 1 & 2, col 2
2009A	5.95	8.36	2009 actual COS, page 11 of 109, lines 1 & 2, col 2
2010A	2.78	8.12	2010 actual COS, page 11 of 109, lines 1 & 2, col 2
2011A	7.38	8.76	2011 actual COS, page 11 of 109, lines 1 & 2, col 2
2012A	7.26	8.50	2012 actual COS, page 11 of 110, lines 1 & 2, col 2
2013T	**9.13**	**9.12**	GRA application exhibit 13, p. 11 of 109, lines 1 & 2, col 2
2014F	8.50	9.48	RFI IC-NLH-141, attach 1, p. 11 of 108, lines 1 & 2, col 2

* Legend: T = test year; A = actual; F = forecast

In the 2013 test year cost of service (COS), the industrial customer demand rate is $9.13 / kW while the demand rate for NP is $9.12 / kW (GRA application, exhibit 13, 2013 test year COS, sch. 1.3, page 1 of 3, lines 1 & 2, col 2). As demonstrated in Table 1, an industrial customer demand rate that is higher than or equal to the NP demand rate is abnormal. In all cases other than the 2013 test year COS, the industrial customer demand rate is significantly lower than the NP demand rate. Other than the 2013 COS, the minimum difference in the two rates is 60¢/kW (2007A). Excluding the 2013 COS, the average difference between the rates is $1.86. Even with the unusually high difference in 2010 omitted from the calculation along with the 2013 COS rates, the average difference between the industrial customer demand rate and the NL demand rate is still significant at $1.36/kW.

(iii) Demand Allocation Methodology

The use of a single coincident peak (1 CP) demand allocator for generation and transmission[2] was approved following the COS methodology hearing in 1992 – 1993. (Reference PUB-NLH-113, attach. 1, p. 75 recommendation 7 and p. 76, recommendation 16). In other words, the classified demand costs are allocated among NP, industrial customers and rural customers based on the customer's peak at the time of the system peak.

In the 2013 test year COS, the industrial customer demand included both the operating industrial customers and the pre-production industrial customers. RFI CA-NLH-004 from the 2013 RSP application shows that the monthly demand forecast for the industrial customers increased from 60,100 kW in January 2013 to 79,600 in December 2013, an increase of 32.4%. The same response shows that the 19,500 kW increase is strictly due to the "ramping-up" of the two pre-production companies, Vale and Praxair. As the COS annual peak was in December (IC-NLH-154, lines 13 to 16), the full 19,500 kW demand increase from the ramping up of Vale and Praxair was included in the calculation of demand rates. This is the sole reason that the industrial customer and NP demand rates from the 2013 COS are nearly the same. As discussed above, this result is abnormal in comparison to historical demand rates between the customer classes.

The fact that the similarity of demand rates between the industrial customer and NP classes was the direct result of the use of the December peak is demonstrated and quantified in Hydro's response to RFI IC-NLH-140, which read:

> Please provide a revised cost of service study that maintains the Vale and Praxair annual energy but "normalizes" the monthly peaks to reflect a peak Power On Order level (consistent with the 2013 annual energy) more representative of a high load factor industrial customer.

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[2] Except transmission used solely or dominantly for the purpose of connecting remotely-located generation to the main transmission line.

The rates in Table 2 are taken from the RFI response:

Table 2: 2013 COS Demand Rates for IC and NP Assuming Normal Load Factor for Vale and Praxair

	IC Demand ($/kW)	NP Demand ($/kW)	Source (GRA RFI IC-NLH-140, attach. 1)
2013 modified (IC-NLH-140)	7.59	9.21	Page 11 of 109, lines 1 & 2, col 2

The results demonstrate that, if all five industrial customers were in stable operation, the industrial customer demand rate would be $7.59/kW rather than $9.13/kW, a difference of $1.54/kW. In other words, including the peak "ramp-up" demand in the 1 CP calculation has caused the IC rate for the pre-production IC customers to be higher than normal. The use of a rate that reflects all industrial customers being in stable production is consistent with the PUB orders holding that pre-production industrial customers were to be charged the standard industrial customer energy and demand rates; rates which reflected stable industrial customer demand. By using a demand rate that does not reflect the fact that two of the five industrial customers accounted for in the test year are ramping up through the test year, the three operating industrial customers are subjected to the same disproportionately high demand rate. As a result, a disproportionate share of the total demand expense has been allocated to all the industrial customers.

As the results of the allocation methodology produced abnormal results, one has to consider both the appropriateness of the methodology and the particular circumstances for the test year being used. The 1 CP allocator has been the approved methodology for over 20 years. For transmission plant, the PUB's decision to use a 1 CP allocator was based on an agreement that "transmission line costs correlate almost completely with their capacity and therefore are attributable to the demands placed on them" (Reference PUB-NLH-113, attach. 1, p. 43, second paragraph). During the 1992-1993 Cost of Service methodology hearing, the PUB heard a number of different views on classification and allocation of generation plant. However, the

PUB ultimately concluded that the "CP allocator would be preferable" (Reference PUB-NLH-113, attach. 1, p. 23, first paragraph).

While the use of a 1 CP provided an equitable distribution demand costs in a situation where all industrial customers were in stable operation, the 1 CP allocator does not result in an equitable distribution of demand costs where one or more of the industrial customers is ramping up during the test year. The treatment of NP's hydro generation in the 2006 GRA provides precedent for normalization of a COS factor when the COS was based on an abnormal test year (see Parties Agreement on COS, Rate Design and Other Issues dated November 23, 2006[3] at p. 4, Art. 9; and PUB Order P.U. 8 (2007) at pp. 22-23 and 65[4])

The use of other allocation methods, such as a 4 coincident peak (e.g. average over the four winter months) or a 12 coincident peak instead of the 1 CP is possible. Multiple coincident peak averages the peaks over several months and would tend to average out the "ramping up" effect of pre-production industrial customers such as Vale and Praxair. The downside of a multiple coincident peak average is that, under stable demand conditions, the rates would not reflect the cost causation principles that led the PUB to accept the 1 CP allocation methodology.

(iv) Conclusion

In this GRA, the PUB is being asked to set rates based on a test year that is characterized by an unstable period of demand. Rather than continue to use a 1 CP allocator based on the 2013 COS customer peaks as presented by Hydro, a preferred approach would be keep the methodology the same but to "normalize" the abnormal 2013 IC peak demand for rate making purposes. Hydro's response to IC-NLH-140 is a fair and equitable way to "normalize" the allocation of the demand expenses.

[3] http://www.pub.nf.ca/hydro2006gra/files/corresp/PartiesAgreement-Nov23-06.pdf
[4] http://www.pub.nf.ca/hydro2006gra/files/order/pu8-2007.pdf.

2. The Calculation of O&M Costs in Specifically Allocated Charges

The 2013 COS shows that Vale's annual specifically assigned charge is $533,724 (GRA 2013 COS, page 40 of 109, line 21, col 2). However, responses to RFIs V-NLH-063 and V-NLH-064 indicate that the depreciation is $1,785 lower than shown is the COS. At this point in time, the COS has not been changed to incorporate the $1,785 reduction.

A more significant issue with the specific allocated charge attributed to Vale results from the calculation of the operating and maintenance ("O&M") expense portion of the charge. Table 3 shows the breakdown of the total specific assigned charge, of which the O&M expense of $459,565 is by far the largest component.

Table 3: Vale Specifically Assigned Charges*

Operating and maintenance expense	$459,565
Depreciation	$ 45,702
Return on debt (interest)	$ 22,096
Return on equity	$ 8,696
Other**	($ 2,335)
Total	**$533,724**

* Reference: RFI PUB-NLH-10 from the RSP application

** Other includes expense credits, gain/losses on disposal of assets and revenue related costs

Vale's O&M expense of $459,565 is composed of two separate components/functions, transmission ($247,748; see GRA 2013 COS, page 40 of 109, line 21, sum of col. 3, 4 & 6) and administration & general ($211,818; see GRA 2013 COS, page 40 of 109, line 21, col 5). The specific assigned O&M is largely determined by prorating the O&M expense on the basis of plant in service (see V-NLH-066 to 068).

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.

According to the Bank of Canada's inflation calculator[5], the consumer price index increased at an average annual rate of 4.29% for each year between 1968 and 2013. Therefore, a basket of goods that cost $100 in 1968, cost $663.24 in 2013. Table 4 shows the inflation at five year intervals.

Table 4: Bank of Canada Consumer Price Index*

Year	Cost of a Basket of Goods ($)
1968	100
1973	123
1978	191
1983	307
1988	378
1993	461
1998	492
2003	556
2008	606
2013	663

* Reference: http://www.bankofcanada.ca/rates/related/inflation-calculator/

This significant difference in the value of the money that forms the plant in service costs for different assets results in new industrial customers paying a disproportionate amount of the total O&M expense.

In V-NHL-083, Vale requested a revised 2013 test year COS with the plant in service for each asset restated in 2013 dollars instead of original cost. Hydro replied as follows:

> Given that Hydro has more than 40,000 assets with in-service years ranging back to the 1960's, this request is onerous and cannot be completed within the time frame for this proceeding.

While it is acknowledged that there is work involved with the request to provide a 2013 test year COS with the plant in service for each asset restated in 2013 dollars

[5] http://www.bankofcanada.ca/rates/related/inflation-calculator/

instead of original cost, the work is justified by the fact that the use of plant in service costs results in an inequitable distribution of O&M expenses between Hydro's customers. In order to achieve an equitable distribution of O&M expenses between Hydro's customers, all original costs should be restated in constant year dollars (2013 or other year).[6]

3. <u>Conservation and Demand Management</u>

Given the significant marginal cost of power generation at the Holyrood generating station and the continued load growth on the island system, a greater focus has to be placed on energy conservation and demand management. As the load variation portion of the rate stabilization plan renders Hydro financially neutral regardless of whether a kilowatt-hour of energy is saved or not, the current system does not provide Hydro with a financial incentive to achieve such savings. To achieve the maximum achievable energy conservation and demand management results, Hydro's conservation and demand management program has to be expanded and there needs to be a clear financial incentive for the utility to be fully engaged.

Demand side management is currently of utmost importance as Hydro has applied to the PUB for the installation of a 100 mW combustion turbine on an accelerated schedule and at a significant cost. It may be possible for Hydro to enter into interruptible power contracts that would eliminate the need for the turbine or at least reduce the required capacity. Based on the desired timeline for installation of the proposed turbine, formal meetings with the industrial customers to explore the possibility of interruptible power contracts need to happen immediately.

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[6] As an alternative, the O&M expenses could be pro-rated based on the replacement value for all assets. However, this would undoubtable be more work. Another alternative is to use an estimate for average system age, and then the new customer's assets could be restated to that particular year. This possibility is somewhat arbitrary and could lead to much discussion for any assets installed after the estimated average system age.

4. The RSP

The load variation component of the RSP has been in existence since the RSP started back in 1986 (V-NLH-040, page 1 of 2, lines 14 to 18). As acknowledged by Hydro in RSP-V-NLH-001, the RSP's load variation component is unique in North America. In the current GRA, Hydro is not only seeking to maintain the load variation component of the RSP but also to change the allocation of any balance in the load variation component from the current allocation methodology to one based on customer class energy usage within the previous twelve months. Hydro is also proposing to extend the RSP to cover purchased power. If the RSP is being expanded and the unique to Newfoundland load variation component of the RSP is being maintained, the RSP should be further expanded to include a fuel conversion factor.

The current RSP does not account for the Holyrood fuel conversion factor. The 2013 COS conversion factor is 612 kWh / bbl (GRA 2013 COS, page 20 of 109, line 21, col. 2). The response to V-NLH-074 indicates that from 2014 to 2016, the forecasted fuel conversion factor will increase up to 628 kWh / bbl. Should this occur, Hydro's net income will increase by approximately $11.5 million. This increased efficiency should be accounted for in the RSP.

Mel Dean