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June 23, 2015

Comments on the Amended General Rate Application of Newfoundland Labrador Hydro

submitted to the
NL Public Utilities Board

on behalf of

the Innu Nation

by

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1. INTRODUCTION

I have been asked by the Innu Nation to review the aspects of Hydro's Amended General Rate Application (GRA) that most affect the Innu communities of Sheshatshiu and Natuashish.

Sheshatshiu is part of the Labrador Interconnection System (LIS), and so will be affected by the dramatic rate increases for that system proposed by Hydro. These issues are addressed in sections 2 through 4.

Natuashish is an isolated diesel system but, as we shall see below in section 5, its electric service is subject to conditions not found elsewhere in Newfoundland and Labrador.

Should these issues be resolved, Natuashish would be served under the same rates as the other isolated diesel communities. The GRA does not propose a substantial rate increase for these communities. However, due to the interplay between the existing rate structures and the Northern Strategic Plan subsidy, electric bills in these communities would increase substantially as well. Comments about this situation are presented in section 6.

In section 7, I will briefly comment on the failure to move forward with an integrated resource planning (IRP) process for NLH, despite past Board pronouncements in this regard.

Finally, in section 8, I will summarize my conclusions and recommendations.

These comments supersede those that I presented on April 28, 2014.

2. LABRADOR INTERCONNECTED RATES

2.1. Amended GRA proposal

Under the amended GRA proposal, Labrador Interconnected rates would not rise dramatically. However, under the original proposal, residential rates would have risen by about 26% and general service rates by 15-30%.[1]

While there are many differences between the original proposal and the amended one, the most significant difference, with respect to Labrador Interconnected rates, is the change in NLH's approach to the rural deficit.

I addressed this issue in detail in my April 2014 evidence, and NLH cited my report, as well as others, in explaining its choice to revisit the issue. The position taken by Hydro in the amended GRA resembles in many ways that proposed in my earlier evidence. However, this new position has not been endorsed by the other parties to this proceeding, or by the Board. For this reason, my evidence will address this issue, among others.

2.2. Drivers for rate increase

The principal drivers for this rate increase for the LIS can be seen in the following table, which compares the LIS revenue requirement for 2007 with that proposed for 2013 in the original GRA and for 2015 in the amended GRA:[2]

[1] CA-NLH-006, pages 3-4.
[2] Derived from CA-90, At. 1.

Table 1. Rural Labrador Interconnected Revenue Requirement

Rural Labrador Interconnected Revenue Requirement

		Source (2013 and 2015)	2007*	2013	% increase over 2007	2015	% increase over 2007	% increase over 2013
1	Operating, Maintenance and Admin	Sched. 1.1, line 1	4,747,780	6,348,048	34%	11,976,563	152%	89%
2	Fuels	Sched. 1.1, lines 3, 4	160,349	273,631	71%	273,824	71%	0%
3	Return on Rate Base	Sched. 1.1, lines 23, 24	3,459,597	5,762,760	67%	6,256,863	81%	9%
4	Total System Revenue Requirement	Sched. 1.1, line 25	14,164,360	17,596,591	24%	23,556,057	66%	34%
5	CFB Revenue Credit	Sched. 1.2		863,434		912,568		
6	Rural Deficit Allocation	Sched. 1.2.1, p. 2	4,443,984	6,842,261	54%	2,408,108	-46%	-65%
7	**Revenue Requirement after Rural Deficit + Rev. Credit Allocation**	Sched. 1.2, line 12; lines 4 + 5 6	18,608,344	25,302,286		26,876,733	44%	6%
8	Allocation to industrial customers	CA-NLH-90, Att. 1		-2,122,468		-5,448,771		
9	**Rural Revenue Requirement after Rural Deficit + Rev. Credit Allocation**	Sched. 1.2, line 13; lines 7 + 8 - 5	**15,595,763**	**22,316,384**	**43%**	**20,515,394**	32%	-8%

*** Source: CA-NLH-090, Att. 1**

The revenue requirement before allocation of the rural deficit and the CFB revenue credit (line 4) has risen by 66% over 2007 (and by 34% over 2013). After that allocation (line 7), the increase is of 44% compared to 2007 (and 6% compared to 2013). Finally, after excluding the portion of the LIS revenue requirement paid by industrial customers, the rural revenue requirement (line 9) is seen to have increased by 32% compared to 2007 (and to have been reduced by 8% since 2013).

Thus, most of the reduction in the rural deficit charge is compensated by the increase in the other elements of the revenue requirement. As the table makes clear, the lion's share of this increase is in Operating, Maintenance and Administration, which has increase by 89% over 2013, and by 152% over 2007.

The key drivers for the 32% increase in the Labrador Interconnected rural revenue requirement since 2007, are thus:

- Operating expenses, Maintenance and Administration (152% increase);
- Rural deficit allocation (46% reduction under current proposal; 54% increase under 2013 proposal); and
- Return on rate base (81% increase).

The O&M increase appears to relate primarily to Hydro's taking over O&M responsibilities with respect to the Twinco transmission assets. The other two categories will be addressed in the following chapters.

It is important to note that, due to other factors, the 32% increase in the LIS revenue requirement over 2007 results in only a 2.1% average rate increase. However, if the rural deficit allocation from the 2013 GRA were applied to the Amended GRA, the average LIS rate increase would increase to 24.2%, as seen in Table 2.

Table 2. LIS Rate Increase

		Source	rural deficit allocation from amended GRA	rural deficit allocation from original GRA
1	Operating, Maintenance and Admin	Sched. 1.1, line 1	11,976,563	11,976,563
2	Fuels	Sched. 1.1, lines 3, 4	273,824	273,824
3	Return on Rate Base	Sched. 1.1, lines 23, 24	6,256,863	6,256,863
4	Total System Revenue Requirement	Sched. 1.1, line 25	23,556,057	23,556,057
5	CFB Revenue Credit	Sched. 1.2	912,568	912,568
6	Rural Deficit Allocation	Sched. 1.2.1, p. 2	2,408,108	6,842,261
7	**Revenue Requirement after Rural Deficit + Rev. Credit Allocation**	Sched. 1.2, line 13; lines 4 + 5 + 6	26,876,733	31,310,886
8	Allocation to industrial customers	CA-NLH-90, Att. 1	-5,448,771	-5,448,771
9	**Rural Revenue Requirement after Rural Deficit + Rev. Credit Allocation**	Sched. 1.2, line 13; lnes 7 + 8 - 5	**20,515,394**	**24,949,547**
10	**Revenue at Existing Rates (p. 4.50)**	P. 4-50	**20,093,239**	**20,093,239**
11		(line 9 / line 10) - 1	2.1%	24.2%

For this reason, the allocation of the rural deficit remains a question of critical importance in the present proceeding.

3. RURAL DEFICIT

As seen in Table 1, the rural deficit cost allocated to Labrador Interconnected in the 2013 GRA showed an increase since 2007 of 54% (an increase of $2.4 million), and accounted for 36% of the 2013 proposed rate increase. Apart from the one proposed in the Amended GRA, there has been no change in the methodology of cost allocation since it was established in 1993.

The rural deficit represents the difference between cost of service and revenues collected for several distinct categories of customers. These include:

- Isolated (diesel) communities on the Island and in Labrador,
- Customers of the Anse au Loup system, which are served to a large extent with energy from Hydro-Quebec's Lac Robertson hydro project, and
- Rural interconnected customers on the Island.

It is noteworthy that isolated customers (both on the Island and in Labrador) represent only 55% of the rural deficit, with Island interconnected rural customers representing 40%.[3]

The evolution of the rural deficit since 2007 is shown in Table 3, broken down by source:[4]

Table 3. Rural deficit, 2007-2015

Rural Deficit by Rural Deficit Area ($000s)									
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014 Test Year**	**2015 Test Year**
Island Interconnected	15,953	16,106	13,086	15,569	19,496	17,345	16,582	26,065	25,655
Island Isolated	6,472	7,035	7,306	6,791	7,640	7,222	7,233	7,976	8,312
Labrador Isolated	18,323	22,379	17,801	19,252	23,067	23,179	23,867	27,291	27,453
L'Anse au Loup	1,986	2,987	1,958	1,967	3,140	3,037	3,196	4,027	3,563
CFB Revenue Credit	(2,860)	(4,051)	(979)	(3,418)	(3,972)	(1,524)	(327)	(743)	(913)
Total	**39,874**	**44,456**	**39,172**	**40,161**	**49,371**	**49,259**	**50,551**	**64,616**	**64,070**

We see that the rural deficit was relatively stable from 2007 to 2010, but increased by some $9 million (over 20%) in 2011 and by $14 million (28%) in 2014.

The 2011 increase was largely due to fuel costs.[5] One important contributing factor to the 2014 increase is Order-in-Council OC2009-063. This Order in Council specified not only that Hydro's target return on equity should be equal to that applied to Newfoundland Power, but also that this rate of return should be applied "on the entire rate base … including amounts used solely for the

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3 CA-NLH-099, rev. 1. Ignoring the CFB Revenue Credit.

4 Ibid.

5 NP-NLH-099, Rev. 2, Att. 1, Chart 1, page 62 of 67.

provision of service to its rural customers."[6] Until then, such assets did not earn a return on equity, presumably because they did not contribute to profits. The return on equity on rural assets accounts for $5,375,091 of the 2015 revenue requirement, and of the rural deficit.[7]

Adjusting to constant dollars gives the following:[8]

Table 4. Rural deficit, 2007-2015 (constant dollars)

Rural Deficit by Hydro Rural Area in 2015 Dollars ($000s)

	2007	2008	2009	2010	2011	2012	2013	2014	2015 Test Year
Island Interconnected	18,362	17,845	14,826	17,173	20,568	18,230	17,212	26,482	25,655
Island Isolated	7,449	7,795	8,278	7,490	8,060	7,590	7,508	8,104	8,312
Labrador Isolated	21,090	24,796	20,169	21,235	24,336	24,361	24,774	27,729	27,453
L'Anse au Loup	2,286	3,310	2,218	2,170	3,313	3,192	3,317	4,091	3,563
CFB Revenue Credit	(3,292)	(4,489)	(1,109)	(3,770)	(4,190)	(1,602)	(339)	(755)	(913)
Total	**45,895**	**49,257**	**44,382**	**44,298**	**52,086**	**51,771**	**52,472**	**65,651**	**64,070**

We see that the constant-dollar rural deficit was relatively stable from 2007 to 2010, but has increased by some 45% from 2010 to 2015.

The cost of the rural deficit is borne by the customers of Newfoundland Power and of the LIS. Until the end of 1999, Island industrial customers also bore a share of this cost responsibility, but the amendments to *EPCA* absolved them of it. While the number of customers served by diesel systems was reduced by the interconnection of St. Anthony's in 1996, those customers continue to form part of the rural deficit (as "Island Interconnected" rather than Isolated customers), though their contribution to it is smaller than it was before.

[6] CA-NLH-024, Att. 4, p. 1.
[7] PUB-NLH-055, Rev. 1, Att. 1, page 1.
[8] CA-NLH-208, rev. 1.

3.1. The rural deficit in the 2013 GRA

The effect of the rural deficit cross-subsidization on Labrador Interconnected rates is substantial: under the original GRA proposal, it would have increased them by 27% to 58% (30.7% on average), depending on the rate class, as seen in the following table.[9]

Table 5. Effect of rural deficit on LIS rates (original GRA)

Labrador Interconnected rates	proposed increase	w/o rural deficit	net effect
Domestic	26.0%	-12.7%	38.7%
GS 0-10kW	28.5%	-12.7%	41.2%
GS 10-100 kW	16.6%	-10.9%	27.5%
GS 110-1000 kVA	16.9%	-19.2%	36.1%
GS over 1000 kVA	22.0%	-18.9%	40.9%
Street Lighting	42.8%	-15.6%	58.4%

Hydro explained this effect as follows:[10]

> The impact of the rural deficit on the Labrador Interconnected System is larger than that of NP mainly because the Labrador Interconnected revenue requirement is much smaller than that of NP, and the rural deficit makes up a larger share of the Labrador Interconnected revenue requirement, than it does for NP. The reallocation of the $6.8 million rural deficit originally allocated to Labrador Interconnected as provided in response to IN-NLH-132, represents an overall reduction in revenue requirement to that system of 30.7%, while the same $6.8 million reallocation to NP represents an increase of 1.5%. [11]

This suggests that, were all of the rural deficit costs originally to be borne by Labrador Interconnected customers to be instead assigned to Newfoundland Power (NP) customers, their rates would increase by only 1.5%.

In its initial hearing on the methodology for the allocation of the rural deficit, the Board stated that, because there is no cost causation at all on the part of the subsidizing groups, “there is no

[9] The first two columns are from IN-NLH-132. In the Amended GRA the proposed increase is 1.9%; without the rural deficit, rates would have declined by 10.1% (except for street lighting). IN-NLH-132, rev. 1.

[10] IN-NLH-222, pp. 1-2.

[11] Unless otherwise noted, underlining in quoted passages in this report has been added by the author.

cause and effect relationship upon which to fairly allocate the deficit. … Fairness cannot be assessed as due to the method used, but instead we must assess fairness on the basis of the result, a shared burden among the classes of customers that is fair to all and not discriminatory."[12]

In an RFI, the Consumer Advocate asked if the use of this method is still "fair" today, 20 years after it was established. Hydro response was unenlightening, simply commenting that:

> Based on the Board's reasoning in arriving at a decision on the allocation of the rural deficit, there would be no basis to believe that there should be a concern on the "fairness" of using this method today versus 20 years ago.[13]

The question, however, is entirely relevant — especially since the magnitude of the rural deficit has more than doubled since 1993 (from $28 million to $64.6 million[14]), and it is supported by a smaller base (given the exclusion of the Industrial Customers in 1999). Indeed, section 4.3.1 of the amended GRA is devoted to this question.

As the Board itself acknowledged, fairness in this context can only be judged by the result. One must therefore, first, compare the result of this methodology today with that adopted by the Board in 1993, to judge whether or not there is reason to reopen the methodological question. We will look in detail at that methodology later on.

3.2. History of the rural deficit

From 1993 to 2013, the rural deficit grew by 229% from $28 million to $60 million. While the lion's share of the rural deficit is borne by NP, the growth in these costs for LIS, under the current methodology, is much greater. NP's allocated rural deficit cost grew by 164%, while that allocated to LIS grew by 563%, based on the allocation in the 2013 GRA.[15]

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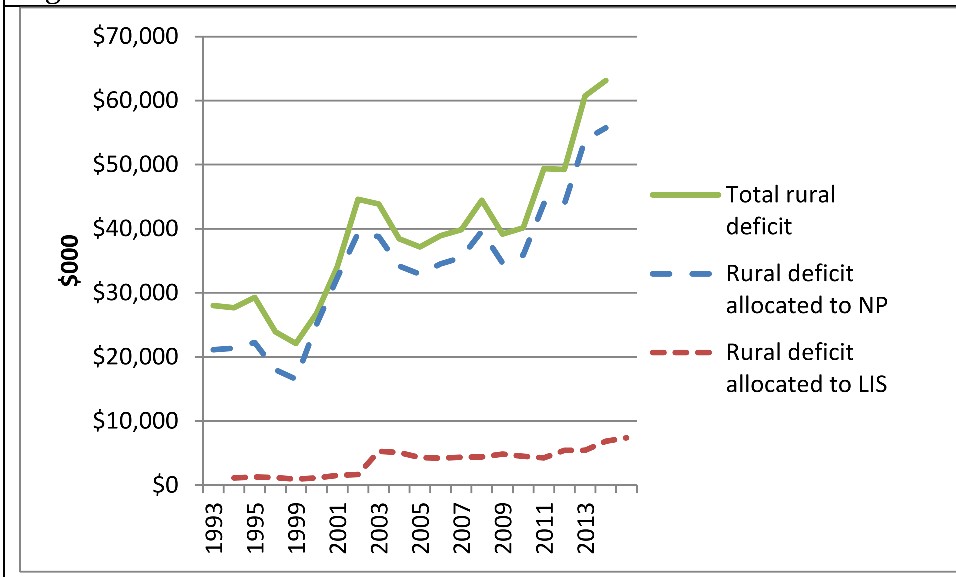
[12] PUB-NLH-113, Att. 1, page 63 of 83. (Report of the NLPUB on A Referral by NLH for the Proposed Cost of Service Methodology, Feb. 1993, page 60.)

[13] IN-CA-166. A revised and entirely different version of this response, provided later, is discussed in section 3.4, below.

[14] 1993 figure from LWHN-NLH-055.

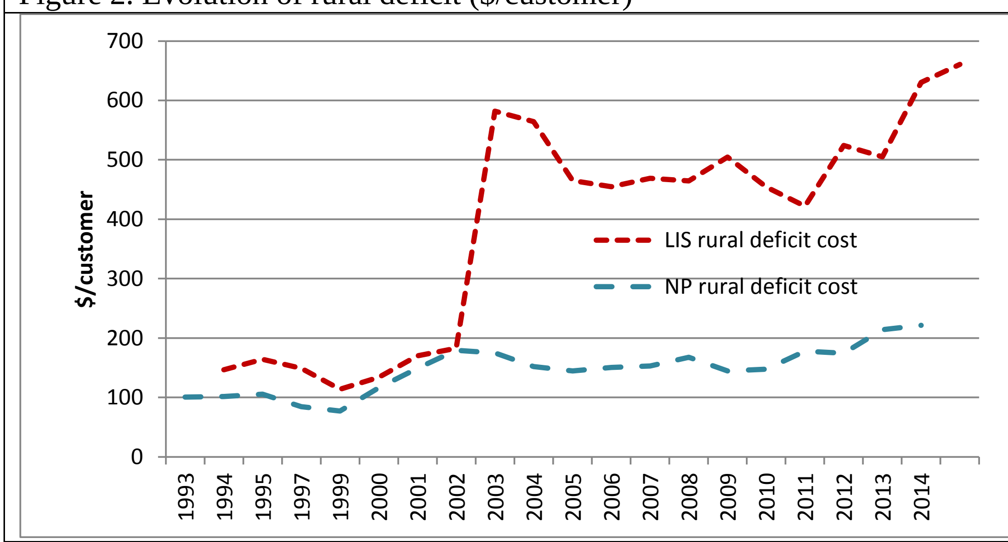
[15] Derived from LWHN-NLH-055, Att. 1 (1993-1999) and LWHN-NLH-055, Att. 1 (2000-14). Confirming data found CA-NLH-99 for 2007-2014.

Figure 1. Evolution of rural deficit



The same effect is seen if we look at cost per customer. For NP — again, based on the allocation in the original GRA — it had grown from $100 to $222, whereas, for the LIS, it had grown from $147 to $661, as seen in Figure 2, again according to the allocations in the original GRA.

Figure 2. Evolution of rural deficit ($/customer)



It is clear from these graphs that a drastic change took place in 2002. It is possible to identify several contributing reasons for this change. For example, the 2002 GRA represented the first time that NLH implemented the Government's 1989 Directive to recover the rural deficit from NLH customers.[16] However, I have not been able to fully explain these effects, based on the documents in the file.

3.3. The 1993 Methodology

The method of allocation of the rural deficit was determined by the Board in its 1993 generic hearing on COS methodology. That method, the results of which were set out in Appendix 1 of the report, was based on the proposal by the Board's expert witness, Mr. George C. Baker, based on an approach described as a "mini cost-of-service". While not described in detail in the Board's report, based on the calculations presented in the Appendix it appears that this method functions as follows:

1. The costs of the contributing systems are divided into demand, energy and customer cost components.
2. These values are prorated to divide the rural deficit among the same components.
3. Total kW and kWh consumption and adjusted unweighted customer accounts for the contributing systems are divided by the prorated share of the rural deficit, to produce unit costs for each component.
4. These unit costs are multiplied by the corresponding kW and kWh consumption and adjusted customer accounts for each for the Island and for Labrador, to determine the overall cost allocation for each system.[17]

When this method was established in 1993, the rural deficit amounted to $28.5 million. The method resulted in Labrador absorbing 14% of the rural deficit, though its share of total allocated costs was only 6%.

[16] P.U. 7 (2002-03), p. 123.

[17] Mr. Baker's description of the method is found at IN-PUB-002, Att. 1, p. 29. His approach is also summarized in PUB-NLH-483.

The Baker method includes a surprising feature, namely the use of "equivalent unweighted customer accounts" in calculating the deficit unit costs. Table 2 of Exhibit GCB-5.1, from the 1993 Report, gives a value of 9,574 for this category for NP. This is obviously far lower than the actual number of customer accounts. The figure of 7,560 used for Labrador, however, reflects the actual number of customer accounts on the Labrador Interconnected system.

In the present filing, Hydro has presented the detail of its calculation of Equivalent Unweighted Customers for NP, and has explained its procedure in a number of RFIs.[18] It divides the total of Island Rural Customer Costs by the number of Island Rural customers.[19] In effect, this resulting figure represents Hydro's average customer cost for Island rural customers. It then divides total NP Customer Costs by this average cost.[20] The result can be thought of, in a sense, as the number of customers that NP would have to have, given its total Customer Costs, if they all had the same Customer Cost as do Hydro's rural customers. The result is only about one twenty-fifth of its actual number of customers.

The first two steps of the methodology described above produce unit costs (kW, kWh and customer) for the rural deficit. No convincing reason has been proposed why, in allocating that deficit between NP and the Labrador Interconnected system, the LIS share should be based on the actual number of LIS customers, whereas the NP share should be based on a derived "equivalent customer" basis that produces a value of less than 4% of the actual number of NP customers.

This method is further explained in additional responses.[21] It is clarified that this calculation is based on Newfoundland Power's customer costs, which are Specifically Assigned, based on the assets dedicated to serving NP.[22] Replacing this derived figure for NP customers with its actual number of customers would result in reducing the LIS share of the deficit by about 10%.

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[18] See, in particular, LWHN-NLH-011, IN-NLH-306 and PUB-NLH-483.

[19] LWHN-NLH-013.

[20] There is also an adjustment for specifically assigned distribution costs, but the underlying figures have not been provided.

[21] IN-NLH-305, PUB-NLH-392 and PUB-NLH-483.

[22] IC-NLH-088, rev. 1.

It is also important to mention the change in treatment of the CFB Goose Bay Revenue Credit. Initially, a substantial portion of this revenue credit was applied to the LIS revenue requirement. This amount has been phased out, and the entire revenue credit is now applied to the rural deficit, meaning that most of it benefits NP customers rather than LIS customers.[23] Furthermore, as we saw in Table 3, the amount of this revenue credit has declined from over $4 million in 2008 to under $1 million in 2015.

3.4. Allocation of the rural deficit: The amended GRA proposal

On April 22, 2014, NLH submitted a revised response to CA-NLH-166 (quoted earlier), which, strikingly, reversed its position with respect to the fairness of using the Baker methodology today.

Hydro stated:

> Hydro believes that the current methodology [i.e., that found in its own application] does not provide a reasonable sharing of the rural deficit between Labrador Interconnected Customers and Newfoundland Power customers.[24]

This, of course, implies that the rates proposed in its own GRA were also not reasonable.

Hydro proposed two alternate methodologies, one based on the revenue requirements of the two systems, and the other based on the number of customers.

Strikingly, either of these two solutions would result in the elimination of the drastic rate increase for the LIS that was at the heart of the original 2013 GRA, as shown above in section 2.1.

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[23] PUB-NLH-089.

[24] Ibid.

Table 6. Impact of rural deficit on rate change proposals[25]

Table 6

Impact of Rural Deficit Allocation on Rate Change Proposals

	Labrador Interconnected	Newfoundland Power	Newfoundland Power Customer
Current Method	25.1%	-4.8%	-3.2%
Revenue Requirement Method	-0.6%	-3.7%	-2.5%
Number of Customer Method	0.6%	-3.8%	-2.5%

Hydro's first alternate methodology, based on the revenue requirement, is in fact the same one proposed by Hydro in 1993, which was rejected by the Board.[26] The Board had noted NP's position that this approach would be unfair because it would "allow Labrador Customers with low rates to receive a small share of the deficit burden."[27] NP's proposal was that "the deficit be allocated on the basis of 50% energy and 50% revenue requirement."[28]

In making this proposal, NP pointed out:

> the concern the paying classes have for a level playing field where all parties are assessed on the same basis regardless of the rate they are paying.[29]

It should be noted that the second methodology proposed by Hydro, based on an equal payment per customer, respects this criterion.

In his report submitted to the Board in 1993, Mr. Baker pointed out that he was not:

> aware of any generally accepted cost of service methodology for dealing with this particular situation. In finding the best solution, judgment must play a part.[30]

He further explained that his judgment was, in part, based on:

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[25] Source: CA-NLH-166 rev.2, p. 7.
[26] PUB-NLH-113, Att. 1, p. 58 of 83.
[27] Ibid., p. 59 of 83.
[28] Ibid.
[29] Ibid., p. 64 of 83.
[30] IN-PUB-02, p. 28.

> the inference that public policy at this time requires those who are fortunate enough to enjoy cheap electric service to share their good fortune with those who are not so lucky.[31]

This inference led him to propose his "mini-COS" approach, which would have the result that:

> the percentage increase would be over twice as large for Labrador as for the Island.[32]

This result apparently seemed fair to him, and to the Board, in 1993. Since then, however, two important factors have changed.

First, as we have seen above, the percent increase for Labrador resulting from his proposed method is now more than three times greater than that for the Island. Its fairness cannot be deduced from the 1993 Report. More important, his inference that public policy favours a levelling of the rate differential between the Island and Labrador has not, to the best of my knowledge, found support either from government – through its Orders-in-Council and its formal policy documents – or from the Board in its decisions over the last 20 years.

For all these reasons, I believe it is appropriate to put aside the Board's decision of 1993 with respect to the allocation of the rural deficit, and to take a fresh look at the methodology for this allocation, as now proposed by Hydro.

Regarding the second methodology described by Hydro in its revised response — allocation based on the number of customers — it is interesting to note that Hydro's calculations are based on the actual number of cus1tomers, not on the "equivalent unweighted customer accounts" used by Baker (and by Hydro in its original filing).

In a report dated April 20, 2014, Dr. Feehan presented an analysis of the rural deficit allocation which in many ways resembles the one presented by Hydro in its revised response (dated April 22, 2014). Like Hydro, he compares costs allocated to NP and to LIS customers based on the unit energy cost to each[33] and on the cost allocated per customer.[34]

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[31] Ibid.

[32] Ibid., p. 30.

[33] Table 1 of the Feehan report, and Table 1 of the revised response.

[34] Table 3 of the Feehan report, and Table 2 of the revised response.

Dr. Feehan described four alternate methodologies which overlap, to a certain extent, with those put forward by Hydro. His Alternative A (Every Customer Pays the Same Dollar Amount) closely resembles Hydro's "allocation per customer" approach.[35] His recommended Alternative D, which would allocate the rural deficit between NP and LIS based on the number of customers, and then allocate the deficit between rate classes within each system based on consumption, is also very similar to the suggestion found in note 12 of the NLH's revised response:

> The use of the allocation of the rural deficit using number of customers may be reasonable for allocation between Newfoundland Power and Labrador Interconnected Customers. However, further allocation by rate class would normally consider customer usage characteristics and be allocated based upon a revenue basis.[36]

NLH concluded its revised response by proposing that the Baker methodology be replaced with either one of the two alternate methodologies.

These same two proposals are made in s. 4.3.1 of the amended GRA. Hydro recommends the use of the revenue requirement method, which ensure the same revenue:cost ratio for Labrador Interconnected customers as for NP. I support this recommendation.

4. RETURN ON RATE BASE FOR THE LABRADOR INTERCONNECTED SYSTEM

As seen in Table 1 above, return on rate base for the LIS in the Amended GRA represents an increase of $2.8 million over 2007, an 81% increase. The highlights of the changes in the Labrador Interconnected rate base in the original application were described in s. 3.7.1.1 of the GRA, which identified an increase of $26.2 million in net book value (reflecting an increase in original cost of $39.0 million) resulting from the conversion of the Labrador City distribution system to 25kV.[37] There is no corresponding section in the amended GRA.

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[35] Feehan, p. 7, and Revised Response, p. 6.

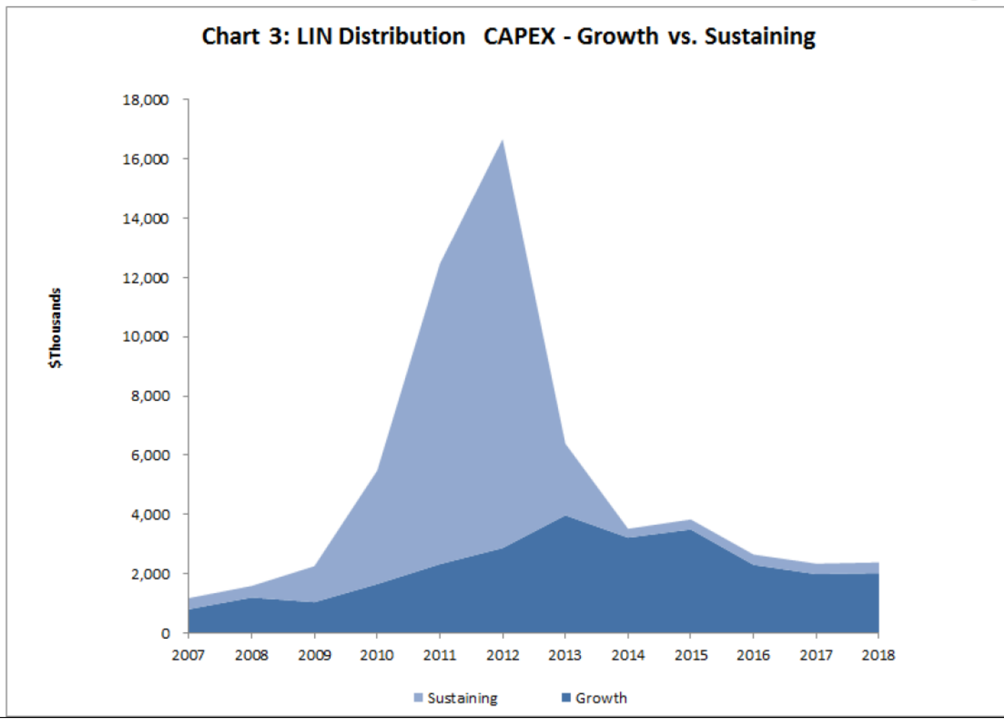
[36] CA-NLH-166, rev. 3, p. 7 of 8, note 12.

[37] Application, page 3.23.

In 2012 and 2013, approximately $31 million of transmission and distribution assets relating to this project were placed in service.[38] Another $3.2 million was placed in service in 2014, and $1.8 million was budgeted to be commissioned in 2015.[39]

The following figure shows the capital expenditures for Distribution in the Labrador Interconnected System since 2007.[40]

Figure 3. Capital expenditures for Distribution (LIS)



It seems clear that the vast majority of these expenditures were related to the Labrador City Distribution Upgrade project. It is surprising, however, that they are described here as "sustaining" since, as we shall see in the following sections, they were in fact made necessary by projected load growth in Labrador West.

38 Ibid. and IN-NLH-048

39 IN-NLH-048, rev. 1.

40 IN-NLH-178, rev. 2, p. 3 of 3.

4.1. Labrador City Distribution Upgrade

4.1.1. Benefits limited to Labrador West

NLH acknowledged in response to an RFI that these investments will not result in any improvements in reliability or any other characteristics of electric service in Labrador East or in the Labrador Isolated systems.[41] While the need to upgrade the Lab City distribution system is the result of the ramp up of mining activity in the area, the transmission level customers (IOCC and Wabush Mines) have played no role in financing this upgrade.[42]

In this proceeding, the Board will be reviewing the prudency of these costs. The question remains, however, which consumers should bear the costs of these investments, based on the principle of cost causation and relevant precedents. These will be addressed later on. First, we will review the justification for the Labrador City distribution upgrade.

4.1.2. Justification

As described in the report, "Labrador City Voltage Conversion Terminals and Transmission Reconfiguration," presented to the Board as part of the 2009 Capital Budget Application, the Labrador City Upgrading Project would replace the 4.6 kV distribution system in Labrador City with a 25 kV system. The 4.6 kV system was able to support up to 52 MW of load.[43]

At the time, Labrador City loads were forecast to increase by around 0.9% per year, and were projected to reach 55.6 MW by 2027.[44] The gross peak in 2013 was forecast at 53,528 kW.

> The load forecast for Labrador City is based on a combination of historical data since 1992, the effects of increased mining activities, the impacts of the new college and hospital, a modest amount of new residential construction and electric heat conversions.[45]

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[41] IN-054.

[42] IN-051.

[43] IN-NLH-50, Att. 1, pp. 3-4 of 177.

[44] Ibid., p. 17 of 177.

[45] Ibid., App. B, p. 14.

Furthermore:

> While the load forecast represents the expected energy and demand growth on the Labrador City System, the risk of higher load growth exists due to several factors. A fully utilized housing stock along with the changing demographic in the region from retiree retention and new employees for the mining operations, along with the impacts of the IOCC expansion, and the Bloom Lake Development could potentially spawn new residential developments. In combination with approximately 2 MW of electric heat conversion potential in the region, the load could approach 60 MW over the next 20 years.[46]

This last comment was prescient. Lab City demand for 2018 is currently forecast at 58.3 MW,[47] higher than the level forecast in 2008 for 2027!

The 2008 report was unequivocal:

> The status quo is not an option. The 4.16 kV distribution system that currently supplies the customers in Labrador City was designed to supply a peak load of 52 MW. The system load is forecasted to exceed 52 MW in 2009 and to continue to grow to 55 - 60 MW. The distribution system is now at its operational limit. Continuing with the status quo will result in low voltages to customers, lower system reliability, and could compromise the ability to protect people and equipment when faults on the system occur.[48]

In other words, the upgrade of the Lab West distribution system was made necessary by the continuing load growth in that region, which in turn flowed in large part from the increased industrial activity in the region. While forecast loads may have declined with the downturn in the mining sector, the fact remains that the 52 MW original design capability of the 4.16 kV system has already been exceeded.[49] There appears thus to be no doubt that the upgrade was needed to reliably serve loads in Labrador City.

4.1.3. Cost responsibility

In IN-NLH-185, it was asked why Hydro considers that it is just and reasonable that consumers in Sheshatshiu or elsewhere in Labrador East pay the costs of the Labrador West distribution

[46] Ibid., p. 17.
[47] IN-NLH-005, rev. 1, page 3.
[48] IN-NLH-50, Att. 1, p. 18 of 177.
[49] IN-NLH-301

system upgrades, which provide them no improvements in reliability or any other characteristic of electric service (IN-NLH-054). **Hydro did not actually affirm that such cross-subsidization is just and reasonable.** Instead, it simply responded:

> Hydro is not aware of any precedent in this provincial jurisdiction for assigning costs of a distribution upgrade, such as has occurred in Labrador West, to the specific customers that benefit from it. (IN-185, p. 2)

Of course, the absence of a specific precedent in Newfoundland and Labrador does not in itself dictate the appropriate solution. Is it just and reasonable, and is it fair, that customers in one geographic area (Labrador East) be called upon to share cost responsibility for assets that provide them with no benefits?

In the following sections, we shall look at the underlying regulatory principles that speak to this question, and how they have been applied here and elsewhere.

4.1.3.1. Regulatory principles

In its 1993 report on Cost of Service Methodology,[50] the Board set out its understanding of the fundamental principles underlying a cost of service study and resulting rate design. It is worth quoting this section at length:

> Cost of Service Objective and Principles
>
> Where methodological variations exist, what criteria would be used to make a choice between them? On this question, there were some differences of opinion. Dr. Sarikas' views were stated as follows in response GTCB-14 (a):
>
>> "A cost study is not regarded as an end in itself. Thus the objective is not merely to reflect, as accurately as possible, cost causation in the Newfoundland and Labrador System. Objectives relate to rate design and not to cost analysis. Cost analysis is regarded as a tool for rate design. Rate design involves balancing a number of objectives. The most significant of these objectives is fairness and economic efficiency."

[50] PUB-NLH-113, att. 1, pp. 9-11 of 83.

In the response, rate design objectives were said to include: meeting the revenue requirement, fairness, economic efficiency, simplicity and ease of understanding, conservation of resources, stability and gradualism, social goals, administrative ease, employment, and protection of the environment.

NP's expert, Mr. Brockman, stated that:

> "Bonbright's principle of fairness in the apportionment of costs and the NARUC principle of attributing costs based upon how customers cause costs to be incurred, are inextricably intertwined. In fact, the principle of causality (cost causation) is almost universally claimed in attempts to justify various cost of service methodologies as fair."

The Board's consultant testified that equity, or fairness, based on causal responsibility or user-pay considerations, would constitute a sufficiently broad criterion for the selection of appropriate methodology. …

The opinions expressed are unanimous in supporting fairness as a criterion, but differ on the extent to which other considerations should be taken into account. …

Within the limits imposed, it is the Board`s opinion that economic efficiency is best promoted by the allocation of costs on a causal basis. If other rate considerations should be imposed for a need for compromise, the required adjustment may best be achieved in the process of rate design.

Recommendation 1:

That Hydro`s Cost of Service Study be of the embedded type and that the methodological objective be to allocate costs to rate classes in a fair and equitable manner based on causal responsibility for cost incurrence.[51] (underlining added)

The Board's conclusion, that the objective of a cost of service study is to allocate costs to rate classes in a fair and equitable manner based on causal responsibility for cost incurrence, falls squarely within the North American regulatory tradition.

In P.U. 7 (2002-03), the Board presented in more detail its views regarding fairness in cost allocation, as follows:

3. Fair Cost Apportionment

Fairness of specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness, capriciousness, inequities or discrimination. Under this principle, customers in similar situations should be treated equally (horizontal equity),

[51] PUB-NLH-113, Att. 1, pp. 10-11 of 83.

> while those in different situations should be treated differently (vertical equity). This principle would not deny cross-subsidization of rates among customers of equal circumstances but such subsidization should not cause undue discrimination. The principle of horizontal equity (i.e. equals treated equally) is set forth in Section 73(1) of the *Act* which requires that *"all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, …"*. Furthermore, the aspect of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the *EPCA* which declares it to be "*…the policy of the province that the rates to be charged ………should be reasonable and not unjustly discriminatory."* (P.U. 7, p. 29)

And in P.U. 14 (2004), it reiterated the "fair and equitable" criterion, adding that:

> Cost assignment is not an exact methodology and often requires the exercise of judgment.[52]

These passages raise several important questions:

- Are the customers in Labrador East and in Labrador West "of equal circumstances"?
- Does cross-subsidization between them "cause undue discrimination"?
- Are the resulting rates "fair"?

4.1.3.2. Direct (or Specific) Assignment

Direct assignment — the assigning of the full cost of a given asset to the customer or class of customers on whose behalf it was acquired — is an essential element of determining the cost of service. The Board's 1993 generic report on COS methodology described direct assignment as the first step in COS procedures:

> Cost of service studies are routinely and almost universally used in rate proceedings to determine the cost responsibility of the various customer classes. In broad outline the procedures used have become highly standardized. They comprise (1) identification and segregation of costs directly attributable to any particular **class**, (2) arrangement of the remaining costs so that they can be allocated to the various groups of customers which are jointly responsible for the incurrence, and (3) allocation of such costs in accordance with physically measurable attributes of the services provided to customer classes.[53] (emphasis added)

[52] P.U. 14 (2004), p. 94.

[53] PUB-NLH-113, Att. 1, p. 4 of 84.

Hydro has used two different formulations to explain when direct assignment is appropriate. One formulation states that assets "dedicated to serve one customer should be specifically assigned, and costs of (plant and equipment of) substantial benefit to more than one customer should be apportioned among all customers."[54]

This formulation is found in the Definitions section of Hydro's System Planning Guidelines,[55] along with the definition of Common Plant as "plant that is of benefit to two or more customers." This same formulation was also provided by Hydro in an RFI.[56]

However, in quoting this definition in PU7 (2002-03), the Board saw fit to add a footnote specifying that:

> Specifically assigned costs are costs associated with services or products that are of benefit to a single customer or class of customers. This implies that the facilities can be considered entirely apart from the integrated system. Costs associated with services or products that are of joint benefit to all customers or classes or customers are referred to as common costs.[57]

This footnote was also quoted by NLH in response to another RFI in the present proceeding.[58]

As far back as 1993, the Board applied the notion of direct assignment to classes rather than individual customers:

> Direct assignment of cost entails diverting the assigned costs from the normal steps of cost of service analysis and charging them directly to the responsible class.[59]

The distinction is important. Under the first formulation, as soon as an asset is of benefit to two or more customers, its costs must be shared by all customers. In some cases, this would clearly conflict with the principle stated above "that costs should be allocated to classes only for the facilities used by such classes."

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[54] NLPUB Rural Electric Service Report (1995), p. 39, quoted in P.U. 7 (2002-03), p. 110.
[55] CA-NLH-093, p. 6 of 40.
[56] IN-NLH-113, p. 2.
[57] P.U. 7 (2002-03), p. 110, note 13.
[58] IN-NLH-193, p. 1.
[59] PUB-NLH-113, Att. 1, p. 16 of 83.

Furthermore, the Board pointed out that, when the cost responsibility of a given asset is shared between several classes, “extemporaneous measures” other than Direct Assignment should be used:

> If the cost responsibility is shared by more than one <u>class</u>, and the normal means of splitting such costs have been by-passed, extemporaneous measures would be necessary to distribute the assigned costs between the responsible <u>classes</u>. For this reason, <u>direct assignment should be used only in the case of plant dedicated to the use of a single class.</u>[60]

Thus, the regulator has a broad pallet of solutions available – Direct Assignment to an individual customer, Direct Assignment to a class, or “extemporaneous measures” when more than one class is concerned – to ensure that cost causality is respected in cost allocation.

Thus, the Board clearly has discretion to apply its judgment to ensure that cost allocation, and the resulting rates, are fair and equitable. As we shall see in the following section, it used this discretion to find an equitable solution with regard to the allocation of costs of the Great Northern Peninsula transmission line.

4.1.3.3. Specific assignment of Great Northern Peninsula transmission

In addressing the treatment of the Great Northern Peninsula (GNP) transmission line, the Board addressed many of the issues raised here. In its 1993 Report on Cost of Service Methodology, the Board first addressed the question of how to allocate costs for this transmission line, which provides benefit only to certain distribution customers.[61]

The Board first affirmed that “Hydro’s decision to avoid direct assignment was proper,” because “direct assignment should be used only in the case of plant dedicated to the use of a single <u>class</u>.”[62] It continued:

> However, the Board is not persuaded that the conversion of Rural Customers from one class to several should result in changing the costs allocated to NP and IC.[63]

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[60] Ibid.

[61] PUB-NLH-113, Att. 1, pp. 14-18 of 83.

[62] Ibid., p. 13 of 84.

Instead, in order to permit the allocation of the GNP transmission costs to all rural classes, it created a **unique sub-transmission function**, for this purpose:

> The Board considers that the cost of transmission lines dedicated to the service of Rural classes be included in a sub-transmission function and allocated to such classes. The principle that costs should be allocated to classes only for the facilities used by such classes would justify a second sub-transmission function for common lines used by NP and IC but not by Hydro Rural, provided the costs related thereto were significant.[64]

In doing so, it appears to have followed a path indicated by Mr. Baker, who quoted the NARUC Cost Allocation Manual as follows:

> "By carefully choosing subfunctions within the main functions, the analyst attempts to assign costs within a function to groupings for which particular groups of customers are responsible. "[65]

The Board thus reaffirmed the principle that costs should be allocated to classes only for the facilities used by such classes.

In its 1996 Report on Rural Electric Service, the Board again addressed the question of how to allocate costs for this transmission line, which provides benefit only to certain distribution customers.[66] The question was deferred for further study.

It was deferred again in P.U. 7 (2002-03), where the Board noted:

> that its decision to deny NLH's proposed change in assignment of GNP assets in the COS [to common] will result in … additional costs of over $1,000,000 being assigned to the Labrador Interconnected system due to the allocation of the rural deficit.

The issue was definitively resolved in P.U. 14 (2004), when the Board accepted the "proposed assignment of transmission assets on the GNP to Hydro Rural."[67]

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63 Ibid., p. 14 of 84.

64 Ibid., p. 17 of 83.

65 Baker, IN-PUB-02, Att. 1, p. 14.

66 LWHN-10, att. 1, pp. 37-38 of 42.

67 P.U. 14 (2004), p. 93.

It made this assignment, despite the fact that the GNP generation was assigned as common plant, because the common use of the line (to interconnect the GNP generation) "is not of sufficient magnitude to justify the assignment of the GNP transmission assets to common, given the dominant use of the transmission system to serve NLH's rural customers."[68]

The GNP transmission case demonstrates the Board's commitment to the notion that <u>costs should be allocated to classes only for the facilities used by such classes.</u>

4.1.3.4. Single cost of service study

Another issue that the Board has returned to several times over the years is the decision to perform a single cost of service study for the Labrador Interconnected system. While this decision has been contested on occasion by the Towns of Labrador City and Wabush, including an unsuccessful appeal to the NL Court of Appeal,[69] the Board has never wavered in its conclusion:

> The Board has already ruled in the 1993 generic COS methodology that there be a single cost of service study for the Labrador Interconnected system and is not persuaded that there is sufficient evidence to reconsider the matter at this time.[70]

The reasons invoked by the Board for this decision — essentially, the commonality of generation and transmission assets throughout the Labrador Interconnected System — are clear and unimpeachable.

The question remains, however, as to whether or not, within the Labrador Interconnected System, it would be appropriate to establish geographically distinct <u>classes</u> of customers. We will address this question in the next section.

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[68] Ibid., p. 92.

[69] Referred to in P.U. 8 (2007), p. 45.

[70] P.U. 7 (2002-03), p. 119.

4.1.3.5. Distinct classes of service to reflect geographic cost differentials

While many utilities use the same basic rate classes, regulators in fact have considerable discretion in selecting them. As George C. Baker explained in his testimony, as expert witness for the PUB, in a 1993 proceeding on rural electric supply:

> The applicable regulatory principle is that rates should reflect costs.…
>
> Nevertheless, the degree to which this principle is reflected in rates can, and does, vary from one jurisdiction to another depending on the structure of rate classes. For customers of the same type, it is generally cheapest to serve urban loads and more expensive to serve rural loads. If all the customers of one type (residential, for instance) are placed in the same class, urban customers subsidize rural customers, even though the rate charged may exactly recover the cost of serving the class as a whole.
>
> …
>
> It is of course much more expensive to serve isolated loads. Therefore, if urban, rural and isolated customers of the same type were to be included in a single class, the degree of cross-subsidization would be considerably greater.[71]

In other words, though the service provided to residential customers in urban, rural and isolated communities may be identical, the cost of service is radically different, which leads many jurisdictions to establish different rate classes for them.

Mr. Baker then pointed out that, in New Brunswick and Manitoba, "residential rates are differentiated on the basis of customer density," and that "fixed charge differentials reflect the differences in distribution cost between the relevant groups." He quoted Manitoba Hydro as stating:

> "Current rate zone distinctions are intended to reflect real differences in distribution cost."[72]

That is, in those two provinces, two or more residential rate classes were established, in order to better reflect cost causation and reduce cross-subsidization.

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[71] G.C. Baker, Direct Testimony, NLPUB, An Inquiry into issues relating to the supply of electricity to isolated rural areas of the Province (rev. Dec. 10, 1993), pp. 3-4. IN-PUB-01, Att. 1.

[72] Ibid., p. 4. He pointed out, however, that Manitoba was considering changing this practice.

Like many other analysts, Mr. Baker references the principles set out by Bonbright,[73] and provides them in his Appendix I. He summarizes them as follows:

> The major requirements are that rates be accurate in raising the revenue requirement, conducive to efficient use of electricity and <u>equitable as between both customer classes and individuals within each class</u>.[74] (emphasis added)

When asked how these attributes can best be realized, he responds: "Mainly by ensuring that rates reflect responsibility for cost causation."[75]

Mr. Baker's testimony concerned the rural deficit, but the principles he cites are equally applicable to geographic cross-subsidization within the LIS. The cost increase on the part of interconnected customers to pay the rural subsidy at the time was on the order of roughly 10%.[76] The cross-subsidization from Lab East to Lab West with respect to the Labrador City Distribution Upgrade appears to be considerably greater.

Mr. Baker's testimony in both of these proceedings repeatedly emphasized the importance of cost causality in ratemaking. Describing the general procedure set out in the 1973 NARUC cost allocation manual, he stated:

> NARUC's description suggests, both directly by reference and indirectly as a consequence of the defined procedure, that causal responsibility for the existence of costs is the proper basis for their allocation.[77]

And he approvingly quoted the testimony of Mr. Brockman from an earlier hearing:

> "Causality is the guiding principle of all cost of service work."[78]

Mr. Baker emphasizes the critical role of judgment in resolving the "inherent conflict between Bonbright's desirable attributes of equity on the one hand and simplicity and understandability on the other."

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[73] Bonbright, Principles of Public Utility Rates, 1961; Bonbright et al., 1988.
[74] Baker, IN-PUB-01, Att. 1, p. 24.
[75] Ibid.
[76] Ibid., p. 13.
[77] Baker, IN-PUB-02, Att. 1, p. 3.
[78] Ibid., p. 5.

> Judgment in any particular case is no doubt based on all the pertinent factors <u>including the extent of the inequity</u>, which is relatively small between urban and rural customers in these examples; and the weight accorded to customer understanding and acceptance. <u>Judgment can be expected to vary from case to case</u>.[79]

The clear implication is that — when application of a standard approach leads to an inequitable result — the Board should use its judgment in search of the most equitable solution.

4.1.4. Socio-economic differences between Lab East and West

A review of data collected by Statistics Canada in its 2011 National Household Survey reveal significant socio-economic differences between the communities of Labrador West and Labrador East.

In this section, we will compare socio-economic indicators for three communities: Labrador City, Happy Valley-Goose Bay, and Sheshatshiu. As the population of HVGB represents over 90% of that of Labrador East (excluding Sheshatshiu),[80] it is used here as a proxy for Labrador East. As data for Wabush are not available[81] and its population is only 25% of that of Lab City, Lab City data will be used as a proxy for Lab West.

Education

In Labrador City, 65.6% of the population over the age of 15 has a post-secondary degree, and only 12.6% do not have a high school diploma. The educational levels in HVGB are only slightly lower: 63.8% have a post-secondary degree, and only 16.2% do not have a high school diploma.

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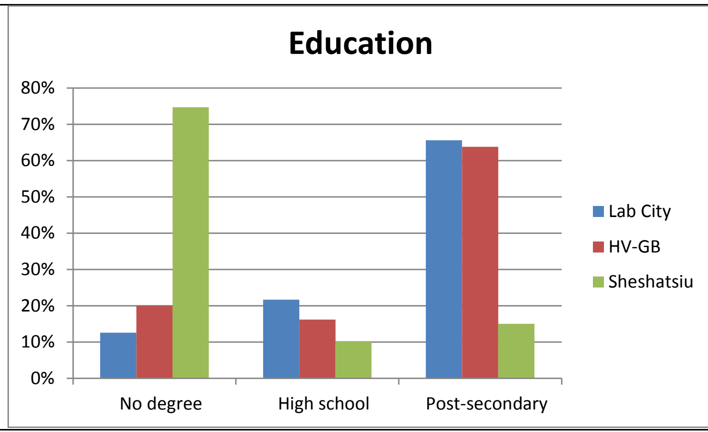
[79] Baker, IN-PUB-01, Att. 1, p. 5.

[80] HVGB's population was reported in 2011 as 7,450, compared to 555 for Northwest River and 1314 for Sheshatshiu.

[81] According to the StatsCan website for the National Household Survey, "Data for this area has been suppressed for data quality or confidentiality reasons."

In Sheshatshiu, however, the proportions are reversed: only 15.1% have a post-secondary degree, and 74.7% do not have a high-school diploma.

Figure 4.

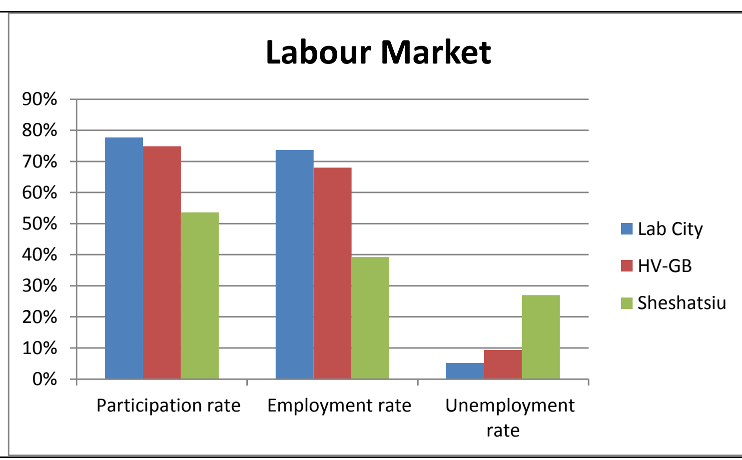


Employment

Labrador City has an employment rate of 73.7%, and an unemployment rate of 5.2%. In HVGB, unemployment is almost twice as high (9.4%), and the employment rate is 73.7%.

In Sheshatshiu, on the other hand, the unemployment rate is 27%, and the employment rate is only 39.2%.

Figure 5



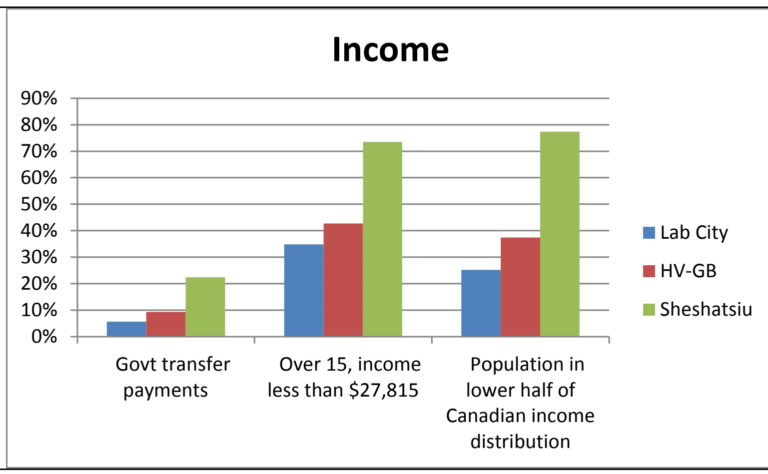
Income

The income disparities between the three communities are substantial.

Government transfers represent 22.4% of total income in Sheshatshiu, but only 5.7% in Labrador City. In HVGB, the figure is 9.3%.

The percentage of Labrador City residents over the age of 15 with an annual income of less than $27,815 is 34.8% — considerably less than the figures for Canada (50%) or the province of Newfoundland and Labrador (56.1%). For HVGB, the percent of the population with incomes under this level is somewhat higher: 42.7%. However, for Sheshatshiu, it is more than twice as high: 73.5%.[82]

Figure 6

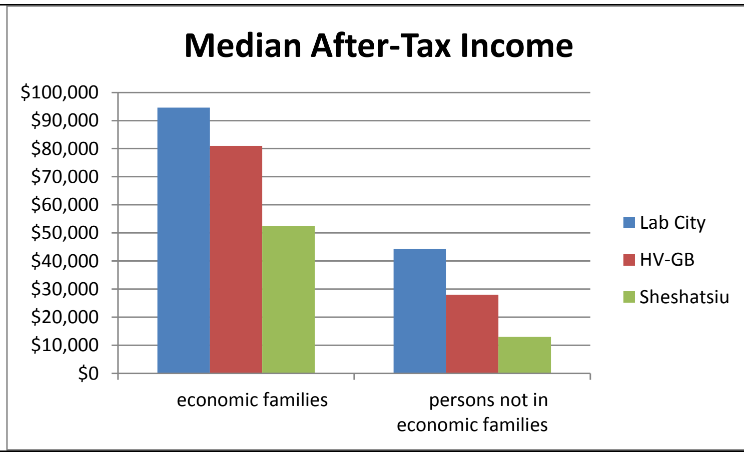


The disparities in after-tax income are even greater. In Lab City, the median after-tax income for people in economic families was $94,967. It was lower (about $81,000) in HVGB, and dramatically lower ($52,502) in Sheshatshiu.

For persons not in economic families, the median after-tax incomes were much lower: $44,173 in Labrador City, about $27,000 in HVGB and only $11,635 in Sheshatshiu.

[82] The figure for Sheshatshiu represents incomes under $29,999.

Figure 7



Conclusion

The statistics summarized above demonstrate that there are significant socio-economic disparities between Labrador City (and, presumably, Labrador West as a whole) and Labrador East.[83] Labrador City has much higher levels of income, education, and employment than does Happy Valley-Goose Bay, and vastly higher levels than Sheshatshiu.

To a certain extent, cross-subsidization is a necessary evil of all utility regulation, in that the precise costs of service to any given customer may be higher or lower than the rate charged to the relevant rate class. However, ratemaking involves judgment, and equity considerations are an important component of wise application of that judgment. Standard ratemaking practices should not be applied blindly when the result would be to create substantial cross-subsidization of wealthier communities by poorer ones, as is the case here.

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[83] The population of Northwest River is just 555, compared to 7,450 in HVGB and 830 in Sheshatshiu.

4.1.5. Precedents from other jurisdictions

The treatment in the GRA of the Labrador City Distribution Upgrade appears to be based on two principles:

- A cost-of-service study necessarily aggregates costs for all geographic areas covered by the study area; and
- Rates for a given type of electric service must be the uniform all across a cost-of-service study area.

In this section, we will look at several examples from other jurisdictions that demonstrate the contrary.

4.1.5.1. Geographical disaggregation in cost-of-service study

4.1.5.1.1. Gaz Métropolitain (Quebec)

In a 1997 decision, the Régie de l'énergie du Québec (the Quebec Energy Board) required that the cost of gas mains be allocated by region. It wrote:

> La Régie est d'opinion que l'allocation par région du coût des conduites principales, à l'aide de demandes quotidiennes maximales par région, est une amélioration importante de la méthode actuellement en vigueur car elle reflète mieux les liens de causalité entre le coût des conduites et les clients pour lesquels elles ont été construites. L'allocation se fait donc en fonction de l'utilisation des conduites principales par les clients actuels des différentes régions. …
>
> En effet, la Régie comprend de la méthode proposée que les coûts des conduites principales seraient alloués aux clients qui les utilisent dans chacune des régions et que les coûts pour desservir chaque classe tarifaire de chacune des régions seraient bien identifiés.
>
> En effet, la Régie comprend de la méthode proposée que les coûts des conduites principales seraient alloués aux clients qui les utilisent dans chacune des régions et que les coûts pour desservir chaque classe tarifaire de chacune des régions seraient bien identifiés.[84]
>
> [The Régie is of the opinion that the allocation by region of the cost of gas mains, based on the maximum daily demand by region, is a significant improvement to the method currently in use, as it better reflects the causal links between the cost of the mains and the clients for whom they were built. The allocation should thus be based on the use of the mains by the current clients in the various regions.

[84] Régie de l'énergie, D-97-47 (Dec. 19, 1997), p. 17.

> The Régie understands that, under the proposed method, the cost of the mains would be allocated to the clients that use them in each region, and that the costs to serve each rate class in each region would be identified.]

Thus, Gaz Metropolitain's cost-of-service study allocates the cost of these mains differently for different communities, depending on the extent to which they use the mains. To date, the Régie has declined to require that these regional costs be reflected in rates, though it has indicated that, in principle, this would be appropriate.

4.1.5.1.2. Pacific Gas & Electric (PG&E)

In its cost of service studies, PG&E distinguishes the cost of service in more than a dozen distinct geographical zones. To understand its approach, some background is necessary.

Like other utilities regulated by the California Public Utilities Commission (CPUC), the rates of Pacific Gas & Electric (PG&E) are based on marginal costs. As noted by Mr. Baker back in 1993, many economists consider marginal costs to be a better basis for ratemaking than embedded costs.[85] The CPUC has relied on marginal costs for its ratemaking processes for since 1981. For distribution assets, PG&E considers only distribution investments related to load growth.

PG&E's service territory has an extremely diverse geography and customer density, resulting in a wide variation in marginal distribution costs among the more than 240 distribution planning areas (DPAs) that comprise its electric system, which are aggregated into 18 divisions. In its cost of service study, PG&E establishes location-specific marginal distribution capacity costs (MDCCs) for each one.

> … MDCCs vary by area to reflect the fact that investments during the planning horizon are needed at different times and in different sizes for different areas depending on the installed capacity and load growth unique to each area.[86]

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[85] IN-PUB-02, Att. 1, p. 4.

[86] Pacific Gas & Electric, General Rate Case 2014, Phase II, Exhibit PG&E-2, p. 1-13.

This approach has for the most part remained stable since 1993, and is meant to reflect cost differences between the 18 geographic divisions.[87]

> Ideally, a DPA has uniform load distribution, uniform load growth rate, a single primary distribution voltage, strong distribution ties among substations inside the area and no ties to substations outside the area. Although ideal DPAs are not encountered in practice, DPAs are defined as nearly as practicable to that ideal.[88]

MDCCs vary greatly between PG&E's 18 geographical divisions. For example, primary distribution marginal costs vary between $13.08 and $78.19/kW.

It should be noted that these MDCCs are not directly reflected in rates at this time, apparently because the current rate structure, based on five tiers and ten climate zones, is already quite complicated. However, the CPUC and PG&E are both committed to "move further toward cost-based rates," implying that regional marginal cost differences will likely eventually be reflected in rates.

4.1.5.2. Alternatives to single-tariff pricing

4.1.5.2.1. Pacific Gas and Electric

As noted above, PG&E's rate structure distinguishes ten climate zones and five tiers. While the ¢/kWh rate for each tier is identical across all zones, the size of the block covered by each tier is not.[89] As a result, the billed amount for a given level of consumption can vary widely across the PG&E service territory.

4.1.5.2.2. Union Gas (Ontario)

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[87] Ibid., p. 5-1.

[88] Ibid., pages 5-2 and 5-3.

[89] The first tier represents a sort of lifeline block – the minimum consumption estimated necessary based on the climate in each of 10 climate zones. Tiers 2-5 consist of percentages above that lifeline block. Thus, Tier 2 consists of 101-130% of the baseline block. In recent years, rate increases have been limited to tiers 3-5, resulting in extremely high rates for these tiers (over 40 cents/kWh in some areas). http://www.pge.com/myhome/saveenergymoney/plans/rateanalysis/howratesset/

Union Gas has distinct distribution rates for its northern and southern regions, based on their different cost structures. Union North (formerly Centra) is served directly from the Trans-Canada mains, and has significantly lower distribution costs than Union South, which requires additional infrastructure, including storage. After the merger with Centra in 1998, Union Gas decided to maintain distinct rates for Union North and South, in order to respect cost causation.[90]

4.1.5.2.3. Massachusetts Department of Public Utilities

The Department of Public Utilities (DPU) in Massachusetts allows utilities to apply a rate rider of up to 2% for municipalities which have opted for underground distribution lines, which are of course far more expensive than overhead lines.[91]

More generally, while the DPU favours single-tariff pricing, it has, on occasion, departed from that practice based on specific facts. It particular, it has approved rates differentiated by zone "in recognition of a specific set of circumstances where cost-causation principles justify a departure from the general rationale behind single-tariff pricing." It has also "approved the use of surcharge mechanisms for utilities to recover the costs associated with particular infrastructure items when traditional ratemaking principles were found to be inadequate for the task."[92]

4.1.6. Regulatory mechanisms

In response to an RFI, Hydro wrote:

> To Hydro's knowledge, the Board has never specifically assigned assets to a small group of customers for rate setting purposes. It has either assigned the costs to a single customer or it has treated them as common costs and collected the costs of those assets from the whole rate

[90] Personal communication, Chris Ripley, Union Gas.

[91] Personal communication, Paul Osborne, Assistant Director, Rates and Revenue Requirements Division, Massachusetts Department of Public Utilities.

[92] Massachusetts Department of Public Utilities, Decision, Petition of Aquarion Water Company of Massachusetts to the Department of Public Utilities for a General Rate Increase as set forth in M.D.P.U. No. 1, D.P.U. 08-27, March 31, 2009, p. 167.

> class, or more than one rate class, in that system. Whether it would be proper for the Board to specifically assign assets to a small group of customers for rate setting purposes is a hypothetical question which cannot be determined absent more factual context.[93]

The question is how best to reflect, in rates, substantial differences in cost of service, due to the costs of particular assets used by one group only, between groups of consumers in different locations which are otherwise similar. One solution is to directly assign those costs to the sub-class of consumers that benefit from them; another solution is to create geographically distinct rate classes. A third, and simpler, solution is to establish a rate rider that applies only to the customers in the area that benefits from the improvement.

In his 1993 testimony in a proceeding relating to the supply of electricity to rural areas, the Board's consultant George C. Baker addressed the question of rate class structure.

> Q. How should rate classes be structured?
>
> A. In order to avoid the sort of cross-subsidization discussed in the first part of this testimony, each rate class should be as nearly as possible homogeneous in terms of unit costs of service. This means that the cost-causative characteristics of electric use should be similar and that the class should be served from the same source of supply.[94]

He recognized, however, that the application of this rule may, under some circumstances, lead to an excessive number of rate classes. To avoid this result, he suggested the use of rate riders:

> Often rate "riders" are used to modify a rate in certain cases and to keep the number of classes from expanding beyond reason. For example, industrial customers at various voltage levels may form one class under a rate which has a rider to adjust for the difference in the cost of line losses. In such a case the class is one class for cost of service purposes and the operation of the rider ensures an equitable division of allocated cost between the sub-groups.[95]

He reiterated the importance of flexible approach in order to find the best solution for situations where existing rate class structures do not reflect cost causation.

> Q. Isn't there some possibility that some customers will not fit well in any given class structure of reasonable simplicity?

[93] IN-NLH-224.

[94] Baker, IN-PUB-01, att. 1, p. 26.

[95] Ibid., p. 27.

> A. Yes, there is.
>
> Most utilities have a real concern for their customers, and when this happens, the utility usually will, and should, try to find some method of eliminating the problem.
>
> This can sometimes be accomplished by means of a rate rider, or sometimes may justify some modification of class structure.[96]

As we have seen, applying the costs of the Labrador City Distribution Upgrade to all distribution voltage ratepayers in the Labrador Interconnected System would result in a substantial cross-subsidization of these costs on the part of the residents of Labrador East, which do not benefit from them in any way. Given the large socio-economic disparities between the two regions, this cross-subsidization is particularly problematic.

As demonstrated above, the regulator has many options to choose from to avoid such an outcome. Under the circumstances, I believe that a rate rider applied to the customers directly benefiting from this upgrade is the best solution. An alternate, but more complex, solution would be to create new rate classes for the Lab West region.

It should be noted that, as we shall see below, customers served under the Labrador Isolated are also indirectly impacted by the LIS rate increase, in that it creates a corresponding reduction in the provincial NSP subsidy. Indeed, the Order-in-Council creating the NSP rebate[97] specifically cites the rates in Happy Valley-Goose Bay, so the application of a rate rider in Labrador West would not affect it.

4.2. Rate impacts of forecast capital expenditures in the LIS

Significant capital expenditures are forecast for the Labrador Interconnected System. Given that general rate adjustments are not held every year, it is important to have an idea of the rate implications in coming years of these planned capital expenditures.

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[96] Ibid., p. 28.

[97] OC2007-304, IN-NLH-123, Att. 4.

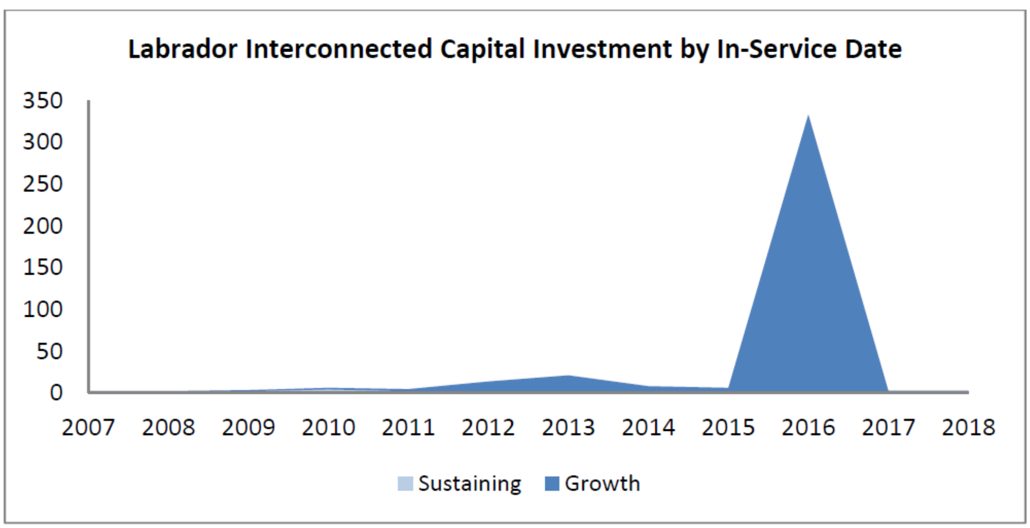
While several documents have been produced that provide such forward-looking information, the relationships between them are not obvious. In this section, we will address these various information sources. These include:

- IN-NLH-030 rev. 1, which graphically indicates LIS capital investments by in-service date;
- IN-NLH-245, Att. 1, which provides this same information in tabular form; and
- IN-NLH-249, Att. 1, which presents detailed calculations of the revenue requirement impacts of the capital program.

Establishing correspondence between these various data sources is complicated by the fact that the largest single investment, the Lab West Transmission Line, is treated differently in different documents.

IN-NLH-30 Rev. 1 presents the following graph representation of future capital investment in the LIS, by in-service date.

Table 7. LIS Capital Investment by In-Service Date



In IN-NLH-245, Att. 1, the detailed list of forecast capital expenditures used to prepare this graphic is presented, indicating for each the in-service date and the capital cost of each.

The following table summarizes presents the year-by-year totals, from 2015 through 2018.

Table 8. Forecast capital expenditures from IN-NLH-245		
In-service date	**Forecast capital expenditures ($000)**	
	With Lab West Transmission Line	Without Lab West Transmission Line
2015	6,150	6,150
2016	332,748	4,056
2017	16,117	16,117
2018	2,679	2,679

The data presented in the NLH document are found in the middle column. However, as work on the Lab West Transmission Project (LWTP) has been suspended, I have also shown the totals subtracting out the cost of this investment (the last column). Clearly, the LWTP dwarfs all other forecast capital expenditures in the LIS.

4.2.1. Revenue requirement impacts of forecast capital expenditures

IN-NLH-249 requested an analysis of the rate implications of the capital expenditures in the LIS. The table presented in response is reproduced here:

Table 9. Revenue requirement impacts of LIS capital expenditures

Line No		A 2014	B 2015	C 2016	D 2017	E 2018	Reference
1	Forecast Capital Expenditures	48,431	188,845	163,431	27,309	17,080	
2	Lab West Transmission line[1]	(37,484)	(163,145)	(128,963)			
3	**Net Plant in Service Available for Equity Return**	10,947	25,700	34,468	27,309	17,080	
4	Annual Depreciation Expense Estimate	3,270	3,459	3,679	3,908	4,619	
5	Current year Depreciation Expense Estimate	1,635	5,000	8,569	12,362	16,626	Line 4 from prior years plus one-half Line 4 for current year
6	**Net Book Value for Forecast Capital Expenditures**	9,312	20,701	25,900	14,947	455	Line 3 - Line 5
7	**Average Change to Rate Base**	4,656	19,662	42,968	63,386	71,087	Line 6 from prior years plus one-half Line 6 for current year
8	Return on Rate Base - Debt Component	4.938%	4.938%	4.938%	4.938%	4.938%	2015 Test Year
9	Return on Rate Base - Equity Component	1.879%	1.879%	1.879%	1.879%	1.879%	2015 Test Year
	Revenue Requirement Impacts						
10	Return on Debt	230	971	2,122	3,130	3,510	Line 7 x Line 8
11	Return on Equity	88	370	808	1,191	1,336	Line 7 x Line 9
12	Annual Depreciation Expense Estimate	1,635	5,000	8,569	12,362	16,626	Line 5
13	**Total Revenue Requirement Impacts**	1,953	6,341	11,499	16,683	21,472	Lines 10 to 12

[1] Work has been suspended on this line until Alderon has confirmed financing for the Kami mine. For the purposes of this table, this amount has been removed due to uncertainty as to completion date.

This response shows revenue requirements impacts for the LIS related to capital expenditures ranging from $2.0 million in 2014 to $21.5 million in 2018 (line 13).

Revenue requirement impacts are clearly an important factor contributing to rate impacts.[98] Table 10 presents the same results as Table 9, with the following lines added at the end:

- Line 14: Total Revenue Requirement: 2015 revenue requirement increased by cumulative revenue requirement impacts (line 13); and
- Line 15: Cumulative Revenue Requirement Impacts (%): the cumulative revenue requirement impacts, expressed as a percentage of the 2015 revenue requirement.

Table 10. Revenue requirement impacts of LIS capital expenditures

Line No		2015	2016	2017	2018	Reference
1	Forecast Capital Expenditures	188,845	163,431	27,309	17,080	
2	Lab West Transmission line[1]	(163,145)	(128,963)	0		
3	**Net Plant in Service Available for Equity Return**	25,700	34,468	27,309	17,080	
4	Annual Depreciation Expense Estimate	3,459	3,679	3,908	4,619	
5	Current year Depreciation Expense Estimate	5,000	8,569	12,362	16,626	Line 4 from prior years plus one-half Line 4 for current year
6	**Net Book Value for Forecast Capital Expenditures**	20,701	25,900	14,947	454	Line 3 - Line 5
7	**Average Change to Rate Base**	19,662	42,962	63,386	71,086	Line 6 from prior years plus one-half Line 6 for current year
8	Return on Rate Base - Debt Component	4.938%	4.938%	4.938%	4.94%	
9	Return on Rate Base - Equity Component	1.879%	1.879%	1.879%	1.879%	
10	**Revenue Requirement Impacts** Return on Debt	971	2121	3130	3510	Line 7 x Line 8
11	Return on Equity	369	807	1191	1336	Line 7 x Line 9
12	Annual Depreciation Expense Estimate	5,000	8,569	12,362	16,626	Line 5
13	**Total Revenue Requirement Impacts**	**6,340**	**11,497**	**16,683**	**21,471**	Sum of Lines 10 to 12
14	Total Revenue Requirement	23,556	35,053	40,239	45,027	2015 values from Exh. 13, Sch. 1.1
15	Cumulative Revenue Requirement Impacts (%)	27%	48.8%	70.8%	91.2%	Line 13 / Line 14 (2015)

Line 15 shows cumulative revenue requirement impacts of 91.2% by 2018.

There are several surprising aspects to these tables. First, the negative numbers in line 2 (Lab West Transmission Line). These represent the annual investments made prior to commissioning.[99] Normally, as in IN-NLH-033 Att. 1, the series of negative numbers are followed by a positive one of the same absolute value. Thus, the amounts spent are deducted each year during construction, and are added to rate base in the year of commissioning.

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[98] There are of course others factors that also contribute to rate impacts, such as changes in expenses and in sales.

[99] Explained in IN-NLH-248, page 2, lines 8-12.

In this case, a note explains that work has been suspended on the Lab West Transmission line, until such time as financing is confirmed for the Kami Mine. It is not clear, however, why substantial expenditures are included in the table for this project in 2015 and 2016, if work has been suspended. Indeed, the table seems to take into account the expenditure of the full capital amount ($330 million), but not of the line's commissioning. Given that work has been suspended, this is a surprising portrait indeed.

These negative numbers also imply that the figures in this table are reported on an as-spent basis, as opposed to according to in-service dates. However, the data from IN-NLH-245, shown above in Table 8, are unambiguously presented on an in-service basis. Replacing lines 1 and 2 of Table 10 with the data from the last column of Table 8 (without the LWTP) results in Table 11.

Table 11. Revenue requirement impacts of LIS capital expenditures (without the LWTP)

Line No		2015	2016	2017	2018	
1	Forecast Capital Expenditures (Transmission)	6,150	4,056	16,117	2,679	
3	**Net Transmission Plant in Service Available for Equity Return**	6,150	4,056	16,117	2,679	
4	Annual Depreciation Expense Estimate	219	155	2,306	724	
5	Current year Depreciation Expense Estimate	784	971	2,202	3,717	Line 4 from prior years plus one-half Line 4 for current year
6	**Net Book Value for Forecast Capital Expenditures (Transmission)**	5,366	3,085	13,915	1,038	Line 3 - Line 5
7	**Average Change to Rate Base**	10,474	14,699	23,199	29,637	Line 6 from prior years plus one-half Line 6 for current year
8	Return on Rate Base - Debt Component	4.938%	4.938%	4.938%	4.94%	
9	Return on Rate Base - Equity Component	1.879%	1.879%	1.879%	1.879%	
10	**Transmission Revenue Requirement Impacts** Return on Debt	517	726	1146	1463	Line 7 x Line 8
11	Return on Equity	197	276	436	557	Line 7 x Line 9
12	Annual Depreciation Expense Estimate	784	971	2,202	3,717	Line 5
13	**Total Transmission Revenue Requirement Impacts**	**1,498**	**1,973**	**3,784**	**5,738**	Sum of Lines 10 to 12
14	Total Revenue Requirement	23,556	25,529	27,340	29,294	2015 values from Exh. 13, Sch. 1.1
15	Cumulative Revenue Requirement Impacts over 2015 (%)		8.4%	16.1%	24.4%	Line 13 / Line 14 (2015)

However, if the Labrador West Transmission investments are included, with an in-service date of 2016, the picture changes dramatically, as shown in Table 12.

Table 12. Revenue requirement impacts of LIS capital expenditures (with the LWTP)

Line No		2015	2016	2017	2018
1	Forecast Capital Expenditures (Transmission)	6,150	332,748	16,117	2,679
3	**Net Transmission Plant in Service Available for Equity Return**	6,150	332,748	16,117	2,679
4	Annual Depreciation Expense Estimate	219	12,742	2,306	724
5	Current year Depreciation Expense Estimate	784	7,264	14,789	16,304
6	**Net Book Value for Forecast Capital Expenditures (Transmission)**	5,366	325,484	1,328	13,625
7	**Average Change to Rate Base**	10,474	175,898	339,304	333,156
8	Return on Rate Base - Debt Component	4.938%	4.938%	4.938%	4.94%
9	Return on Rate Base - Equity Component	1.879%	1.879%	1.879%	1.879%
10	**Transmission Revenue Requirement Impacts** Return on Debt	517	8686	16755	16451
11	Return on Equity	197	3305	6376	6260
12	Annual Depreciation Expense Estimate	784	7,264	14,789	16,304
13	**Total Transmission Revenue Requirement Impacts**	**1,498**	**19,255**	**37,919**	**39,015**
14	Total Revenue Requirement	23,556	42,811	61,475	62,571
15	Cumulative Revenue Requirement Impacts over 2015 (%)		81.7%	161.0%	165.6%

We now see a cumulative revenue requirement impact of over 81% in 2016, and of over 160% in 2017, due to the capital investments identified in IN-NLH-245 — including the Lab West Transmission Project. Thus, LIS revenue requirements will have almost tripled from $23.6 million in 2015 to $62.6 million in 2018.

This analysis demonstrates the extraordinary scale of this investment, in relation to the LIS revenue requirement. The situation is complicated by the fact that, as we shall see below, the need for this project is driven by unregulated power sales.

While work on this line has been suspended, it has not been cancelled. Given that its fate will most likely be decided before the next General Rate Application, it is important to consider it at this time.

4.2.2. Labrador West Transmission Project

4.2.2.1. Description and justification

The Labrador West Transmission Project (LWTP) consists of a 220 km 230-kV line, a new Flora Lake Terminal Station, and interconnections with the existing Wabush Terminal Station. Under the Labrador West Transmission Exemption Order (Reg. 11/14), NLH is exempt from EPCA and PUA "for all planning, design, construction and contribution activities pertaining to the Labrador West Transmission Project". (s. 3)

The justification of the LWTP is to supply new non-regulated sales. In a news release dated February 13, 2014, Premier Tom Marshall announced that the line's construction would "help to supply power for planned new developments, such as the Kami Iron Ore Project, and improve reliability for all customers in the Labrador region."[100] The fact that Hydro has suspended work on the LWTP until such time as financing of the Kami Mine project is assured provides eloquent confirmation of this statement.[101]

In response to an RFI of the Innu Nation, Hydro suggested that, while the LWTP would indeed provide some reliability benefits for existing customers, in the event of worst-case contingency events, it would not be justified, given the cost of the line.

> The present configuration has been in place and maintained to supply customers in Labrador West under similar load and higher load situations for a number of years.[102]

Thus, while the LWTP would indeed provide some reliability benefits to other customers, those benefits are clearly not sufficient to justify the investment.

[100] http://www.releases.gov.nl.ca/releases/2014/exec/0213n05.htm
[101] LWHN-NLH-067 Rev. 1, IN-NLH-235, IN-NLH-247.
[102] IN-NLH-299.

4.2.2.2. Regulatory treatment

New industrial developments in Labrador are served under the Labrador Industrial Rate, established by the NL Government, which became effective in May 2013. The generation component is unregulated and set by market forces; the transmission component is regulated.[103]

The press release announcing the Labrador Industrial Rate further stated:

> In addition to charges for generation, industrial customers will pay an additional amount based on the costs of required transmission. Under the recommended policy, <u>transmission service and rates would be fully regulated by the PUB beginning in 2015 based on the cost of service principles currently in use on the Island</u>. Transmission owners would be entitled to recover costs and collect a rate of return on their assets in Labrador.[104]

The government backgrounder concluded by stating: "The industrial rate policy will not affect Labrador residential and commercial rates."

Subsequently, in February 2014, an Order-in-Council directed the Board regarding the treatment of the costs of the LWTP. It stated:

> … where the Board determines that costs [of the Labrador West Transmission Project] were prudently incurred within the scope of the project, the Board shall include such costs in Newfoundland and Labrador Hydro's rate base for recovery in Newfoundland and Labrador Hydro's rates.[105]

Nevertheless, the Board retains jurisdiction with respect to cost allocation:

> In accordance with the Labrador Industrial Rates Policy Framework, the transmission system in Labrador will be fully regulated and therefore cost allocation to customers will be determined in a manner approved by the Board.[106]

In the following section, we will look at the methodology proposed by LNH in the amended GRA for the allocation of transmission costs, and their implications for the LWTP. In the subsequent section, we will look at alternative methodologies used by other regulators.

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103 IN-NLH-117.

104 IN-NLH-117, att. 1, p. 2.

105 OC2014-034

106 LWHN-NLH-068, rev. 1, p. 2, lines 9-12.

4.2.2.3. Hydro's proposed methodology

Hydro's proposed methodology for setting the Labrador Industrial Transmission Rate ("LITR") is set out on page 4.48 and 4.49 of the Amended GRA. To the best of my knowledge, this is the first time that this methodology has been proposed to the Board.

Hydro's proposed LITR is set out in Table 4.14 of the Amended GRA, reproduced below.[107]

Table 13. Labrador Industrial Transmission Rate (Table 4.14 of the Amended GRA)

Calculation of Labrador Industrial Transmission Rate	
Total Labrador Interconnected Transmission Demand Cost ($)[1]	6,378,120
Labrador Industrial Allocation based on CP[2]	63.37%
Allocated Transmission Demand Cost ($)[3]	4,041,656
(Firm) Billing Demand (kW)[4]	270,000
Annual Cost ($ per kW)	14.97
Monthly Rate ($ per kW)	**1.25**

[1] See Exhibit 9, Schedule 2.1E, Page 1 of 2, Line 23, Col 5.
[2] See Exhibit 9, Schedule 3.1E, Page 1 of 2, Line 14, Col 5.
[3] See Exhibit 9, Schedule 3.2E, Page 3 of 4, Line 62, Col 5.
[4] See Exhibit 9, Schedule 1.3.2, Page 3 of 3, Line 8, Col 2, divided by 12.

Table 14 indicates the calculations implicit in Table 4.14, as well as some of the other figures on which it is based.

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[107] The footnotes in the table apparently refer to Exhibit 13, not to Exhibit 9.

Table 14. Derivation of the Labrador Industrial Transmission Rate

			Notes
1	Total LIS Transmission Demand cost ($)	6,378,120	Table 4.14
2	Labrador Total Demand (kW)	431,777	IN-NLH-257
3	Firm Industrial Billing Demand (kW)	273,606	IN-NLH-257 ("60 to 70 MW"); IN-NLH-235 ("60 to 100 MW")
4	Labrador Industrial Allocation based on CP	63%	line 3 / line 2
5	Transmission Demand Cost Allocated to Industrial Customers($)	4,041,651	line 1 * line 4
6			
7	Annual Cost ($/kW)	14.77	line 5 / line 3
8	Monthly Rate ($/kW)	1.23	line 7 / 12
9	Amount paid by industrial customers ($)	4,041,651	line 5
10	Amount paid by other customers ($)	2,336,469	line 1 - line 5
	Regulated Customer Revenue Requirement	23,556,000	

How will the addition of the LWTP to the LIS rate base affect the LITR?

First, the impact of the LWTP must be added to the Total LIS Transmission Demand Cost (line 1). Using the methodology illustrated above in Table 11 and Table 12, this additional amount can be estimated at around $28.5 million in the first full year after commissioning, as shown in Table 15.

In this case, the annual depreciation estimate (line 4) is based on straight-line depreciation over a 50-year period. However, there is no guarantee that the Kami Mine will continue to require power for 50 years. Indeed, an Alderon release indicates that the mine has an expected lifetime of 30 years.[108] Based on a 30-year payback period, the first-year rate would climb to $32,616,000, compared to the $28,533,000 shown here. However, if one assumes that other mining projects will eventually appear that will also require use of the LWTP, the 50-year depreciation may be appropriate.

[108] http://www.alderonironore.com/_resources/news/ADVNR20130109.pdf

Table 15. Annual capital cost related to LWTP

Line No		2017	2018	2019	2020
1	Forecast Capital Expenditures	328,692			
3	**Net Plant in Service Available for Equity Return**	328,692	0	0	0
4	Annual Depreciation Expense Estimate	6,574	0	0	0
5	Current year Depreciation Expense Estimate	3,287	6,574	6,574	6,574
6	**Net Book Value for Forecast Capital Expenditures**	325,405	6,574	6,574	6,574
7	**Average Change to Rate Base**	162,703	322,118	315,544	308,970
8	Return on Rate Base - Debt Component	4.938%	4.938%	4.938%	4.938%
9	Return on Rate Base - Equity Component	1.879%	1.879%	1.879%	1.879%
10	**Revenue Requirement Impacts** Return on Debt	8034	15906	15582	15257
11	Return on Equity	3057	6053	5929	5806
12	Annual Depreciation Expense Estimate	3,287	6,574	6,574	6,574
13	**Total Revenue Requirement Impacts**	**14,378**	**28,533**	**28,084**	**27,636**

Second, Firm Industrial Billing Demand must be increased to account for the new industrial customer(s). The Kami mine demand was estimated by Alderon in 2013 at 60 to 70 MW.[109] In this example, we use a value of 65 MW. Table 16 demonstrates the expected increase in the LIS rural revenue requirement for 2018, taking into account the Lab West Transmission Project.

Table 16. Derivation of the Labrador transmission rate (LITR), including the LWTP

		Current	Lab West/Kami	After commissioning	Additional amount paid	% of LWTP annual cost	Notes
1	Total LIS Transmission Demand cost ($)	6,378,120	28,532,635	34,910,755			Table 4.14 (GRA), Table 15 (above)
2	Labrador Total Demand (kW)	431,777	65,000	496,777			IN-NLH-257, IN-NLH-235
3	Firm Industrial Billing Demand (kW)	273,606	65,000	338,606			
4	Labrador Industrial Allocation based on CP	63.4%		68.2%			line 3 / line 2
5	Transmission Demand Cost Allocated to Industrial Customers($)	4,041,651		23,795,367			line 1 * line 4
6	Annual Cost ($/kW)	14.77		70.27			line 5 / line 3
7	Monthly Rate ($/kW)	1.23		5.86			line 7 / 12
	Amount paid by IOCC ($)	4,041,651		19,227,525	15,185,874	53%	
	Amount paid by Alderon ($)			4,567,842	4,567,842	16%	
8	Amount paid by industrial customers ($)	4.041.651		23.795.367	19.753.716	69%	line 5
9	Amount paid by rural customers ($)	2.336.469		11.115.388	8.778.919	31%	line 1 - line 5
	Total				28,532,635	100%	
10	Additional amount paid by industrial customers ($)			19,753,716			line 5: col. 3 - col. 1
11	Additional amount paid by other customers ($)			8,778,919			line 10: col. 3 - col. 1
12	LIS Rural Revenue Requirement	20,505,394		29,284,313			2015 LIS Rural, from Sched. 1.2
13	% increase in LIS Rural Revenue Requirement			43%			(line 12, col. 3) / (line 12, col. 1) - 1

[109] A PPA was executed on February 19, 2014. LWHN-NLH-068, Rev. 1.

The key elements of this analysis are as follows:

- In line 1, the total LIS Transmission demand cost increases from $6.4 million to $34.9 million;
- In line 2, the Labrador total demand increases from 432 MW to 497 MW;
- In Line 3, the firm industrial billing demand increases from 274 MW (IOCC) to 339 MW;
- Based on these changes, the Labrador Industrial Allocation (line 4) increases from 63.4% to 68.2%;
- In line 5 (and in line 8), the Transmission costs allocated to industrial customers increase from $4 million to $24 million;
- In lines 6 and 7, this translates into an increase an almost 5-fold increase in the transmission unit rate, from $1.23/kW-month to $5.86/kW-month;
- Even though $19.7 million (68.2% of the increased revenue requirement) is paid by unregulated industrial customers (line 10), there remains some $8.8 million of increased revenue requirement to be paid by rural customers (line 11);
- The LIS Rural Revenue Requirement would increase from $20.5 million to $29.3 million (line 12);
- This represents an increase of approximately 43% over the 2015 Labrador rural revenue requirement of $20.5 million.

This analysis demonstrates that, if the LWTP is ever completed, and if its costs are allocated according to the methodology proposed in the Amended Application, it will result in a drastic revenue requirement increase for rural Labrador regulated consumers, despite the government assurance quoted above that: "The industrial rate policy will not affect Labrador residential and commercial rates." Based on the assumptions used here, the increase in the LIS revenue requirement would be 43%.

It should also be noted that the transmission charges for IOCC would almost quintuple, from $4.0 million per year, based on the annual rate of $14.77/kW, to $19.2 million, based on the new annual rate of $70.27/kW, an increase of $15.2 million/year. This amount accounts for 53% of the additional revenue requirements due to the LWTP, which represents IOCC's share of total LIS demand, after the addition of the Kami Mine.[110] Thus, paradoxically, because IOCC's load is

[110] This analysis does not take into account forecast changes in other Labrador loads.

so much greater than Alderon's, it would be forced to absorb a much larger share of the revenue requirement impact. As seen in Table 17, under the transmission rate methodology proposed by Hydro in the amended GRA, Alderon would pay only 16% of the additional revenue requirement caused by the LWTP.

Table 17. Annual capital cost related to LWTP, based on NLH proposed methodology

	Current	After commissioning	Additional amount paid	% of LWTP annual cost
Amount paid by IOCC ($)	4,041,651	19,227,525	15,185,874	53%
Amount paid by Alderon ($)		4,567,842	4,567,842	16%
Amount paid by rural customers ($)	2,336,469	11,115,388	8,778,919	31%
Total			28,532,635	100%

Given the magnitude of these rate impacts, it is important that the Board provide some indication as to how it intends to allocate the costs of the LWTP.

4.2.2.4. Methodologies used by other regulators in North America

To the best of my knowledge, the NLPUB has never had to address the issue of the allocation of costs resulting from transmission system expansion until now, as it has never had a distinct transmission tariff. However, many other regulators, most notably the Federal Energy Regulatory Commission (FERC) in the United States, have devoted considerable attention to this issue — precisely to avoid results like those shown in Table 16 and Table 17, where native load rates increase dramatically as a result of providing transmission service to a non-regulated entity.

While the frontier between federal and state jurisdiction in the U.S. with regard to electricity is complex, it is safe to say that FERC has jurisdiction over the wholesale electricity market, including transmission.[111] Under the legislative mandate to promote competitive power markets provided by the Energy Policy Act of 1993, FERC undertook a major revision of transmission

[111] "FERC regulates the transmission and wholesale sales of electricity in interstate commerce." http://www.ferc.gov/about/ferc-does.asp.

regulation, which eventually led to the issuance of Order 888 in 1996. Order 888 and its accompanying pro forma Open Access Transmission Tariff (OATT) were crafted so as to oblige transmission-owning utilities to let third parties use their transmission systems on the same terms as they do themselves. It is no exaggeration to say that Order 888 and its successors (especially Order 890 of 2010) were responsible for the creation of the competitive power market in the United States. In the process, they have become the standard for transmission regulation throughout North America.

While FERC has no jurisdiction in Canada, most large transmission-owning utilities in Canada have subsidiaries or affiliates for whom the right to transact freely in the United States is very important. Order 888 has reciprocity requirements, which essentially require any utility that makes use of an open access tariff to offer similar open access on its own transmission system. Furthermore, FERC's system for issuing power marketer authorization — necessary in order to transact freely in US power markets — also requires that the marketer's transmission-owning affiliates have open access transmission tariffs that meet or exceed that standards set, first, by Order 888, and now, by Order 890. As a result, most transmission-owning Canadian utilities have open access transmission tariffs that meet these standards.

For all these reasons, the transmission ratemaking policies established by FERC have become a widely accepted standard in North America. Situations like the one presented by the Labrador West Transmission Project, in which an expensive transmission upgrade is needed to provide service to a new industrial customer or other user of the transmission system, are common in other jurisdictions, and the regulatory mechanisms that are applied to them are well known.

As an isolated system, essentially disconnected from the Eastern Interconnection, Newfoundland and Labrador has had no need until now to address this question. It is likely, however, that, once the Maritime Link is in service, the need for an open access transmission tariff for NLH will come to the fore.

For all these reasons, it is useful to look at the way a project such as this would be handled under FERC transmission policies.

4.2.2.5. FERC policy for network upgrades

A concise summary of FERC policy regarding network upgrades was prepared last year by Judy W. Chang of the Brattle Group.[112] The relevant excerpt is attached to this testimony as Appendix A.

Ms. Chang explains that:

> The network upgrade policies in the U.S. center on <u>protecting existing transmission customers from excess costs induced by network upgrades associated with customers requesting transmission services</u>. (p. 4)

She adds:

> At the time of restructuring, FERC's primary policy objective was to ensure that transmission providers offered non-discriminatory open access to the transmission network, particularly for customers that were not traditional native load. However, since native load customers, prior to restructuring, had funded (and were going to continue to fund) the infrastructure that made the delivery of power to them possible, <u>FERC also wanted to ensure that existing transmission users would not be unduly harmed by costs imposed by customers requesting transmission service involving network upgrades that could increase the embedded costs of the system. Thus, FERC's initial "higher of" policy was designed to ensure that existing (and growing) native load was protected</u>, while the wholesale market developed, allowing new customers to interconnect to the existing transmission network that was predominantly funded by existing native load. In a policy statement in the mid-1990s, FERC stated that <u>one of the goals of its new pricing policy was "to hold native load customers harmless</u>."[5]

As noted above, the LWTP, required to provide service to Alderon's Kami Mine project, can be seen as a typical case of a network upgrade that results from a customer's transmission request. How would the costs of such an upgrade be treated under FERC's "higher of" network upgrade policy?

The essence of FERC's "higher of" policy is that the transmission provider will charge the customer requiring the upgrade the <u>higher of</u> the embedded cost or the incremental cost of the upgrade. Here, "embedded cost" simply refers to the rate that would result from treating the

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[112] The report was prepared on behalf of Hydro-Quebec and filed before the Quebec Energy Board, in support of an application to modify HQ's network upgrade policy. The details of that policy do not concern us here.

upgrade as a normal addition to the rate base — the "rolled in" approach. In this case, the embedded rate is the one illustrated in Table 16 — $5.86/kW-month.

The "incremental cost", on the other hand, refers to a transmission rate based on the cost of the upgrade, amortized over the life of the contract:

> Under the Commission's "higher of" pricing policy, when the requested transmission service requires network upgrades, <u>the transmission provider should calculate a monthly incremental cost transmission rate using the revenue requirement associated with the required upgrades</u> and compare this to the monthly embedded cost transmission rate, including the expansion costs. <u>This incremental rate should be established by amortizing the cost of the upgrades over the life of the contract.</u>[113]

If this cost is higher than the embedded cost — as it clearly is, in the case of LWTP — this amounts to charging the customer a rate that covers the cost of the upgrade, leaving the native load and other customers harmless.

In Table 18, we have calculated the incremental transmission rate for the LWTP using the same methodology presented in the amended GRA. The resut is that the customer requiring the addition — Alderon — would pay the full revenue requirement associated with the upgrade.

Table 18. Derivation of an incremental transmission rate for Alderon

LWTP Total Transmission Demand cost ($)	28,532,635
Alderon Kami Mine Demand (kW)	65,000
Transmission Demand Cost Allocated to Industrial Customers($)	28,532,635
Annual Cost ($/kW)	438.96
Monthly Rate ($/kW)	36.58
Amount paid by Alderon ($)	28,532,635

It should be noted that there are a number of other regulatory tools that could be used in such a case, including Direct (or Specific) Assignment. Another policy that is commonly applied in this

[113] FERC Order No. 890, February 16, 2007, paragraph 870, pp. 508-509, footnotes omitted.

type of situation is that of direct contribution, as applied for instance in the case of Muskrat Falls Corporation's contribution to the costs of providing power supply to its construction site.[114]

Generally, direct contribution is a more appropriate solution when either the anticipated use of the assets is relatively short (as is the case of MFC's construction power needs), or to mitigate risk that the requesting party will cease activities before the time period on which the rates were calculated have elapsed.

The most important difference between a tariff-based solution and direct contribution is the risk related to the company requiring the transmission service. In Quebec, for instance, when Hydro-Quebec Production requires the construction of a new transmission line to connect a new generating station to the grid, under Quebec's FERC-based open access transmission tariff, HQP can choose between the two methods: contribute the costs upfront, or pay them as an annual transmission fee for the life of the project. On a present value basis, the two methods yield the same result. There is an important difference, however, in the allocation of risk. Under the tariff option, should the dam cease production for whatever reason, it is the other users of the transmission system (primarily Quebec's native load) that would have to support the capital costs of the line. For that reason, direct contribution is generally preferable to the tariff option.

In the same way, under the tariff option, it is the other users of the Labrador transmission system that bear the risk that Kami will cease production prematurely, for whatever reason.

However, specific assignment or requiring a direct contribution may be incompatible with the requirement in OC2014-034 that "the Board shall include such costs in Newfoundland and Labrador Hydro's rate base for recovery in Newfoundland and Labrador Hydro's rates." The Order in Council may thus close the door to all regulatory solutions other than the tariff-based on presented in Table 18, in which an incremental rate is charge to the customer requiring the upgrade. This approach does indeed include the project's costs for recovery in Hydro's rate base, and relies upon the Board's discretion with regard to cost allocation.

[114] "In the 2013 Test Year, the costs for Muskrat Falls Construction Power (MFCP) assets were assumed to be fully funded by LCP and ownership would be transferred to Hydro." IN-NLH-254.

Obviously, the financial implications of this regulatory decision are great for Alderon, as well as for IOCC and other consumers in Labrador. If the Board retains the methodology proposed by Hydro as illustrated in Table 17 (together with the assumptions used therein), the annual transmission cost to Alderon would be $4.56 million, whereas, under the incremental rate approach illustrated in Table 18, the first-year transmission cost to Alderon would be over $28 million – or more, if the rate is calculated taking into account the expected 30-year life of the Kami Mine. A difference this large could clearly be material in the business decisions before Alderon – and for that matter, IOCC – so it is, again, important that this policy question be clarified in advance.

4.2.2.6. Regulatory treatment in the event of abandonment

As noted earlier, it is not clear how much money NLH has spent on the LWTP prior to suspension. The table in IN-NLH-249, Att. 1, reproduced above in Table 9, suggests that some $37.5 million was spent in 2014, and that some portion of the $163 million scheduled to be spent in 2015 may have been disbursed prior to suspension.

Normally, development costs do not affect rates until such time as a project is commissioned, based on the traditional “used and useful” criterion. In the event of cancellation, however, NLH could seek to recover the monies spent in rates. Given the unique nature of this project — authorized by Hydro’s shareholder for the benefit of a non-regulated customer, without input from the Board — such recovery would be unjustified. Rather, the shareholder should bear the consequences of its decision to authorize construction of the project before the customer had confirmed its financing.

5. NATUASHISH

In IN-NLH-069, Hydro described the services it provides to remote communities (other than Natuashish). These services include:

- Operation and Work Execution,
- Short-Term Planning and Work Scheduling,
- Long-Term Asset Planning,
- Support Services,
- Customer Services,
- Project Execution and Technical Service,
- System Planning,
- Human Resources, and
- Inventory Control and Purchasing.

Hydro acknowledges in the response that it does not provide most of these services to consumers in Natuashish. Rather, the utility's main function in Natuashish is "to operate and maintain the diesel plant and distribution facilities on behalf of Mushuau Innu First Nation (MIFN) on a full cost recovery basis."[115] According to its RFI responses, Hydro does provide the following services in Natuashish:

- Long-Term Asset Planning Services, comprising "providing advice to MIFN as to the optimum maintenance and capital works required for the sustained reliable and efficient operation of the assets in the diesel plant;"[116]
- Meter reading;[117]
- Project Execution and Technical services;[118]
- System Planning services, comprising "load forecasting and planning of generation and distribution facilities required to address the forecast growth in power and energy requirements";[119]

115 IN-NLH-069.
116 IN-NLH-322.
117 IN-NLH-324.
118 IN-NLH-325.
119 IN-NLH-326.

- Operational support and recommendations to MIFN on system design capability and other technical matters;[120]
- Inventory control with respect to equipment, spare parts, consumables and lubricants, but not with respect to fuel.[121]

However, in a letter to Mr. Eric Coombs from Mr. Phil Clarke, on behalf of PwC LLP, Co-Manager for the MIFN dated June 17, 2015, provides a different picture of the services provided to MIFN by Hydro. According to Mr. Clarke, Hydro does not provide any reporting to MIFN concerning the following services:

- Long-term asset planning (para. 7);
- System planning (para. 8);
- Load forecasting (para. 9); or
- Planning with respect to fuel delivery or storage (para. 15).

Mr. Clarke also states that, to the best of his knowledge:

- Hydro does not consult with MIFN or the residents of Natuashish with regard to load growth (para. 10);
- Hydro does not report to MIFN with regard to cost control activities (para. 17);
- Meters are not read systematically, and Hydro does not provide MIFN with meter reading data (para. 19);
- Neither Hydro nor any other body or agency provides any conservation or demand management services in Natuashish (para. 20).

This raises important concerns regarding the management and maintenance of the Natuashish electric system with respect to meeting electric requirements safely, reliably and at least cost.

While maintaining adequate generation capacity is a key element of providing safe and reliable electric service, maintaining an adequate fuel supply is essential as well. According to Mr. Clarke's letter, maintenance and operation of the fuel supply system are carried out by MIFN

[120] Ibid.
[121] IN-NLH-328.

(para. 11), and Hydro does not participate in any planning with respect to fuel delivery or storage (para. 15).

According to Mr. Clarke, fuel can only be delivered between late June and late October or early November. He states that, in 2014, fuel rationing was required because the existing fuel storage capacity was inadequate to support all winter needs (para. 12). While this did not affect electricity generation, rationing of other uses of fuel, including home heating and heavy equipment, was required (para. 13).

According to Mr. Clarke:

> MIFN does not have the capacity to determine how this storage capacity shortage will evolve in the coming years, nor to predict whether or not there will be enough fuel to provide electric service throughout the winter without rationing. (para. 14)

Obviously, such planning would require a forecast of electric load growth in Natuashish. As mentioned earlier, Hydro has stated that:

> Hydro's staff, primarily based in its head office, provides System Planning services to MIFN. These System Planning services comprise load forecasting and planning of generation and distribution facilities required to address the forecast growth in power and energy requirements. This group also provides operational support and recommendations to MIFN on system design capability and other technical matters.[122]

However, in another response, it stated:

> Please note that Hydro does not prepare individual load forecasts for the communities requested [including Natuashish].[123]

Hydro does, however, prepare individual load forecasts for the other isolated communities Labrador.[124]

The *Electrical Power Control Act* specifies, in section 3, that:

> **3.** It is declared to be the policy of the province that …

[122] IN-NLH-326.
[123] IN-NLH-232.
[124] IN-NLH-061, rev. 1.

> (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,
> >
> > (ii) that would result in consumers in the province having equitable access to an adequate supply of power,
> >
> > (iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service,

Arguably, “equitable access to an adequate supply of power” and “reliable service” require an adequate fuel supply. In would then appear that the existing institutional structure, in which no entity with the capacity to forecast fuel storage needs has any responsibility to ensure that such capacity is available, is incompatible with the policy enunciated in the *EPCA.*

It should also be noted that, according to the testimony of Eric Coombs:

> MIFN has limited financial capacity and is presently incapable of managing its own financial affairs. Where these circumstances exist, AANDC can, as a condition of their funding arrangements, require the Band to engage the services of an outside financial manager. As a result, MIFN have been in "co-management" for approximately 12 years….
>
> The current co-manager is PricewaterhouseCoopers LLP (PWC) in Halifax, N.S. who have been in place for five years. The majority of the accounting records of MIFN are maintained in Halifax, N.S. including the journals, general ledger and supporting documentation.
>
> The accounting for the electrification costs and revenues is handled predominately by PWC. This would include ordering fuel, analyzing the consumption of fuel, submitting claims to AANDC and issuing invoices to third party users of fuel purchases and electrical consumption.

Thus, it appears that PWC is the *de facto* manager of the Natuashish electric system, on behalf of MIFN. That said, it seems clear from the testimony of Mr. Coombs and Mr. Clarke that PWC’s role is limited to financial management, and that several functions performed by Hydro for the other isolated communities in Labrador are simply not carried out in Natuashish.

Another important policy instrument of the NL government concerning Labrador is the Northern Strategic Plan, announced in 2007. Among many other initiatives, the NSP promised to provide:

> $1.6 million annual electricity rebate for home owners using diesel generated power in rural isolated communities along the Labrador coast[125]

The government Backgrounder explained the NSP electric subsidy as follows:

> $1.6 million annually for an energy rebate to address one of the most pressing issues for rural isolated communities in Labrador. The rebate will reduce the cost of basic electricity consumption needs of Labrador rural isolated residential customers to a level on par with the Labrador Interconnected Rates. Customers in the Labrador Straits area will receive a similar rebate to achieve the same goal.[126]

And the formal publication described it in these terms:

> **Objectives**
>
> 1. Ensure the unique challenges that Labrador's communities face are reflected when implementing new or existing programming. …
>
> iv) Introduce an energy rebate to reduce the cost of basic electricity consumption needs (on the Lifeline Block) for residential customers in Labrador's rural isolated communities and the Labrador Straits to a level on par with the Labrador Interconnected Rates[127]

Under the present institutional structure, residents of Natuashish are not eligible for the NSP energy rebate for the Lifeline Block.

Hydro's testimony appears to suggest that, in its view, it has no obligation to provide electric service in Natuashish because that community is a First Nation reserve under Federal jurisdiction.[128] Hydro has stated, however, that:

> … <u>were it to become the owner and operator of the electrical system in Natuashish</u> and collect rates from the individual customers for the service it provides, it would be required to

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[125] News release, April 20, 2007.

[126] BACKGROUNDER: Northern Strategic Plan for Labrador - New Initiatives, http://www.releases.gov.nl.ca/releases/2007/exec/0420n04bk1.htm.

[127] Government of Newfoundland and Labrador. The future of our land. A future for our children. A Northern Strategic Plan for Labrador, p. 40.

[128] In-NLH-278 and IN-NLH-317, rev. 1. Hydro does provide electric services to residents and businesses in the First Nation reserves of Sheshatshiu and Samiajij Miawpukek (Conne River).

> provide service under the approved rates and rules as set by the Board under Section 70 and other applicable sections of the *Public Utilities Act.*[129]

While that is no doubt true, it is not clear why Hydro would have to own the electrical system in Natuashish in order for it to provide electric service there.

Hydro has identified a number of situations in which it used transmission and distribution assets owned by third parties to supply electricity to its customers. These include assets owned by Corner Brook Pulp and Paper (CBPP), NP and Twin Falls Power Corp.[130]

Similarly, Hydro does not own all of the generating stations supplying its customers, as it purchases electricity produced at several generating stations owned by third parties. These include Churchill Falls (Labrador) Corp. (CF(L)Co), CBPP, Star Lake, Corner Brook Cogen, Exploits River Project, St. Lawrence Wind, Fermeuse Wind and others.[131]

Thus, Hydro could provide service to Natuashish customers by purchasing electricity from the owner of the Natuashish diesel plant and by leasing the existing distribution infrastructure.

In response to an RFI from the Innu Nation, Hydro indicated the conditions under which it has discretion to refuse to provide service or to connect electric service within its service area.[132] However, it subsequently indicated that the term "service area" is not defined in the *Public Utilities Act* or its regulations.[133] The response appears to suggest that Natuashish is not part of Hydro's service area because "the residents and businesses in that community are not Hydro's customers."[134] The circularity of the argument is self-evident.

NLH concludes the response by indicating:

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[129] IN-NLH-208.
[130] IN-NLH-216.
[131] Regulated Activities, Schedule VI.
[132] IN-NLH-124.
[133] IN-NLH-194, p. 1.
[134] Ibid., lines 18-19.

> It could be argued that a customer who is in close proximity to a utility that owns distribution or transmission plant of a suitable nature is within that utility's service territory or service area.

However, we have seen above that ownership is not of itself a determining factor. In the absence of any transfer of ownership of either the diesel plant or the distribution infrastructure, NLH could still provide electric service to residential, commercial and institutional customers in Natuashish, by purchasing power from the owner of the diesel plant and leasing the use of the distribution assets.

How are the relationships between off-grid First Nation reserves and Crown utilities elsewhere in Canada? To provide some insight into this question, my colleague Mr. Rick Hendriks has prepared a summary of the activities of Hydro One Remote Communities Inc. ("Remotes"), which is responsible for providing electric service in the remote communities of northern Ontario. This review is attached as Appendix B.

The relevant findings of this report can be summarized as follows:

- Remotes is a subsidiary of Hydro One Inc. It operates diesel generating stations and carries out distribution in 21 isolated communities, 15 of which are First Nation reserves. It owns the generating stations in most but not all of these communities.
- Remotes is 100% debt financed, operates as a break-even business, and is licensed by the Ontario Energy Board ("OEB").
- Remotes generally has Electrification Agreements with AANDC whereby Remotes funds operation and maintenance in First Nation communities and AANDC funds capital upgrades and system expansions.
- Rates for residential and general service customers, including in First Nations, are subsidized by the Rural and Remote Rate Protection program, funded by a surcharge set by the OEB, which applies to all grid-connected customers.
- Remotes carries out oversight planning functions for each remote community, including:
    - Tracking energy usage by customer class and time period,
    - Preparing usage (load) forecasts and fuel forecasts,
    - Tracks service quality indicators (connection, interruption data, SAIFI, SAIDI and CAIDI),

Remotes also:

- carries out customer demand management (CDM) programs in the remote communities, including:

- deploying energy efficient appliances, including a partnership with Northern stores to offer Energy Star appliances,
- focussing on electricity conservation in Band-operated facilities such as Band offices, arenas and water and sewage plants,
- hiring, training and developing local expertise,

  - has introduced a competitive tender process for contracting fuel supply and delivery,
  - has introduced renewable generation in some communities and offers PPAs based on the avoided cost of diesel fuel, for First Nation renewable projects.

While in most Ontario First Nations, ownership of the generation and distribution assets were transferred to Remotes as part of the Electrification Agreements, there is one important exception: the Marten Falls First Nation.

> In 2009, Remotes applied to the OEB and was subsequently approved for an amendment to its licence to include the community of Marten Falls within its service territory. Prior to that time, Marten Falls First Nation had owned and operated its system as an independent community electrical system. Under the terms of the Electrification Agreement between Marten Falls First Nation, Remotes and AANDC, the First Nation retained ownership of the existing generation and distribution assets.[135]

While the Marten Falls case is unusual, it demonstrates that utility ownership of generation and distribution assets is not necessarily a precondition for utility service in a remote First Nations community under the supervision of a provincial public utilities board.

Under a typical electrification agreement, the capital costs of system upgrades due to load growth would be paid by AANDC. However, for the period 2011-17, AANDC has provided no funding for generation upgrades in its capital plan, due to funding constraints.[136] During that period, system upgrades were required in several of Remotes' communities. Lacking these financial contributions, Remotes was unable to connect new customers in those communities where generation had reached its limits. Due to the delays to planned upgrades, Remotes' capital

[135] Hendriks, Electricity Generation and Distribution Services: Remote Communities in Ontario, p. 7.

[136] Hendriks, p. 6.

and maintenance work programs had to be increased in order to meet safety, environmental and reliability standards.

In Quebec, Hydro-Quebec serves 30 remote communities. Two of these (Opteciwan, also known as Obedjiwan, and La Romaine) are First Nation reserves.[137] Most of the others are Inuit communities, administered under the provisions of the James Bay and Northern Quebec Agreement. The largest of these remote communities is the French-speaking community of Îles-de-la-Madéleine.

To the best of my knowledge, no distinction is made based on the reserve status, or lack thereof, in the administration of these remote systems. System planning and cost information for each is presented in the triennial supply plan hearing before the Quebec Energy Board (the Régie de l'énergie).[138] As in other provinces, rates in these remote communities do not fully cover their costs. The shortfall is made up by electric rates in the rest of the province.

As we have seen above, managing a diesel electrical system in order to ensure its capacity to reliably provide service now and in the future requires substantial planning and oversight. MIFN clearly does not have the technical capacity to perform these functions, and, at the present time, it appears that no one else is taking responsibility for these activities. As a result, the EPCA objectives mentioned above are clearly not being met.

Under the circumstances, it is clear that Hydro is the only entity with the capacity to perform these functions. For it do so, it would have to include Natuashish within its service territory, and accept the residents and businesses of that community as its customers. There are many different possible arrangements under which this could occur, any one of which would be superior to the status quo.

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[137] There is also a small francophone community served by the La Romaine diesel generating station, but this is not the case in Opteciwan.

[138] http://publicsde.regie-energie.qc.ca/projets/12/DocPrj/R-3748-2010-B-0006-DEMANDE-PIECE-2010_11_09.pdf

6. LABRADOR ISOLATED RATES

The amended GRA proposes a rate increase of 7.1% for the non-lifeline portion of residential customers and of 19% for General Service customers in the Labrador Isolated systems.[139] Bills for customers in the Labrador Isolated systems are forecast to increase by 11.4%, taking into account the impact of the proposed rate changes for the LIS on the Northern Strategic Plan (NSP) Rebate.[140] Should the residents and businesses of Natuashish become customers of Hydro, they would also be affected by these changes.

The NSP subsidizes rates in the Labrador Isolated Systems (and on the L'Anse au Loup System) to the level of Labrador Interconnected rates for the Lifeline Block of 700-1000 kWh/month). Without this subsidy, they would pay the same rates as NP customers, which are much higher.[141]

It is important to realize that, should the Board approve an allocation of the rural deficit that resembles Hydro's original proposal, rather than the amended proposal, the operation of the NSP subsidy would result in substantial impacts on the Labrador Isolated System as well. The large increase for the Labrador Interconnected System that would flow from such an allocation would mean that the amount of the provincial NSP subsidy for the Labrador Isolated Systems would be very much lower.

Table 22 shows the rate impact on the Labrador Isolated Systems, net of the NSP, under the Amended GRA. [142] It shows that, while the rate increase is only 2.80%, the net effect on customers, taking into account the effects of the NSP, is four times as great (11.38%).

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139 Amended GRA, p. 4.41.

140 PUB-NLH-107, rev. 1.

141 IN-NLH-137, rev. 1. Current Labrador Isolated rates are found at IN-NLH-059, rev. 1.

142 PUB-NLH-107, Att. 1, rev. 1.

Table 19. LIS rate impact, net of the NSP (amended GRA)

		Amended GRA
	REVENUES	
1	Revenues at existing rates, effective July 1, 2014	2,840,160
2	15% deferred rate Increase [1]	**4.20%**
3 **=ln1*(1+ln2)**	Revenues at existing rates including 15% deferred rate increase	2,959,447
4	Proposed GRA rate increase	**2.80%**
5 **=ln3*(1+ln4)**	Revenue at proposed rates	3,042,311
	Change in Revenue	
6 **=ln1**	Revenues at existing rates, effective July 1, 2014	2,840,160
7 **=ln5**	Revenue at proposed Rates	3,042,311
8 **=ln7-ln6**	Change in revenue	202,151
9 **=ln8/ln6**	Percentage change in revenue	**7.12%**
	Including Rebates - Charge to Customers	
10 **=ln1**	Revenue at existing Rates	2,840,160
11 **=Pg2 ln9**	Rebate at existing rates	1,484,593
12 **=ln10-ln11**	Charge to customers	1,355,567
13 **=ln5**	Revenue at proposed rates	3,042,311
14 **=Pg2 ln9**	Rebate at proposed rates	1,532,483
15 **=ln13-ln14**	Charge to customers	1,509,828
16 **=ln15-ln12**	Change in charge to customers	154,261
17 **=ln16/ln12**	Percentage change in charge to customers	11.38%

Because the NSP brings rates for the Lifeline Block in the Labrador Isolated Systems to the level of Labrador Interconnected rates, any increase in the Labrador Interconnected rates will affect the level of that subsidy. In the event that the Board rejects Hydro's proposal to modify the allocation of the rural deficit, Labrador Interconnected rates will be substantially higher. What effect would that have on Labrador Isolated rates?

In order to quantify this effect, we first need to determine the effect of such a change on the NSP rebates (customer charge and energy for the lifeline block). If the Labrador Interconnected rate were to be the same as that proposed in the original GRA, those rebates would change from the ones shown in lines 3 and 4 of Table 20 to the ones shown in lines 5 and 6.

Table 20. NSP rebate calculation (amended GRA with LIS increase from original GRA)

	EXISTING REBATES	**Island**	**Labrador**	
		Interconnected	**Interconnected**	
	Billing Determinant	**Existing Rates**	**Existing Rates**	**Rebate**
1	Basic Customer Charge ($/bill)	15.68	7.15	8.53
2	Energy ($/kWh)	0.11178	0.0328	0.07898
	AMENDED GRA	**Island**	**Labrador**	
		Interconnected	**Interconnected**	
	Billing Determinant	**Proposed Rates**	**Proposed Rates**	**Rebate**
3	Basic Customer Charge ($/bill)	16.12	7.29	8.83
4	Energy ($/kWh)	0.1149	0.03341	0.08149
	Amended GRA, with LIS increase from original GRA			
5	Basic Customer Charge ($/bill)	16.12	9.02	7.1
6	Energy ($/kWh)	0.1149	0.04131	0.07359

Thus, the customer charge rebate would decline by about 20% (from $8.83 to $7.10 per month), and the lifeline block energy charge by 10% (from $0.081 to $0.074/kWh).

Using these values, we can calculate the impact on the total amount rebated, as seen in Table 21.

Table 21. NSP total rebates in LIS (amended GRA with LIS increase from original GRA)

			Rebates, Existing	**Rebates, Proposed (AMENDED GRA)**	**Rebates, Proposed (Amended GRA, with LIS increase from original GRA)**
		Billing Determinant			
1		Basic Customer Charge ($/bill)	8.53	8.83	7.1
2		Energy ($/kWh)	0.07898	0.08149	0.07359
3		Number of Bills	24,528	24,528	24,528
4	**line 1 * line 3**	Subtotal	$209,224	$216,582	$174,149
5		kWh's Rebated	16,148,000	16,148,000	16,148,000
6	**line 2 * line 5**	Subtotal	$1,275,369	$1,315,901	$1,188,331
7	**line 4 + line 6**	**Total**	$1,484,593	$1,532,483	$1,362,480

Substituting these values for the Rebate at Proposed Rates (line 14 of Table 19) yields the results seen in Table 22.

Table 22. LIS rate impact, net of the NSP (with LIS increase from original GRA)

			Amended GRA	Amended GRA, with LIS increase from original GRA
		REVENUES		
1		Revenues at existing rates, effective July 1, 2014	2,840,160	2,840,160
2		15% deferred rate Increase [1]	**4.20%**	**4.20%**
3	**=ln1*(1+ln2)**	Revenues at existing rates including 15% deferred rate increase	2,959,447	2,959,447
4		Proposed GRA rate increase	**2.80%**	**2.80%**
5	**=ln3*(1+ln4)**	Revenue at proposed rates	3,042,311	3,042,311
		Change in Revenue		
6	**=ln1**	Revenues at existing rates, effective July 1, 2014	2,840,160	2,840,160
7	**=ln5**	Revenue at proposed Rates	3,042,311	3,042,311
8	**=ln7-ln6**	Change in revenue	202,151	202,151
9	**=ln8/ln6**	Percentage change in revenue	**7.12%**	**7.12%**
		Including Rebates - Charge to Customers		
10	**=ln1**	Revenue at existing Rates	2,840,160	2,840,160
11	**=Pg2 ln9**	Rebate at existing rates	1,484,593	1,484,593
12	**=ln10-ln11**	Charge to customers	1,355,567	1,355,567
13	**=ln5**	Revenue at proposed rates	3,042,311	3,042,311
14	**=Pg2 ln9**	Rebate at proposed rates	1,532,483	1,362,480
15	**=ln13-ln14**	Charge to customers	1,509,828	1,679,831
16	**=ln15-ln12**	Change in charge to customers	154,261	324,264
17	**=ln16/ln12**	Percentage change in charge to customers	11.38%	23.92%

Thus, the decrease in the total NSP subsidy amount from $1,532,483 to $1,362,480, due to the increase in the Labrador Interconnected rates, results in **doubling** the after-subsidy rate impact on consumers in the Labrador Isolated System, from 11.38% to 23.92%.

Thus, should the proposed revision of the rural deficit allocation methodology be refused, the actual rate impact for customers Labrador Isolated System of the 2.80% increase proposed in the Amended GRA would double, from 11.38% to 23.92%.

It is important to note that, under this scenario, the dramatic increase in Labrador Isolated Systems bills would not in fact contribute to meeting Hydro’s revenue requirement, but would instead accrue to the provincial government, which would see the cost of the NSP subsidy decrease substantially.

It should be noted that the Order-in-Council OC2007-304, which created the NSP subsidy, refers to the costs paid by residential consumers in Happy Valley – Goose Bay.[143] Thus, should the outcome of this hearing result in different rates for residential consumers in Lab West and in Lab East, it is the rates in HVGB (Labrador East) that would determine the level of provincial subsidy to the Labrador Isolated systems.

7. INTEGRATED RESOURCE PLANNING

As far back as 1993, it was suggested that the magnitude of the DSM effort should be determined based on least-cost planning principles, in order to minimize the cost of service.

> [W]hile the well-known California tests are useful for sifting DSM possibilities, I am firmly convinced that they do not provide a satisfactory criterion for the size and content of the overall DSM effort. <u>In my opinion, DSM should be part of least-cost planning.</u> The overall DSM package should be such that it minimizes the present worth of subsidy required through the planning period. The suggested criterion is strictly in line with Hydro's objective to minimize the degree of cross-subsidization required. The California tests are not. They can be, and have been, applied in such a way as to increase the utility's cost of service.[144]

Twenty years later, no such process has yet been put in place.

In its last two orders resulting from NLH GRAs, the Board has addressed the possibility of requiring NLH to carry out Integrated Resource Planning (IRP). In P.U. 14 (2004), it:

> confirmed that it has the authority and responsibility to ensure that adequate planning occurs for the production, transmission and distribution of least cost power in the Province, pursuant to sections 3, 4 and 6 of the *EPCA*. In addressing the question of whether Hydro should be required to undertake an integrated resource planning exercise, the Board noted (pg. 149):
>
>> "…implementation of Integrated Resource Planning may present sound opportunities for coordinated planning and improved regulation involving both utilities. This process brings together strategic planning, future supply and demand, least cost analysis, demand side management options and environmental considerations."

143 OC2007-304, IN-123, Att. 4.

144 G. C. Baker, IN-PUB-01, Att. 1, p. 22.

> The Board concluded, however, that more detailed information was required before the Board can move forward with an IRP, including a marginal cost study.[145]

Three years later, however, in P.U. 8 (2007), the Board stated that:

> The Board is not prepared to proceed with an IRP exercise <u>given the pending release of the [2007] Energy Plan</u> and completion of the various rate design reviews and conservation and demand management studies currently underway. In the Board's view the province's future policy direction respecting energy supply will be a key ingredient in formulating an IRP. As well these various studies/reviews would also comprise important inputs needed to stimulate informed discussion and debate contributing to a comprehensive IRP acceptable to all stakeholders.

As more than six years have passed since the 2007 Energy Plan was released, there is no apparent reason why the Board should not again pick up the process envisioned earlier for the implementation of IRP.

NLH has indicated that:

> At this time, Hydro does not intend to implement Integrated Resource Planning, unless requested to do so by the Board.[146]

It has also indicated that the Board never convened the "meeting of stakeholders including Hydro and the parties to this proceeding to discuss the scope of an IRP Process", as mentioned in P.U. 8.[147]

It seems clear that, had an IRP process been undertaken earlier, the important decisions of the last few years could have been taken in a more orderly and reflective manner. Similarly, there will undoubtedly be additional system planning decisions to be made in the coming years, which would benefit from the careful analysis that an IRP process entails.

I would therefore encourage the Board to request that NLH initiate an IRP process, and to consult with stakeholders with regard to nature of that process.

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[145] Quoted in P.U. 8 (2007), pp. 59-60.

[146] IN-NLH-152.

[147] IN-NLH-230.

8. CONCLUSIONS AND RECOMMENDATIONS

8.1. Labrador Interconnected Rates

8.1.1. Rural deficit

In the Amended GRA, Hydro has substantially changed its proposed approach for allocating the rural deficit.

The Labrador Interconnected System (LIS) revenue requirement has increased by 32% since 2007, but the proposed rate increase is only 2.1%. However, were the rural deficit allocation from the original GRA to be applied, the average LIS rate increase would be over 24%.

The methodology for allocating the cost of the rural deficit has not been changed since it was first established in 1993. Use of this methodology leads to results that are clearly inequitable. Since 1993, the cost of the rural deficit per customer in Labrador has increased by a factor of 4.5:1, whereas that for Newfoundland Power customers has only increase by a factor of 2.2:1.[148]

In the Amended GRA, Hydro recommends the use of the revenue requirement method, which ensure the same revenue:cost ratio for Labrador Interconnected customers as for NP. I support this recommendation.

8.1.2. Return on rate base

In the Amended GRA, the return on rate base for the Labrador Interconnected System has increase by 81% compared to 2007. The lion's share of this increase is due to the commissioning of the Labrador City Distribution Upgrade, with a total cost of over $40 million.

Looking forward, the Labrador West Transmission Project, is ever completed, will have very dramatic impact on LIS revenue requirement in years ahead.

148 As seen in Fig. 9, above.

8.1.2.1. Labrador City Distribution Upgrade costs

The Labrador City Distribution Upgrade provides no benefits to consumers in Labrador East. While distribution costs are usually "socialized" within a COS study area, regulators have many tools at their disposal to ensure that results are equitable and respect the principle of cost causation.

Given the magnitude of these costs, the fact that the benefits of the project are unambiguously limited to Labrador West and that socio-economic conditions in that region are substantially superior to those in Labrador East, which will derive no benefit from the project, I recommend that the Board consider assigning those costs to Labrador West. Of the various regulatory mechanisms available, a rate rider appears to be the simplest to apply.

8.1.2.2. Labrador West Transmission Project

The Labrador West Transmission Project (LWTP) consists of a 220 km 230-kV line, apparently meant to supply new non-regulated sales. NLH is exempt from NLPUB jurisdiction "for all planning, design, construction and contribution activities pertaining to the Labrador West Transmission Project".

Work on the LWTP has been suspended, and it is unclear how much has already been spent on it. If and when it is completed, and assuming that the transmission rate methodology proposed in the Amended GRA is applied to it, the revenue requirement impacts for the LIS would be enormous. Applying Hydro's proposed methodology to the LWTP would result in more than doubling the LIS revenue requirement in the second year after commissioning.

This analysis demonstrates the extraordinary scale of this investment, in relation to the LIS revenue requirement. The situation is complicated by the fact that, as we shall see below, the need for this project is driven by unregulated power sales.

While work on this line has been suspended, it has not been cancelled. Given that its fate will most likely be decided before the next General Rate Application, it is appropriate to consider it at this time.

Applying the methodology described above to the isolated costs of the LWTP demonstrates that it would result in a revenue requirement of $28.5 million for the second year after commissioning. The implications for the Labrador Industrial Transmission Rate, according to the methodology set out in Table 4.14 of the Amended GRA, is seen in Table 18.

This analysis demonstrates that, if the LWTP is ever completed, and if its costs are allocated according to the methodology proposed in the Amended Application, it will result in a drastic revenue requirement increase for rural Labrador regulated consumers, despite the government assurance quoted above that: "The industrial rate policy will not affect Labrador residential and commercial rates." Based on the assumptions used here, the increase in the LIS revenue requirement would be 43%. At the same time, IOCC's transmission charges would almost quintuple, from $4.0 million per year to $19.2 million.

Given the magnitude of these rate impacts, it is important that the Board provide some indication as to how it intends to allocate the costs of the LWTP.

The transmission rate policies of the US Federal Energy Regulatory Commission (FERC) are the *de facto* standard in North America. FERC policy regarding network upgrades, developed over many years, is based on the principle that the transmission provider should charge the customer requiring the upgrade the "higher of" the embedded cost or the incremental cost of the upgrade. In this case, the incremental rate would come to $438.96/kW-yr, meaning that Alderon would pay all of the LWTP revenue requirement, leaving the native load and other customers harmless.

Another important question is the treatment of the costs incurred to date in the event that the project is abandoned. Normally, development costs do not affect rates until such time as a project is commissioned, based on the traditional "used and useful" criterion. In the event of cancellation, however, NLH could seek to recover the monies spent in rates. Given the unique nature of this project — authorized by Hydro's shareholder for the benefit of a non-regulated customer, without input from the Board — such recovery would be unjustified. Rather, the shareholder should bear the consequences of its decision to authorize construction of the project before the customer had confirmed its financing.

8.2. Natuashish

At the present time, Hydro does not provide or offer electric service consumers in Natuashish. Instead, it simply operates and maintains the diesel plant and distribution facilities on behalf of Mushuau Innu First Nation (MIFN) on a full cost recovery basis.

Managing a diesel electrical system in order to ensure its capacity to reliably provide service now and in the future requires substantial planning and oversight. MIFN clearly does not have the technical capacity to perform these functions, and, at the present time, it appears that no one else is taking responsibility for these activities.

Under the circumstances, it is clear that Hydro is the only entity with the capacity to do so. Without them, it is not clear how, under these circumstances, safe, reliable and least-cost electric service in that community can be maintained. For this to occur, Hydro would have to include Natuashish within its service territory, and accept the residents and businesses of that community as its customers. There are many different possible arrangements under which this could occur, any one of which would be superior to the status quo.

8.3. Labrador Isolated Rates

The amended GRA proposes a rate increase of 7.1% for the non-lifeline portion of residential customers and of 19% for General Service customers in the Labrador Isolated systems.[149] Bills for customers in the Labrador Isolated systems are forecast to increase by 11.4%, taking into account the impact of the proposed rate changes for the LIS on the Northern Strategic Plan (NSP) Rebate.[150] Should the residents and businesses of Natuashish become customers of Hydro, they would also be affected by these changes.

It is important to realize that, should the Board approve an allocation of the rural deficit that resembles Hydro's original proposal, rather than the amended proposal, the operation of the NSP

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[149] Amended GRA, p. 4.41.

[150] PUB-NLH-107, rev. 1.

subsidy would result in substantial impacts on the Labrador Isolated System as well. The large increase for the Labrador Interconnected System that would flow from such an allocation would mean that the amount of the provincial NSP subsidy for the Labrador Isolated Systems would be very much lower.

As a result, the total NSP subsidy amount would decrease from $1,532,483 to $1,362,480. This would result in doubling the after-subsidy rate impact on consumers in the Labrador Isolated System, from 11.38% to 23.92%.

Thus, should the proposed revision of the rural deficit allocation methodology be refused, the actual rate impact for customers Labrador Isolated System of the 2.80% increase proposed in the Amended GRA would double, from 11.38% to 23.92%.

It is important to note that, under this scenario, the dramatic increase in Labrador Isolated Systems bills would not in fact contribute to meeting Hydro's revenue requirement, but would instead accrue to the provincial government, which would see the cost of the NSP subsidy decrease substantially.

8.4. Integrated Resource Planning

In its last two orders resulting from NLH GRAs, the Board has addressed the possibility of requiring NLH to carry out Integrated Resource Planning (IRP). In 2007, however, it declined to proceed with such a process, due to the then-imminent release of the government's energy plan.

As more than six years have passed since the 2007 Energy Plan was released, there is no apparent reason why the Board should not again pick up the process envisioned earlier for the implementation of IRP. Hydro has indicated that it does not intend to implement Integrated Resource Planning, unless requested to do so by the Board.

It seems clear that, had an IRP process been undertaken earlier, the important decisions of the last few years could have been taken in a more orderly and reflective manner. Similarly, there will undoubtedly be additional system planning decisions to be made in the coming years, which would benefit from the careful analysis that an IRP process entails.

I therefore encourage the Board to request that NLH initiate an IRP process, and to consult with stakeholders with regard to nature of that process.

QUALIFICATIONS

Cofounder of the Helios Centre, Philip Raphals has extensive experience in many aspects of sustainable energy policy, including least-cost energy planning, utility regulation (including transmission ratemaking) and green power certification. He is the author of numerous studies and reports and frequently appears as an expert witness in the regulatory arena.

From 1992 to 1994, Mr. Raphals was Assistant Scientific Coordinator for the Support Office of the Environmental Assessment of the Great Whale hydro project, where he coauthored a study on the role of integrated resource planning in assessing the project's justification.[151]

In 1997, he advised the Standing Committee on the Economy and Labour of the Quebec National Assembly in its oversight hearings concerning Hydro-Quebec. In 2001, he authored a major study on the implications of electricity market restructuring for hydropower developments, entitled *Restructured Rivers: Hydropower in the Era of Competitive Energy Markets*. In 2005, he advised the Federal Review Commission studying the Eastmain 1A/Rupert Diversion hydro project with respect to project justification. Later, he drafted a submission to this same panel on behalf of the affected Cree communities of Nemaska, Waskaganish and Chisasibi.

Mr. Raphals appeared as an expert witness on behalf of Grand Riverkeeper Labrador Inc. in the hearings of the Joint Review Panel (JRP) on the Lower Churchill Generation Project, which retained many of his suggestions. He also presented testimony to the Newfoundland and Labrador Public Utilities Board in the context of its advisory hearings concerning the Muskrat Falls project.

Last year, he presented expert testimony to the Nova Scotia Utility and Review Board in the proceedings concerning the Maritime Link, on behalf of the Canadian Wind Energy Association and, for the compliance phase, the Low Power Rates Alliance.

[151] J. Litchfield, L. Hemmingway, and P. Raphals. 1994. *Integrated resources planning and the Great Whale Public Review*. Background paper no. 7, Great Whale Public Review Support Office, 115 pp. *(also published in French).*

In British Columbia, he provided expert testimony on behalf of the Treaty 8 Tribal Association before the Joint Review Panel examining the proposal to build the Site C Hydroelectric Project.

Mr. Raphals chairs the Renewable Markets Advisory Panel for the Low Impact Hydropower Institute (LIHI) in the United States, and he now chairs LIHI's. He has also played a role in developing the low impact renewable electricity guideline for the Canadian Ecologo programme.

Mr. Raphals is also a frequent expert witness before the Quebec Energy Board (the Régie de l'énergie du Québec). He has appeared before the Régie de l'énergie as an expert witness with respect to transmission tariffs (FERC), issues related to the integration of wind power, security of supply with respect to hydropower, energy efficiency and avoided costs, and sustainable development criteria.

APPENDIX A

POLICY ON NETWORK UPGRADES (EXCERPT)

DIRECT TESTIMONY OF JUDY W. CHANG

Policy on Network Upgrades (excerpt)

Direct Testimony of Judy W. Chang

On Behalf of Hydro-Québec TransÉnergie

APRIL 30, 2014

II. General Principles Used in Network Upgrade Policies in the U.S. Centers on Open Transmission Access and Protecting Transmission Customers from Undue Cost Burdens

Transmission providers typically recover the costs of network upgrades that result from customers' transmission service requests through charges that are either: a) "rolled-in" with existing transmission costs that all customers pay over time; or b) assigned to and paid for by the requesting transmission customer, or group of customers, in the form of direct "contributions" or incremental rates. Using these two methods allows transmission providers to distinguish between the costs that are shared across all customers and those assigned to specific users.

The network upgrade policies in the U.S. center on protecting existing transmission customers from excess costs induced by network upgrades associated with customers requesting transmission services. This section describes the high-level principles.

As a part of U.S. electricity industry restructuring in the 1990s, FERC outlined its transmission pricing policy. FERC indicated a desire to ensure that its "transmission pricing policies promote economic efficiency, fairly compensate utilities for providing transmission services, reflect a reasonable allocation of transmission costs among transmission users, and maintain the reliability of the grid."[3] More specifically, FERC identified five principles for evaluating transmission pricing proposals. In a 1995 Order to clarify its 1994 transmission pricing policy, FERC stated the following:

> The first principle is that transmission pricing should conform to the traditional embedded cost revenue requirement. However, the Commission also provided procedures whereby utilities can propose rates that do not conform to the traditional revenue requirement and thus do not meet the first principle, i.e., non-conforming proposals. The second principle requires that any new transmission pricing proposal, conforming or non-conforming, must meet the Commission's comparability standard. The remaining three principles (concerning economic efficiency, fairness, and practicality) reflect goals that an applicant must try to meet, but that may need to be balanced against one another in the Commission's determination of whether the proposed rates are just and reasonable.[4]

At the time of restructuring, FERC's primary policy objective was to ensure that transmission providers offered non-discriminatory open access to the transmission network, particularly

[3] See *Policy Statement,* FERC, Docket No. RM93-19-000, October 26, 1994, pp. 1-2.

[4] See *Order on Reconsideration and Clarifying Policy Statement*, FERC Docket No. RM93-19-001, May 22, 1995, pp.1-2, footnote omitted.

for customers that were not traditional native load. However, since native load customers, prior to restructuring, had funded (and were going to continue to fund) the infrastructure that made the delivery of power to them possible, FERC also wanted to ensure that existing transmission users would not be unduly harmed by costs imposed by customers requesting transmission service involving network upgrades that could increase the embedded costs of the system. Thus, FERC's initial "higher of" policy was designed to ensure that existing (and growing) native load was protected, while the wholesale market developed, allowing new customers to interconnect to the existing transmission network that was predominantly funded by existing native load. In a policy statement in the mid-1990s, FERC stated that one of the goals of its new pricing policy was "to hold native load customers harmless."[5]

Under the FERC's "higher of" policy, a transmission customer's service request that requires transmission upgrades would pay the higher of the "embedded cost" or "incremental cost" of the upgrade. As part of its Order No. 890, FERC clarified its position expressed in the earlier restructuring Order No. 888 by stating:

> Under the Commission's "higher of" pricing policy, when the requested transmission service requires network upgrades, the transmission provider should calculate a monthly incremental cost transmission rate using the revenue requirement associated with the required upgrades and compare this to the monthly embedded cost transmission rate, including the expansion costs. This incremental rate should be established by amortizing the cost of the upgrades over the life of the contract.[6]

The FERC transmission policy regarding cost recovery for network upgrades is that a transmission provider can charge a customer, either a new or an existing customer requesting

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5 See *Policy Statement,* FERC Docket No. RM93-19-000, October 26, 1994, footnote 7 where the FERC referenced prior decisions that articulated three of its goals governing requests for firm transmission service: (1) to hold native load customers harmless, (2) to provide the lowest reasonable cost-based price to third-party firm transmission customers, and (3) to prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions.

6 FERC Order No. 890, February 16, 2007, paragraph 870, pp. 508-509, footnotes omitted.

additional transmission service, the higher of the incremental cost of transmission or the embedded cost, but not both.[7] This means that if the incremental cost transmission rate is greater than the embedded cost transmission rate (including upgrade costs), the transmission provider has the option to charge the requesting customer the incremental cost of the upgrade. If the incremental cost transmission rate is less than the embedded cost transmission rate (including the upgrade cost), the transmission provider can charge the embedded cost transmission rate.

Overall, FERC's "higher of" policy aims to balance the interest of all transmission customers because if the incremental transmission cost of the upgrade is lower than the embedded cost, then the customer requesting the transmission service would pay the same rate for transmission service as all other customers, while reducing the average rate and benefitting all customers. On the other hand, if the incremental transmission cost of the upgrade is greater than the embedded cost of transmission, then the transmission provider could require the customer requesting the transmission service to pay more than the embedded-cost rate, and thereby cover the incremental cost and, thus, protectw the interest of all other customers.

[7] See *Policy Statement,* ERC, Docket No. RM93-19-000, October 26, 1994, p. 5.

APPENDIX B

ELECTRICITY GENERATION AND DISTRIBUTION SERVICES: REMOTE COMMUNITIES IN ONTARIO

Rick Hendriks, Senior Analyst
Helios Centre

RESEARCH, ANALYSIS AND EXPERTISE IN ENERGY

Electricity Generation and Distribution Services: Remote Communities in Ontario

Rick Hendriks, Senior Analyst

June 22, 2015

1 INTRODUCTION

1.1 Hydro One Remote Communities Inc.

Hydro One Remote Communities Inc. ("Remotes"), a subsidiary of Hydro One Inc., is an Ontario corporation with its head office in Toronto, and its operations office in Thunder Bay, Ontario.

Remotes carries on all business relating to ownership, operation, maintenance and construction of generation and distribution assets used in the supply of electricity to remote communities throughout northern Ontario. This includes generating electricity at diesel generating stations in 21 isolated communities and distributing the electricity on 19 distribution systems to customers in each community. Figure 1 illustrates Remotes service territory.

Information concerning Remotes was summarized below from publicly available sources, including the corporation's most recent General Rate Application.[1]

1.2 Business Environment

Similar to other remote system utilities, Remotes conducts its business in the context of low customer densities, climatic and logistical challenges, and in the absence of an integrated transmission system. Complex funding arrangements with third parties, including Aboriginal Affairs and Northern Development Canada ("AANDC"), also differentiate Remotes from other Ontario electricity distributors. Remotes is 100% debt financed, operates as a break-even business, and is licensed by the Ontario Energy Board ("OEB").[2]

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[1] Hydro One Remote Communities Inc. September 17, 2012. EB-2012-0137 – Hydro One Remote Communities Inc. 2013 Revenue Requirement and Rates Application – Application and Pre-filed Evidence. ("EB 2012-0137")

[2] EB-2012-0137, Exhibit A, Tab 9, Schedule 1, Page 1 of 4

Figure 1: Map of Remotes' Service Territory[3]

The communities of Whitesand and Collins are served through the Armstrong Distribution System.

Ontario Hydro, the predecessor to Hydro One Inc., initially provided electrical services to off-grid communities in northern Ontario through a series of agreements for electrical services negotiated with AANDC and, in the case of non-First Nation remote communities, with the Provincial Government. Remotes inherited from Ontario Hydro the former utility's obligations to provide electricity to the off-grid communities. Under the arrangements for First Nation

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[3] EB-2013-0142 – Hydro One Remote Communities Inc. 4GIRM 2014 Distribution Rate Application – Application and Evidence Filing, Exhibit A, Tab 2, Schedule 3, Page 2 of 2.

communities, the federal government (through AANDC) funded the original capital installation of facilities, and these arrangements remain in place.

> *The Agreements specify that Remotes is responsible for funding ongoing operation and maintenance of the system and that AANDC is responsible for funding capital related to system expansions and capital upgrades. Remotes' revenue requirement does not include funding for these capital projects, and Remotes does not depreciate this contributed capital.* [4]

Remotes currently serves approximately 3,500 customers, with the vast majority of those customers paying rates below the cost of service. Rates for Residential and General Service customers within Remotes' services area, including in First Nation communities, are financially supported through a cross-subsidy from government customers within Remotes' service area who pay rates slightly above cost of service ("Standard A" Rates). In addition, Ontario Regulation 442/01 established the Rural and Remote Rate Protection ("RRRP"), which subsidizes the rates paid in rural and remote communities in Ontario, including in the communities serviced by Remotes. The RRRP is funded through a $0.0011/kWh charge to all grid-connected customers in Ontario that is set by the Ontario Energy Board.[5] The Regulation results in two broad categories of customers in Remotes' service area:

- Customers who receive Rural and Remote Rate Protection ("Residential and General Service" customers); and
- Customers occupying Government premises, defined as customers who receive direct or indirect funding from government ("Standard A" customers).

The business and system planning activities, generation and distributions facilities, customer service, and work execution activities of Remotes are summarized in the following sections.

2 BUSINESS AND SYSTEM PLANNING

2.1 Introduction

Remotes performs its business planning annually, focusing on the development of a five-year plan consisting of a detailed plan for the first three years and a less detailed outlook for the remaining two years.

> *Annually, required investments are determined based on asset condition, engine hours, load growth and external factors (AANDC funding, winter roads). Investments are then ranked against financial, operational, environmental, safety, regulatory and legal requirements and risks. The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and takes*

[4] EB-2012-0137 Exhibit A, Tab 4, Schedule 1.

[5] EB-2012-0137 Exhibit A, Tab 4, Schedule 1, Page 6 of 7.

into account levels of investment and associated risk mitigation against financial, operational, environmental, safety, regulatory and legal considerations. [6]

Remotes prepares its financial plan, incorporating operations, maintenance and administration as well as capital work program requirements consistent with the investment plan. Forecasts of revenue, fuel, depreciation and amortization expense, as well as financing charges, income tax, and working capital are factored into the planning process. Ongoing work programs are also reviewed annually, taking into consideration factors such as regulatory requirements, business efficiencies, impacts on customers, reliability, environment and safety along with any other relevant information. On a monthly basis, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures and work accomplishments.[7]

2.2 Fuel Supply

Fuel Usage

Remotes employs a fairly sophisticated process for forecasting fuel requirements, as described in its most recent rate application:

Remotes tracks actual historical data on energy usage by community, customer class, and time period. This historical data provides the baseline starting point for forecasting usage/kWh sold. Adjustments are made to this baseline data on a going-forward basis using average load growth, historical customer growth patterns and seasonality. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads.

The Usage Forecast (kWh's sold) forms the basis of the fuel forecast. Once kWh's sold are established, historic operating fuel efficiency ratios and load loss rates are utilized to forecast generated kWh's and fuel litres required. The fuel forecast is done on a site by site basis, given different load characteristics, plant efficiency and community load loss.

Expected fuel commodity prices are based on market prices at the time the forecast is made. Fuel commodity prices are escalated based on CPI. As there is no Canadian forecast for diesel fuel commodity prices, commodity pricing is confirmed through a high level analysis of the published fuel indices that are used by each supplier.

The cost of delivery accounts for about 45% of the delivered price of fuel. As a result, supply delivery contract data is critical in developing the forecast costs. Supplier contracts are subject to a competitive tendering process and delivery

[6] EB-2012-0137 Exhibit A, Tab 14, Schedule 1.

[7] EB-2012-0137 Exhibit A, Tab 14, Schedule 2.

costs are forecast on the basis of supplier contracts and historical deliveries of winter road fuel.[8]

<u>Fuel Cost Management</u>

The management of fuel cost is a key factor in managing the overall cost of electricity service in Remotes' service area, as it is in similar systems. Remotes has some influence over the volume and cost of fuel delivery, but limited influence over fuel price. In terms of volumes, Remotes has introduced a customer demand management ("CDM") program and has also been making engine and station efficiency improvements. In terms of delivery, Remotes has increased the use of winter road deliveries (when available), and has also introduced a comprehensive and competitive tender process for contracting fuel supply and delivery. The competitive process established a larger network of suppliers than had previously been available, reducing overall delivery costs.[9] Remotes also expanded its contracting within its service communities to try to increase the purchase of fuel from tank farms owned by First Nations.

In addition to the above, Remotes has introduced renewable energy generation (including several wind and small-scale hydro facilities) to reduce diesel fuel requirements, improved fuel generating efficiency through supervisory control and data acquisition (SCADA) technology, implemented a proactive scheduled maintenance program, maintained an active generation asset replacement program, and introducing more efficient technology. [10]

2.3 Load Forecasting

Remotes forecasts load in order to plan for and meet customer electricity requirements, to estimate customer revenues, and to forecast its fuel and maintenance costs. Forecasting is supported by monthly tracking of numbers of customers and kWh usage by community and by rate class. Adjustments are made to this baseline data for future years based on average historical growth in usage and historical annual customer changes. Historical trends include the impact of Remotes' CDM program, but forecast program results are not specifically included in the load forecast.[11]

Additional sources of information are also used in compiling the load forecast. First, Remotes annually solicits information on planned construction projects from First Nations. In addition, Remotes holds an annual planning meeting with AANDC for information on program activities that could affect load. Finally, field employees share information about pending connections and are also canvassed for information on communities where generation capacity has reached its limits, constraining future near-term load growth. [12]

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[8] EB-2012-0137 Exhibit C1, Tab 2, Schedule 2, Page 9 of 12.

[9] EB-2012-0137 Exhibit C1, Tab 2, Schedule 2, Page 10 of 12.

[10] EB-2012-0137 Exhibit C1, Tab 2, Schedule 2, Page 11 of 12.

[11] EB-2012-0137 Exhibit G1, Tab 1, Schedule 3, Page 2 of 8.

[12] EB-2012-0137 Exhibit G1, Tab 1, Schedule 3, Page 2 of 8.

2.4 Capital Programs

As indicated above, the Electrification Agreements stipulate that AANDC funds new generation and distribution capital within the First Nation communities served by Remotes.[13] However, Remotes ultimately takes ownership of these assets, although they are not included in the rate base or revenue requirement, as they have a nominal carrying value because they are provided as contributed capital.[14] Relevant aspects of Remotes' capital program[15] include the following:

- Remotes' ongoing capital expenditures relate primarily to asset and equipment replacements required to safely and reliably deliver electricity to the 21 communities in its service territory.
- Remotes invests in assets as replacements are required due to end-of-life, equipment failure, to meet new standards or to improve the overall operations and efficiency of the plant when an upgrade is not planned.
- Remotes capitalizes costs that are directly attributable to the acquisition and construction of capital projects. Remotes also capitalizes certain overhead and indirect costs that are causally or beneficially related to supporting its capital projects.
- Remotes' capital programs fall into three main categories: generation, distribution and facilities.
- Remotes plans its capital investments in accordance with customer requirements and good utility practice, in order to maintain or improve safety and reliability, and to ensure that it is compliant with regulatory requirements and operational standards.

Following devolution of responsibility for community infrastructure AANDC to First Nation communities in the 1990s, the Department now transfers funding directly to First Nations. As a result, the First Nations are responsible for administering approximately 85 percent of AANDC's program funds. Pursuant to these funding arrangements, the process for capital upgrades is complex and not completely within Remotes' control.

During the period 2011 through 2017, AANDC provided no funding for generation upgrades in its capital plan due to funding constraints. During that period, system upgrades were required in several of Remotes' communities. Lacking these financial contributions, Remotes was unable able to connect new customers in those communities where generation had reached its limits. Due to the delays to planned upgrades, Remotes' capital and maintenance work programs had to be increased in order to meet safety, environmental and reliability standards.[16]

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[13] EB-2012-0137 Exhibit A, Tab 4, Schedule 1.

[14] EB-2012-0137 Exhibit D1, Tab 2, Schedule 1, Page 1 of 11.

[15] EB-2012-0137 Exhibit D1, Tab 2, Schedule 1, Page 2 of 11.

[16] EB-2012-0137 Exhibit A, Tab 4, Schedule 1.

3 ELECTRICITY GENERATION

3.1 Generation

Diesel Generation

The primary source of electricity in Remotes 21 communities is diesel generation. There are a total of 57 diesel generators in service, ranging in size from 65kW to 1250kW, with most stations having three generators, sized to meet community load at different times of the day and year. The stations are designed to maximize fuel efficiency and create generation redundancy in the event of engine failure. Remotes' automated operation ensures that each generator is dispatched to match community load, thereby maximizing fuel efficiency. The largest unit is sized to meet the peak load in the community, and equals the output of the two smaller units.[17]

The specific generating facilities and related assets in each community include the following:

> *a fenced site property, including a generator building and storage outbuildings; diesel generator sets, comprised of diesel engines, and alternating current generators; electrical switch gear with engine controls, breakers and step up transformers; a Programmable Logic Controller (PLC) including a Supervisory Control and Data Acquisition (SCADA) System; an engine cooling system including piping and external radiators; an engine exhaust system comprised of manifolds, silencers and exhaust stacks; a diesel fuel system including multiple bulk fuel tanks, transfer pumps, piping, automated valves, day tanks, fuel coolers, meters and an off-load kiosk; and a building auxiliary system including secondary heating system (ventilation system), communications, lighting and station service and compressed air.*[18]

The vast majority of generation assets are transferred to Remotes from AANDC under the terms of the Electrification Agreements, and are treated as contributed capital. One exception within Remotes' service territory concerns the diesel generation facility in Marten Falls First Nation. In 2009, Remotes applied to the OEB and was subsequently approved for an amendment to its licence to include the community of Marten Falls within its service territory. Prior to that time, Marten Falls First Nation had owned and operated its system as an independent community electrical system. Under the terms of the Electrification Agreement between Marten Falls First Nation, Remotes and AANDC, the First Nation retained ownership of the existing generation and distribution assets.

> *The agreement with the Marten Falls First Nation specifies that capital funding for generation upgrades and distribution expansions and connections will*

[17] EB-2012-0137 Exhibit A, Tab 16, Schedule 1.

[18] EB-2012-0137 Exhibit D1 Tab 1 Schedule 2, page 1 of 3.

continue to be supported by Indian and Northern Affairs Canada ("INAC"), so INAC is a party to the agreement for this purpose. Remotes will be responsible for capital replacement, operating and maintenance costs, including the purchase of diesel fuel, consistent with the terms under which Remotes operates in other First Nation reserve communities. The costs to operate and maintain the system, as well as the rates applicable to the community were approved by the Board in EB-2008-232.[19]

Non-diesel Generation

Remotes owns and operates two run-of-the-river mini-hydroelectric generating facilities and four demonstration project wind turbines. While diesel remains the most reliable and cost effective technology, Remotes continues to assess the feasibility of using further renewable technologies.

Remotes believes that First Nations must be involved in renewable energy projects in their communities, and is working with local First Nations and with private sector developers to assist in developing renewable energy resources. Remotes will continue to offer technical assistance to the communities in reviewing opportunities through the Aboriginal Loan Program Guarantee Program and the Aboriginal Community Energy Plan. Remotes would enter into power purchase agreements based on the avoided cost of diesel fuel to support these projects.[20]

3.2 Operations

Remotes generation operations represent expenditures required for safe and reliable operation of the generating plants, and for keeping the generating station and associated facilities in a standard operating condition as required to meet community load.

Within each community, Remotes contracts for local operators, who perform regular routine inspection and maintenance of equipment at generating facilities including the generating units, auxiliary equipment and the bulk storage tank farm. The operators provide on-site monitoring of fuel deliveries, and the safe handling, transportation and disposal of waste. Operators are also responsible for keeping the stations clean, undertaking filter changes, checking diesel plants and reporting and troubleshooting problems to the Thunder Bay Service Centre. Operators are also responsible for responding to emergencies such as power outages, house fires and spills. Over the past two years, Remotes has increased

[19] Hydro One Networks Inc. November 12, 2009. Letter from Susan Frank, VP and Chief Regulator Officer, HONI to Kirsten Walli, Secretary, Ontario Energy Board Re: Licence Amendment to Include the Community of Marten Falls in Hydro One Remote Communities Inc.'s Service Territory.

[20] EB-2012-0137 Exhibit A, Tab 16, Schedule 1.

the number of agents in most communities to ensure that qualified personnel are available on site.[21]

Remotes maintains additional operations personnel in a regional location in Thunder Bay, Ontario, who are responsible for:

- ensuring that the diesel plants operate safely and reliably;
- acting as primary contacts for operators, responsible for: supervising and scheduling, developing plant-specific procedures, logistical and troubleshooting support, assisting the operator in emergency response, plant reporting, and ensuring that the operators are competent to perform daily maintenance activities; and
- conducting and documenting local operator training, including ensuring that each operator successfully completes a comprehensive on-site training program each year.[22]

3.3 Maintenance

Maintenance programs and projects relate to improvements in the efficiency, reliability, safety and operation of the generation assets, and prevent premature equipment and system failures. Generation maintenance consists of both planned and unplanned maintenance related to the generation site, buildings, engines, systems, fuel storage and fuel systems.

Delays to required upgrades resulting from AANDC funding constraints have increased generation maintenance and operations requirements and costs, as generation assets and facilities age and approach end of life.

Planned maintenance includes:

- implementing measures prescribed by the engine manufacturer required to keep generating units available and operating to meet community load;
- scheduling of intensive maintenance procedures based on engine hours as these vary from year to year;
- forecasting engine maintenance expense based on a forecast of engine hours;
- performing engine maintenance based on the actual load in each community, considering the hours each engine is selected to operate by the automated control system;
- maintaining plant and auxiliary systems, including inspection and maintenance of all electrical, SCADA, secondary heating, primary cooling and ventilation systems;
- inspecting and maintaining overhead cranes; and
- annually inspecting fire suppression systems.[23]

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[21] EB-2012-0137 Exhibit C1, Tab 2, Schedule 2, Page 6 of 12.

[22] EB-2012-0137 Exhibit C1, Tab 2, Schedule 2, Page 7 of 12.

[23] EB-2012-0137 Exhibit C1, Tab 2, Schedule 2.

Remotes shift to innovative new electrical and SCADA systems has helped to improve safety and environmental performance, including a 10% improvement in fuel efficiency with improvements anticipated pursuant to further innovation by engine manufacturers. [24]

Unplanned maintenance includes maintenance and repair related to trouble reports and equipment or component failures.

3.4 Fuel Tanks

Remotes maintains diesel fuel storage tanks in each community within its service territory to ensure adequate diesel fuel supply. Key aspects of operations and maintenance include:

- equipping the tanks with measurement and alarm devices to reduce the risk of fuel spills and to improve fuel control measurement;
- using double walled tanks to enhance containment; and
- performing regular inspections to address deficiencies in the generating station fuel offload, bulk storage tanks and fuel transfer equipment in order to keep fuel systems in standard operating condition.[25]

Remotes also recently negotiated more fuel contracts directly with the First Nation communities with fuel storage on site where Remotes does not have adequate fuel storage facilities. This allowed Remotes to take better advantage of winter road delivery pricing and to expand its available storage capacity.[26]

3.5 Other Facilities

The high cost of transportation to Remotes' communities necessitates that Remotes' staff reside in the communities while undertaking planned and unplanned maintenance. As such, the utility maintains staff houses and trailers at 14 locations, while using commercial accommodations at the other sites.[27] As facilities deteriorate, repairs and capital replacements are undertaken.

4 ELECTRICITY DISTRIBUTION

4.1 Distribution

Within each of its isolated diesel systems, Remotes is responsible for transformation, voltage regulation, delivery and metering of power. The major distribution system components within each isolated distribution system include conductors, switches, transformers, insulators,

[24] EB-2012-0137 Exhibit C1, Tab 2, Schedule 2.

[25] EB-2012-0137 Exhibit C1, Tab 2, Schedule 2.

[26] EB-2021-0137 Exhibit C1, Tab 2, Schedule 2.

[27] EB-2012-0137 Exhibit D1, Tab 1, Schedule 2.

reactors, capacitors, connecting hardware, associated protection and control equipment, foundations, grounding systems and revenue meters.[28]

Distribution voltages range from 4.8 kV to 25 kV within the distribution systems. As of 2011, they collectively included approximately 233 kilometers of line, 4610 wood poles, 1,122 transformers and 265 switches distributed throughout the system. [29]

4.2 Distribution System Code

Remotes is bound by the terms of its distribution licence to adhere to the requirements of the Distribution System Code ("DSC"), administered by the OEB.[30]

> *[The DSC] sets the minimum conditions that a distributor must meet in carrying out its obligations to distribute electricity under its licence and the Energy Competition Act, 1998. Unless otherwise stated in the licence or Code, these conditions apply to all transactions and interactions between a distributor and all retailers, generators, distributors, transmitters and consumers of electricity who use the distributor's distribution system.*[31]

The DSC establishes conditions for the distribution of electricity by distributors, including Remotes, in relation to the following:

- Standards of Business Practice and Conduct – including in relation to liability, force majeure, Conditions of Service (including minimum requirements), customer reclassification, bill issuance and payment, payment of arrears, opening and closing accounts, use of load control devices, and estimated billing
- Connections and Expansions – including connections (and refusals), expansions, enhancements, and plant relocation
- Operations – including quality of supply, disconnection and reconnection, unauthorized energy use, system inspection requirements and maintenance, unplanned outages and emergency conditions, health and safety and environment
- Metering – including provision of meters and metering service, metering requirements for generating facilities, VEE (validating, estimating and editing) for settlement and billing purposes
- Distributors' Responsibilities – including to load customers, to generators, for the generation connection process, technical requirements for generation connection, load transfers, provision of information to consumers
- Service Quality Requirements – including for connection of new services, appointments, telephone accessibility, telephone abandon call rates, written responses to enquiries, emergency response, reconnection standards, and billing accuracy

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[28] EB-2012-0137 Exhibit D1, Tab 1, Schedule 2.

[29] EB-2012-0137 Exhibit D1, Tab 1, Schedule 2.

[30] EB-2012-0137 Exhibit A, Tab 12, Schedule 1.

[31] Ontario Energy Board. April 15, 2015. Distribution System Code, at p.7.

By order of the OEB,[32] Remotes is exempt from some of the conditions established in the DSC to address matters that are specific to the operating conditions faced by Remotes as a distributor in remote communities. Some of these exemptions relate to the following sections of the DSC:

- Arrears payment arrangements (ss.2.7.1.2, 2.7.2, 2.7.1.3);
- Opening and closing of accounts (ss.2.8.1, 2.8.2, 6.1.2.1, 6.1.2.2);
- Standard timelines for disconnection notice (ss.4.2.2.3, 4.2.3.1) – The standards applicable to Remotes reflect the time for notification to arrive at remote locations, and are described in Remotes' Conditions of Service;[33] and
- Reconnection standards (s.7.10) – the two-day standard does not apply to Remotes given the challenges of access to remote communities, and applicable standards are described in Remotes' Conditions of Service.[34]

Other factors relevant to the application of the DSC to Remotes include the following:

- New connections – since the costs of new connections are paid for by AANDC in accordance with the Electrification Agreements, Remotes does not connect new services until payment from AANDC is confirmed;[35]
- Obligation to connect customers – The isolation of communities serviced by Remotes means that when the generating plant reaches its capacity, no new electrical load can be connected to the distribution system; Remotes has a legislative exemption from the obligation to connect customers if the generating station is at capacity;[36]
- Cost allocation – the Electrification Agreements specify that AANDC is responsible for funding capital related to system expansions and capital upgrades, and Remotes does not depreciate this contributed capital, instead treating it as an initial input for cost allocation prior to application of the RRRP; and
- Feed-in Tariff (FIT) contracts – Remotes is not eligible for the Ontario Power Authority's FIT program for connection of renewable generation.[37]

4.3 Operations

Operations activities and expenditures are driven by the need to meet customer, regulatory and statutory requirements regarding service and reliability. Distribution operations include data collection and system condition assessment used to plan corrective and preventive maintenance, joint use activities and engineering support for distribution.

The DSC requires Remotes to assess the condition of its assets and monitor its distribution lines to identify structural problems, damaged equipment and components that may cause a power

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[32] Ontario Energy Board. April 25, 2013. Decision and Order.

[33] EB-2012-0137 Exhibit G1-3-1, Appendix A, Hydro One Remotes Communities Conditions of Service, at s.2.2.

[34] EB-2012-0137 Exhibit G1-3-1, Appendix A, Hydro One Remotes Communities Conditions of Service, at ss.2.2.4 and 2.2.5.

[35] EB-2012-0137 Exhibit G1-3-1, Appendix A, at s.2.1.2.

[36] Definitions and Exemptions, Ontario Regulation 160/99, at s.2.3.

[37] EB-2012-0137 Exhibit A-16-1, Appendix B.

interruption, as well as any hazards such as leaning poles, damaged equipment enclosures and vandalism.[38]

4.4 Maintenance

Distribution maintenance includes both planned and unplanned maintenance and trouble calls. Planned maintenance includes:

- equipment maintenance that is primarily cyclical in nature, including maintenance of equipment (line reclosers and line regulators); and
- routine inspection and maintenance of revenue meters, in accordance with the requirements of Measurement Canada, including regular removal from service to verify performance accuracy within specification.[39]

Unplanned maintenance is reactive and variable in response to external factors such as storms, equipment deterioration and equipment failures.

5 WORK EXECUTION

5.1 Electrical Safety

In addition to the high priority placed on safety that is typical of electrical utilities, Remotes is also subject to the *Electrical Distribution Safety Regulation 22/04*. This regulation establishes objective-based requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors.[40]

Electrical safety is a high priority for Remotes, which is typical for electrical utilities. Remotes has implemented comprehensive training programs to ensure all Electrical Safety Regulations are adhered to across its business. The Electrical Safety Authority (“ESA”) also undertakes regular compliance reviews to ensure that Remotes work complies with distribution standards and the overall objectives of Regulation 22/04.[41]

5.2 Environmental Management

Remotes developed an Environmental Management System (“EMS”) in 1999 to help address a history of spills, and to improve environmental performance. In addition, Remotes has achieved operating efficiency improvements and reduced diesel requirements through installation of automated Programmable Logic Controller (“PLC”) controls, installation of SCADA systems, engine upgrades, and improvements in generating and fuel-handling software to support its PLC programs.

[38] EB-2012-0137 Exhibit C1, Tab 2, Schedule 3.

[39] EB-2012-0137 Exhibit C1, Tab 2, Schedule 3.

[40] See EB-2012-0137, Exhibit A, Tab 12, Schedule 1 for more details respecting Regulation 22/04.

[41] EB-2012-0137 Exhibit A, Tab 12, Schedule 1.

In addition to the establishment of an EMS and to being subject to federal and provincial environmental legislation, Remotes has established a number of environmental management programs, including in relation to fuel and hazardous materials and waste management.

> ***Fuel Management***. *Remotes handles 14 to 17 million litres of fuel each year. Fuel is handled in accordance with rules and standards set out by the Technical Standards and Safety Authority (TSSA). The TSSA also establishes operation and maintenance standards for fuel management, handling and transfer. Remotes' fuel storage and auxiliary systems are designed and operated in accordance with these standards, and the TSSA regularly inspects Remotes' fuel systems. Remotes also has several ongoing activities related to fuel management, handling and transfer.*
>
> ***Hazardous Materials and Waste***. *Management and Transportation of hazardous materials and wastes such as oils and solvents are managed in accordance with regulatory requirements and good management practices. Remotes' generating facilities have secure outbuildings to safely store waste materials. Hazardous waste is transported out of communities over winter roads in accordance with various reporting requirements under the Environmental Protection Act and Waste Management Regulation 347.*
>
> *Hazardous materials such as wastes (oils, solvents, etc.) are managed in accordance with regulatory requirements and good management practices.* [42]

5.3 Policy

In addition to statutory and regulatory requirements, Hydro One Inc. has a number of internal corporate policies that apply to Remotes that are regularly revised and updated. The objectives of these policies are to ensure:

- compliance with statutory and regulatory obligations;
- fair and consistent commercial relationships with customers;
- efficient management of assets;
- consistent criteria for decision making;
- compliance with generally-accepted accounting principles;
- consistency for transaction processing; and,
- accurate and timely recording and reporting of financial information.[43]

5.4 Quality Indicators

Remotes currently monitors and records service quality indicators as required in Chapter 15 of the *Ontario Energy Board 2006 Electricity Distribution Rate Handbook*.[44] Not all Service Quality

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[42] EB-2012-0137 Exhibit A, Tab 12, Schedule 1, Page 3 of 6.

[43] EB-2012-0137 Exhibit A, Tab 13, Schedule 1, Page 1 of 3.

Requirements (SQRs) of the OEB are tracked by Remotes due to the isolated nature of Remotes communities. The following SQRs are tracked:

- Customer Service – connection of new services, emergency response, written response to inquiries; and
- Service Reliability – interruption data, monthly OEB reliability indices (i.e. SAIFI,[45] SAIDI[46] and CAIDI[47]).[48]

Service connections are typically planned through First Nation Council offices, are grouped together to reduce costs, and are performed when appropriate Remotes staff is in the community. The SQR is modified to reflect these factors. In order to support continual improvement, when the annual performance targets are met, the targets for the following year are established based on improvements to the 5-year average.[49]

6 CUSTOMER SERVICE

6.1 Customer Care

Customer Care expenses represent the costs associated with meter reading, customer billing, collections and bad debt expenses.

Remotes provides general customer account services including in-community customer service activities to all customers connected to its distribution system, including billing, collections, meter reading, dealing with outstanding accounts and responding to customer inquiries and complaints.

Certain customer care services are handled at Remotes Thunder Bay offices, including entering meter readings into the Customer Service System, answering customer calls and inquiries, entering bill payments, organizing collection trips, contacting customers and band councils prior to collection activity and negotiating payment arrangements. Field staff undertakes collection activities, while meter reading is contracted out through the First Nations to individuals in the communities.[50]

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[44] http://www.ontarioenergyboard.ca/documents/edr_final_ratehandbook_110505.pdf

[45] System Average Interruption Frequency index - The average number of times that customers served by Remotes were interrupted in the year.

[46] System Average Interruption Duration Index – The average number of hours that customers served by Remotes were without power in the year.

[47] Customer Average Interruption Duration Time – The average interruption duration (in hours) of customers who were interrupted.

[48] EB-2012-0137 Exhibit A Tab 15 Schedule 1.

[49] EB-2012-0137 Exhibit A Tab 15 Schedule 1, Page 3 of 5.

[50] EB-2012-0137 Exhibit C1, Tab 2, Schedule 4, Page 1 of 3.

6.2 Community Relations

Community Relations activities include Remotes' CDM programs, outreach activities, the Customer Advisory Board ("CAB"), and community safety program.

Conservation and Demand Management (CDM)

CDM is the largest element of Remotes' Community Relations activities. Remotes' CDM activities involve the delivery of energy conservation and demand management strategies designed to have a measurable impact on energy consumption rates as well as to develop local expertise within the community itself. While energy conservation assists customers in managing their electricity bills, as noted previously, it also reduces Remotes' fuel usage.

Key aspects of Remotes CDM program include the following:

- deploying energy efficient appliances within the communities, including a partnership with Northern stores to offer Energy Star appliances and coordination with Canada Mortgage and Housing Corporation to provide energy efficient appliances in new homes and construction to energy efficiency standards;
- focusing on electricity conservation in band operated assets such as Band offices, arenas and water and sewage plants, as these are typically the largest users in Remotes' communities;
- hiring, training and development local expertise, which is critical to the effectiveness and persistence of conservation measures;
- encouraging communities to perform commercial lighting replacements; and
- improving the program to include greater support community energy advisors and direct involvement of Band Councils. [51] [52] [53]

Program results have varied considerably since the program's inception based on the availability of energy advisors in the communities. In 2011, Remotes' customer conservation programs resulted in 245,600 kWh of in-year savings and life cycle savings of 1,891,878 kWh.[54]

Other Community Relations Activities

Remotes' other community relation's activities include the following:

- an ongoing Customer Advisory Board ("CAB"), including residential and commercial customers within Remotes service territory, that offers advice on service policies and procedures, and on ways to improve services within the communities;
- customer research activities, including annual surveys of customers and Band Councils to assess service satisfaction, planned program activities, areas that services can be improved and related matters; and

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[51] EB-2012-0137 Exhibit G1, Tab 1, Schedule 3, Page 2 of 8.

[52] EB-2012-0137 Exhibit C1, Tab 2, Schedule 5, Page 1 of 3.

[53] EB-2012-0137 Exhibit I, Tab 2, Schedule 7, Page 1 of 2.

[54] EB-2012-0137 Exhibit C1, Tab 2, Schedule 5, Page 2 of 3.

- community meetings and other outreach activities to discuss service issues.[55]

6.3 Conditions of Service

As required under section 2.4 of the Distribution Service Code, Remotes' Conditions of Service describe the operating practices and connection policies and set out the terms and conditions upon which Remotes offers and customers accepts off-grid distribution services.

These practices and connection policies include those in relation to the following:

- Relations between Remotes and Customers – including customer rights, Remotes' Distributor Rights and resolution of Disputes;
- Connections – including building that lies along, offer to consent, connection denial, inspections before connection, relocation of plant, easements, contracts;
- Disconnection – including for reasons of non-payment, without notice, liability, reconnection, and related charges;
- Conveyance of Electricity – including limitations on guarantee of supply, power quality, electrical disturbances, standard voltage offerings, voltage guidelines, back-up generators, metering;
- Rates and Charges – including in relation to service connection, energy supply, deposits, billing; and
- Customer Information – provision of current usage data to customers.[56]

[55] EB-2012-0137 Exhibit C1, Tab 2, Schedule 5, Page 3 of 3.

[56] EB-2012-0137 Exhibit G1-3-1, Appendix A.

Attachment A – Qualifications

Rick Hendriks is a senior analyst at the Helios Centre as well as the Director of Camerado Energy Consulting, an Ontario-based consulting firm providing management consulting, strategic planning, research, and negotiation services with respect to energy planning, assessment, development and conservation. Mr. Hendriks' work has focused on the review and assessment of the need, alternatives and environmental implications of proposed hydroelectric, transmission and mining developments across Canada.

From 1999 to 2002, and again from 2007 through 2011, Mr. Hendriks advised the Innu Nation on environmental, socio-economic and technical matters in relation to the development of the Lower Churchill Project, including associated high voltage transmission in central Labrador. He was the primary author for Innu Nation submissions to the joint panel review environmental assessment for the Lower Churchill Hydroelectric Generation Project, and the comprehensive study environmental assessment of the Labrador-Island Transmission Link.

From 2003 through 2006, he managed environmental, socio-economic and technical review for an environmental assessment of a remote open pit diamond mine and associated transportation, energy and transmission infrastructure on behalf of the Attawapiskat First Nation.

In 2010, Mr. Hendriks supported successful negotiation of a feasibility study partnership agreement between Smith's Landing First Nation, Atco Power and TransCanada Energy in relation to the proposed Slave River Hydro Development in northern Alberta. He provided expert testimony to the Alberta Utilities Commission: Inquiry on Hydroelectric Power Generation in relation to regulatory, policy and planning context for hydroelectric development in Alberta. In 2013, he presented on similar matters to the Legislature of Alberta – Standing Committee on Resource Stewardship: Review of the Potential for Expanded Hydroelectric Energy Production in Northern Alberta.

From 2010 through 2014, Mr. Hendriks managed the environmental and technical review of the proposed Site C Project on the Peace River on behalf of the Treaty 8 Tribal Association, including in relation to design and system alternatives to the proposed Project. He provided testimony to the environmental assessment joint review panel in relation to numerous matters, including avoidance and mitigation measures, and smaller-scale hydroelectric alternatives. Mr. Hendriks also provided written testimony to the British Columbia Ministry of Energy Review of Industrial Electricity Policy and Review of the BC Utilities Commission.

In 2014, Mr. Hendriks provided expert testimony before the Manitoba Public Utilities Board concerning the evaluation of the macroenvironmental impact of energy alternatives and the socio-economic implications of additional wind development as part of the Need For and Alternatives To Review of Manitoba Hydro's Keeyask and Conawapa projects.