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April 24, 2015

Delivered by RESS, Email and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2701
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: North Bay Hydro Distribution Ltd. ("NBHDL")
Board File No. EB-2014-0099

Pursuant to Procedural Order No. 1, please find enclosed NBHDL's Interrogatory Responses in regards to the above noted matter.

Yours very truly,

BORDEN LADNER GERVAIS LLP
Per:

Original signed by John A.D. Vellone

John A.D. Vellone

cc: Todd Wilcox, Cindy Tennant, Melissa Casson and Matt Payne, NBHDL
Parties in EB-2014-0099

TOR01: 5916418: v1

EB-2014-0099

North Bay Hydro Distribution Ltd. (“North Bay Hydro”)

Interrogatory Responses

April 24, 2015

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North Bay Hydro Interrogatory Responses

EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS

1-Energy Probe-1

Reference: Exhibit 1, Tables 1-1 through 1-5

Interrogatory:

a) Please explain why the target levels remain significantly below the actual results for the years shown. In other words, why have the targets not increased?

b) Does NBHDL have any incentive plan for any employees, which are, in part, impacted by whether or not the target levels are achieved? If yes, fully explain.

c) Please update the tables to include data for 2014.

Response:

a) The targets shown on tables 1-1 through 1-5 of Exhibit 1 are the industry service quality requirements per the Distribution System Code.

b) NBHDL does not have an incentive plan for any employees, which are, in part, impacted by whether or not the target levels are achieved.

c) Tables 1-1 through 1-5 have been updated for 2014 data and are provided below.

Table 1-1: Percentage of Scheduled Appointments Met on Time.

Year	2009	2010	2011	2012	2013	2014
Percentage of scheduled appointments met on time	100%	99.60%	100%	100%	100%	100%
Target: 90%						

Table 1-2: Percentage of Telephone Calls Answered on Time.

Year	2009	2010	2011	2012	2013	2014
Percentage of calls answered on time	53.20%	76.50%	71.60%	77.20%	78.20%	78.40%
Target: 65%						

Table 1-3: Percentage of New Residential or Small Business Services Connected on Time.

Year	2009	2010	2011	2012	2013	2014
Percentage of scheduled appointments met on time	100%	100.00%	100%	100%	100%	100%
Target: 90%						

Table 1-4: Percentage of New Customer Connection Requests for Low Voltage Connected on Time.

Year	2008	2009	2010	2011	2012	2013	2014
Percentage of new customer connection for low voltage connected on time	100%	100%	100%	100%	100%	100%	100%
Quantity within 5 days	132	114	134	86	104	61	38
Target: 90%							

Table 1-5: Percentage of New Customer Connection Requests for High Voltage (i.e. greater than 750V) Connected on Time.

Year	2008	2009	2010	2011	2012	2013	2014
Percentage of new customer connection for low voltage connected on time	100%	100%	100%	100%	100%	100%	100%
Quantity within 5 days	10	8	8	3	4	9	2
Target: 90%							

North Bay Hydro Interrogatory Responses

EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS

1-Energy Probe-2

Reference: Exhibit 1, Page 18

Interrogatory:

a) Please quantify the amount included in the budget for the test year for an operational review to assess the performance in respect of the coordination of infrastructure replacement requirements to minimize duplicative civil and construction work.

b) Please explain why NBHDL did not undertake this operational review prior to the test year.

c) Has NBHDL amortized the expenses associated with this review over a 5 year period or kept all of the expenses in the test year?

d) If the response to part (c) is the test year, is this a one-time cost or will the cost continue in future years?

e) What is the expected future savings as a result of minimizing duplicative civil and construction work?

Response:

a) The amount included in the budget for the test year for an operational review is $41,600.

b) NBHDL did not undertake this operational review prior to the test year because of other priorities.

c) As explained on page 75 of Exhibit 4, NBHDL has amortized the total estimated costs of this review ($208,000) over a 5 year period.

d) NBHDL has categorized this as a one-time cost as shown in Table 4-28 of Exhibit 4.

e) The intent of the section 1.4 on page 18 of Exhibit 1, “Coordinating infrastructure replacement to minimize duplicative civil and construction work”, is meant to illustrate the efforts NBHDL makes with the City of North Bay through various initiatives to avoid duplicative work. As stated in the section, NBHDL does not currently have quantitative measures to assess performance in respect of this objective.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-3

Reference: Exhibit 1, Tables 1-12 and 1-13

Interrogatory:

a) Please confirm that NBHDL's targets for each table are, in fact, to stay within the ranges achieved in 2009 through 2013.

b) Please update the tables to reflect 2014 data.

Response:

a) NBHDL confirms that NBHDL’s targets for the test year for each table are, in fact, to stay within the ranges achieved in 2009 through 2013.

b) The tables below reflect the 2014 data:

Average Number of Hours that Power to a Customer is Interrupted.

Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Average number of hours that power is interrupted	1.56	2.72	2.87	1.60	2.32	1.55
Target: Within 1.56 – 2.87						

Average Number of Times that Power to a Customer is Interrupted.

Year	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Average number of times that power is interrupted	1.48	2.75	2.16	2.29	1.89	1.14
Target: Within 1.48 – 2.75						

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-4

Reference: Exhibit 1, Table 1-6

Interrogatory:

a) Please update the table to reflect actual data for 2014.

b) Please confirm that this table shows the return on equity based on deemed equity and not on actual equity. If this cannot be confirmed, please provide a table that shows the actual return on deemed equity.

Response:

a) Table 1-6 below has been updated to reflect data for 2014.

Table 1-6: NBHDL Profitability: Regulatory Return on Equity.

Year	2011	2012	2013	2014
Percentage of profitability	10.15%	9.08%	8.88%	6.44%

Targets:
OEB Permitted Return (for rates effective May 1, 2011): 9.58%
OEB Permitted Return (for rates effective May 1, 2012): 9.12%
OEB Permitted Return (for rates effective May 1, 2013): 8.98%

b) NBHDL confirms that table 1-6 shows the return on equity based on deemed equity and not on actual equity.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-5

Reference: Exhibit 1, Table 1-15

Interrogatory:

Please provide the efficiency groupings for NBHDL for each of 2009 through 2011 (based on the 3 groups available during those years).

Response:

NBHDL's efficiency grouping for 2009 and 2010, based on the 3 groups available during those years, was Group 2 and 2011 was Group 1.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-6

Reference: Exhibit 1, Table 1-16

Interrogatory:

a) Please extend Table 1-16 to include the figures for 2014 and 2015 based on the current application.

b) Please provide a table that replaces the 2014 bridge year forecast (as requested in part (a) above) with actual figures for 2014.

Response:

a) Table 1-16 provides the total cost per customer and total cost per Km per line included on NBHDL's 2013 Scorecard. These costs are based on figures that were generated by the Ontario Energy Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and as such Table 1-16 cannot be extended to include the figures for 2014 and 2015 based on the current application.

b) Please see response to a) above.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-7

Reference: Exhibit 1, Table 1-17

Interrogatory:

a) Please expand Table 1-17 to show data for 2009 and 2010.

b) How many FTE's did NBHDL forecast for its bridge (2009) and test years (2010) in its last cost of service application?

c) Please provide a breakdown of the table requested in part (a) above to show the number of FTE's by executive, management, non-union and unionized.

Response:

a) Exhibit 4 Table 1-17 below has been expanded to show data for 2009 and 2010. The table has also been updated with the correct value of 48 for 2014. Please reference Table 4-11 – Full Time Employees by Department page 49 of Exhibit 4.

Year	2009	2010	2011	2012	2013	2014	2015
Number of full-time employees	45	46	47	47	47	48	48
Target: Fifty (50) full-time employees or less							

b) In its last cost of service application NBHDL forecasted 42 FTE’s at year end in the 2009 bridge year and 50 FTE’s in the 2010 test year (year-end counts).

c) The breakdown of the table requested in part (a) above is provided below and shows the number FTE's by executive, management, Non-union and unionized.

Year	2009	2010	2011	2012	2013	2014	2015
Number Employee FTE's							
Management (including executive)	9	9	9	10	10	10	10
Non-Management (union and non-union)	36	37	38	37	37	38	38
Total	45	46	47	47	47	48	48

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-8

Reference: Exhibit 1, Pages 34-35

Interrogatory:

a) Please quantify the increase in the 2015 capital expenditures related to each of the 3 significant exceptions noted in lines 2 through 14 on page 34.

b) Please add columns to Table 1-23 that show actual capital expenditures for 2010 through 2014.

Response:

a) The 3 signification exceptions noted in lines 2 through 14 on page 34, and the associated 2015 capital expenditure level, are as follows:

1) Capital Infrastructure Modernization – upgrade of non-interval capable meters - $199,213

2) MS# 22 – Replacement of MS# 9 - $1,781,297

3) General plant – replacement bucket truck - $370,000

b) Table 2-32 in Exhibit 2 shows the actual capital expenditures for 2010 through 2014 forecast. NBHDL has updated Table 2-32 for 2014 actuals and included this in response to 2-Energy Probe-27 c).

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-9

Reference: Exhibit 1, Page 50

Interrogatory:

Please explain, at a high level, why a revenue deficiency of about $1.7 million results in lower distribution costs for almost all customers shown in Table 1-28. If this decrease is driven by the disposition of deferral and variance accounts, please provide a version of Table 1-28 that removes the disposition of these accounts from both the 2014 and 2015 distribution rates.

Response:

The decrease is driven by the disposition of deferral and variance accounts. The following table provides a version of Table 1-28 that removes the disposition of these accounts from both the 2014 and 2015 distribution rates. The excluded deferral and variance accounts include Group 1 and Group 2 accounts, accounts 1568, 1576 and 1592.

Rate Class	kWh	kW	2014 Dist Bill $	2015 Dist Bill $	$ Difference	Bill Impact %	2014 Total Bill $	2015 Total Bill $	Bill Impact $	Bill Impact %
Residential - TOU	100		$18.63	$19.21	$0.58	3.11%	$32.57	$33.18	$0.61	1.87%
	250		$20.57	$21.49	$0.93	4.52%	$53.38	$54.39	$1.00	1.88%
	500		$23.79	$25.27	$1.48	6.22%	$88.07	$89.68	$1.62	1.84%
	800		$27.66	$29.78	$2.12	7.66%	$129.70	$132.03	$2.34	1.80%
	1,000		$30.24	$32.80	$2.56	8.47%	$157.45	$160.28	$2.82	1.79%
	1,500		$36.69	$40.35	$3.66	9.98%	$226.83	$230.89	$4.06	1.79%
	2,000		$43.14	$47.90	$4.76	11.03%	$296.20	$301.50	$5.29	1.79%
GS < 50 kW - TOU	1,000		$49.24	$46.07	($3.17)	(6.44%)	$175.82	$172.74	($3.08)	(1.75%)
	2,000		$65.74	$65.27	($0.47)	(0.71%)	$317.27	$317.09	($0.18)	(0.06%)
	5,000		$115.24	$122.87	$7.63	6.62%	$741.64	$750.14	$8.50	1.15%
	10,000		$197.74	$218.87	$21.13	10.69%	$1,448.93	$1,471.90	$22.97	1.59%
	15,000		$280.24	$314.87	$34.63	12.36%	$2,156.21	$2,193.67	$37.46	1.74%
GS 50-2,999 kW	20,000	60	$418.31	$488.91	$70.59	16.88%	$2,755.90	$2,857.50	$101.60	3.69%
	40,000	100	$501.21	$585.76	$84.55	16.87%	$5,066.76	$5,201.93	$135.17	2.67%
GS 3,000-4,999 kW	900,000	3,000	$9,133.00	$10,302.92	$1,169.92	12.81%	$113,231.82	$116,311.90	$3,080.08	2.72%
	1,800,000	5,000	$11,325.60	$12,688.12	$1,362.52	12.03%	$213,496.92	$218,007.32	$4,510.40	2.11%
Unmetered Scattered Load	150		$9.43	$7.05	($2.38)	(25.21%)	$26.93	$24.53	($2.40)	(8.91%)
Street Lighting	150	1	$30.55	$33.54	$2.99	9.79%	$50.62	$54.11	$3.49	6.89%
Sentinel Lighting	150	1	$20.34	$23.98	$3.64	17.89%	$39.27	$43.06	$3.79	9.66%

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-10

Reference: Exhibit 1, Page 66

Interrogatory:

a) Please provide all the assumptions used to come up with the 2016 through 2019 bills in each of Tables 1-29 and 1-30.

b) Please reconcile the $2.30 decrease shown in Table 1-29 for 2015 with the $5.68 decrease noted at line 33.

Response:

a) NBHDL made the following assumptions in coming up with the 2016 through 2019 bills in each of Tables 1-29 and 1-30:

- 2016 through 2019 distribution rates (i.e.; fixed and volumetric rates only) were increased by a Price Cap Index % only to reflect the IRM position that NBHDL will be in through that period. The increase was based on the assumption that the proposed 2015 rates utilized in the illustration of bill impacts would be approved by the Board.

- NBHDL assumed a PCI of 1.4% based on the 2014 IRM rate proceeding.

- All rate riders would have a one-year term, including Account 1576, and expire in 2016. No future DVA riders were estimated.

- Costs outside of NBHDL's control (i.e.; TOU, WMS, Network, DRC, etc.) remained static at 2015 amounts.

b) The $5.68 decrease noted at line 33 is specifically in reference to the Account 1576 disposition request and its related impact to the overall net $2.30 decrease shown in Table 1-29.

Rate Description	Incremental Change - 2015
Monthly Service Charge	2.35
SMDA / SMIRR / SMRR	(1.85)
LRAMVA (2011 & 2012 CDM Activities)	0.16
STS Rate Rider	0.16
Rate Rider for Account 1576	**(5.68)**
Distribution Volumetric Rate	1.68
DVA Rate Rider	0.88
Net Incremental Change	**(2.30)**

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-11

Reference: Exhibit 1, Page 67

Interrogatory:

What is the net level of costs included in the 2015 test year revenue requirement associated conservation programs?

Response:

There are no costs included in the 2015 test year revenue requirement associated with conservation programs. Conservation programs are funded through the OPA (now IESO).

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-12

Reference: Exhibit 1, Page 71

Interrogatory:

Is the $122,000 included in the test year revenue requirement for customer engagement and communications a one-time expense? If not, please provide the forecast for the 2016 through 2019 period.

Response:

The $122,000 included in the test year revenue requirement for customer engagement and communications is an annual expense. The forecast for 2016 through 2019 is $122,000 per year.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-13

Reference: Exhibit 1, Page 79

Interrogatory:

The evidence indicates that in early 2013 NBHDL used a third party to review the meter-to-cash process. Did NBHDL also review its working cash requirements through a lead/lag study? If not, please explain fully why not.

Response:

NBHDL did not review its working cash requirements through a lead/lag study as part of the meter-to-cash process. The meter-to-cash review focused on internal processes not working cash requirements.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-14

Reference: Exhibit 1, Page 80

Interrogatory:

The evidence states that NBHDL will continue to make cost reduction and productivity improvement measures a priority.

a) Has NBHDL estimated the impact on ratepayers of a one percentage change in the working capital allowance percentage used to calculate rate base? If not, why not?

b) Please provide an estimate of the impact on ratepayers of a 1 percent point reduction in the working capital allowance (i.e. from 13% to 12%). Please show all calculations and assumptions used.

c) Has NBHDL done any analysis of its working capital requirement and/or whether the default value of 13% is appropriate and in the best interests of ratepayers? If not, why not?

d) Has NBHDI attempted to do any benchmarking of its working capital requirement relative to distributors that have filed lead/lag studies? If not, why not?

Response:

a) NBHDL has not estimated the impact on ratepayers of a one percentage change in the working capital allowance percentage used to calculate rate base. NBHDL applied the 13% working capital allowance in the application because the filing requirements state the following:

> *In a letter dated April 12, 2012, the Board provided an update to electricity distributors and transmitters on the options established in the June 22, 2011 cost of service filing requirements for the calculation of the allowance for working capital for the 2013 rate year. The applicant may take one of two approaches for the calculation of its allowance for working capital: (1) the 13% allowance approach; or (2) the filing of a lead/lag study.*
>
> *The only exception is if the applicant has been previously directed by the Board to undertake a lead/lag study on which its current working capital allowance is based.*

NBHDL was not previously directed by the Board to undertake a lead/lag study. As a result, NBHDL choose the 13% allowance approach.

NBHDL is aware that the working capital allowance issue has been addressed by the Board in at least two cases and based on the Board's decision in these cases the 13% approach is consistent with the Board decision. In the first case Kitchener-Wilmot Hydro Inc. (EB-2013-0147) the Board's findings are as follows.

> *On the matter of whether KWHI responded to all relevant Board directions from previous proceedings, the Board accepts KWHI's interpretation of the Board's April 12, 2012 letter as being reasonable and therefore does not find that KWHI was required to perform and file a lead-lag study in support of this Application.*
>
> *Based on the finding above, and in recognition of section 2.5.1.3 of the Filing Requirements for Electricity Distribution Rate Applications, which establishes the Board's expectation with respect to the WCA and allows for the default 13% approach in the absence of previous direction by the Board to undertake a lead/lag study; the Board does not find it necessary to consider whether any WCA other than the default 13% used by KWHI is more appropriate in this Application.*

In the second case Hydro One Brampton Networks Inc. (EB-2014-0083) the Board's findings were as follows.

> *The Board has been clear that an applicant may follow one of two approaches, (1) the 13% Working Capital Allowance, an amount which was determined as a result of the Board's policy, or (2) the filing of a lead lag study. The only exception to this approach is if the applicant has been previously directed by the Board to file a lead lag study on which its Working Capital Allowance is based. HOBNI has not been ordered to conduct such a study.*

> *The Board has commenced a policy review on Working Capital Allowance. Until that work is complete, the existing policy will remain in effect.*

b) The following tables outline the impact on rate base, revenue requirement and the overall distribution rate impact for a 1% reduction in working capital allowance.

2015 Rate Base Calculation	12% WCA	Application	Difference
Fixed Assets Opening Balance 2015	52,531,878	52,531,878	-
Fixed Assets Closing Balance 2015	57,844,415	57,844,415	-
Average Fixed Asset Balance for 2015	55,188,146	55,188,146	-
Working Capital Allowance	8,190,735	8,873,296	682,561
Rate Base	63,378,881	64,061,442	682,561
Regulated Rate of Return	6.28%	6.28%	6.28%
Regulated Return on Capital	3,982,459	4,025,348	42,889
Deemed Interest Expense	1,609,554	1,626,888	17,334
Deemed Return on Equity	2,372,905	2,398,460	25,555

Revenue Requirement	12% WCA	Application	Difference
OM&A Expenses	7,091,420	7,091,420	0
Amortization Expenses	2,569,662	2,569,662	0
Regulated Return On Capital	3,982,459	4,025,348	42,889
PILs	153,511	162,510	9,000
Revenue Requirement	13,797,052	13,848,941	51,889
Revenue @ Existing Rates	12,185,840	12,185,840	
Overall Rate Distribution Rate Impact	13.2%	13.6%	

c) Please see response to a)

d) Please see response to a)

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-15

Reference: Exhibit 1, Appendix 1-H

Interrogatory:

Please confirm that there are no costs included in the test year revenue requirement, the bridge year forecast or any of the historical years included in the OM&A costs for any of the corporate entities shown in the chart, other than NBHDL itself, including Board of Director costs. If this cannot be confirmed, please explain and quantify fully.

Response:

The table below summarizes the OM&A costs in the test year revenue requirement, the bridge year forecast and other historical years for Board of Directors and affiliated corporate entities shown in Appendix 1-H.

Board Expenses	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Forecast	2014 Actual	2015 Test Year
Directors & Officers Insurance	8,105	7,615	8,277	7,934	8,839	8,839	10,610
Board meeting meals	300	644	700	850	1,040	633	1,040
HOLDCO	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Generation	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Total	10,565	10,419	11,137	10,944	12,039	11,632	13,810

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Energy Probe-16

Reference: Exhibit 1, Page 104

Interrogatory:

Does NBHDL have a shareholder's agreement with its holding company and/or the City of North Bay? If yes, please provide a copy of the agreement that is currently in place.

Response:

a) NBHDL has a shareholder declaration with its holding company. A copy is included as Attachment-1-Energy Probe-16.

NORTH BAY HYDRO HOLDINGS LIMITED

SHAREHOLDER DECLARATION

RELATING TO NORTH BAY HYDRO DISTRIBUTION LIMITED

November 1, 2000

TABLE OF CONTENTS

SHAREHOLDER DECLARATION

SHAREHOLDER DECLARATION made as of the 1st day of November, 2000

BY:

THE CORPORATION OF THE CITY OF NORTH BAY (the " City" herein)

and

NORTH BAY HYDRO HOLDINGS LIMITED

(hereinafter referred to as the "Shareholder")

RE: NORTH BAY HYDRO DISTRIBUTION LIMITED, a corporation incorporated pursuant to the *Business Corporations Act* (Ontario)

(hereinafter referred to as the "Corporation")

WHEREAS Section 142 of the *Electricity Act, 1998* ("Electricity Act") requires that any municipal corporation that generates, transmits, distributes or retails electricity must cause a corporation to be incorporated under the *Business Corporations Act* (Ontario) ("OBCA");

AND WHEREAS pursuant to subsection 142(2) of the Electricity Act, the Corporation of the City of North Bay (the "City of North Bay") has incorporated the Corporation and North Bay Hydro Holdings Limited under the OBCA for the purpose of carrying on the distribution, and retailing of electricity, telecommunications services and other associated business activities currently carried on by The Hydro-Electric Commission of the City of North Bay ("North Bay Hydro");

AND WHEREAS the Shareholder is the owner of all of the issued and outstanding shares of the Corporation and the City is making this Declaration as the owner of all the shares of the Shareholder, and in support of the City's Shareholder Declaration for the Holding Company;

AND WHEREAS subsection 108(3) of the OBCA permits the beneficial owner of all of the issued shares of a corporation to make a written declaration that restricts in whole or in part the powers of the directors to manage or supervise the management of the business and affairs of a corporation;

AND WHEREAS the Shareholder has entered into this Shareholder Declaration with the intent that it shall be deemed pursuant to subsection 108(3) of the OBCA to be a unanimous shareholder agreement for the purpose of restricting the powers of the board of directors of the Corporation (the "Board) to manage or supervise the management of the business and affairs of the Corporation as specifically set out herein;

AND WHEREAS the City of North Bay, as sole shareholder of the Shareholder, will enter into, concurrently with the Shareholder entering into this Shareholder Declaration, a shareholder declaration (the "City of North Bay Shareholder Declaration") with the Shareholder restricting the powers of the directors of the Shareholder to manage or supervise the management of the business and affairs of the Shareholder and assuming such powers, in the same manner and to the same extent that the powers of the Board are restricted and assumed by the Shareholder pursuant to this Shareholder Declaration;

NOW THEREFORE, in consideration of the premises and of the mutual covenants herein contained, the parties hereto hereby agree as follows:

ARTICLE 1
INTERPRETATION

1.1 DEFINITIONS

In this Declaration, the following terms will have the meanings set out below:

"**Board**" has the meaning given to it in the recitals;

"**body corporate**" means a firm, partnership, unincorporated association, joint venture, body corporate, corporation, bank, trust, pension fund, union, governmental agency, board, tribunal, ministry or commission or other legal entity of any kind whatsoever, but excludes an individual or natural person;

"**Business**" means the electricity distribution business and all activities permitted by the Regulation to be carried on in connection therewith, as formerly carried on by North Bay Hydro and now carried on by the Corporation;

"**City of North Bay Shareholder Declaration**" has the meaning given to it in the recitals;

"**distribute**" means to convey electricity at voltages of 50 kilovolts or less, and "**distributing**" and "**distribution**" have corresponding meanings;

"**Financial Statements**" means, for any particular period, audited or unaudited (as the case may be), consolidated or unconsolidated (as the case may be), comparative financial statements of the Corporation consisting of not less than a balance sheet, a statement of income and retained earnings, a statement of changes in financial position, a report or opinion of the Auditor (in the case of audited Financial Statements) and such other statement, reports, notes and information prepared in accordance with generally accepted accounting principles (consistently applied) and as are required in accordance with any applicable law;

"**OBCA**" has the meaning given to it in the recitals;

"**person**" means an individual, a natural person or a body corporate;

"**Regulator**" means the Ontario Energy Board, the Independent Electricity Market Operator and each other governmental or regulatory authority having jurisdiction over the Corporation, as applicable in the circumstances;

"**Regulation**" means the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* and all codes, guidelines, orders and regulations created pursuant or in relation thereto; and

"**subsidiary**" shall have the meaning given to it in the OBCA.

"**sustaining profit**" means that level of return on equity (income after payment of taxes in lieu) which will generate sufficient net income to ensure that the utility is able to meet all cash flow requirements for capital expenditures, depreciation, operating expenses, debt servicing, system expansion and re-investment, but does not generate sufficient surplus funds that could be disbursed to the shareholder in the form of a dividend.

1.2 REGULATORY MATTERS:

In the event of any conflict between any approval or direction or other requirement of the Shareholder under this Declaration and any decision, order or policy of any Regulator, the decision, order or policy of the Regulator shall govern and the Shareholder and the Corporation will at all times comply with any decision, order or policy of the Regulator whether or not an approval or direction has first been given in respect thereof by the Shareholder under this Declaration. The Corporation will not seek any order from any Regulator for any matter that would require the approval of the Shareholder under this Declaration without first giving notice of its intention to seek such an order to the Shareholder.

1.3 OTHER ASSISTANCE:

The parties hereto shall sign such further and other papers, cause such meetings to be held, votes cast, special resolutions and resolutions passed, by-laws enacted and documents executed, and do and perform and cause to be done and performed such further and other acts and things as may be necessary or desirable to give full effect to the terms of this Declaration.

1.4 APPLICABLE LAW:

This Declaration shall be construed and enforced in accordance with the laws of the Province of Ontario and the applicable laws of Canada.

1.5 SUCCESSORS AND ASSIGNS:

This Declaration shall enure to the benefit of and be binding on the parties to this Declaration, all future shareholders of the Corporation and all persons who may hereafter be elected or appointed directors of the Corporation, and their respective heirs, executors, administrators, successors and assigns.

ARTICLE 2
POWERS OF DIRECTORS

2.1 RESTRICTION ON POWERS OF THE BOARD:

(a) The rights, powers and duties of the Board and all other persons who may hereafter be elected or appointed as directors of the Corporation to manage or supervise the management of the business and affairs of the Corporation, whether such rights, powers or duties under the Act, the articles or by-laws of the Corporation, or otherwise, are hereby restricted in the manner and to the extent specifically set out herein.

(b) The Board and all other persons who may hereafter be elected or appointed as directors of the Corporation are hereby relieved of the rights, powers, duties, obligations and liabilities imposed on them as directors of the Corporation whether arising under the Act or otherwise in the manner and to the extent specifically set out herein.

(c) The Shareholder hereby assumes the rights, powers, duties, obligations and liabilities of the Board, and of all other persons who may hereafter be elected or appointed as directors of the Corporation, whether arising under the Act or otherwise, in the manner and to the extent specifically set out herein.

ARTICLE 3
OBJECTIVES AND PRINCIPLES

3.1 PURPOSES:

The purpose of this Declaration is to restrict, to the extent and in the manner specifically set out herein, the Board's authority to manage or supervise the management of the business and affairs of the Corporation, and to provide the Shareholder with the Hydro to make decisions regarding those matters as to which it has been advised that the City of North Bay considers fundamental to the Business and in the best interests of the City of North Bay so that the City of North Bay may, in turn, assume the Hydro to make decisions regarding such matters pursuant to the City of North Bay Shareholder Declaration.

3.2 SHAREHOLDER OBJECTIVES:

The Shareholder's objectives in managing the business and affairs of the Corporation as set forth herein are to ensure that:

(a) The Business is integral to the well-being and the infrastructure of the City of North Bay. And it is in the best interests of the community of customers and residents of the City of North Bay whom the Business affects, that the Distribution Company conducts its affairs:.

(A) on a commercially prudent and sustaining profit basis;

(B) in a manner consistent with the policies established by the Shareholder from time to time; and

(C) in accordance with the financial performance objectives of the Shareholder as set out herein.

(b) The Distribution Company will provide a reliable, effective and efficient electricity distribution system.

(c) Distribution rates applicable to customers of the Distribution Company will be set by the Distribution Company Board and according to the rules of the Ontario Energy Board from time to time.

(d) The Business is at all times subject to such licences, codes, policies, rules, orders, interim orders, approvals, consents and other actions of any Regulator.

(e) The Distribution Company will provide its services regarding customer satisfaction, energy conservation and environmental responsibility.

(f) The Board is responsible for causing the Distribution Company to conduct its affairs in accordance with the same,

and the Board shall manage the Corporation on the basis of such objectives.

3.3 PRINCIPLES:

The following principles will govern the operations of the Corporation:

The Distribution Company shall make such decisions as are necessary to operate the Distribution Company on a sustaining profit basis, where the Shareholder requires a sustaining profit model for the Distribution Company, under which

(a) there is a sufficient return to maintain the value of the utility assets and the viability of the utility;

(b) the Shareholder will not require any shareholder dividend;

(c) any operating surplus is sufficient to recover the depreciation of assets and to pay any taxes that may be assessed, and that any operating surplus balance is applied to distribution purposes only;

(d) any operating surplus balance should not exceed the average of such surplus over the previous three years (on a rolling average basis); and, for greater certainty, any operating surplus balance should not create Year-end Working Capital that is in excess of the average of such surplus over the previous three years (on a rolling average basis) expressed as a percentage of Net Expenses.

ARTICLE 4
BUSINESS OF THE CORPORATION

4.1 BUSINESS OF THE CORPORATION:

The Corporation may engage only in the business activities in accordance with and permitted by the Regulation to be carried on by the Corporation, being, at the date hereof, the following business activities:

(a) distributing electricity;

(b) distributing (i) directly, (ii) through a subsidiary, (iii) through a third party, or (iv) through a combination of the foregoing, electricity to every person connected to the distribution system of the Corporation;

(c) business activities, the principal purpose of which is to use more effectively the assets of the distribution system of the Corporation, including, without limiting the generality of the foregoing:
   (i) meter reading services;
   (ii) billing and collection services;
   (iii) tree trimming services for the purpose of line maintenance;
   (iv) repair and maintenance for the distribution lines and facilities;
   (v) construction of distribution lines and facilities;
   (vi) general administrative support services;
   (vii) telecommunications services for electricity distribution; and
   (viii) activities that are essential to enable the conveyance of electricity;

(d) using the real property that the Corporation has the right to use for the purpose of providing telecommunications services, or entering into agreements with any third party, including subsidiaries, authorizing such third party or subsidiaries to use such real property for the purpose of providing telecommunications services;

(e) until such time as Section 71 of the *Ontario Energy Board Act* is proclaimed in force, or as otherwise advised by the Shareholder, (i) street lighting services; (ii) renting or selling of hot water heaters; (iii) renting of sentinel lights; and (iv) fibre optic cable services.

ARTICLE 5
BOARD OF DIRECTORS

5.1 BOARD RESPONSIBILITIES:

Subject to any matters requiring approval of the Shareholder pursuant to this Declaration, the Board will supervise the management of the business and affairs of the Corporation, including the following specific matters:

(i) Financial Structure - the Distribution Company Board shall establish policies to develop and maintain a prudent financial and capitalization structure for the corporation consistent with the industry's norm and sound financial principles on the basis that the Distribution Company is intended to be self-financing; and

(ii) Financial Return - the Distribution Company Board shall establish policies to provide the City of North Bay (as indirect shareholder of the Corporation) with a sustaining profit return on the Business which maintains or increases the value of the utility

(iii) give notice to and allow the Chief Executive Officer of the Holding Company to attend and participate in, but not vote at meetings of the Board of the Distribution Company.

ARTICLE 6
SHAREHOLDERS MATTERS

6.1 MATTERS REQUIRING SHAREHOLDER APPROVAL UNDER THE OBCA:

In accordance with the provisions of the OBCA, the Corporation will not, without the approval of the Shareholder:

(a) change the name of the Corporation;

(b) add, change or remove any restriction upon the business or businesses that the Corporation may carry on or upon the powers that the Corporation may exercise;

(c) add, change or remove any shares that the Corporation is authorized to issue or any maximum consideration for which any shares of the Corporation are authorized to be issued;

(d) create new classes of shares;

(e) change the designation of all or any of its shares, and add, change or remove any rights, privileges, restrictions and conditions, including rights to accrued dividends, in respect of all or any of its shares, whether issued or unissued;

(f) change the shares of any class or series, whether issued or unissued, into a different number of shares of the same class or series or into the same or a different number of shares of other classes or series;

(g) divide a class of shares, whether issued or unissued, into series and fix the number of shares in each series and the rights, privileges, restrictions and conditions thereof;

(h) authorize the directors to divide any class of unissued shares into series and fix the number of shares in each series and the rights, privileges, restrictions and conditions thereof;

(i) authorize the directors to change the rights, privileges, restrictions and conditions attached to unissued shares of any series;

(j) revoke, diminish or enlarge any authority conferred under clauses (h) and (i);

(k) increase or decrease the number, or minimum or maximum number, of directors; and

(l) add, change or remove restrictions on the issue, transfer or ownership of shares of any class or series.

6.2 OTHER MATTERS REQUIRING SHAREHOLDER APPROVAL:

(a) Distribution Rates – In setting the distribution rates charged to customers, the Distribution Company shall ensure that reasonable distribution rates are established which recognize the sustaining profit return required to maintain the value of the assets and the viability of the Business and as may be permitted by the Ontario Energy Board.

(b) Without the approval of the Shareholder, the Corporation will not:
   (i) Expenditures – incur expenditures beyond those required to maintain the integrity of the existing distribution system and accommodate normal expansion within City of North Bay borders in an amount in excess of $2,000,000.00 per project;

   (ii) Acquisitions – purchase any assets of a business or shares of a business;

   (iii) Sales – sell any distribution assets except in the normal course of business;

(iv) Capital – issue, redeem or purchase any shares or convertible shares of the corporation or make any other change in the issued capital;

(v) Capital Contribution – establish any requirement for capital contribution to the corporation from the Shareholder or the City of North Bay;

(vi) Financial Obligations – take on or assume any financial obligation which would increase the debt/equity ratio of the Corporation on a consolidated basis above the ratio of 50:50;

(vii) Tax, Regulatory Matters – make any decision which would adversely affect the tax or regulatory status of the Corporation in a material way;

(viii) Real Estate – sell any real estate assets, (excluding only distribution line easements which are no longer necessary for the distribution system) without the consent of the Shareholder to the sale and the application of the proceeds of the sale or other disposition of the property or any portion thereof or any additions thereto.

ARTICLE 7
REPORTING

7.1 BUSINESS PLAN:

Not later than 60 days prior to the end of each fiscal year, the Board will approve and submit to the Shareholder City of North Bay, pursuant to the City of North Bay Shareholder Declaration a business plan for the next five fiscal years (the "Business Plan"). The Business Plan will be prepared on a consistent basis with the Business Plan then in effect. The Corporation will carry on its business and operations in accordance with the Business Plan which will include, in respect of the period covered by such plan:

(a) the strategic direction and any new business initiatives which the Corporation will undertake;

(b) an operating and capital expenditure budget for the next fiscal year and an operating and capital expenditure projection for each fiscal year thereafter, including the resources necessary to implement the draft business plan;

(c) the projected annual revenues and profits for each fiscal year for the Corporation and each of the subsidiaries;

(d) pro forma consolidated and unconsolidated Financial Statements;

(e) an acquisition budget setting forth the nature and type of capital expenditures proposed to be made in the following fiscal year, supported by explanations, notes and information upon which the budget was based;

(f) environmental plans;

(g) any material variances in the projected ability of any business activity to meet or continue to meet the financial objectives of the Shareholder; and

(h) any material variances from the Business Plan then in effect.

7.2 SEMI-ANNUAL REPORTS:

Within 45 days after the end of each half of the fiscal year, the Board will prepare (on a consistent basis with the previous fiscal period) and submit to the Shareholder a semi-annual. The semi-annual report will include, in respect of the immediately precedent fiscal period:

(a) quarterly unaudited consolidated and unconsolidated Financial Statements;

(b) such explanations, notes and information as is required to explain and account for any variances between the actual results from operations and the budgeted amounts set forth in the current Business Plan, including any material variances in the projected ability of any business activity to meet or continue to meet the financial objectives of the Shareholder;

(c) information that is likely to materially affect the Shareholder's financial objectives or energy policies;

(d) information that is likely to materially affect customers' perceptions or opinions regarding the Corporation;

(e) information regarding any matter, occurrence or other event which is a material breach or violation of any law; and

(f) any such additional information as the Shareholder may specify from time to time.

7.3 ACCESS TO RECORDS:

The duly appointed representatives of the Shareholder (as approved by report to the Municipal Council of the City of North Bay from time to time) shall have unrestricted access to the books and records of the Corporation during normal business hours. Such representatives shall treat all information of the Corporation with the same level of care and confidentiality as any confidential information of the Shareholder.

7.4 AUDIT:

The Corporation's consolidated and unconsolidated Financial Statements will be audited annually. The first auditor of the Corporation is KPMG, Chartered Accountants, (the "Auditor").

7.5 ACCOUNTING:

The Corporation will, in consultation with the Auditor, adopt and use the accounting policies and procedures which may be approved by the Board from time to time and all such policies and procedures will be in accordance with generally accepted accounting principles and applicable regulatory requirements.

7.6 ANNUAL FINANCIAL STATEMENTS:

The Board will cause the Auditor to deliver, as soon as practicable and in any event within 90 days after the end of each fiscal year, the audited consolidated Financial Statements of the Corporation for consideration by the Shareholder.

ARTICLE 8
MISCELLANEOUS

8.1 CONFLICT OF INTEREST POLICY:

The directors and officers of the Corporation will abide by the requirements of the OBCA and the Corporation's articles and by-laws in respect of conflicts of interest, including any requirements in respect of disclosure and abstention from voting.

8.2 CONFIDENTIALITY:

The Shareholder and the directors and officers of the Corporation (each a "Receiving Party") will ensure that no confidential information of the Shareholder or the Corporation is disclosed or otherwise made available to any person, except to the extent that:

(a) disclosure to a Receiving Party's employees or agents is necessary for the performance of any Receiving Party's duties and obligations under this Declaration;

(b) disclosure is required in the course of judicial proceedings or pursuant to law; or

(c) the confidential information becomes part of the public domain (other than through unauthorized disclosure by the Receiving Party).

8.3 AMENDMENTS:

This Declaration may be amended solely at the discretion of the Shareholder. The Shareholder will consult with the Board and then provide ten (10) days prior written notice to the Board of any proposed amendments to this Declaration.

DATED at North Bay this 1st day of November, 2000.

NORTH BAY HYDRO HOLDINGS LIMITED
By Its Attorney:

Michael B. Burke

This declaration is executed pursuant to the Power of Attorney executed by North Bay Hydro Holdings Limited on the 1st day of November, 2000 pursuant to By-Law No. 2000-93 passed by the Council of The Corporation of the City of North Bay to approve the form of the Shareholders Declaration.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-1

Reference: Page 9, Line 6

Interrogatory:

"Mission - NBHDL is committed to distributing electricity to its customers in a safe, reliable and efficient manner that provides good value for money while being responsive to customer and community needs and contributing to provincial and local public policy objectives."

How does the phrase "good value for money" align with NBHDL adding approx $2.5 million to delivery rates in the form of deemed interest and return on equity in excess of what is required for the delivery of electricity?

In particular, please indicate how this practice is evidence that NBHDL's objectives are appropriately aligned with the preference of customers as required in the OEB's Requirements for Filing – Chapter 2.

Response:

As described in Exhibit 5 of the Application, NBHDL has prepared its 2015 COS Application in accordance with the Board's policies provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009. In these interrogatory responses, NBHDL has updated its evidence to reflect the cost of capital parameters issued by the Board on November 20, 2014 for rates with effective dates in 2015.

Compliance with the Board's cost of capital policies best aligns with NBHDL's mission as described in Exhibit 1 at page 9 of the Application. NBHDL has provided a description the core objectives it uses to implement its mission (Exhibit 1, pages 9-13). Compliance with the Board's cost of capital policies is consistent with NBHDL's core objective number 5, found at Exhibit 1 page 13, to "Actively support provincial and local public policy objectives." It also aligns with two of the Board's RRFE Outcomes - Public Policy Responsiveness and Financial Viability.

We would refer you to the response to 1-NBTA-2 for a further description of the rationale supporting use of the Board's cost of capital policies.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-2

Reference: Page 18, Line 14

Interrogatory:

“NBHDL has strived to provide good value service for money to its customers in the City of North Bay, in providing its shareholder with a rate of return”.

Since ratepayers, taxpayers and the company’s beneficial owners are the same group of people, how can customers receive a benefit by from any “rate of return” since they supply any funds used for this “rate of return” through delivery rates?

Please provide an explanation of how customers benefit from the practice of charging them more for the delivery of electricity than is required to maintain the system and deliver the electricity?

Response:

The Board’s policy on cost of capital reflects a considered balancing of interests: ensuring investors have an opportunity to earn a fair rate of return on their investment while protecting the interests of consumers.

This policy was derived by an independent regulator after extensive public consultations, involving input from numerous stakeholder groups and numerous experts in utility regulation and econometric analysis (see the Consultation Process on Cost of Capital Review (EB-2009-

0084) and the Cost of Capital, 2nd Generation Incentive Regulation Mechanism and Licence Amendment Proceeding (EB-2006-0087, EB-2006-0088, EB-2006-0089)).

As the name of the Board's policy implies – the cost of capital is a cost of doing business. If equity investors are not compensated by a fair rate of return, then the financial viability of a utility may be put at risk. Specifically, absent the provision of a fair rate of return (which an equity provider is entitled to by law) existing equity providers would be incented to withdraw their equity stake, which could then be redeployed in more lucrative ways. The utility could also find itself unable to raise additional equity in the future.

This explanation is further described in response to 2-NBTA-21.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-3

Reference: Page 57, Line 19

Interrogatory:

"In 2015, NBHDL has committed to continue implementing a more formal customer engagement program that commenced in 2014."

It seems quite evident from the low customer involvement and the recurring themes in these "engagement programs" that customers only interest in NBHDL is that they are getting a service at a value for money cost which ensures that when the customer flips a switch the light goes on.

This application demonstrates that the applicant will continue to charge customers using the same rate calculation method as in previous years which has resulted in collecting millions from customers in PIL's and countless more millions to pay dividends and increase its own working capital.

Please indicate how the cost of continuing to implement more formal customer engagement programs year after year will benefit customers.

Response:

In the *Report of the Board on Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012 (the "**RRFE Report**") the Ontario Energy Board identified customer focus - services are provided in a manner that responds to identified customer preferences - as among four key outcomes that ensure that Ontario's electricity system provides value for money for customers.

In response to this increased focus on customer engagement, Section 2.4.3 of the Chapter 2 Filing Requirements states:

> "The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations. The Board expects distributors to provide an overview of customer engagement activities that the distributor has undertaken with respect to its plans and how customer needs have been reflected in the distributor's application.
>
> Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits and the impact on rates. The application should discuss any feedback provided by customers and how this feedback shaped the final application.
>
> Distributors should also reference any other communications sent to customers about the application such as bill inserts, town hall meetings held, or other forms of outreach undertaken to engage customers and explain to them how the application serves their needs and expectations and the feedback heard from customers through these engagement activities.
>
> If distributors have not undertaken customer engagement activities, distributors must explain why and if any such activities are planned in the future."

In response to the Board's Filing Requirements to engage customers on the specific proposals contained in the Application, in the summer of 2014 NBHDL undertook a more formal customer engagement program by retaining Innovative Research Group, Inc. ("INNOVATIVE") to design, collect feedback and document its customer engagement and consultation process as part of the development of the Application. NBHDL asked that customers be engaged on both NBHDL's capital infrastructure and operational plans.

This customer engagement work and a summary of the customer preferences and NBHDL's efforts to respond to those preferences is described at Exhibit 1, Page 60, Line 7 to Exhibit 1, Page 72, Line 13. A complete copy of the INNOVATIVE Customer Engagement Report is attached to the Application as Appendix 1-A.7.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-4

Reference: Page 57, Line 23

Interrogatory:

"77% of residential and 84% of GS customers agree that "Nobody likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local electrical system for future generations."

The question gives the impression to respondents that NBHDL needs higher rates to maintain the reliability of the system. Based on the fact that NBHDL continues to pay yearly dividends to the City of North Bay plus the PILS's associated with those dividends, has spent over $25 million in capital expenditures in since 2010 to maintain the system and has accumulated over $10 million in working capital, it would appear that NBHDL has more than enough money to maintain the reliability of the system without raising rates.

Please explain how this leading question, other than in the most oblique way, satisfies the OEB requirement stated in "Requirements for Filing - Chapter 2 that "Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application and the values of those proposals to customers i.e. costs, benefits and the impact on rates and how customer feedback to the survey shaped the final application."

Response:

The question quoted above must be read in the context of the comprehensive customer engagement efforts undertaken by NBHDL.

NBHDL retained Innovative Research Group, Inc. ("INNOVATIVE") to design, collect feedback and document its customer engagement and consultation process as part of the development of this Application.

INNOVATIVE describes their approach to customer engagement in considerable detail in the INNOVATIVE Customer Engagement Report attached to the Application as Appendix 1-A.7.

INNOVATIVE readily acknowledges that there are no established practices and there are a number of options available to engage with customers. Appendix 1-A.7 explains how in detail how INNOVATIVE approached the engagement.

A key challenge in getting customer feedback on North Bay Hydro's rate application was the lack of knowledge customers have toward Ontario's electricity system and North Bay Hydro's role as the local distributor within the system.

To address this challenge, INNOVATIVE developed a consultation workbook a copy of which is attached as an appendix to the INNOVATIVE Customer Engagement Report. The workbook was used to inform customers on the proposals being considered for inclusion in the application and the values of those proposals to customers i.e. costs, benefits and the impact on rates.

Customer feedback from the workbook-facilitated discussion groups also informed the design of the subsequent telephone surveys by identifying unique issues and concerns of North Bay Hydro customers.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-5

Reference: Page 73, Line 15

Interrogatory:

The graph in the ACA report on page 243 indicates that 85% of NBHDL's distribution assets are in good or very good condition. Of the remaining 15%, 12% are in fair condition.

Based solely on these findings, how does the applicant support the timetable suggesting the need to spend an average of $6 million per year for the next 4 years as suggested in Table 1- 31.

Response:

NBHDL does not make decisions relating to the long-term investment requirements in its distribution system based solely upon any one metric or factor. A complete description of the NBHDL's proposed capital investment plan, including justifications, is provided in Exhibit 2, Appendix 2-A Distribution System Plan. Specifically, please refer to Section 4.1.3.2 of the Distribution System Plan for a brief description of how, for system renewal investments, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in this category. Capital investment decisions on specific projects consider not only the aggregate health of the distribution system as a whole, but also the health of particular components of the distribution system.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-6

Reference: Page 75, Line 22

Interrogatory:

If there is a savings of approximately $9 per month per customer using the e-billing system why has NDHDL not established a disincentive for those customers who do not use that system?

Response:

NBH received many requests for paperless billing and began offering an eBilling option in 2012 in direct response to customer preferences.

Other customers still prefer other billing options. For example, INNOVATIVE reported in Appendix 1-A.7 at pages 16-17 that:

- An older participant was hesitant to use online billing and felt the utility was trying to encourage him to migrate to this undesirable billing system.

- Another participant was disappointed that local “drop boxes” have been removed and envelopes were no longer being sent with their hydro bill.

As part of a business engagement session in May 2014 conducted by Clark marketing (a summary of which is included at Exhibit 1, Appendix 1-A.4), NBHDL asked "What would encourage you to switch to paperless billing?" and in response Clark reported that "Only one person uses online billing (The rest prefer paper bills because they have to print it out to have it on file anyways)."

NBHDL does not believe that establishing a disincentive for customers not using the eBilling system would be responsive to the above noted customer preferences at this time.

Rather, in light of clear customer preferences, NBHDL has been exploring an option of providing a one-time financial incentive to encourage more customers to switch over to eBilling. This is documented in:

- Exhibit 1, Appendix 1-A.1, where NBHDL asked business customers in a survey "What would encourage you to switch to paperless billing?" and in response, 27.8% of respondents indicated they were already registered for paperless billing, 33.3% suggested providing a one-time financial incentive to switch, and 26.8% indicated there isn't really anything that would encourage them to switch.

- Exhibit 1, Appendix 1-A.5, as part of a residential engagement session in June 2014 conducted by Clark Marketing, in comments from residential customers in response to a question about registration in eBilling, customers indicated a preference for an incentive to register in eBilling.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-7

Reference: Page 75, Line 26

Interrogatory:

"NBHDL also brought bill production and printing in house reducing purchases by $52,000 per year. NBHDL re-allocated workload with its existing staff...."

In 2010, NBHDL purchased a bill presentment system for approximately $75,000 in order to have an electronic method to send out customers' bills.

Did this purchase make possible part of the $52,000 in external purchases that is being saved?

Additionally, please explain how work taken from external contractors can be incorporated into employees' schedules when in the 2010 application, NBHDL indicated that the number of employees on staff at that time were required and fully engaged in providing service to customers.

Response:

There are two questions in this interrogatory. NBHDL will respond to each in turn.

In response to the first question, NBHDL purchased an electronic bill presentment system for $75,000 which primarily provided the capability for e-billing, allowing the customer to receive and view their bill and consumption information electronically. It also streamlined the bill production process reducing time and effort, and improving access for print and re-print. This system did not contribute to the $52,000 in savings as this was primarily from bringing the actual bill printing and inserting into envelops in-house from external contractor(s).

In response to the second question, through continuous improvements in operational efficiencies NBHDL was able to reallocate time of staff that were previously fully utilized to enable NBHDL to do more work with existing staff. These savings are now fully incorporated into rates, and flow directly to the benefit of ratepayers. NBHDL continues to search for further operational efficiencies. For example, in 2013, NBHDL retained Util-Assist to conduct a high-level analysis of meter-to-cash processes to ensure resource time is being used effectively and that systems are meeting requirements. This analysis is included at Exhibit 4, Appendix 4-A.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-8

Reference: Page 104, Line 17

Interrogatory:

"The Board's mandate, as set out in NBHDL's Shareholder Declaration is detailed below.

a) The Business is integral to the well-being and the infrastructure of the City of North Bay. It is in the best interests of the community of customers and the residents of North Bay whom the Business affects, that the Company conducts its affairs:

A) On a commercially prudent and sustaining profit basis"

The applicant's inclusion of the NBHDL Board's mandate suggests that the NBHDL Board of Directors and NBHDL are following the mandate. The complete opposite is true.

The applicant has failed to mention here that NBHDL's "Shareholder's Declaration" definition of "sustaining profit" is as follows:

"sustaining profit" means the level of return on equity (income after in payment of taxes in lieu) which will generate sufficient net income to ensure that the utility is able to meet all cash flow requirements for capital expenditures, depreciation, operating expenses, debt servicing, system expansion and re-investment, but does not generate sufficient surplus funds that could be disbursed to the shareholder in the form of a dividend."

The Declaration also goes on to describe the upper limit of any operating surplus as:

"(d) any operating surplus balance should not exceed the average of such surplus over the previous three years (on a rolling average basis): and for greater certainty, any operating surplus balance should not create Year-end Working Capital that is in excess of the average of such surplus over the previous three years (on a rolling average basis) expressed as a percentage of Net Expenses."

The revenue requirement requested in this application will allow surplus funds to be generated which will be then be disbursed to the shareholder in the form of a dividend. Dividends have been declared every year since 2008 including over $800,000 in 2015 which is clearly in violation of the *Shareholder's Declaration*.

The revenue requirement requested by the applicant will also result in the amount of year-end working capital exceeding mandated limits. That limit has been exceeded by NBHDL every year since 2008 and at the end of 2013 was approximately $6 million over the mandated amount. This is clearly in violation of the *Shareholder's Declaration* and NBHDL's Board of Directors mandate.

Could applicant please explain why NBHDL continues to contravene its Shareholder's Declaration while giving the impression to the OEB and the public that it is following that Declaration?

Also, explain why the applicant continues to apply for delivery rates which are in contravention of the Shareholder's Declaration's mandate?

<u>Response:</u>

The City of North Bay (the "**City**") is the sole and exclusive beneficiary of the Shareholder Declaration, and to the extent the Shareholders Declaration purports to limit the discretion of the board of directors of NBHDL to declare dividends, the City assumes such powers in the same manner and to the same extent that the power of the board of directors of NBHDL are so restricted. Please refer to Attachment-1-NBTA-8 below, being a letter from the City, pursuant to which the City confirms that it has accepted the payment of all dividends to the City since 2008 and the City does not challenge the declaration or the payment of any such dividends.

NORTH BAY
ONTARIO CANADA
Just North Enough to be PERFECT

The Corporation of the City of North Bay
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Office of the CAO
Telephone: 705 474-0400, Ext. 2400
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Friday April 22, 2015

DELIVERED BY EMAIL

North Bay Hydro Distribution Limited
74 Commerce Crescent
North Bay, ON P1A 0B4

Attention: The board of directors of NBHDL

Re: Clarification of Shareholder Declaration

I am writing to you on behalf of the City of North Bay (the "**City**"), the sole shareholder of North Bay Hydro Holdings Limited ("**NBHHL**"), which is in-turn the sole shareholder of North Bay Hydro Distribution Limited ("**NBHDL**") in respect of a question regarding the Shareholder's Declaration made as of November 1, 2000 concerning NBHDL.

The Shareholders Declaration was made pursuant to Section 108(3) of the *Business Corporations Act* (Ontario) (the "**Act**") for the sole and exclusive benefit of the City with the intent of restricting the powers of the board of directors of NBHDL to manage or supervise the management of the business and affairs of the corporation as specifically set out therein.

Since 2008 dividends paid by NBHDL and which have been ultimately paid to the City have been accepted by it. The City has not challenged the declaration or payment of any such dividends.

Sincerely,

J. Knox

Jerry Knox
Chief Administrative Officer
City of North Bay

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-9

Reference: Appendix 1 – A to Appendix 1 – A.7; Appendix 1- A.1 Business Customer Survey Summary, Page 128 – Power point slide; Page 134 – Power Point slide

Interrogatory:

We found a majority of the questions in these surveys to be leading and did also did not provide any evidence on which respondents could base their responses. The questions seemed to be attempts to elicit responses which would justify increases or could be interpreted to justify increases in delivery rates.

In addition, some questions, billing accuracy and response times for example, seem to be attempting to support increased expenditures when in fact they are merely indications that NBHDL is actually doing what they are being paid to do.

In addition, the number of respondents in these surveys is entirely too low to provide any real direction. We think the author's suggestion on page 272 should have read; *"Results contained within this report are based on a limited sample and are not evidentiary of and cannot be relied upon to provide any direction regarding future delivery rates."*

As a general rule, if a NBHDL customer flips a light switch in his home and the light comes on and he gets a bill at the end of the month that is the about the extent of the involvement with the local electricity delivery company that he wants.

NBHDL is a monopoly delivering an essential service. As such, questions concerning customer loyalty and respect are superfluous. Customers exclusively want the service they are paying for at rates which provide value for money.

Since the applicant is a monopoly delivering an essential commodity, the normal criteria for a survey which could be used by a real world business situation where the company is interested in retaining current customers and attracting new ones, do not necessarily apply to NBHDL.

It appears to us that these surveys are an attempt to justify higher delivery costs by changing customers' focus from the real purpose of NBHDL, that of delivering electricity which is a straight forward low cost activity, to one of being a defender of green energy, to being an educator of consumers about energy conservation, to developing social media and smart phone applications and other busy work in the hopes that it will convince ratepayers of the need for ever increasing costs.

We have commented below on some of the specific questions and responses.

Appendix 1- A.1 Business Customer Survey Summary, Page 128 – Power point slide

"What are the most important things North Bay Hydro can do to improve service to its customers?"

The answer that topped the list at 77% was better prices and lower rates.

Page 134 – Power Point slide

This slide indicates that 60% of business respondents do not think that NBHDL operates a cost effective hydro-electric system.

In light of the responses shown on those two slides and if the applicant is truly interested in responding to customers' concerns, please explain why NBHDL continues to engage in a scheme that obligates the company to pay PILS's amounting to millions of dollars, misleads customers about the benefit of dividends, and continues to accumulate excess working capital beyond the limits of its Shareholder's Agreement?

Response:

Prior to addressing the specific question contained in this interrogatory, NBHDL would like to address the issue of bias raised in the preamble to the question by noting that NBHDL engaged third parties, first Clark Marketing, and later INNOVATIVE Research Group Inc. ("INNOVATIVE"), to assist in the design of questions and surveys. One of the key benefits of moving to a more formalized customer engagement approach with INNOVATIVE is that INNOVATIVE clearly describes their approach to customer engagement in considerable detail in the INNOVATIVE Customer Engagement Report attached to the Application as Appendix 1-A.7. This, in turn, permits a rational discussion of both the questions asked and the feedback received.

In terms of survey sampling technique employed by INNOVATIVE, we believe the results of the surveys to statistically significant for the purposes of North Bay Hydro's customer engagement. Participants were randomly selected from customer lists provided by North Bay Hydro (15,576 residential records and 1,731 GS records).

- A sample of 505 residential customers is considered accurate to within ±4.5 percentage points, 19 times out of 20.

- A sample of 100 General Service customers is considered accurate to within ±9.5 percentage points, 19 times out of 20.

Moving now to the specific question raised, NBHDL does not dispute the evidence that many customers want better prices and lower rates or otherwise value the importance of running a cost effective utility.

NBHDL does, however, dispute the unsubstantiated allegation that it “continues to engage in a scheme that obligates the company to pay PILS’s amounting to millions of dollars, misleads customers about the benefit of dividends, and continues to accumulate excess working capital beyond the limits of its Shareholder’s Agreement.”

NBHDL has applied for just and reasonable rates in a manner that is consistent with the Ontario Energy Board’s policies as it relates to the cost of capital, the determination of working capital allowance, and the payment of PILs on net income.

If the NBTA disputes the Board’s policies on these matters, this proceeding in respect of this specific Application is not the right forum to have that debate. Numerous other third parties have an interest in, and should have an opportunity to participate in a proceeding that would lead any substantive changes to Board policy.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-10

Reference: Appendix 1-A.4 – Business Group Engagement Focus Group, Page 185 (at bottom of page)

Interrogatory:

"With everything that we learned and the process we just went through, customer engagement is a new cost to doing business for North Bay Hydro would you be willing to pay a nominal charge of as little as $7 per year, on your hydro bill, to pay for this engagement process? "

Answer: No, absolutely not our bills are already too high."

Even though this survey consisted of 11 participants and in no way could be considered as evidence of any future actions, once again cost control is the major item participants indicated that they are interested in and soundly rejected the idea of having to pay for any "customer engagement" that NBHDL and apparently the OEB, considers an important part of doing business.

The common theme running through all of these surveys is that NBHDL is not running an efficient organization and customers are not willing to see their costs rise whether is it to bury hydro lines, purchase more "green" energy or receive more customer engagement.

In the Customer Engagement Event Summary in Appendix 1- A on Page 111, NBHDL's response to customers concerns about this lack of confidence in the entire electricity system, NBHDL's stated plan of action is not to develop a an efficient system but to develop a "targeted communication plan".

Could the applicant please explain, in light of the OEB's sudden interest in customer feedback, would NBHDL not address customers' concerns directly by reducing delivery rates instead of attempting to convince customers that more costs to cover "customer engagement" are necessary.

Response:

NBHDL did not have discretion as to whether or not to implement a more formal customer engagement process. Please see the response to 1-NBTA-3.

Among the benefits of conducting more formal customer engagement is that the Board and the parties now benefit from better quality evidence on customer preferences in this Application. Please see the response to 1-NBTA-4.

Another benefit of conducting more formal customer engagement is that NBHDL can directly address rhetorical allegations of bias with a formalized and well documented approach to customer engagement. Please see the response to 1-NBTA-9.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-11

Reference: Page 188, Appendix 1-A.5 - Residential Engagement summary, Executive Summary

Interrogatory:

The Event details indicate there were 25 Residential customers present.

We attended this event and there were barely 15 people present including the staff from Clark Marketing. We will excuse the applicant being unaware of this error because no one from NBHDL was actually present at the event. No one was present from NBHDL even though the invitations indicated that residents were invited to join "your community and North Bay Hydro for a Residential Info Session."

This fact that there were no actual NBHDL employees there to answer questions was one of the main topics of conversation among participants and in reality the whole exercise produced no benefits whatsoever.

Please explain how this event benefited ratepayers in any meaningful way and fulfilled any of the OEB's requirements for customer engagement.

Response:

This residential customer information session was one part of a more comprehensive customer engagement effort undertaken by NBHDL, as further described in Exhibit 1, Page 52, Line 7 to Exhibit 1, Page 72, Line 13.

Clark Marketing was engaged to conduct this particular residential customer engagement session. No staff from NBHDL attended the session so that customers could feel free to express their candid views openly. Clark Marketing documented the session, reported that 25 residential customers were present, and this report is included as Appendix 1-A.5 as further evidence of customer feedback received in advance of this Application.

Following this information session, NBHDL determined that a more formal approach to customer engagement was required to address the Board's updated Filing Requirements as it related to customer engagement. Please see the response to 1-NBTA-10.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-12

Reference: Page 253, Appendix 1- A.7 INNOVATIVE Customer engagement report; Page 263 – Executive Summary; Page 264

Interrogatory:

Page 253 - Appendix 1- A.7 INNOVATIVE Customer engagement report

Page 263 – Executive Summary

The first two items on the list of what can NBHDL do better to improve services indicate that customers want rates decreased not increased.

And it seems clear from answers to questions in the other surveys that improving reliability, at third on the list, is a long way from first and second items as an issue.

Page 264

As to the suggestion that a majority of customers are willing to pay more to improve reliability, the question should have been;

"NBHDL spends millions each year on maintaining and upgrading the distribution system. Given your personal experience with reliability, how much more if any, would you be willing to spend to maintain that reliability?"

Please explain how responders could formulate answers to the reliability questions without at least some pertinent knowledge of the current situation.

Response:

As described in response to 1-NBTA-4, INNOVATIVE developed a consultation workbook a copy of which is attached as an appendix to the INNOVATIVE Customer Engagement Report. The workbook was used to inform customers on the proposals being considered for inclusion in the application and the values of those proposals to customers i.e. costs, the drivers, benefits and the impact on rates.

While INNOVATIVE did not ask the specific question invented by the NBTA, we would draw the readers' attention to the responses received to question #8 of the workbook which can be found at page 19 of Appendix 1-A.7 of the INNOVATIVE Customer Engagement Report, and confirmed that 12 respondents agreed that NBHDL should invest what to takes to replace aging infrastructure to maintain system reliability, even if that increases bills, while 4 respondents indicated that NBHDL should lower its investment in renewing the system's aging infrastructure to less the impact of any bill increases, even if that meant more or longer power outages.

INNOVATIVE asked a similar question as part of its residential and GS customer telephone survey, the results of which can be found at pages 50-52 of Appendix 1-A.7.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-13

Reference: Page 293

Interrogatory:

Over half of residential of customers did not know the breakdown of the bill between electricity costs and electricity delivery costs.

This would indicate a lack of knowledge among customers about power issues in general and therefore their ability to meaningfully answer questions contained in the various surveys concerning aging infrastructure, pay levels and other cost drivers.

The question concerning Bill Knowledge might have been better phrased as;

"On your hydro bill, NBHDL describes the items that go into delivery charges as being the cost to deliver electricity to your home and to build and maintain the transmission lines, towers and poles. However, it fails to mention that delivery charges also include amounts used to pay dividends to the City of North Bay and amounts used to increase its own cash reserves, both of which obligate NBHDL to pay PIL's to the Province. By the way did you know that delivery charges are about 20% of your entire bill?"

Please explain how the question about cost breakdown of charges, which is actually diverting customers' attention away from the delivery charge portion of their bill, informs customers about the makeup of the delivery charge on their bills.

Response:

Running the customer consultation on the North Bay Hydro's 2015 Application Review presented a unique challenge, namely the lack of familiarity with the provincial electricity system; including bill knowledge, the distribution system, how it is funded and regulated. This is well documented in Ontario Energy Board and INNOVATIVE's research.

Considering the challenge of low consumer bill knowledge (and the electricity system, in general), INNOVATIVE developed a process that created an opportunity for North Bay Hydro customers learn the basics of the distribution system so they can provide a more informed point of view.

The telephone survey preamble concerning Bill Knowledge cited in the interrogatory above was based upon the discussion of customer electricity bills found at page 7 of the workbook attached as an appendix to Appendix 1-A.7 of the INNOVATIVE Customer Engagement Report.

The purpose of this workbook page, and of the telephone survey preamble, was to inform customers about the different elements of their actual electricity bills and to clearly situate the scope of these consultations as focused on the distribution related delivery component of their electricity bills.

The purpose was not, at this stage, to inform customers about the makeup of the delivery charge on their bills. A discussion of key operating and capital cost drivers came later in the workbook and later during the telephone survey.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-NBTA-14

Reference: Page 364

Interrogatory:

From the brochure “The revenues collected from customers cover North Bay’s capital investments and operating expenses”

Please explain why this statement does not mention the fact that revenues also are used to pay dividends paid to the City of North Bay and also contribute to the continuing accumulation by NBHDL of excess amounts of working capital and the cost of PIL’s associated with these overcharges.

Response:

NBHDL asked INNOVATIVE to focus its consultations specifically on capital investments and operating expenses. In its Application, NBHDL is proposing to apply the Ontario Energy Board’s policies as it relates to cost of capital and return on equity, the calculation of working capital and the payment of PILS associated with any net income.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-1

Reference: Exhibit 1

Interrogatory:

Please provide a copy of all materials provided to the Board of Directors in approving this application, and the underlying Test Year budges. Please also provide a copy of the Applicant's most recent Business Plan.

Response:

The materials provided to the Board of Directors in approving this application and the underlying Test Year budgets are contained in Attachment-1-SEC-1. The 2015 Budget was approved September 18, 2014 and is NBHDL's current 2015 Business Plan.

2015 Proposed Budget

26-Jun-14

Confidential

2015 Proposed Budget

Table of Contents **Page**

Overview of Issues: 2015 Cost of Service Application

● Rates would be effective May 1, 2015 and must sustain the business until May 1, 2020. Minor changes only in the interim years. The last Cost of Service application was submitted in 2009 for rates effective May 1, 2010

● There is a high degree of probability there will be industry consolidation through this period

● Rates/spending finalized through a formal Hearing or Settlement conference

● Rates essentially have two components includeing components that drive distribution revenue (pay for OM&A costs, capital, borrowing etc) and rate riders that cover other costs (smart meters, cost of power balances etc)

● NBH has drivers impacting both OM&A costs and capital expenditures. OM&A increases are being driven by labour, insurance, postage, smart meter infrastructure and forestry program. Capital expenditures are in accordance with asset management/distribution system plan

● NBH must refund $3.6M to customers because of changes to depreciation periods. This refund would be via a rate rider. The balance could be paid over 1 year or longer periods however the cost to the business is the equivalent of 6.8% interest rate per year or $235,000. If re-paid over 1 year there is a significant drop in 2015 followed by a very large increase in 2016. Repaying over longer periods of time smooths rates but costs the business $235,000 from net income for each additional year

● Customers owe NBH $490K for costs of power incurred that have not been recovered. This is mainly because of Global Adjustment costs. Costs can be recovered over 1 year but 2 and 3 year recovery periods are also acceptable to mitigate impacts. Larger businesses will pay the majority of these incurred costs

● Borrowing is going to be required for cashflow purposes and to cover the costs of capital programs. Currently NBH is at a 40:60 debt equity ratio. The OEB deems the business to have a 60:40 structure for rate making purposes

● The province will continue to push for very aggressive conservation results and renewable electricity programs. To offset reduced electricity consumption at the local and provincial level, the province will be adopting fixed monthly rates. This will occur sometime over the next 3 years

● Succession planning will be important to the business as there are at least 9 retirements (20%) in the next 3-4 years

● Increased customer engagement is a key theme for the Ontario Energy Board however customers are showing a reluctance to be engaged

Executive Summary 2015 Proposed Budget

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Budget	2014Forecast	2015 Budget
Customer Billings	55,638,826	50,655,199	54,988,861	59,421,535	61,424,212	67,407,018	69,301,357	73,723,635	70,924,290
Distribution Revenue	9,936,309	9,809,598	10,721,301	11,118,450	11,011,597	11,383,360	13,214,826	13,396,558	11,326,455
O&M (less Depreciation)	5,580,648	4,955,944	4,876,086	5,230,803	5,369,782	5,572,041	6,334,708	6,695,086	6,857,188
Net Income	2,074,916	2,181,792	2,862,976	3,262,451	2,137,447	2,257,726	1,868,716	1,617,239	1,643,617
Cash	12,212,777	9,398,403	5,900,677	6,321,660	7,393,387	7,435,148	5,198,362	7,006,324	5,712,431
Capex	3,624,072	6,394,510	6,086,970	7,018,959	4,641,727	5,358,283	6,374,417	6,366,278	6,932,077
NBV	30,515,241	34,327,569	37,624,054	41,679,603	44,268,318	47,568,985	53,946,183	53,731,010	57,979,978
Debt	19,511,601	21,422,881	22,297,575	22,778,268	22,428,268	22,078,268	21,728,268	25,614,610	30,776,571
Equity	25,762,007	24,525,657	24,792,005	27,363,328	28,882,100	30,503,277	31,713,096	31,442,735	32,905,491
Working Capital	26.6%	19.0%	14.2%	9.9%	11.1%	7.5%	4.1%	9.9%	9.8%
OEB Debt/Equity	52/48	55/45	56/44	51/49	48/52	44/56	40/60	43/57	48/52

Summary Cash Flow 2008 Actual - 2015 Proposed Budget

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2008-2013 Actual	2014 Budget	2014 Forecast	2015 Proposed Budget
OPERATING ACTIVITIES										
Net income for the period	**$ 1,415,859**	**$ 96,600**	**$ 2,118,120**	**$ 3,262,451**	**$ 2,137,447**	**$ 2,257,726**	**$ 11,288,202**	**$ 1,868,716**	**$ 1,617,239**	**$ 1,643,617**
	-	**-**	**-**	**-**	**-**	**-**		**-**	**-**	**-**
Adjustments for:										
Items not involving cash:	2,483,727	2,580,751	2,729,487	3,068,682	1,693,499	2,143,855	14,700,000	2,501,829	2,494,261	2,672,028
Working capital changes	4,198	(261,488)	(1,736,229)	2,013,307	62,142	1,531,975	1,613,905	(734,254)	(2,561,264)	(846,188)
Decrease (increase) in regulatory assets/liabilities (excl future taxes)	449,051	(753,258)	(46,828)	(702,344)	2,345,143	433,866	1,725,630	647,108	1,521,783	(2,501,733)
Cash provided by operating activities	**4,352,835**	**1,662,604**	**3,064,550**	**7,642,096**	**6,238,230**	**6,367,422**	**29,327,737**	**4,283,399**	**3,072,018**	**967,725**
CAPITAL INVESTING ACTIVITIES										
Purchase of property, plant and equipment	(5,078,912)	(7,318,514)	(6,991,971)	(7,483,088)	(5,317,656)	(6,420,222)	(38,610,363)	(7,625,384)	(7,528,916)	(7,436,110)
Contributions received in aid of construction	1,454,840	924,004	905,001	464,129	675,929	1,061,939	5,485,842	1,250,967	1,162,638	504,033
Proceeds on sale of property, plant and equipmen	12,306	6,253	-	8,281	443,898	19,171	489,908	-	6,875	-
Cash used in Capital Investing	**(3,611,766)**	**(6,388,258)**	**(6,086,970)**	**(7,010,678)**	**(4,197,829)**	**(5,339,112)**	**(32,634,613)**	**(6,374,417)**	**(6,359,403)**	**(6,932,077)**
FINANCING ACTIVITIES										
Cash from short term investments	-		-	-	2,000,000	-	2,000,000	-	-	-
Smart Meter Loan/Capital Loan	-	1,911,280	874,694	480,693	(350,000)	(350,000)	2,566,667	(350,000)	(350,000)	(350,000)
Capital Loan 2014	-	-	-	-	-	-	-	-	3,886,342	(231,111)
Capital Loan 2015	-	-	-	-	-	-	-	-	-	5,743,073
Cash provided by Financing activities	**-**	**1,911,280**	**874,694**	**480,693**	**1,650,000**	**(350,000)**	**4,566,667**	**(350,000)**	**3,536,342**	**5,161,962**
Dividends	**(1,000,000)**		**(1,350,000)**	**(691,131)**	**(618,674)**	**(636,549)**	**(4,296,354)**	**(592,115)**	**(677,781)**	**(491,502)**
Net increase in cash (decrease)	**(258,931)**	**(2,814,374)**	**(3,497,726)**	**420,980**	**3,071,727**	**41,761**	**(3,036,563)**	**(3,033,134)**	**(428,824)**	**(1,293,893)**
Cash , beginning of period	**10,471,708**	**10,212,777**	**7,398,403**	**3,900,680**	**4,321,660**	**7,393,387**	**10,471,708**	**8,231,496**	**7,435,148**	**7,006,323**
Cash , end of year	**$ 10,212,777**	**$ 7,398,403**	**$ 3,900,677**	**$ 4,321,660**	**$ 7,393,387**	**$ 7,435,148**	**$ 7,435,145**	**$ 5,198,362**	**$ 7,006,323**	**$ 5,712,431**
Restricted cash and cash equivalents	2,000,000	2,000,000	2,000,000	2,000,000						
Total cash and cash equivalents	12,212,777	9,398,403	5,900,677	6,321,660	7,393,387	7,435,148	7,435,145	5,198,362	7,006,324	5,712,431

2015 Proposed Budget Assumptions

Revenue

- Assumes May 1, 2014 rates through 2015 ~ there is **no assumption for a rate increase from Cost of Service application in distribution revenue**
- Rebasing model shows a $1.6 million or 15% revenue deficiency
- kWh and kW based on load forecast using regression analysis based on 1999 forward adjusted for the decreases in consumption beginning in 2012
- 2015 predicted billed kWh is approx. 32m kWh less than 2013 billed kWh - assumed 14m kWh CDM reduction and 17m kWh reduction from Arclin
- Number of customers generated by load forecast - flat growth for 2015
- Smart meter rate riders expire in April 2014
- Includes collection from customers of $120k for LRAM impacts from CDM program up to 2012
- Assumes approval of disposition for all deferral account balances as of December 31, 2013 plus interest to April 30, 2015
- Assumes approval of disposition of Account 1576 (changes to depreciation based on extension to useful lives in 2012) over a one year period refunded to customers of $3.6m - includes liability of $3.4m plus a return of $235k (at NBHDL's 6.8% regulated rate of return) which is a reduction to net income
- Cost of power rates from RPP Price Report $92.50/MWh or $.09250/kWh
- No Changes are assumed for Network and Connection rates - this information will be available in early 2015
- Other Revenue - services charges are calculated using prior year avg, Bell is considered complete in 2014, interest on RSVA as per balances and OEB rate, interest on cash is based on the March 2014 ytd avg rate

OM&A Expenses

- Adding 1 Engineering employee in October 2014 for retirement at the end of October 2015
- Adding 1 Customer account specialist in January for retirement at the end of July
- Wages increase for union employees at 2.5% as per contract; staff as per 3rd party analysis
- Benefits calculated as per government rates, union contract and forecasted health benefit rates
- Tree Trimming @ $604k up $254k from 2014 budget, up $246k to 2014 forecast
- Engineering/Operations process review included at $100k
- Rebasing expenses in Finance @ $147k in 2014 and $138k in 2015 (charged out to a prepaid to be expensed over 5 years)
- Customer Engagement consulting services in Finance @ $135k
- Asset Management @ $20k down $27k from 2014 forecast included in Engineering O&M expenses
- Employee Future Benefit expense in HR down by $111k due to IFRS changes
- Administration includes $100k for strategic consulting services
- Smart Meter O&M disposition expenses decrease by $413k, $915k for depreciation - on going expenses for labour, Sensus and ODS in O&M instead of regulatory account
- Assumes approval of disposition of Account 1576 (changes to depreciation based on extension to useful lives in 2012) ($2.3m) in depreciation and $2.2m regulatory loss

Capital

- Capital program based on continuation of voltage conversion project, 3 large major betterment projects (Madelena/Wickstead/Melina Close) MS22 design construction (replacement of MS9) & the replacement of a transformer at MS13
- Replacement of truck #'s 5/9/10 (small fleet vehicle) and 2 work trailers as per the fleet replacement schedule
- Improvement to stores area
- IT based on PC and server requirements

Borrowing

- Smart Meter May 2011 of $3.5M rate of 3.82% 10 years - balance at the end of 2014 $2.4 million , 2015 balance $1.9 million
- August 2014 loan of $4M rate of 3.10% 10 years - balance at the end of 2014 $3.9 million , 2015 balance $3.7million
- June 2015 loanof $6M rate of 3.10% 10 years - balance at the end of 2015 $5.7 million

Dividends

- Dividend calculated as per dividend policy
- 2013 dividend balance of $290k paid in 2014
- 2014 dividend total $485k, $388k in 2014, $97k in 2015
- 2015 dividend total $493k, $394k in 2015, $99k in 2016

Financial Summary
2014 Variance to 2014 Budget

	2014 Budget	2014 Forecast	Variance	Comments
Customer Billings	69,301,357	73,723,635	4,422,278	
Cost of Power	56,086,531	60,327,076	4,240,546	
Distribution Revenue	13,214,826	13,396,558	181,732	
Other Revenue	1,261,973	1,182,831	(79,142)	Bell ($88k), OPA $18k
OM&A	6,334,708	6,695,086	360,378	Ops $262k-less labour & overheads to capital; Finance $85k-postage, Junior Acct, customer engagement; Admin $80-Navigant report, legal, smart meters; Engineering ($48k) AM plan; HR ($18k)-Union Contract offset by NBHS charges and Employee benefits
Depreciation	3,353,233	3,355,847	2,614	
Other	1,070,721	1,073,567	2,846	
Gain on Reg Assets	(1,139,412)	(1,152,181)	(12,769)	
Income Prior to Taxes	2,578,724	2,302,709	(276,016)	
PILS	710,008	685,470	(24,538)	
Net Income	1,868,716	1,617,239	(251,477)	
EBITDA	8,061,686	7,803,880	(257,807)	
EBITDA	55.7%	53.5%	-2.2%	
Cash	5,198,362	7,006,323	1,807,962	increase due to borrowing
Capital Spending	6,374,417	6,366,278	(8,140)	
Net Fixed Assets	53,946,183	53,731,010	(215,174)	write off of stranded meters ($278k), opening $74k
Borrowing	2,216,667	6,103,009	3,886,342	$4m Aug 2014 10 years
Dividends	592,115	677,781	85,666	2013 final $146k offset with 2015 forecast ($60k)
Working Capital	4.1%	9.9%	5.8%	increased due to borrowing, 2010-2013 avg 10.7%
CNB Debt-to-Equity	41/59	45/55		
OEB Debt/Equity	37/63	43/57		

Financial Summary
2015 Proposed Budget with Variance to 2014 Forecast

	2014 Forecast	2015 Budget	Variance	Comments
Customer Billings	73,723,635	70,924,290	(2,799,345)	
Cost of Power	60,327,076	59,597,835	(729,241)	
Distribution Revenue	13,396,558	11,326,455	(2,070,104)	Smart meter disp $1.9m, 1576 - deprecation disp $150k.
Other Revenue	1,182,831	1,103,248	(79,583)	Smart meter disp $211k, RSVA $22k, Interest $22k, Bell ($312k), OPA ($185k)
OM&A	6,695,086	6,857,188	162,102	Ops $ 380k - tree trimming, process review; Finance $60k - rebasing, wages offset sm disp; Engineering $20k - AM plan; HR $($161)- employee benefits IFRS, union contract, sucession consultant; Admin ($136k)- IT services, insurance, strategic review offset with sm disp and legal
Depreciation	3,355,847	377,008	(2,978,839)	Smart meter disp ($951k), 1576- depreciation disp ($2.3M), offset by new capital spending
Other	1,073,567	1,379,967	306,399	Smart meter disp $90k, Interest $182k
Gain on Reg Assets	(1,152,181)	(2,171,924)	(1,019,743)	1576- depreciation dispostion (change in useful lives of assets), offset in depreciation and other revenue
Income Prior to Taxes	2,302,709	1,643,617	(659,092)	
PILS	685,470	-	(685,470)	Income for tax purposes negative
Net Income	1,617,239	1,643,617	26,378	
EBITDA	7,803,880	5,490,160	(2,313,719)	
EBITDA	53.5%	44.2%	-9.4%	
Cash	7,006,323	5,712,430	(1,293,893)	operations $3.8m, regulatory disp ($2.8), capital ($6.9), financing $5.1m, dividends ($492k)
Capital Spending	6,366,278	6,932,077	565,799	
Net Fixed Assets	53,731,010	57,979,978	4,248,968	Capital spending $6.9m offset with dep $2.7M
Borrowing	6,103,009	11,264,970	5,161,962	$6M June 2015 10 years
Dividends	677,781	491,502	(186,279)	2013 final $193k offset with 2015 forecast vs 2014 ($6k)
Working Capital	9.9%	9.8%	-0.10%	consistent due to borrowing, 2010-2013 avg 10.7%
CNB Debt-to-Equity	45/55	48/52		
OEB Debt/Equity	43/57	48/52		

Financial Summary
2015 Proposed Budget compared to Budget with rate increase

	2015 Budget	2015 Budget rates increased	Variance	Comments
Customer Billings	70,924,290	71,962,705	1,038,415	
Cost of Power	59,597,835	59,597,835	-	
Distribution Revenue	11,326,455	12,364,870	1,038,415	Inrease due to new rates May-December
Other Revenue	1,103,248	1,104,355	1,107	Interest on cash balances
OM&A	6,857,188	6,857,188	-	
Depreciation	377,008	377,008	-	
Other	1,379,967	1,379,967	-	
Gain on Reg Assets	(2,171,924)	(2,171,924)	-	
Income Prior to Taxes	1,643,617	2,683,139	1,039,522	
PILS	-	-	-	Income for tax purposes still a negative
Net Income	1,643,617	2,683,139	1,039,522	
EBITDA	5,490,160	6,529,682	1,039,522	
EBITDA	44.2%	48.5%	4.3%	
Cash	5,712,430	6,220,760	508,330	Cash from operations $758k, less dividends $249
Capital Spending	6,932,077	6,932,077	-	
Net Fixed Assets	57,979,978	57,979,978	-	
Borrowing	11,264,970	11,264,970	-	assumed same borrowing working capital still under allowed 13%, still in compliance with covenants
Dividends	491,502	740,988	249,486	30% of net income increase less 20% discount
Working Capital	9.8%	11.0%	1.18%	
CNB Debt-to-Equity	48/52	48/52		
OEB Debt/Equity	48/52	48/52		

2015 Proposed Capital

	2014 BUDGET	2014 FORECAST	2014 FORECAST VARIANCE to 2014 BUDGET	2015 BUDGET	2015 BUDGET VARIANCE to 2014 FORECAST	NOTES
DISTRIBUTION SYSTEM ASSETS						
ASSET MANAGEMENT	-	21,523	21,523	-	(21,523)	
GENERATOR CONNECTIONS	92,415	92,415	-	48,016	(44,399)	
MAJOR BETTERMENTS	708,510	615,104	(93,407)	1,266,604	651,500	Madelena & Wickstead - $900k
VOLTAGE CONVERSION	1,117,210	1,187,731	70,522	1,852,043	664,311	
MINOR BETTERMENTS	1,091,671	1,062,961	(28,710)	342,997	(719,964)	Bell complete - VCONV
PORCELIN REPLACEMENTS	97,404	98,181	776	-	(98,181)	Porcelin complete 2014
PRIMARY SERVICES	126,345	126,367	21	215,639	89,273	
SECONDARY SERVICES	329,348	329,451	103	240,615	(88,836)	
SUBDIVISIONS	103,235	103,244	9	99,963	(3,281)	
TRANSFORMER PURCHASES - 850 & 851	369,202	369,202	-	379,248	10,045	
METERING	238,167	230,564	(7,603)	276,216	45,652	
SUBSTATION UPGRADES - 815	1,655,894	1,740,487	84,592	2,103,074	362,587	
ROAD PROJECTS	266,790	96,278	(170,512)	210,094	113,816	5 year avg
					-	
TOTAL DISTRIBUTION SYSTEM ASSETS	**6,196,191**	**6,073,507**	**(122,684)**	**7,034,507**	**961,000**	
GENERAL ASSETS						
OFFICE UPGRADES / FURNITURE	642,613	649,403	6,790	56,652	(592,751)	BLDG/HVAC/Gen 2014
TRANSPORTATION EQUIPMENT	503,000	503,000	-	145,000	(358,000)	Fleet plan
TOOL REQUIREMENTS	47,000	47,000	-	46,151	(849)	
IT REQUIREMENTS	236,580	256,005	19,425	153,800	(102,205)	5 year plan
					-	
TOTAL GENERAL ASSETS	**1,429,192**	**1,455,408**	**26,215**	**401,603**	**(1,053,805)**	
TOTAL CAPITAL SPENDING	**7,625,384**	**7,528,915**	**(96,469)**	**7,436,110**	**(92,805)**	
CONTRIBUTED CAPITAL	**(1,250,965)**	**(1,162,638)**	**88,327**	**(504,033)**	**658,605**	Bell FSA 2014
TOTAL NET CAPITAL SPENDING	**6,374,418**	**6,366,277**	**(8,141)**	**6,932,077**	**565,800**	

Employee Complement - 2008 - Proposed 2015 Year End Position

Department	2010 Actual	2010 Budget	2011 Actual	2012 Actual	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2015 Budget	2015 vs 2014 Forecast	2015 vs 2010 COS
Accounting/Finance	4	4	4	4	4	4	4	5	5	-	1
CAS	5	7	5	5	5	5	5	5	5	-	(2)
Billing	2	2	2	2	2	2	2	2	2	-	-
IT	1	1	-	1	1	1	2	1	1	-	-
Administration	1	1	1	1	1	1	1	1	1	-	-
* CDM	1	1	2	2	1	1	1	1	1	-	-
Human Resources	1	1	1	1	1	1	1	1	1	-	-
Engineering	6	6	7	7	7	8	8	9	8	(1)	2
Lines	15	16	15	15	15	14	14	14	14	-	(2)
Operations Administration	3	4	3	3	3	3	3	3	3	-	(1)
Customer Services Reps.	2	2	2	2	2	2	2	2	2	-	-
Metering	2	2	2	2	2	2	2	2	2	-	-
Substations	2	2	2	2	2	2	2	2	2	-	-
Stores	1	1	1	1	1	1	1	1	1	-	-
Total	**46**	**50**	**47**	**48**	**47**	**47**	**48**	**49**	**48**	**(1)**	**(2)**

2015 Proposed Budget Rate Impacts

RESIDENTIAL (800 kWh)

		1 YR RIDER				2 YR RIDER				3 YR RIDER w/ 2 YR RIDER FOR DVA			
	Current	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*
Fixed Service Charge	14.64	16.78	*2.14*	17.01	*0.23*	16.78	*2.14*	17.01	*0.23*	16.78	*2.14*	17.01	*0.23*
Distribution Variable	10.48	12.00	*1.52*	12.17	*0.17*	12.00	*1.52*	12.17	*0.17*	12.00	*1.52*	12.17	*0.17*
Total Fixed & Variable	25.12	28.78	*3.66*	29.18	*0.40*	28.78	*3.66*	29.18	*0.40*	28.78	*3.66*	29.18	*0.40*
NBHDL distribution revenue rate increase (%)			*14.57%*		*1.40%*		*14.57%*		*1.40%*		*14.57%*		*1.40%*
Fixed Riders													
Smart Meter Riders	2.70	-	*(2.70)*	-	-	-	*(2.70)*	-	-	-	*(2.70)*	-	-
Stranded Meter Rider	-	0.85	*0.85*	-	*(0.85)*	0.85	*0.85*	-	*(0.85)*	0.85	*0.85*	-	*(0.85)*
Volumetric Riders													
Tax Savings	(0.16)	-	*0.16*	-	-	-	*0.16*	-	-	-	*0.16*	-	-
Lost Revenue (2011 & 2012 CDM Activities)	-	0.08	*0.08*	0.08	-	0.04	*0.04*	0.04	-	0.03	*0.03*	0.03	-
Dep'n/Useful Life Change	-	(5.68)	*(5.68)*	-	*5.68*	(3.04)	*(3.04)*	-	*3.04*	(2.16)	*(2.16)*	-	*2.16*
Total Riders	2.54	(4.75)	*(7.29)*	0.08	*4.83*	(2.15)	*(4.69)*	0.04	*2.19*	(1.28)	*(3.82)*	0.03	*1.31*
Total NBHDL Distribution	**27.66**	**24.03**	***(3.63)***	**29.26**	***5.23***	**26.63**	***(1.03)***	**29.22**	***2.59***	**27.50**	***(0.16)***	**29.21**	***1.71***
NBHDL distribution rate increase (%)			*-13.12%*		*21.78%*		*-3.72%*		*9.74%*		*-0.58%*		*6.23%*
Deferral Accounts - Power	(1.44)	(0.56)	*0.88*			(0.28)	*1.16*			(0.28)	*1.16*		
Global Adjustment	-	-	-			-	-			-	-		
Low Voltage	0.03	0.03	-			0.03	-			0.03	-		
Line Losses - COP	3.55	3.55	-			3.55	-			3.55	-		
Smart Meter Entity	0.79	0.79	-			0.79	-			0.79	-		
Total Pass Through Costs	2.93	3.81	*0.88*			4.09	*1.16*			4.09	*1.16*		
Total Distribution	**30.59**	**27.84**	***(2.75)***			**30.72**	***0.13***			**31.59**	***1.00***		
Distribution rate increase (%)			*-8.99%*				*0.42%*				*3.27%*		
Total bill	128.23	125.42				128.39				129.23			
Total bill impact ('16 is approx.)		-2.19%		4.17%		0.12%		2.02%		0.78%		1.33%	

GS<50 (2,000 kWh)

		1 YR RIDER				2 YR RIDER				3 YR RIDER w/ 2 YR RIDER FOR DVA			
	Current	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*
Service Charge	21.69	24.86	*3.17*	25.21	*0.35*	24.86	*3.17*	25.21	*0.35*	24.86	*3.17*	25.21	*0.35*
Distribution Variable	33.40	38.20	*4.80*	38.73	*0.53*	38.20	*4.80*	38.73	*0.53*	38.20	*4.80*	38.73	*0.53*
Total Fixed & Variable	55.09	63.06	*7.97*	63.94	*0.88*	63.06	*7.97*	63.94	*0.88*	63.06	*7.97*	63.94	*0.88*
NBHDL distribution revenue rate increase (%)			*14.47%*		*1.40%*		*14.47%*		*1.40%*		*14.47%*		*1.40%*
Fixed Riders													
Smart Meter Riders	11.05	-	*(11.05)*	-	-	-	*(11.05)*	-	-	-	*(11.05)*	-	-
Stranded Meter Rider	-	1.92	*1.92*	-	*(1.92)*	1.92	*1.92*	-	*(1.92)*	1.92	*1.92*	-	*(1.92)*
Volumetric Riders													
Tax Savings	(0.40)	-	*0.40*	-	-	-	*0.40*	-	-	-	*0.40*	-	-
Lost Revenue (2011 & 2012 CDM Activities)	-	1.00	*1.00*	1.00	-	0.50	*0.50*	0.50	-	0.33	*0.33*	0.33	-
Dep'n/Useful Life Change	-	(14.20)	*(14.20)*	-	*14.20*	(7.60)	*(7.60)*	-	*7.60*	(5.40)	*(5.40)*	-	*5.40*
Total Riders	10.65	(11.28)	*(21.93)*	1.00	*12.28*	(5.18)	*(15.83)*	0.50	*5.68*	(3.15)	*(13.80)*	0.33	*3.48*
Total NBHDL Distribution	**65.74**	**51.78**	***(13.96)***	**64.94**	***13.16***	**57.88**	***(7.86)***	**64.44**	***6.56***	**59.91**	***(5.83)***	**64.27**	***4.36***
NBHDL distribution rate increase (%)			*-21.24%*		*25.42%*		*-11.96%*		*11.34%*		*-8.87%*		*7.28%*
Deferral Accounts - Power	(3.60)	0.40	*4.00*			0.20	*3.80*			0.20	*3.80*		
Global Adjustment	-	-	-			-	-			-	-		
Low Voltage	0.08	0.08	-			0.08	-			0.08	-		
Line Losses - COP	8.88	8.88	-			8.88	-			8.88	-		
Smart Meter Entity	0.79	0.79	-			0.79	-			0.79	-		
Total Pass Through Costs	6.15	10.15	*4.00*			9.95	*3.80*			9.95	*3.80*		
Total Distribution	**71.89**	**61.93**	***(9.96)***			**67.83**	***(4.06)***			**69.86**	***(2.03)***		
Distribution rate increase (%)			*-13.85%*				*-5.65%*				*-2.82%*		
Total bill	313.60	303.33				309.33				311.40			
Total bill impact ('16 is approx.)		-3.27%		4.34%		-1.36%		2.12%		-0.70%		1.40%	

2015 Proposed Budget Rate Impacts

GS>50 (192,000 kWh / 455 kW)

		1 YR RIDER				2 YR RIDER				3 YR RIDER w/ 2 YR RIDER FOR DVA			
	Current	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*
Service Charge	293.97	336.90	*42.93*	341.62	*4.72*	336.90	*42.93*	341.62	*4.72*	336.90	*42.93*	341.62	*4.72*
Distribution Variable	953.95	1,087.27	*133.32*	1,102.49	*15.22*	1,087.27	*133.32*	1,102.49	*15.22*	1,087.27	*133.32*	1,102.49	*15.22*
Total Fixed & Variable	1,247.92	1,424.17	*176.25*	1,444.11	*19.94*	1,424.17	*176.25*	1,444.11	*19.94*	1,424.17	*176.25*	1,444.11	*19.94*
NBHDL distribution revenue rate increase (%)			*14.12%*		*1.40%*		*14.12%*		*1.40%*		*14.12%*		*1.40%*
Volumetric Riders													
Tax Savings	(11.01)	-	*11.01*	-	-	-	*11.01*	-	-	-	*11.01*	-	-
Lost Revenue (2011 & 2012 CDM Activities)	-	18.97	*18.97*	18.97	-	9.49	*9.49*	9.49	-	6.32	*6.32*	6.32	-
Dep'n/Useful Life Change	-	(1,314.18)	*(1,314.18)*	-	*1,314.18*	(698.93)	*(698.93)*	-	*698.93*	(493.84)	*(493.84)*	-	*493.84*
Total Riders	(11.01)	(1,295.21)	*(1,284.20)*	18.97	*1,314.18*	(689.44)	*(678.43)*	9.49	*698.93*	(487.52)	*(476.51)*	6.32	*493.84*
Total NBHDL Distribution	**1,236.91**	**128.96**	***(1,107.95)***	**1,463.08**	***1,334.12***	**734.73**	***(502.18)***	**1,453.60**	***718.87***	**936.65**	***(300.26)***	**1,450.43**	***513.78***
NBHDL distribution rate increase (%)			*-89.57%*		*1034.52%*		*-40.60%*		*97.84%*		*-24.28%*		*54.85%*
Deferral Accounts - Power	(329.47)	116.79	*446.26*			58.39	*387.86*			58.39	*387.86*		
Global Adjustment	150.01	423.28	*273.27*			211.64	*61.63*			211.64	*61.63*		
Low Voltage	6.32	6.68	*0.36*			6.68	*0.36*			6.68	*0.36*		
Line Losses - COP	691.20	691.20	-			691.20	-			691.20	-		
Total Pass Through Costs	518.06	1,237.95	*719.89*			967.91	*449.85*			967.91	*449.85*		
Total Distribution	**1,754.97**	**1,366.91**	***(388.06)***			**1,702.64**	***(52.33)***			**1,904.56**	***149.59***		
Distribution rate increase (%)			*-22.11%*				*-2.98%*				*8.52%*		
Total bill	25,184.51	24,746.00				25,125.38				25,353.55			
Total bill impact ('16 is approx.)		-1.74%		5.31%		-0.23%		2.78%		0.67%		1.95%	

Intermediate (1,720,000 kWh / 3,290 kW)

		1 YR RIDER				2 YR RIDER				3 YR RIDER w/ 2 YR RIDER FOR DVA			
	Current	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*
Service Charge	5,844.10	6,697.56	*853.46*	6,791.33	*93.77*	6,697.56	*853.46*	6,791.33	*93.77*	6,697.56	*853.46*	6,791.33	*93.77*
Distribution Variable	3,668.35	3,915.76	*247.41*	3,970.58	*54.82*	3,915.76	*247.41*	3,970.58	*54.82*	3,915.76	*247.41*	3,970.58	*54.82*
Total Fixed & Variable	9,512.45	10,613.32	*1,100.87*	10,761.91	*148.59*	10,613.32	*1,100.87*	10,761.91	*148.59*	10,613.32	*1,100.87*	10,761.91	*148.59*
NBHDL distribution revenue rate increase (%)			*11.57%*		*13.13%*		*11.57%*		*1.40%*		*11.57%*		*1.40%*
Volumetric Riders													
Tax Savings	(61.52)	-	*61.52*	-	-	-	*61.52*	-	-	-	*61.52*	-	-
Dep'n/Useful Life Change	-	(12,261.83)	*(12,261.83)*	-	*12,261.83*	(6,521.27)	*(6,521.27)*	-	*6,521.27*	(4,607.75)	*(4,607.75)*	-	*4,607.75*
Total Riders	(61.52)	(12,261.83)	*(12,200.31)*	-	*12,261.83*	(6,521.27)	*(6,459.75)*	-	*6,521.27*	(4,607.75)	*(4,546.23)*	-	*4,607.75*
Total NBHDL Distribution	**9,450.93**	**(1,648.51)**	***(11,099.44)***	**10,761.91**	***12,410.42***	**4,092.05**	***(5,358.88)***	**10,761.91**	***6,669.86***	**6,005.57**	***(3,445.36)***	**10,761.91**	***4,756.34***
NBHDL distribution rate increase (%)			*-117.44%*		*-752.83%*		*-56.70%*		*163.00%*		*-36.46%*		*79.20%*
Deferral Accounts - Power	(3,008.05)	1,376.53	*4,384.58*			688.27	*3,696.32*			688.27	*3,696.32*		
Global Adjustment	1,368.31	4,926.20	*3,557.89*			2,463.10	*1,094.79*			2,463.10	*1,094.79*		
Low Voltage	50.67	53.63	*2.96*			53.63	*2.96*			53.63	*2.96*		
Line Losses - COP	1,570.86	1,570.86	-			1,570.86	-			1,570.86	-		
Total Pass Through Costs	(18.21)	7,927.22	*7,945.43*			4,775.86	*4,794.07*			4,775.86	*4,794.07*		
Total Distribution	**9,432.72**	**6,278.71**	***(3,154.01)***			**8,867.91**	***(564.81)***			**10,781.43**	***1,348.71***		
Distribution rate increase (%)			*-33.44%*				*-5.99%*				*14.30%*		
Total bill	204,192.67	200,628.64				203,554.43				205,716.71			
Total bill impact ('16 is approx.)		-1.75%		6.11%		-0.31%		3.20%		0.75%		2.24%	

2015 Proposed Budget Rate Impacts

Street Lights (168,200 kWh / 470 kW)													
		1 YR RIDER				2 YR RIDER				3 YR RIDER w/ 2 YR RIDER FOR DVA			
		2015	*2015*	2016	*2016*	2015	*2015*	2016	*2016*	2015	*2015*	2016	*2016*
	Current	**Proposed**	***Increase***	**Assumed**	***Increase***	**Proposed**	***Increase***	**Assumed**	***Increase***	**Proposed**	***Increase***	**Assumed**	***Increase***
Fixed Service Charge	26,444.72	30,292.21	*3,847.49*	30,716.30	*424.09*	30,292.21	*3,847.49*	30,716.30	*424.09*	30,292.21	*3,847.49*	30,716.30	*424.09*
Distribution Variable	12,278.99	14,072.18	*1,793.19*	14,269.19	*197.01*	14,072.18	*1,793.19*	14,269.19	*197.01*	14,072.18	*1,793.19*	14,269.19	*197.01*
Total Fixed & Variable	38,723.71	44,364.39	*5,640.68*	44,985.49	*621.10*	44,364.39	*5,640.68*	44,985.49	*621.10*	44,364.39	*5,640.68*	44,985.49	*621.10*
NBHDL distribution revenue rate increase (%)			*14.57%*		*16.17%*		*14.57%*		*16.17%*		*14.57%*		*16.17%*
Volumetric Riders													
Tax Savings	(214.60)	-	*214.60*	-	-	-	*214.60*	-	-	-	*214.60*	-	-
Lost Revenue (2011 & 2012 CDM Activities)	-	3,826.81	*3,826.81*	3,826.81	-	1,913.25	*1,913.25*	1,913.25	-	1,275.50	*1,275.50*	1,275.50	-
Dep'n/Useful Life Change	-	(1,202.50)	*(1,202.50)*	-	*1,202.50*	(639.53)	*(639.53)*	-	*639.53*	(451.87)	*(451.87)*	-	*451.87*
Total Riders	(214.60)	2,624.31	*2,838.91*	3,826.81	*1,202.50*	1,273.72	*1,488.32*	1,913.25	*639.53*	823.63	*1,038.23*	1,275.50	*451.87*
Total NBHDL Distribution	**38,509.11**	**46,988.70**	***8,479.59***	**48,812.30**	***1,823.60***	**45,638.11**	***7,129.00***	**46,898.74**	***1,260.63***	**45,188.02**	***6,678.91***	**46,260.99**	***1,072.97***
NBHDL distribution rate increase (%)			*22.02%*		*3.88%*		*18.51%*		*2.76%*		*17.34%*		*2.37%*
Deferral Accounts - Power	(294.88)	(5,717.88)	*(5,423.00)*			(2,858.94)	*(2,564.06)*			(2,858.94)	*(2,564.06)*		
Global Adjustment	134.23	423.78	*289.55*			211.89	*77.66*			211.89	*77.66*		
Low Voltage	5.08	5.36	*0.28*			5.36	*0.28*			5.36	*0.28*		
Line Losses - COP	710.48	710.48	-			710.48	-			710.48	-		
Total Pass Through Costs	554.91	(4,578.26)	*(5,133.17)*			(1,931.21)	*(2,486.12)*			(1,931.21)	*(2,486.12)*		
Total Distribution	**39,064.02**	**42,410.44**	***3,346.42***			**43,706.90**	***4,642.88***			**43,256.81**	***4,192.79***		
Distribution rate increase (%)			*8.57%*				*11.89%*				*10.73%*		
Total bill	64,250.93	68,032.38				69,497.38				68,988.78			
Total bill impact		5.89%		1.77%		8.17%		0.92%		7.37%		0.65%	

Sentinel Lights (150 kWh / 1 kW)													
		1 YR RIDER				2 YR RIDER				3 YR RIDER w/ 2 YR RIDER FOR DVA			
		2015	*2015*	2016	*2016*	2015	*2015*	2016	*2016*	2015	*2015*	2016	*2016*
	Current	**Proposed**	***Increase***	**Assumed**	***Increase***	**Proposed**	***Increase***	**Assumed**	***Increase***	**Proposed**	***Increase***	**Assumed**	***Increase***
Fixed Service Charge	4.42	5.07	*0.65*	5.14	*0.07*	5.07	*0.65*	5.14	*0.07*	5.07	*0.65*	5.14	*0.07*
Distribution Variable	15.44	17.69	*2.25*	17.94	*0.25*	17.69	*2.25*	17.94	*0.25*	17.69	*2.25*	17.94	*0.25*
Total Fixed & Variable	19.86	22.76	*2.90*	23.08	*0.32*	22.76	*2.90*	23.08	*0.32*	22.76	*2.90*	23.08	*0.32*
NBHDL distribution revenue rate increase (%)			*14.60%*		*16.21%*		*14.60%*		*16.21%*		*14.60%*		*16.21%*
Volumetric Riders													
Tax Savings	(0.23)	-	*0.23*	-	-	-	*0.23*	-	-	-	*0.23*	-	-
Dep'n/Useful Life Change	-	(2.37)	*(2.37)*	-	*2.37*	(1.26)	*(1.26)*	-	*1.26*	(0.89)	*(0.89)*	-	*0.89*
Total Riders	(0.23)	(2.37)	*(2.14)*	-	*2.37*	(1.26)	*(1.03)*	-	*1.26*	(0.89)	*(0.66)*	-	*0.89*
Total NBHDL Distribution	**19.63**	**20.39**	***0.76***	**23.08**	***2.69***	**21.50**	***1.87***	**23.08**	***1.58***	**21.87**	***2.24***	**23.08**	***1.21***
NBHDL distribution rate increase (%)			*3.87%*		*13.19%*		*9.53%*		*7.34%*		*11.41%*		*5.53%*
Deferral Accounts - Power	(0.36)	(3.81)	*(3.45)*			(1.90)	*(1.54)*			(1.90)	*(1.54)*		
Global Adjustment	0.17	0.78	*0.61*			0.39	*0.22*			0.39	*0.22*		
Low Voltage	0.01	0.01	-			0.01	-			0.01	-		
Line Losses - COP	0.54	0.54	-			0.54	-			0.54	-		
Total Pass Through Costs	0.36	(2.48)	*(2.84)*			(0.96)	*(1.32)*			(0.96)	*(1.32)*		
Total Distribution	**19.99**	**17.91**	***(2.08)***			**20.54**	***0.55***			**20.91**	***0.92***		
Distribution rate increase (%)			*-10.41%*				*2.75%*				*4.60%*		
Total bill	38.90	36.78				39.46				39.83			
Total bill impact		-5.45%		6.44%		1.44%		3.19%		2.39%		2.23%	

2015 Proposed Budget Rate Impacts

UMSL (150 kWh)		1 YR RIDER				2 YR RIDER				3 YR RIDER w/ 2 YR RIDER FOR DVA			
	Current	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*	2015 Proposed	*2015 Increase*	2016 Assumed	*2016 Increase*
Fixed Service Charge	7.03	8.06	*1.03*	8.17	*0.11*	8.06	*1.03*	8.17	*0.11*	8.06	*1.03*	8.17	*0.11*
Distribution Variable	2.43	2.79	*0.36*	2.83	*0.04*	2.79	*0.36*	2.83	*0.04*	2.79	*0.36*	2.83	*0.04*
Total Fixed & Variable	9.46	10.85	*1.39*	11.00	*0.15*	10.85	*1.39*	11.00	*0.15*	10.85	*1.39*	11.00	*0.15*
NBHDL distribution revenue rate increase (%)			*14.69%*		*16.30%*		*14.69%*		*16.30%*		*14.69%*		*16.30%*
Volumetric Riders													
Tax Savings	(0.03)	-	*0.03*	-	-	-	*0.03*	-	-	-	*0.03*	-	-
Dep'n/Useful Life Change	-	(1.07)	*(1.07)*	-	*1.07*	(0.57)	*(0.57)*	-	*0.57*	(0.41)	*(0.41)*	-	*0.41*
Total Riders	(0.03)	(1.07)	*(1.04)*	-	*1.07*	(0.57)	*(0.54)*	-	*0.57*	(0.41)	*(0.38)*	-	*0.41*
Total NBHDL Distribution	**9.43**	**9.78**	***0.35***	**11.00**	***1.22***	**10.28**	***0.85***	**11.00**	***0.72***	**10.44**	***1.01***	**11.00**	***0.56***
NBHDL distribution rate increase (%)			*3.71%*		*12.49%*		*9.01%*		*7.02%*		*10.71%*		*5.38%*
Deferral Accounts - Power	(0.27)	(0.13)	*0.14*			(0.07)	*0.20*			(0.07)	*0.20*		
Global Adjustment	-	-	-			-	-			-	-		
Low Voltage	0.01	0.01	-			0.01	-			0.01	-		
Line Losses - COP	0.54	0.54	-			0.54	-			0.54	-		
Total Pass Through Costs	0.28	0.42	*0.14*			0.48	*0.20*			0.48	*0.20*		
Total Distribution	**9.71**	**10.20**	***0.49***			**10.76**	***1.05***			**10.92**	***1.21***		
Distribution rate increase (%)			*5.05%*				*10.81%*				*12.46%*		
Total bill	26.66	27.14				27.71				27.88			
Total bill impact		1.80%		3.94%		3.94%		2.06%		4.58%		1.47%	

NBHDL Rate Comparison

Within 5% of NBHDL

Last CoS F	NBHDL Current 2010	NBHDL 2015 Proposed	Sudbury 2013	Lakeland 2013	PUC 2013	Thunder Bay 2013	HON - R1	HON - R2 Custom IR	HON - U1	NOTL 2014	Peterborough 2013	Wellingt on-North 2012	Kitchener 2014	Waterloo 2011	Guelph 2012	Halton 2012	CND 2014
RESIDENTIAL CUSTOMER - 800 kWh																	
2015 Distribution Rates																	
Service Ch	14.64	16.78	16.23	20.22	9.94	12.99	20.15	57.61	12.72	18.19	12.59	18.51	10.66	15.23	14.50	12.73	13.51
Distributior	10.48	12.00	9.98	11.84	13.71	10.06	27.12	29.79	20.46	10.22	9.88	14.82	13.16	15.44	14.11	9.60	13.14
Total Fixec	25.12	28.78	26.21	32.06	23.65	23.05	47.27	87.40	33.18	28.41	22.47	33.33	23.82	30.67	28.62	22.33	26.65
		3.66	2.57	(3.28)	5.13	5.73	(18.49)	(58.62)	(4.40)	0.37	6.31	(4.55)	4.96	(1.89)	0.16	6.45	2.13
		15%	9%	-11%	18%	20%	-64%	-204%	-15%	1%	22%	-16%	17%	-7%	1%	22%	7%
GS<50 kWh CUSTOMER - 2,000 kWh																	
2015 Distribution Rates																	
Service Ch	21.69	24.86	21.69	43.79	16.91	26.69	36.26	-	10.20	37.80	30.65	39.29	26.16	32.04	15.59	27.54	18.74
Distributior	33.40	38.20	37.52	17.85	40.56	27.58	80.50	-	33.68	22.71	17.42	33.62	25.18	28.64	26.16	17.09	26.16
Total Fixec	55.09	63.06	59.21	61.64	57.47	54.27	116.76	-	43.88	60.52	48.06	72.90	51.34	60.68	41.75	44.63	44.90
		7.97	3.85	1.42	5.59	8.79	(53.70)		19.18	2.54	15.00	(9.84)	11.72	2.38	21.31	18.43	18.16
		14%	6%	2%	9%	14%	-85%		30%	4%	24%	-16%	19%	4%	34%	29%	29%

**assumed '14 Board approved rates times IRM increase based on '13 ranking in PEG report*

			1.4%	1.4%	1.4%	1.4%				1.4%	1.25%	1.25%	1.55%	1.55%	1.4%	1.7%	1.4%
			16.01	19.94	9.80	12.81	20.15	57.61	12.72	17.94	12.43	18.28	10.50	15.00	14.30	12.52	13.32
			9.84	11.68	13.52	9.92	27.12	29.79	20.46	10.08	9.76	14.64	12.96	15.20	13.92	9.44	12.96
			21.39	43.19	16.68	26.32	36.26	-	10.20	37.28	30.27	38.80	25.76	31.55	15.37	27.08	18.48
			37.00	17.60	40.00	27.20	80.50		33.68	22.40	17.20	33.20	24.80	28.20	25.80	16.80	25.8

Income Statement 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2015 Proposed Budget	2015 Budget vs 2014 Forecast	Notes 2015 Budget prior to increase vs 2014 Forecast
Income Statement							
Revenue							
Customer Billings	61,424,212	67,407,018	69,301,357	73,723,635	70,924,290	(2,799,345)	
Cost of Power	50,412,615	56,023,658	56,086,531	60,327,076	59,597,835	(729,241)	
Distribution revenue	11,011,597	11,383,360	13,214,826	13,396,558	11,326,455	(2,070,104)	Smart meter disp $ 1.9m, 1576- deprecation disp $150k.
Other operating revenue	1,167,175	1,407,841	1,261,973	1,182,831	1,103,248	(79,583)	Smart meter disp$211k, RSVA $22k, Interest $22k, Bell ($312k), OPA ($185k)
Total Revenue	12,178,772	12,791,201	14,476,799	14,579,390	12,429,703	(2,149,687)	
Operating expenses							
Operations	2,324,477	2,544,722	2,438,619	2,700,543	3,080,884	380,341	Smart meter disp ($25k), tree $246k, review $100k , labour $55k
Finance	1,495,972	1,407,663	1,688,948	1,773,871	1,833,787	59,917	Smart meter disp ($104k), cost of service app $51k, Wages $84k, Postage $23k
Engineering	-	-	47,745	(0)	20,000	20,000	AM Plan
Human Resources	566,270	495,688	570,279	551,544	389,708	(161,835)	Union Contract ($43k), EFB IFRS ($111k), Succession Consultant 9$18k)
Administration	983,063	1,123,968	1,589,117	1,669,128	1,532,808	(136,321)	Smart meter disp ($283k), strategic plan $100k, IT security & mtce $53k, Insurance $20k, Navigant ($22k)
Depreciation and amortization	1,978,195	2,050,588	3,353,233	3,355,847	377,008	(2,978,839)	Smart meter disp ($951k), 1576- depreciation disp ($2.3M), offset by new capital spending
Total OM&A	7,347,977	7,622,629	9,687,941	10,050,933	7,234,195	(2,816,737)	
Income before items below	4,830,796	5,168,572	4,788,858	4,528,457	5,195,508	667,051	
Interest	1,171,090	1,149,551	990,317	1,019,628	1,291,323	271,695	Smart meter disp $90k, regulatory interest $26k,smart meter loan ($13k), 2014 loan $77k, 2015 loan $92k
Property taxes	57,183	62,479	64,354	64,374	66,305	1,931	
Income before other items and PILS	3,602,523	3,956,542	3,734,187	3,444,455	3,837,880	393,425	
					-		
Other items					-		
Gain/(loss) on disposal of PP&E	347,552	12,143	-	6,875	(6,289)	(13,164)	
Gain/(loss) on foreign exchange	(4,060)	11,365	-	19,610	-	(19,610)	
Charitable donation	15,550	21,050	16,050	16,050	16,050	-	
Income before PILS	3,930,465	3,959,000	3,718,137	3,454,890	3,815,541	360,651	
Gain/(loss) on regulatory assets	(1,132,571)	(1,164,967)	(1,139,412)	(1,152,181)	(2,171,924)	(1,019,743)	1576- depreciation dispostion (change in useful lives of assets)
Income before provisions for PILS	2,797,894	2,794,033	2,578,724	2,302,709	1,643,617	(659,092)	
					-		
Payment in lieu of taxes	660,447	536,307	710,008	685,470	-	(685,470)	Income for tax purposes negative
Future	-	-	-	-	-	-	
Income Taxes	660,447	536,307	710,008	685,470	-	(685,470)	
					-		
Net income for the period	**2,137,447**	**2,257,726**	**1,868,716**	**1,617,239**	**1,643,617**	**26,378**	
		-			-		
Retained earnings, beginning of the year	7,851,729	9,370,502	10,924,897	10,991,679	12,241,779	1,250,100	Net income $1.6m, dividends ($678k), IFRS adj $310k
Net income	2,137,447	2,257,726	1,868,716	1,617,239	1,643,617	26,378	
Dividends	(618,674)	(636,549)	(592,115)	(677,781)	(491,502)	186,279	2013 final $193k offset with 2015 forecast vs 2014 ($6k)
Retained earnings, end of month	9,370,502	10,991,679	12,201,498	11,931,137	13,393,893	1,462,756	
					-	-	
EBITDA	**6,736,257**	**7,135,631**	**8,061,686**	**7,803,880**	**5,490,160**	**(2,313,719)**	
EBITDA % of Revenue	***55.3%***	***55.8%***	***55.7%***	***53.5%***	***44.2%***	**-9.4%**	

Balance Sheet 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast vs 2014 Budget	2015 Proposed Budget	2015 Budget vs 2014 Forecast
Balance Sheet							
ASSETS							
Current assets							
Cash and short-term investments	7,393,387	7,435,148	5,198,362	7,006,323	1,807,962	5,712,430	(1,293,893)
Restricted short term investments	-	-	-	-	-	-	-
Accounts receivable	5,571,448	7,093,372	6,086,096	8,137,834	2,051,738	8,042,023	(95,811)
Unbilled revenue	7,740,920	7,733,424	6,492,935	6,877,858	384,923	7,725,255	847,397
Inventory	579,637	448,742	549,581	454,366	(95,215)	454,366	-
Prepaid expenses	532,163	608,750	582,518	889,486	306,967	976,120	86,634
Payments in lieu of taxes	-	35,176	8,135	-	(8,135)	-	-
Total current assets	**21,817,555**	**24,665,391**	**18,917,626**	**23,365,867**	**4,448,241**	**22,910,193**	**(455,673)**
Restricted short term investments	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Property, plant and equipment						-	
Electrical distribution assets	94,203,173	100,212,163	109,522,531	107,065,084	(2,457,447)	114,662,900	7,597,816
General assets	10,969,655	11,400,820	12,569,006	12,669,826	100,819	12,987,973	318,148
WIP	625,281	526,120	705,855	722,149	16,294	21,361	(700,788)
Gross Assets	105,798,108	112,139,102	122,797,391	120,457,058	(2,340,334)	127,672,234	7,215,176
Accumulated depreciation	(55,051,068)	(57,228,872)	(60,519,879)	(58,446,047)	2,073,833	(61,150,623)	(2,704,576)
	50,747,041	54,910,231	62,277,512	62,011,011	(266,501)	66,521,611	4,510,600
Contributions in aid of construction	(6,478,723)	(7,341,246)	(8,331,329)	(8,280,001)	51,328	(8,541,633)	(261,632)
Total property, plant and equipment	**44,268,318**	**47,568,985**	**53,946,183**	**53,731,010**	**(215,174)**	**57,979,978**	**4,248,968**
Other Assets	**6,361**	**6,361**	**6,361**	**6,361**	**-**	**6,361**	**-**
Regulatory assets	3,713,424	4,831,945	1,790,175	835,156	(955,018)	404,656	(430,500)
Future Income Taxes	6,497,137	6,075,056	2,404,643	4,588,904	2,184,261	4,226,329	(362,575)
TOTAL ASSETS	**76,302,795**	**83,147,738**	**77,064,987**	**82,527,297**	**5,462,310**	**85,527,517**	**3,000,220**
LIABILITIES							
Current liabilities							
Accounts payable and accrued liabilities	9,701,698	13,452,110	9,951,043	10,210,228	259,185	10,691,441	481,213
Operating Line	-	-	-	-	-	-	-
Deferred Revenue	275,247	614,896	402,725	455,301	52,576	406,634	(48,667)
Payments in lieu of taxes	153,315	-	-	85,470	85,470	-	(85,470)
Current portion of long-term customer deposits	87,689	80,063	87,689	80,063	(7,626)	80,063	-
Current portion of Smart Meter Capital Loan	350,000	350,000	350,000	350,000	-	350,000	-
Captital Loan 2014	-			113,658	113,658	231,111	117,453
Captital Loan 2015						256,927	
Inter Company	102,181	177,325	117,845	117,845	-	117,845	-
Total current liabilities	**10,670,130**	**14,674,394**	**10,909,302**	**11,412,565**	**503,263**	**12,134,022**	**721,457**
Long-term liabilities							
Customer deposits	883,091	862,925	850,653	805,356	(45,297)	805,356	-
Employee future benefits	4,405,983	4,511,393	4,606,023	4,611,413	5,390	4,289,690	(321,723)
Payable to Corporation of the City of North Bay	19,511,601	19,511,601	19,511,601	19,511,601	-	19,511,601	-
Trust Liability		353,952	352,839	355,044	2,205	-	(355,044)
Smart Meter/Capital Loan	2,566,667	2,216,667	1,866,667	1,866,667	-	1,516,667	(350,000)
Captital Loan 2014				3,772,684		3,424,120	
Captital Loan 2015						5,486,145	
Regulatory Liability - Future Income Taxes	6,497,137	6,075,056	2,404,643	4,588,904	2,184,261	4,226,329	(362,575)
Total long-term liabilities	**33,864,479**	**33,531,594**	**29,592,426**	**35,511,669**	**5,919,243**	**39,259,908**	**3,748,239**
Regulatory liabilities	2,886,086	4,438,473	4,850,164	4,160,329	(689,835)	1,228,096	(2,932,233)
Shareholder's equity							
Capital stock	19,511,601	19,511,601	19,511,601	19,511,601	-	19,511,601	-
Retained earnings, beginning of year	7,851,726	9,370,499	10,924,894	10,991,676	66,782	12,241,776	1,250,100
Dividends	(618,674)	(636,549)	(592,115)	(677,781)	(85,666)	(491,502)	186,279
Dividends in kind	-	-	-	-	-	-	-
Net Income	2,137,447	2,257,726	1,868,716	1,617,239	(251,477)	1,643,617	26,378
Retained earnings, end of year	9,370,499	10,991,676	12,201,495	11,931,134	(270,361)	13,393,890	1,462,756
Total shareholder's equity	**28,882,100**	**30,503,277**	**31,713,096**	**31,442,735**	**(270,361)**	**32,905,491**	**1,462,756**
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**76,302,795**	**83,147,738**	**77,064,987**	**82,527,297**	**5,462,310**	**85,527,517**	**3,000,220**

Cash Flow 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast vs 2014 Budget	2015 Proposed Budget	2015 Budget vs 2014 Forecast
Cash Flow							
CASH PROVIDED BY (USED IN):							
OPERATING ACTIVITIES							
Net income for the period	$ 2,137,447	$ 2,257,726	$ 1,868,716	$ 1,617,239	$ (251,477)	$ 1,643,617	$ 26,378
Adjustments for:							
Items not involving cash:							
Amortization of property, plant & equipment(net of amortization of contributions in aid of construction	1,978,195	2,050,588	2,401,809	2,401,116	(693)	2,676,821	275,705
OPA Depreciation Adjustment	4,827	-	-		-		-
Gain/loss on sale of property, plant and equipment	(373,907)	(12,143)	-	(6,875)	(6,875)	6,289	13,164
Accrual for employee future benefits	84,384	105,410	100,020	100,020	-	(11,081)	(111,101)
Write-down of regulatory assets	1,132,571	1,164,967	1,139,412	1,152,181	12,769	-	(1,152,181)
Future Income Taxes	-	422,081	2,700,261	1,486,152	(1,214,109)	362,575	(1,123,577)
Change in non-cash operating working capital:	-	-	-	-	-	-	-
Accounts receivable	(90,042)	(2,832,703)	(150,026)	266,317	416,343	95,811	(170,507)
Unbilled revenue	149,883	7,496	(180,264)	855,566	1,035,830	(847,397)	(1,702,963)
Inventory	178,834	130,895	50,419	(5,624)	(56,043)	-	5,624
Prepaid expenses	64,497	(76,587)	(53,927)	(280,736)	(226,809)	(86,634)	194,102
Accounts payable and accrued liabilities	(858,014)	3,750,412	(753,168)	(3,241,882)	(2,488,714)	481,213	3,723,095
Deferred Revenue	116,729	339,649	(156,924)	(159,595)	(2,671)	(48,667)	110,929
Payments in lieu of taxes	327,576	(188,491)	470,008	120,646	(349,362)	(85,470)	(206,116)
(Increase) decrease in other assets	-	-	-	-	-	-	-
Intercompany	179,055	75,144	39,628	(59,480)	(99,108)	-	59,480
Cash provided by operating activities	5,032,034	7,194,444	7,475,964	4,245,045	(3,230,919)	4,187,076	(57,969)
INVESTING ACTIVITIES							
Purchase of property, plant and equipment	(5,317,656)	(6,420,222)	(7,625,384)	(7,528,916)	96,468	(7,436,110)	92,806
Contributions received in aid of construction	675,929	1,061,939	1,250,967	1,162,638	(88,328)	504,033	(658,605)
Proceeds on sale of property, plant and equipment	443,898	19,171	-	6,875	6,875	-	(6,875)
Decrease (increase) in regulatory assets/liabilities	1,212,572	(1,153,182)	(3,192,565)	(1,116,550)	2,076,015	(2,864,308)	(1,747,758)
Cash used in investment activities	(2,985,257)	(6,492,294)	(9,566,982)	(7,475,953)	2,091,029	(9,796,385)	(2,320,432)
FINANCING ACTIVITIES							
Increase (decrease) in customer deposits	(6,376)	(27,792)	-	(57,569)	(57,569)	-	57,569
Deferred Revenue/Operating Loan	-	-	-	-	-	-	-
Dividends / Dividends in kind	(618,674)	(636,549)	(592,115)	(677,781)	(85,666)	(491,502)	186,279
(Increase) decrease in Note Receivable Services	2,000,000	-	-	-	-	-	-
Smart Meter Loan/Capital Loan	(350,000)	(350,000)	(350,000)	(350,000)	(0)	(350,000)	0
Capital Loan 2014	-			3,886,342	3,886,342	(231,111)	(4,117,453)
Capital Loan 2015					-	5,743,073	5,743,073
Trust Fund		353,952	-	1,092	1,092	(355,044)	(356,136)
Principal reduction of employee future benefits liability		-	-	-	-	-	-
Cash provided by financing activities	1,024,950	(660,389)	(942,116)	2,802,083	3,744,199	4,315,415	1,513,332
				-		-	
Net increase in cash	3,071,727	41,761	(3,033,134)	(428,824)	2,604,309	(1,293,893)	(865,069)
Cash , beginning of period	4,321,660	7,393,387	8,231,496	7,435,149	(796,347)	7,006,324	(428,824)
Cash , end of year	$ 7,393,387	$ 7,435,148	$ 5,198,362	$ 7,006,324	$ 1,807,963	$ 5,712,431	$ (1,293,893)
Represented by:							
Cash and cash equivalents	7,393,387	7,435,148	5,198,362	7,006,323	1,807,962	5,712,431	(1,293,892)
Restricted cash and cash equivalents	-	-	-	-	-		-
	7,393,387	7,435,148	5,198,362	$ 7,006,323	$ 1,807,962	$ 5,712,431	$ (1,293,892)

Working Capital 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013Actual	2014 Budget	2014 Forecast	2014 Forecast vs 2014 Budget	2015 Proposed Budget	2015 Proposed Budget vs 2014 Forecast
Working Capital							
Total Assets	76,302,795	83,147,738	77,064,987	82,527,297	5,462,310	85,527,517	3,000,220
Less Net Fixed Assets	(44,268,318)	(47,568,985)	(53,946,183)	(53,731,010)	215,174	(57,979,978)	(4,248,968)
Less Regulatory Assets	(3,713,424)	(4,831,945)	(1,790,175)	(835,156)	955,018	(404,656)	430,500
Less Future Income Taxes	(6,497,137)	(6,075,056)	(2,404,643)	(4,588,904)	(2,184,261)	(4,226,329)	362,575
Working Capital Assets	21,823,916	24,671,752	18,923,987	23,372,228	4,448,241	22,916,554	(455,673)
Total Liabilities	47,420,695	52,644,461	45,351,892	51,084,563	5,732,671	52,622,026	1,537,463
Less Debt to City of North Bay	(19,511,601)	(19,511,601)	(19,511,601)	(19,511,601)	-	(19,511,601)	-
Less Smart Meter Loan/Capital Loans	(2,916,667)	(2,566,667)	(2,216,667)	(6,103,009)	(3,886,342)	(11,264,970)	(5,161,962)
Less Regulatory Liabilities	(9,383,223)	(10,513,529)	(7,254,807)	(8,749,233)	(1,494,426)	(5,454,425)	3,294,808
Working Capital Liabilities	15,609,204	20,052,664	16,368,817	16,720,720	351,903	16,391,029	(329,690)
Working Capital	$ 6,214,712	$ 4,619,088	$ 2,555,170	$ 6,651,508	4,096,338	$ 6,525,525	$ (125,983)
% of Eligible Expenses	11.1%	7.5%	4.1%	9.9%	5.8%	9.8%	-0.1%
WC Allowance							
OM&A	5,369,782	5,572,041	6,334,708	6,695,086	360,378	6,857,188	162,102
Cost of Power	50,412,615	56,023,658	56,086,531	60,327,076	4,240,546	59,597,835	(729,241)
Total Eligible Expenses	55,782,397	61,595,699	62,421,239	67,022,162	4,600,924	66,455,023	(567,139)
Allowance	8,367,360	9,239,355	9,363,186	10,053,324	690,139	8,639,153	(1,414,171)
Allowance %	15%	15%	15%	15%		13%	-2%
Excess Working Capital	$ (2,152,647)	$ (4,620,267)	$ (6,808,016)	$ (3,401,817)	$ 3,406,199	$ (2,113,628)	$ 1,288,189

Covenants 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast vs 2014 Budget	2015 Proposed Budget	2015 Budget vs 2014 Forecast
City of North Bay							
Debt/Equity (Interest Bearing Debt) CNB							
Interest Bearing Long Term Debt CNB	19,511,601	19,511,601	19,511,601	19,511,601	-	19,511,601	-
Operating Loan	-	-	-	-	-	-	-
Interest Bearing Long Term Debt Infrastructure Ontario	2,916,667	2,566,667	2,216,667	2,216,667	-	1,866,667	(350,000)
Interest Bearing Long Term Debt				3,886,342	3,886,342	9,398,303	5,511,962
Total Debt	22,428,268	22,078,268	21,728,268	25,614,610	3,886,342	30,776,571	5,161,962
					-		
Equity	28,882,100	30,503,277	31,713,096	31,442,735	(270,361)	32,905,491	1,462,756
Total Interest Bearing Long Term Debt and Shareholder's Equity	51,310,368	52,581,545	53,441,364	57,057,344	3,615,981	63,682,062	6,624,718
Debt	***44%***	***42%***	***41%***	***45%***	***4%***	***48%***	***3%***
Equity	***56%***	***58%***	***59%***	***55%***	***-4%***	***52%***	***-3%***
OEB Debt/Equity							
Prior Year Net Fixed Assets	41,679,603	43,643,037	47,042,865	47,042,865	-	53,008,861	5,965,996
Current Year Net Fixed Assets	44,268,318	47,042,865	53,240,328	53,008,861	(231,467)	57,958,617	4,949,756
Average Net Fixed Assets	42,973,960	45,342,951	50,141,597	50,025,863	(115,734)	55,483,739	5,457,876
Cost of Power	50,412,615	56,023,658	56,086,531	60,327,076	4,240,546	59,597,835	(729,241)
OM&A	5,369,782	5,572,041	6,334,708	6,695,086	360,378	6,857,188	162,102
Total	55,782,397	61,595,699	62,421,239	67,022,162	4,600,924	66,455,023	(567,139)
Working Capital	8,367,360	9,239,355	9,363,186	10,053,324	690,139	8,639,153	(1,414,171)
Working Capita l%	15%	15%	15%	15%		13%	-2%
Rate Base	51,341,320	54,582,306	59,504,782	60,079,187	574,405	64,122,892	4,043,705
Debt	22,428,268	22,078,268	21,728,268	25,614,610	3,886,342	30,776,571	5,161,962
Debt 60%	***43%***	***40%***	***37%***	***43%***	***6%***	***48%***	***5%***
Equity 40%	***57%***	***60%***	***63%***	***57%***	***-6%***	***52%***	***-5%***

Covenants 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast vs 2014 Budget	2015 Proposed Budget	2015 Budget vs 2014 Forecast
			Debt/Equity Infrastructure Ontario				
Interest Bearing Long Term Debt CNB	19,511,601	19,511,601	19,511,601	19,511,601	-	19,511,601	-
Interest Bearing Long Term Debt Infrastructure Ontario/TD	2,916,667	2,566,667	2,216,667	2,216,667	-	1,866,667	(350,000)
Interest Bearing Long Term Debt CNB - Merrick	-			3,886,342	3,886,342	9,398,303	5,511,962
Operating Loan	-	-	-	-	-	-	-
Total Debt	$22,428,268	$22,078,268	$21,728,268	$25,614,610	$3,886,342	$30,776,571	5,161,962
Equity	28,882,100	30,503,277	31,713,096	31,442,735	- 270,361	32,905,491	1,462,756
Less Future Taxes Asset	6,497,137	6,075,056	2,404,643	4,588,904	2,184,261	4,226,329	(362,575)
Total Equity	22,384,963	24,428,221	29,308,453	26,853,831	- 2,454,622	28,679,162	1,825,332
Total Interest Bearing Long Term Debt and Shareholder's Equity	44,813,231	46,506,489	51,036,721	52,468,440	1,431,719	59,455,734	6,987,293
Debt (60%<)	***50%***	***47%***	***43%***	***49%***	***6%***	***52%***	***3%***
Equity	***50%***	***53%***	***57%***	***51%***	***-6%***	***48%***	***-3%***
1. Debt Service Coverage							
Net Income	2,137,447	2,257,726	1,868,716	1,617,239	(251,477)	1,643,617	26,378
+ depreciation	1,978,195	2,050,588	3,353,233	3,355,847	2,614	377,008	(2,978,839)
+taxes	660,447	536,307	710,008	685,470	(24,538)	- -	685,470
+(-) extraordinary	(789,079)	(1,141,459)	(1,139,412)	(1,125,696)	13,716	(2,178,213)	(1,052,517)
+interest	1,171,090	1,149,551	990,317	1,019,628	29,311	1,291,323	271,695
= EBITDA	6,736,257	7,135,631	8,061,686	7,803,880	(257,807)	5,490,160	(2,313,719)
Interest on existing debt	975,580	975,580	975,580	1,017,159	41,579	1,186,107	168,949
+P&I on IO's Loan	472,124	457,149	443,584	443,584	-	430,202	(13,382)
Net Capex	4,641,727	5,358,283	6,374,417	6,366,278	(8,140)	6,932,077	565,799
+75% of Net Capex	3,481,295	4,018,712	4,780,813	4,774,708	(6,105)	5,199,058	424,349
+Dividends	618,674	636,549	592,115	677,781	85,666	491,502	(186,279)
=Total annual obligations	5,075,549	5,630,841	6,348,509	6,469,648	121,140	6,876,667	407,019
DSCR 1:1	***1.327***	***1.267***	***1.270***	***1.206***	***(0.064)***	***0.798***	***(0.408)***
2. Current Ratio							
Current Assets	21,817,555	24,665,391	18,917,626	23,365,867	4,448,241	22,910,193	(455,673)
Current Liabilities	10,670,130	14,674,394	10,909,302	11,412,565	503,263	12,134,022	721,457
Working Capital Surplus	11,147,425	9,990,997	8,008,324	11,953,302	3,944,978	10,776,171	(1,177,130)
Current Ratio	***2.045***	***1.681***	***1.734***	***2.047***	***0.313***	***1.888***	***(0.159)***
Surplus over loan	***8,230,758***	***7,424,330***	***5,791,657***	***9,736,635***	***3,944,978***	***8,909,505***	***(827,130)***

Covenants 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast vs 2014 Budget	2015 Proposed Budget	2015 Budget vs 2014 Forecast
			Debt/Equity TD Bank				
Interest Bearing Long Term Debt CNB	19,511,601	19,511,601	19,511,601	19,511,601	-	19,511,601	-
Operating Loan	-	-	-	-	-	-	-
Interest Bearing Long Term Debt Infrastructure Ontario	2,916,667	2,566,667	2,216,667	2,216,667	-	1,866,667	(350,000)
Interest Bearing Long Term Debt CNB - TD				3,886,342	3,886,342	9,398,303	5,511,962
Customer Deposits (2012 change)							-
Regulatory Liabilities (2012 change)					-		-
Total Debt	22,428,268	22,078,268	21,728,268	25,614,610	3,886,342	30,776,571	5,161,962
Equity	28,882,100	30,503,277	31,713,096	31,442,735	(270,361)	32,905,491	1,462,756
Add Contributed Capital	6,478,723	7,341,246	8,331,329	8,280,001	(51,328)	8,541,633	261,632
Less Intangibles	6,361	6,361	6,361	6,361	-	6,361	-
Total Equity	35,354,462	37,838,162	40,038,064	39,716,375	(321,689)	41,440,763	1,724,388
					-		
Total Interest Bearing Debt and Shareholder's Equity	57,782,730	59,916,430	61,766,332	65,330,985	3,564,653	72,217,334	6,886,350
Debt (60%<)	***39%***	***37%***	***35%***	***39%***	***4%***	***43%***	***3%***
Equity	***61%***	***63%***	***65%***	***61%***	***-4%***	***57%***	***-3%***
(000's)							
EBT	2,797,894	2,794,033	2,578,724	2,302,709	(276,016)	1,643,617	(659,092)
Add: Interest	1,171,090	1,149,551	990,317	1,019,628	29,311	1,291,323	271,695
Add: Amortization	1,978,195	2,050,588	3,353,233	3,355,847	2,614	377,008	(2,978,839)
Less: Extraordinary	(789,079)	(1,152,824)	(1,139,412)	(1,145,306)	(5,894)	(2,178,213)	(1,032,907)
EBITDA	6,736,257	7,146,996	8,061,686	7,823,490	(238,197)	5,490,160	(2,333,329)
Less: CAPEX	(5,317,656)	(6,420,222)	(7,625,384)	(7,528,916)	96,468	(7,436,110)	92,806
Add: Contributed Capital	675,929	1,061,939	1,250,967	1,162,638	(88,328)	504,033	(658,605)
Add: Proceeds	443,898	19,171	-	6,875	6,875	-	(6,875)
Net CAPEX	(5,993,585)	(5,339,112)	(6,374,417)	(6,359,403)	15,015	(6,932,077)	(572,674)
Net CAPEX at 40%	(2,397,434)	(2,135,645)	(2,549,767)	(2,543,761)	6,006	(2,772,831)	(229,070)
Less:PILs	660,447	536,307	710,008	685,470	(24,538)	-	(685,470)
Cash Flow	3,678,377	4,475,044	4,801,911	4,594,259	(207,653)	2,717,329	(1,876,929)
Interest (change 2012)	1,097,704	1,082,729	1,069,164	1,110,742	41,579	1,266,309	155,567
Principal	350,000	350,000	350,000	463,658	113,658	838,038	374,380
Total P&I	1,447,704	1,432,729	1,419,164	1,574,400	155,237	2,104,347	529,947
DSC 1.20:1	***2.54***	***3.12***	***3.38***	***2.92***	***-0.47***	***1.29***	***-1.63***

2015 Proposed Capital Budget Detail

DISTRIBUTION SYSTEM ASSETS	
GENERATOR CONNECTIONS	
Generator Connections	35,700
Engineering Tech Capital	8,948
Engineering Supervisor Capital	3,368
Supervisor Labour	
	48,016
MAJOR BETTERMENTS	
2015 Projects:	
WO# 458570 - Wickstead U/G Rebuild	408,893
WO# 458572 - Sylvan Cres. U/G Rebuild	18,951
WO# 458573 - Melina Close U/G Rebuild	274,742
WO# 458571 - Madelenda U/G Rebuild	496,055
Operations Supervisor Capital	35,874
Engineering Tech Capital	11,386
Engineering Supervisor Capital	20,701
Supervisor Labour	
	1,266,604
VOLTAGE CONVERSION	
2014 Projects:	
WO# 464210 - Second Ave. - John to Creek	22,930.08
WO# 464187 - Main St W - Partial Line rebuild	201,594.35
WO# 464151 - First Ave. - Partial Line Rebuild	127,510.17
WO# 464135 - Ferguson Rebuild	261,133.29
WO# 464197 - Jet Ave.	23,095.83
WO# 464162 - Regina Rebuild	76,104.95
WO# 464165 - Sherbrooke Rebuild	105,680.66
WO# 464551 - 18F1 Voltage Conversion	31,641.52
WO# 464547 - 18F2 Voltage Conversion	13,174.65
WO# 464548 - 18F3 Voltage Conversion	35,321.29
WO# 464549 - 7F2 Voltage Conversion	15,485.48
WO# 464550 - 1F1 Voltage Conversion	19,085.65
WO# 458566 - McIntyre Rebuild	424,297.76
WO# 457198 - Fourth Ave. Partial Line Rebuild	137,871.61
WO# 457124 - Fifth Ave. Partial Line Rebuild	144,469.69
WO# 457828 - Fraser St. 12kV Rebuild	108,689.06
Projects include Wyld and all b/w 2nd and Oak St.	2,368.91
Operations Supervisor Capital	53,527
Engineering Tech Capital	16,639
Engineering Supervisor Capital	31,422
Supervisor Labour	
	1,852,043

2015 Proposed Capital Budget Detail

MINOR BETTERMENTS

Various (hours based on AM plan)	324,593
Bell Canada - FSA Work	-
Operations Supervisor Capital	9,715
Engineering Tech Capital	3,083
Engineering Supervisor Capital	5,606
Supervisor Labour	
	342,997

PRIMARY SERVICES

Various (hours based on AM plan)	204,069
Operations Supervisor Capital	6,108
Engineering Tech Capital	1,939
Engineering Supervisor Capital	3,524
Supervisor Labour	
	215,639

SECONDARY SERVICES

SV1PHS-Single phase 100-200 amp	233,623
Operations Supervisor Capital	6,992
Supervisor Labour	
	240,615

SUBDIVISIONS

Various (hours based on AM plan)	94,599
Operations Supervisor Capital	2,831
Engineering Tech Capital	899
Engineering Supervisor Capital	1,634
	99,963

TRANSFORMER PURCHASES - 850 & 851

Underground	216,910
Overhead (includes work for rewinding and retanking)	162,338
	379,248

2015 Proposed Capital Budget Detail

METERING	
Capital Infrastructure Modernization - Util-Assist Strategy	199,213
Spare Rack - Arclin	48,000
Interval installations	10,000
Smart Meter Replacement Meters	15,000
Operations Supervisor Capital	4,003
Supervisor Labour	
	276,216
SUBSTATION UPGRADES	
2014 Projects:	
MS22	1,781,297
Various SCADA WORK	15,735
MS13-T1 Transformer Replacement	271,470
Engineering Tech Capital	895
Engineering Supervisor Capital	33,676
Supervisor Labour	
	2,103,074
ROAD RELOCATIONS	
Various (hours based on AM plan)	198,821
Operations Supervisor Capital	5,951
Engineering Tech Capital	1,889
Engineering Supervisor Capital	3,434
Supervisor Labour	
	210,094
Estimated contributed capital	(504,033)
Estimated contributed capital (net)	**(504,033)**
Total Distribution System Assets	**6,530,474**

2015 Proposed Capital Budget Detail

GENERAL ASSETS	
Office Upgrades / Furniture	
Operations	
Stores Upgrade	36,652
Misc. upgrades as needed	20,000
	56,652
Transportation Equipment	
Small Fleet	
Truck # 5 - replacement	35,000
Truck # 9 - replacement	35,000
Truck # 10 - replacement	35,000
TRAILER/MOBILE EQUIPMENT	
T5 - replacement (reel trailer)	20,000
T6 - replacement (material trailer)	20,000
	145,000
Tool Requirements	
Operations	
Running Grounds	1,300
Work Signs	1,200
Battery Operated Tools	4,000
Live Line Tools - will cover anywhere from 5 - 10 units >$700 / unit	5,000
Chain Saws	1,500
Greenlea Hydraulic Drills	2,000
U/G bypass jumpers - load/source kit (meter base)	3,586
U/G bypass jumpers - 10m / 15m extension x 2	4,089
Locator	5,976
Stations	
Portable Generator - Inverter Based	2,000
Engineering	
Trimble XH Handheld (replacement for Trimble GeoExplorer 2008)	13,000
Antenna for new handheld	2,500
	46,151

2015 Proposed Capital Budget Detail

IT Requirements

Servers	
CLEO Server	2,500
Naviline Server	4,000
AS2 Proxy Server	2,500
SAN	20,000
VM Server (Hot Standby)	18,000
AS400 Drive Array	8,000
Document Management/Mindoka Server	10,000
FOG/Ghost Imaging Server	6,500
Network	
Router	3,000
Software	
Office License Update	8,000
PC-Updates	
Finance - Laptop	1,000
Operations - Mobile notebooks (Locates/Metering)	15,000
Operations - Initializer (Sensus)	4,500
Eng'g - Laptop	1,000
Metering - Computers/tablets	6,000
IT - Mngr computer	1,000
IT - Analyst computer	1,000
IT/Billing - Laptop/tablets	3,000
Server Room Upgrade	
UPS Upgrade	5,000
Environmental Monitor	800
Network Operation Center Upgrade	
Re-model office (furniture etc)	6,000
Printers / Copiers	
Department Printers (x3)	9,000
HP Design Jet	3,500
Cheque Printer	1,200
Comm Room	
Env. Monitor Sensors	300
Engineering	
ESRI	4,000
Seqel Server - (to support ESRI)	9,000
	153,800
Total General Assets	**401,603**
Total Capital Budget	**6,932,077**

Operations - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actuals	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	
Labour:								
Regular time	819,335	856,007	698,332	829,311	130,979	858,918	29,608	2014 Variance due to less charges to capital than budgeted
NBHS - Services	15,702	16,153	34,726	29,792	(4,934)	13,874	(15,918)	2015 wage rate increase
Smart Meters	510							
Overtime	157,459	148,465	151,082	149,434	(1,648)	148,987	(446)	
Payroll burden	457,438	505,870	389,118	430,515	41,397	472,476	28,241	
	1,450,444	1,526,495	1,273,256	1,439,051	165,795	1,494,255	55,204	
Items purchased	96,600	75,109	80,350	81,037	687	83,091	2,055	
Contracted services	677,484	781,216	854,825	863,465	8,640	1,214,372	350,907	
Smart Meters	5,495	10,649	46,186	46,136	(50)	11,995	(34,142)	Smart Meter disposition $
NBHS	3,009	6,712	11,071	11,990	918	8,704	(3,286)	
Stores	124,033	110,173	130,166	145,703	15,537	162,873	17,170	
Truck Time	190,075	189,133	195,774	248,268	52,494	240,986	(7,283)	
Meals/Entertain/Supplies and Other	88,178	74,955	58,593	58,328	(265)	61,871	3,543	
Vehicles - fuel, parts, maintenance	311,329	293,453	298,553	306,922	8,369	310,207	3,285	
Truck Recoveries	(576,825)	(531,730)	(556,345)	(568,404)	(12,059)	(600,242)	(31,839)	
Charges to Affiliates	(60,245)	(48,213)	(79,970)	(70,459)	9,511	(49,898)	20,561	Less labour and contracted services $26k
Charges to Regulatory				22,129	22,129		(22,129)	
Charges to Smart Meters								
Total	2,309,577	2,487,952	2,312,459	2,584,166	271,707	2,938,213	354,047	
Allocated Overheads:								
Allocated into Dpmt.	873,265	876,469	902,416	1,038,662	136,246	1,065,548	26,886	
Allocated out of Dpmt - 2014 COS				(22,129)	(22,129)		22,129	
Allocated out of Dpmt.	(858,306)	(819,696)	(776,256)	(900,151)	(123,895)	(922,877)	(22,726)	
Net Overheads	14,959	56,773	126,160	116,382	(9,778)	142,671	26,288	
Net Function Spending	**2,324,536**	**2,544,725**	**2,438,619**	**2,700,548**	**261,929**	**3,080,884**	**380,336**	
Items Purchased								
Small Tools	37,882	22,557	30,224	28,298	(1,926)	28,298	0	
Health & Safety	13,955	11,750	13,158	13,157	(0)	14,256	1,099	Mainly gloves
Underground	663	106						
Overhead	2,800	1,132						
Ops - Operating Supplies	4,243	3,177	2,320	3,092	772	3,248	156	Includes Pop / water/ (Railway Permits
Preventative Mtnc Program	3,269	3,897	2,100	4,047	1,947	4,412	365	Vertical Panels / rock mount signs
Substations	22,839	8,011	9,800	9,800		9,800		Operating supplies/signs
Meter - Misc.	3,754	15,328	14,748	12,548	(2,200)	12,799	251	Meter Rings / THHN Wire / Alpha Meters / Test Switches
Customer Service	275	1,191	1,000	1,200	200	1,200		
Computer Supplies	540		500	375	(125)	500	125	
Reels	(3,429)	(288)		445	445		(445)	
Facility - Operating Supplies	9,809	8,248	6,500	8,074	1,574	8,578	504	garbage bag /salt /soap/paper towels janitorial supplies
Total Items purchased	**96,600**	**75,109**	**80,350**	**81,037**	**687**	**83,091**	**2,055**	

Operations - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actuals	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	
Contracted Services								
Eng to Operations Process Review - Optimus						100,000	100,000	Eng to Ops process review
Lines: Tree Trimming	151,168	319,030	350,000	358,415	8,415	604,350	245,935	2015 Arbor Works plan / tree growth (15K) / Stump removal (80K) /tree trimming notices
Lines: Tree Trimming Consultants			5,000	5,000			(5,000)	Arbor works - 2014 Tree triming plan
Lines: Joint use, leases, easements, rentals	27,803	32,722	32,611	32,610	(0)	32,676	65	Bell Canada 2012 pole count of (23K), Hydro One 2012 invoices (5.8K). Easements (3.6K)
Operations - OH Construction Work	2,517	2,422	1,500	2,470	970	2,520	49	
Operations - Permanent Ground Mats	2,063	172	2,500	597	(1,904)	608	12	
Operations - UG Services Construction	25,984	34,229	20,000	25,000	5,000	30,000	5,000	Aultman Rental Dig and Repair Work, burn offs, etc. - 2014 budget and increased by 5K for actual trends for burn offs
Operations - Health & Safety	10,368	10,358	13,096	11,999	(1,096)	12,158	159	Glove Tests/ Blanket Tests / Line Hose Testing (341) etc
DRC	2,249	2,672	2,432	2,725	293	2,778	53	
Operations - Small Tool R&M	3,922	3,381	3,400	3,400		3,753	353	
Operations - General Misc. (Admin and Lines GM)	10,351	2,866	10,850	10,873	23	10,850	(23)	Pole Extention Drilling / incidents due to weather or unforeseen events
Operations - Misc. Construction	2,664	5,106	7,680	6,517	(1,163)	6,700	183	Misc. Clean up costs, Misc repairs on pole pads and Float costs to move transformers
Operations - Sent Lights								
Total Operations	**239,089**	**412,958**	**449,068**	**459,607**	**10,539**	**806,394**	**346,787**	
Substation Joint use	4,274	6,400	7,068	8,302	1,235	8,810	508	Tower rentals/easements
Substation - Mtnc	58,265	6,453	39,500	19,000	(20,500)	19,000	0	Substation Repairs/ Calibrations / Tree Spray / Costello
Substation - Facility Costs	6,894	6,522	11,800	8,718	(3,082)	5,847	(2,871)	CNB Water /sewer / Snow Removal
Substation - Scada	34,126	35,118	35,712	37,543	1,831	38,766	1,223	Survalent / Costello/ Hydro One Communication/ COGEN / Measurement Canada Radio Authorization
Substation - PCB transfer disposal	1,140		1,640	1,500	(140)	1,500		
Substation - Misc.	16,295	13,978	13,165	12,407	(758)	11,436	(971)	Siemens / Rondar (Lab analysis) / All Season Car
Substations: Lowell Security	24,034	7,300	7,675	7,556	(119)	7,595	39	
Total Substations	**145,027**	**75,771**	**116,559**	**95,026**	**(21,533)**	**92,953**	**(2,073)**	
Meter - Service Provider	17,294	17,769	19,096	19,491	395	20,518	1,027	MSP Billing / Interrogation Services and MDS Web / IESO Meter Changes and Installation Verification
Meter - Itron - MV90 Mtnc.	14,251	6,379	6,602	6,570	(33)	6,666	97	
Meter - meter testing, includes shipping	844	5,628	5,764	4,230	(1,534)	4,452	222	IESO Meter Programming and Testing / Other Meter Testing
Meter - Misc.	838	65	2,000	500	(1,500)	500		meter relocation expenses
Total Metering	**33,227**	**29,841**	**33,462**	**30,791**	**(2,672)**	**32,137**	**1,346**	
Facility - Advertising	5,398	1,337	996	996		1,026	30	
Facility -Shipping Costs	13,496	7,027	6,974	11,284	4,310	11,844	559	
Facility - Cell Phone Expenses	20,066	22,186	21,946	22,482	536	23,072	591	Neil Communication/ Bell Mobility/ Global Star
Facility - Union Gas	6,865	7,431	6,934	8,353	1,419	8,521	167	
Facility / Lowell Security / North Bay Security	14,543	15,963	13,650	12,670	(980)	13,831	1,161	
Facility - North Bay Mat Rental	2,377	2,392	2,377	2,453	76	2,551	98	
Facility - Janitorial Services	30,000	30,000	30,000	30,045	45	30,000	(45)	
Facility - Miller Waste	11,553	16,115	11,000	11,000		11,000		removal of old poles resulting in increased waste of scrap
Facility - CNB Water	2,888	1,115	1,357	1,232	(125)	1,256	25	
Facility - Hydro Expenses	36,265	41,686	42,470	42,926	455	44,214	1,288	
Facility - Northern Communications - Answering servic	12,422	8,554	9,825	8,687	(1,138)	9,229	542	
Facility - Telephone System Expenses	55,321	54,128	51,344	54,949	3,605	55,210	260	Bell increased for 2% inflation
Facility - Building Mtnc. / Anderson Ross	4,530	946	1,450	1,450		1,474	24	garage door inspection / Contingency of 1K
Facility - Building Mtnc. Other	18,023	15,691	15,389	15,388	(0)	15,696	308	Contingency for unexpected Building repairs
Facility - Equip Mtce		5,171	2,500	15,006	12,506	16,090	1,084	Postage Machine Mtce/lease/ Postage
Facility - Aultman - snowplow	14,942	15,895	14,946	17,781	2,834	18,136	355	
Total Facility	**248,689**	**245,637**	**233,159**	**256,701**	**23,543**	**263,150**	**6,448**	
Customer Service - Locates- One Call	23	7,081	8,030	6,792	(1,238)	5,049	(1,743)	
Customer Service-Meter Reading-seal offs/reconnects	11,429	9,928	14,548	14,548		14,689	141	Olameter Seal off/Collections increased for 2% inflation / year
Total Customer Service	**11,452**	**17,009**	**22,577**	**21,340**	**(1,238)**	**19,738**	**(1,602)**	
Total General Contracted Services	**677,484**	**781,216**	**854,825**	**863,464**	**8,638**	**1,214,371**	**350,907**	

Operations - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actuals	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	
Smart Meters								
Meter - Olameter - Itron Rental Fees	5,495	10,495	20,495	20,445	(50)	11,995	(8,450)	Itron system rental fee, Powerstream annual testing & presampling
Smart Meter Disposition costs			25,691	25,691			(25,691)	
Items		154						
Total Smart Meter	**5,495**	**10,649**	**46,186**	**46,136**	**(50)**	**11,995**	**(34,142)**	
NBHS								
Customer Service - NBHS Costs	1,475	799	666	791	125	879	88	
Advertising		5,913	10,404	10,188	(216)	6,794	(3,394)	Yellowpages "Yellow Pages Analytics" will not be renewed
Vehicle Costs				1,011	1,011	1,031	20	
Operations - Sentinel Lights	1,534		1			1		
Total NBHS	**3,009**	**6,712**	**11,071**	**11,990**	**920**	**8,705**	**(3,286)**	

Finance - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	Notes
Labour:								
Regular time	545,784	546,217	556,884	560,805	3,921	624,413	63,607	New Accountant full year and rate increases
CDM	-	-	-	-	-	-	-	
Smart Meters	35,610	27,095	70,889	71,445	556	27,853	(43,592)	Smart meter disposition
NBHS/Merrick	53,796	76,941	70,672	78,667	7,994	84,539	5,873	
Overtime	23,960	25,593	35,527	62,083	26,557	37,233	(24,851)	COS reduction $15k; Other ot bal
Payroll burden	223,489	250,941	294,154	297,138	2,984	321,444	24,306	
	882,639	926,787	1,028,127	1,070,138	42,012	1,095,482	25,344	
Items purchased	15,189	8,971	12,872	11,193	(1,680)	9,286	(1,907)	
Contracted services General	503,107	568,936	489,975	612,552	122,577	614,126	1,574	
Contracted services Smart Meters Savage OD	39,872	48,879	99,354	99,414	60	44,703	(54,711)	Smart meter disposition
	-	-						
Stores	-	-	-	-	-	-	-	
	-	-						
Equipment costs	-	-	-	-	-	-	-	
	-	-						
Meals/Entertain/Training/Supplies and Other	16,696	42,081	61,613	48,779	(12,834)	54,924	6,145	Accountant/Regulary training
	-							
Vehicle Costs	-	-	-	-	-	-	-	
	-	-						
Truck Recoveries	-	-	-	-	-	-	-	
	-	-						
Bad Debt Expense/Collection Fees	114,063	23,582	150,000	159,245	9,245	159,245	-	
	-	-						
Banking/Finance Fees	32,507	37,599	41,550	40,165	(1,385)	42,000	1,835	
	-	-						
Transfer out of Dpmt	(128,031)	(143,764)	(141,617)	(148,457)	(6,840)	(158,160)	(9,703)	
Rebasing/IFRS	(18,773)	(141,606)	(88,811)	(155,765)	(66,954)	(65,732)	90,033	Rebasing chargeback June2015 >
Smart Meters	-	-	-	-	-	-	-	
Total Spending	1,457,269	1,371,465	1,653,064	1,737,264	84,200	1,795,874	58,610	
Allocated Overheads:								
Allocated into Dpmt.	38,702	36,195	35,868	36,608	740	37,913	1,305	
Allocated out of Dpmt.		-	-	-	-	-	-	
Net Overheads	38,702	36,195	35,868	36,608	740	37,913	1,305	
Net Function Spending	**1,495,971**	**1,407,660**	**1,688,932**	**1,773,872**	**84,941**	**1,833,787**	**59,915**	

Finance - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	Notes
Contracted Services								
Canada Post/Crosstown Postage	190,036	195,783	169,012	171,594	2,582	193,397	21,804	Postage increase/allocation
Canada Post Disconnect notices	-	-	-	13,108	13,108	15,312	2,204	Split from above prior years
Mobile Mail/Data Group	52,116	-	-	-	-	-	-	
Northern Business Solutions - mailing machine		4,309	5,700	-	(5,700)	-	-	Moved to facitily not billing
Northern Business Solutions - inserter				1,273	1,273	1,325	52	
Northern Business Solutions - printer				11,541	11,541	11,798	257	
Savage EBT etc	9,232	9,232	9,286	9,286	-	9,286	-	
Olameter								
Brink's	6,734	3,120	3,120	3,212	92	3,318	106	
Crosstown Delivery	15,130	3,913	6,480	4,020	(2,460)	4,136	116	
Billing Customization								
SDS-Wholesale Settlement	44,016	44,019	44,868	45,329	461	46,683	1,354	
Enerconnect								
Banking RFP								
Credit Bureau	16,197	12,813	14,400	18,500	4,100	18,540	40	
Audit Fees	36,950	29,250	32,750	35,750	3,000	34,750	(1,000)	
Legal	4,925	7,292	8,400	8,400	-	8,400	-	
Regulatory Consultants Richardson	780	1,000	780	780	-	780	-	
Regulatory Consultants	11,612	15,083	-	-	-	-	-	
Rebasing Consultant 2010	71,308	71,304	23,768	23,768	0	-	(23,768)	ends April 2014
Rebasing Consultant 2014	-	141,008	80,811	124,427	43,616	128,000	3,573	
Util-Assist Meter to Cash Consultants	18,980	17,967	-	-	-	-	-	
Sector Review - Sudbury Hydro	6,356							
IFRS	10,000	-	8,000	8,000	-	3,000	(5,000)	Most work completed in 2014
HMT Audit	(5,363)							
Misc/Nugget/Bill Inserts/Mindoka/Clarke	14,095	12,843	82,600	133,563	50,963	135,400	1,837	customer engagement/surveys
Total	503,104	568,936	489,975	612,552	122,577	614,126	1,574	

Engineering - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	Notes
Labour:								
Regular time	186,589	176,113	217,672	221,689	4,017	241,080	19,391	
Overtime	5,549	13,056	9,414	9,851	437	8,671	(1,180)	
Eng Mgmt - Regulatory OT / Burden				61,297		11,467	(49,830)	
Payroll burden	98,750	101,388	110,127	109,016	(1,111)	116,694	7,678	
	290,888	290,557	337,213	417,060	79,847	377,912	(39,148)	
		-	-	-	-	-	-	
Items purchased	698	2,105	2,000	2,000	-	2,000	-	Small Tools $1K and Plotting Paper $1K
	-							
Contracted services	20,084	23,662	81,069	76,139	(4,930)	52,292	(23,848)	
	-							
Stores	399	-	450	473	23	467	(6)	
	-							
Equipment costs	1,357	2,443	8,687	8,557	(130)	8,577	20	
	-							
Meals/Entertain/Supplies and Other	16,384	9,247	34,459	33,517	(942)	32,264	(1,253)	Traning and conferences (EDA - Sault)
	-							
Vehicle Costs	-	-	-	-	-	-	-	
	-							
Truck Recoveries	-	-	-	-	-	-	-	
	-			-	-			
Total Spending	**329,810**	**328,014**	**463,878**	**537,746**	**73,868**	**473,511**	**(64,235)**	
		-	-	-	-	-	-	
Allocated Overheads:		-	-	-	-	-	-	
Allocated into Dpmt.	29,654	27,733	24,960	28,050	3,090	29,056	1,007	
Allocated out of Dpmt - 2014 COS application costs				(106,297)	(106,297)	(11,467)	94,830	
Allocated out of Dpmt.	(359,480)	(355,747)	(441,093)	(459,499)	(18,406)	(471,100)	(11,602)	
Net Overheads	(329,826)	(328,014)	(416,133)	(537,746)	(121,613)	(453,511)	84,235	
		-	-	-	-	-	-	
Net Function Spending	**(16)**	**-**	**47,745**	**(0)**	**(47,745)**	**20,000**	**20,000**	
	-	-	-	-	-	-	-	

Engineering - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	Notes
			-	-	-	-	-	
Contracted Services			-	-	-	-	-	
Metsco	990	-	-	-	-	-	-	
AESI - Acumen (Compliance)	2,840	2,833	2,918	2,890	(28)	2,948	58	
Imaginit (Autocad)	1,854	1,920	1,978	1,959	(19)	2,521	562	
ESRI	3,737	5,605	6,489	6,695	206	6,977	282	
USF	8,750	8,751	9,488	9,604	116	9,225	(379)	
Terranet Subscription		-	1,000	1,000	-	750	(250)	
Spida Software Licensing Fees		-	-	1,846	1,846	2,717	871	
City's MC (municipal consent)				2,000	2,000	2,000	-	
Engineering Consultants	-	-	5,000	-	(5,000)	-	-	
Misc. Eng consultants	695	-	-	-	-	-	-	
Essex Energy Corp	-	2,896	2,896	2,896	-	2,954	58	
Legal	-	338	5,100	1,000	(4,100)	1,000	-	
Cansel	1,200	1,200	1,200	1,200	-	1,200	-	
Write off of Intantible Asset	-	-	-	-	-	-	-	
IFRS related costs	-	-	-					
Miscellaneous	-	-		50	50	-	(50)	
AM Plan	18	119	45,000	45,000	-	20,000	(25,000)	Annual updating of AM plan
	20,084	23,662	81,069	76,139	(4,930)	52,292	(23,848)	

Human Resources - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	Notes
Labour:								
Union Contract Signing Bonus				36,000	36,000	-	(36,000)	2014 Contract Signing Bonus
Regular time	46,289	37,921	52,434	39,936	(12,498)	37,546	1,260	
NBHS/OPA	-	36,975	-	21,039	21,039	26,736	5,697	
Overtime	-	1,156	-	981	981	-	(981)	
Payroll burden	20,136	-	28,776	21,584	(7,192)	20,736	(849)	
	66,425	76,052	81,210	119,540	38,330	85,017	(30,873)	
Items purchased	1,191	1,229	2,907	3,133	226	2,600	(533)	
Contracted services	33,491	31,989	65,924	75,444	9,520	56,879	(18,565)	Succession consultant
Meals/Entertain/Training/Supplies and Other	47	550	1,460	1,460	-	1,435	(25)	
Health Benefits	380,544	300,206	318,728	275,209	(43,519)	283,293	8,084	
							-	
Actuarial Adjustment	84,384	105,410	100,020	100,020	-	(11,081)	(111,101)	IFRS adj
NBHS/OPA - Contra	(1,956)	(21,752)	(1,956)	(25,290)	(23,334)	(30,535)	(5,245)	
					-		-	
Total Spending	564,126	493,684	568,292	549,516	(18,777)	387,608	(158,257)	
Allocated Overheads:								
Allocated into Dpmt.	2,143	2,004	1,986	2,028	41	2,100	72	
Allocated out of Dpmt.					-		-	
Net Overheads	2,143	2,004	1,986	2,028	41	2,100	72	
					-		-	
Net Function Spending	**566,269**	**495,688**	**570,279**	**551,544**	**(18,735)**	**389,708**	**(158,186)**	

Human Resources - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	Notes
Contracted Services								
Financial Consulting Fees- Actuarial Report	425	8,950	3,950	3,381	(569)	3,950	569	
Misc								
AYS Consulting Fees / CYR Consulting		-	-	-	-	-	-	
ANTEBI	4,261	2,940	2,700	2,700	-	4,500	1,800	
ADP costs	5,849	6,417	6,720	7,305	585	7,531	226	
Benefit Consultant		-	-	375	375	-	(375)	
EFAP Dues	3,196	2,314	2,304	1,836	(468)	2,448	612	
Paisley Park		-	-	-	-	-	-	
Recruiting	1,871	1,532	750	2,123	1,373	1,500	(623)	
School safety program		4,325	5,000	5,000	-	5,000	-	
Health & Safety Consultants		-	-	-	-	-	-	
HR Services, Elenchus	1,650	2,385	32,000	32,000	(0)	20,000	(12,000)	Succession consultant
Legal fees	11,377	3,125	10,000	17,174	7,174	10,200	(6,974)	
EDA		-	-	-	-	-	-	
MEARIE HRIS		-	-	-	-	750	750	
RC Whitney/Pockele and Assoc.		-	-	-	-	-	-	
Misc		-	-	50	50	-	(50)	
Mindoka Tech fees (doc maint and editing)		-	-	1,000	1,000	1,000	-	
Relocation	4,863	-	2,500	2,500	-	-	(2,500)	
	33,492	31,988	65,924	75,444	9,520	56,879	(18,565)	

Administration - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	Notes
Labour:								
Regular time	133,961	171,936	239,921	225,648	(14,273)	234,176	8,528	2014 var to budget- syn op outsource
CDM	31,866	(6,671)	10,940	14,781	3,841	11,859	(2,921)	2015 rate increase
Smart Meters	55,177	53,827	50,459	51,754	1,295	51,306	(448)	
NBHS	16,290	18,897	32,312	29,619	(2,693)	33,258	3,639	
Payroll burden	51,515	73,927	103,953	81,633	(22,319)	85,014	3,381	
	288,809	311,916	437,585	403,435	(34,149)	415,614	12,179	
Items purchased*	7,983	14,778	15,836	16,800	964	17,336	536	
Contracted services General	543,384	599,165	659,909	753,226	93,317	883,635	130,409	
Contracted service CDM	96	33,086	-	-	-	-	-	
Contracted services Smart Grid	-	-	-	-	-	-	-	
Contracted services Smart Meters	123,487	168,618	451,171	467,763	16,592	189,043	(278,720)	2014 Smart Meter disposition $283k
Contracted services - NBHS	-	-	-	63	63	-	(63)	
Stores	-	-	-	-	-	-	-	
Meals/Entertain/Training**	30,606	30,874	52,120	54,759	2,639	56,382	1,623	
Vehicle/equipment costs	-	-	-	-	-	-	-	
Charged to Regulatory or Affiliates								
Conservation and Demand OPA	-	(33,215)	(10,940)	(14,781)	(3,841)	(11,859)	2,921	
Smart Grid & Fit contra	(19,477)	-	-	-	-	-	-	
Smart Meter - Contra	(2,991)	-	-	-	-	-	-	
NBHS - Contra	(17,184)	(27,768)	(42,844)	(40,209)	2,635	(45,116)	(4,907)	
COS Application - Contra	-	-	-	1,266	1,266	-	(1,266)	
	(39,652)	(60,983)	(53,784)	(53,723)	60	(56,976)	(3,252)	
Total Spending	954,713	1,097,454	1,562,837	1,642,323	79,486	1,505,034	(137,289)	
Allocated Overheads:								
Allocated into Dpmt. (facility chargeout)	28,352	26,515	26,280	26,805	525	27,774	968	
Allocated out of Dpmt.	-	-	-	-	-	-	-	
Net Overheads	28,352	26,515	26,280	26,805	525	27,774	968	
Net Function Spending	**983,065**	**1,123,969**	**1,589,117**	**1,669,128**	**80,011**	**1,532,808**	**(136,320)**	

Administration - 2012 Actual to Proposed 2015 Budget

	2012 Actual	2013 Actual	2014 Budget	2014 Forecast	2014 Forecast Variance to 2014 Budget	2015 Budget	2015 Budget Variance to 2014 Forecast	Notes
Contracted Services								
IBM/Nicky Design	13,530	15,741	16,800	13,636	(3,164)	13,917	281	
Sale of Fibre	14,091	14,088	14,088	14,088	-	14,088	-	
Util-Asist		38,860	-	56,183	56,183	57,572	1,389	Sync operator
Mindoka	17,550	20,175	20,700	20,925	225	22,956	2,031	
H.T.E.	101,491	99,244	126,267	104,856	(21,411)	120,850	15,993	Exchange/new H.T.E. Modules
Ontera - other than Smart Meters	4,516	7,840	19,084	19,024	(60)	24,084	5,060	
Google	1,900	-	-	-	-	-	-	
CNB IS services	90,856	96,986	95,730	99,996	4,266	104,903	4,907	
Vianet, Northern Comm	773	368	1,140	92	(1,048)	-	(92)	
Bell Cell/WiFi Units x4	-	2,141	2,400	2,436	36	2,754	318	
IT Security Audits				10,056	10,056	32,847	22,791	New regulations
Total IT	244,707	295,443	296,209	341,292	45,083	393,970	52,678	
Property Insurance	67,860	68,140	76,357	76,357	0	88,139	11,782	based on asset value and rate increase
Liaiblity Insurance	39,778	56,984	79,548	68,184	(11,364)	75,145	6,961	based on revenue and rate increase
Cyber Insurance	0	9,445	10,542	11,364	822	12,732	1,368	
Total Insurance	107,638	134,569	166,447	155,905	(10,542)	176,016	20,111	
OEB assessment	78,142	73,559	73,908	73,147	(761)	75,386	2,239	
EDA membership	42,200	44,300	46,200	46,200	-	48,181	1,981	
ESA assessment	11,642	12,303	11,845	11,761	(84)	12,081	320	
Total Regulatory	131,984	130,162	131,953	131,108	(845)	135,649	4,541	
BLG - Finance	5,831	0	-	-	-	-	-	
Advertising/Customer Information	850	0	1,000	500	(500)	1,000	500	
Cyr & Assoc	0	4,800	2,500	4,800	2,300	4,800	-	
Customer First		15,696	32,000	32,420	420	40,000	7,580	New partnership
Navigant				22,000	22,000	-	(22,000)	One time consultant
Strategic Plan						100,000	100,000	
Misc consulting	29,076	2,016	5,600	5,050	(550)	8,000	2,950	
Total Misc Consulting	35,757	22,512	41,100	64,770	23,670	153,800	89,030	
Legal costs	17,298	10,479	18,000	53,000	35,000	18,000	(35,000)	2014 shareholder declaration
Board Expenses Holdco & Couriers	6,000	6,000	6,200	7,150	950	6,200	(950)	
	543,384	599,165	659,909	753,226	93,317	883,635	130,409	

May 2014 Smart Meter May 2015 1576-Depreciation Change Disposition Summary

	2014 Smart Meter Disposition	2015 1576 Disposition
Income Statement		
Revenue		
Customer Billings	1,905,953	(147,691)
Cost of Power		
Distribution revenue	1,905,953	(147,691)
Other operating revenue	(210,639)	
Total Revenue	1,695,314	(147,691)
Operating expenses		
Operations	25,691	
Finance	104,015	
Engineering		
Human Resources		
Administration	282,830	
Merrick Expense		
Depreciation and amortization	951,425	(2,299,813)
Total OM&A	1,363,961	(2,299,813)
Income before items below	331,353	2,152,122
Interest	(90,490)	
Capital tax		
Property taxes		
Income before other items and payment in lieu of taxes	421,843	2,152,122
Other items		
Gain/(loss) on disposal of property, plant & equipment		
Gain/(loss) on foreign exchange		
Charitable donation		
Income before payment in lieu of taxes	421,843	2,152,122
Gain/(loss) on regulatory assets		(2,171,924)
Income before provisions for income taxes	421,843	(19,802)

2015 Proposed Budget

18-Sep-14

Confidential

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Financial Summary
2014 Forecast Variance to 2014 Budget

	2014 Budget	2014 Forecast	Variance	Comments
Customer Billings	69,301,357	70,720,163	1,418,806	
Cost of Power	56,086,531	57,307,862	1,221,331	
Distribution Revenue	13,214,826	13,412,301	197,475	
Other Revenue	1,261,973	1,261,537	(435)	Bell ($92k), OPA $18k, Collection charges $24k, RSVA $32k, NBHS Mgt fee $5k, contributed capital amortization $12.5k (IFRS)
Operations	2,438,619	2,677,584	238,965	Less labour & overheads to capital $218k, vehicles $8k, facilities $15k
Finance	1,688,948	1,876,173	187,226	Postage $27k, Junior Acct $23k, customer engagement $50k, bad debts $41k, banking RFP $18k, Training $10k, Smart meters $12k
Engineering	47,745	0	(47,745)	AM plan
Human Resources	570,279	456,329	(113,950)	Union Contract $36k, Benefits ($43k) and EFB ($106k) IFRS
Administration	1,589,117	1,574,577	(14,540)	Elenchus $13k,Util Assist $59k, IT security audits $10k - offset labour ($36k), insurance ($11k), H.T.E. ($21k), CustomerFirst ($32k)
Depreciation	3,353,233	3,344,261	(8,972)	Capital spending changes and contributed capital to other revenue
Total OM&A	9,687,941	9,928,925	240,983	
Other	1,070,721	1,174,759	104,038	Interest on loans $30k, RSVA $29k, loss on w/o assets $58k, offset by $15k gain on foreign exchange
Gain on Reg Assets	(1,139,412)	(1,147,924)	(8,512)	
Income Prior to Taxes	2,578,724	2,422,231	(156,493)	
PILS	710,008	473,813	(236,195)	Change in Income for taxes related to deferral accounts and CCA
Net Income	1,868,716	1,948,418	79,702	
EBITDA	8,061,686	8,006,622	(55,065)	
EBITDA	55.7%	54.6%	-1.1%	
Cash	5,198,362	7,480,477	2,282,115	increase due to borrowing
Capital Spending	6,374,417	6,015,685	(358,732)	Bldg ($138k), Truck ($350k) offset Contributed Capital $123k
Net Fixed Assets	53,946,183	54,452,881	506,698	Contributed Capital to Deferred Revenue $1.1M, Spend ($482k), w/o stranded meters ($278k), w/o DA of ($65),kopening $74k.
Borrowing	2,216,667	6,131,046	3,914,379	$4m Sept 2014 10 years
Dividends	592,115	757,264	165,149	2013 final $146k offset with 2015 forecast $19

Financial Summary
September 2015 Proposed Budget with Variance to June 26 Proposed Budget

	June 26th 2015 Budget	Sept 18th 2015 Budget	Variance	Comments
Customer Billings	70,924,290	70,708,236	(216,053)	
Cost of Power	59,597,835	59,371,782	(226,053)	
Distribution Revenue	11,326,455	11,336,454	10,000	
Other Revenue	1,103,248	1,117,596	14,347	Interest ($16k), Contributed Capital $31k IFRS
Operations	3,080,884	3,195,736	114,852	Operational review $108k, overheads $7k
Finance	1,833,787	1,918,801	85,014	Bad debts $32k, Rebasing $56k
Engineering	20,000	20,000	0	
Human Resources	389,708	391,108	1,400	HR Consultants
Administration	1,532,808	1,480,728	(52,080)	Board remuneration ($17k), CustomerFirst ($40k), IBM $5k.
Depreciation	377,008	376,044	(964)	Capital spending changes and contributed capital to other revenue
Total OM&A	7,234,195	7,382,418	148,223	
Other	1,379,967	1,442,339	62,373	Interest on loans ($16k), loss on w/o assets $72k, Property taxes $4k, Donations $2k
Gain on Reg Assets	(2,171,924)	(2,171,924)	-	
Income Prior to Taxes	1,643,617	1,457,369	(186,248)	
PILS	-	(774,821)	(774,821)	Income for tax purposes negative, loss carry back
Net Income	1,643,617	2,232,190	588,573	
EBITDA	5,490,160	5,359,100	(131,060)	
EBITDA	44.2%	43.0%	-1.1%	
Cash	5,712,430	5,478,093	(234,338)	
Capital Spending	6,932,077	7,253,969	321,893	Truck $350k, Meter rack ($49k)
Net Fixed Assets	57,979,978	59,454,636	1,474,658	Capital spending and contributed capital to deferred revenue/other revenue (IFRS)
Borrowing	11,264,970	11,173,743	(91,228)	Change in timing and borrowing rates
Dividends	491,502	652,631	161,128	2014 final $20k, 2015 increased net income $141k

Capital Forecast
2014 Forecast Variance to 2014 Budget

	2014 BUDGET	2014 FORECAST	Variance	Comments
DISTRIBUTION SYSTEM ASSETS				
ASSET MANAGEMENT	-	22,469	22,469	
GENERATOR CONNECTIONS	92,415	52,415	(40,000)	
MAJOR BETTERMENTS	708,510	734,054	25,543	
VOLTAGE CONVERSION	1,117,210	1,232,006	114,796	
MINOR BETTERMENTS	1,091,671	1,063,070	(28,601)	
PORCELIN REPLACEMENTS	97,404	98,051	646	
PRIMARY SERVICES	126,345	126,385	39	
SECONDARY SERVICES	329,348	329,479	131	
SUBDIVISIONS	103,235	103,263	28	
TRANSFORMER PURCHASES - 850 & 851	369,202	369,202	-	
METERING	238,167	177,162	(61,005)	Arclin meter rack
SUBSTATION UPGRADES - 815	1,655,894	1,772,951	117,057	
ROAD PROJECTS	266,790	96,045	(170,745)	
TOTAL DISTRIBUTION SYSTEM ASSETS	**6,196,191**	**6,176,551**	**(19,641)**	
GENERAL ASSETS				
OFFICE UPGRADES / FURNITURE	642,613	504,672	(137,940)	Bldg - only doing driveway
TRANSPORTATION EQUIPMENT	503,000	153,063	(349,937)	Trk #30 boom pushed to '15
TOOL REQUIREMENTS	47,000	47,000	-	
IT REQUIREMENTS	236,580	262,476	25,896	
TOTAL GENERAL ASSETS	**1,429,192**	**967,211**	**(461,981)**	
TOTAL CAPITAL SPENDING	**7,625,384**	**7,143,762**	**(481,622)**	
CONTRIBUTED CAPITAL	(1,250,965)	(1,128,077)	122,888	
TOTAL NET CAPITAL SPENDING	**6,374,418**	**6,015,685**	**(358,734)**	

Capital Spending
September 2015 Proposed Budget with Variance to June 26 Proposed Budget

	June 26th 2015 BUDGET	Sept 18th 2015 BUDGET	Variance	Comments
DISTRIBUTION SYSTEM ASSETS				
ASSET MANAGEMENT	-	-	-	
GENERATOR CONNECTIONS	48,016	48,016	-	
MAJOR BETTERMENTS	1,266,604	1,266,811	207	
VOLTAGE CONVERSION	1,852,043	1,852,358	315	
MINOR BETTERMENTS	342,997	342,995	(2)	
PORCELIN REPLACEMENTS	-	-	-	
PRIMARY SERVICES	215,639	215,638	(1)	
SECONDARY SERVICES	240,615	240,613	(2)	
SUBDIVISIONS	99,963	99,962	(1)	
TRANSFORMER PURCHASES - 850 & 851	379,248	379,248	-	
METERING	276,216	227,548	(48,668)	Fabrene meter rack
SUBSTATION UPGRADES - 815	2,103,074	2,103,074	-	
ROAD PROJECTS	210,094	210,094		
TOTAL DISTRIBUTION SYSTEM ASSETS	**7,034,507**	**6,986,353**	**(48,154)**	
GENERAL ASSETS				
OFFICE UPGRADES / FURNITURE	56,652	56,652	-	
TRANSPORTATION EQUIPMENT	145,000	515,000	370,000	Trk #30 boom pushed to '15
TOOL REQUIREMENTS	46,151	46,151	-	
IT REQUIREMENTS	153,800	153,800	-	
TOTAL GENERAL ASSETS	**401,603**	**771,603**	**370,000**	
TOTAL CAPITAL SPENDING	**7,436,110**	**7,757,956**	**321,846**	
CONTRIBUTED CAPITAL	(504,033)	(503,987)	47	
TOTAL NET CAPITAL SPENDING	**6,932,077**	**7,253,969**	**321,893**	

RESIDENTIAL (800 kWh)

	Current	1 YR RIDER 2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
Fixed Service Charge	14.64	16.78	16.99	*0.21*	2.35	16.99	-
Distribution Variable	10.48	12.00	12.16	*0.16*	1.68	12.16	-
Total Fixed & Variable	25.12	28.78	29.15	*0.37*	4.03	29.15	-
NBHDL distribution revenue rate increase (%)					*16.04%*		*0.00%*
Fixed Riders							
Smart Meter Riders	2.70	-	-	-	(2.70)	-	-
Stranded Meter Rider	-	0.85	**0.85**	-	0.85	-	*(0.85)*
Volumetric Riders							
Tax Savings	(0.16)	-	-	-	0.16	-	-
Lost Revenue (2011 & 2013 CDM Activities)	-	0.08	0.16	*0.08*	0.16	0.08	-
Dep'n/Useful Life Change	-	(5.68)	(5.68)	-	(5.68)	-	*5.68*
Total Riders	2.54	(4.75)	(4.67)	*0.08*	(7.21)	0.08	*4.83*
Total NBHDL Distribution	**27.66**	**24.03**	**24.48**	***0.45***	**(3.18)**	**29.23**	***4.83***
NBHDL distribution rate increase (%)					*-11.50%*		*19.40%*
Deferral Accounts - Power	(1.44)	(0.56)	(0.56)	*0.88*			
Global Adjustment	-	-	-	-			
Low Voltage	0.03	0.03	0.03	-			
Line Losses - COP	3.55	3.55	3.55	-			
Smart Meter Entity	0.79	0.79	0.79	-			
Total Pass Through Costs	2.93	3.81	3.81	*0.88*			
Total Distribution	**30.59**	**27.84**	**28.29**	***1.33***			
Distribution rate increase (%)			*-7.52%*				
Total bill	128.23	125.42	125.88				
Total bill impact ('16 is approx.)		-2.19%	-1.83%				

GS<50 (2,000 kWh) - 1 year rider

	Current	1 YR RIDER 2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
Service Charge	21.69	24.86	25.17	*0.31*	3.48	25.17	-
Distribution Variable	33.40	38.20	38.80	*0.60*	5.40	38.80	*0.60*
Total Fixed & Variable	55.09	63.06	63.97	*0.91*	8.88	63.97	*0.60*
NBHDL distribution revenue rate increase (%)					*16.12%*		*0.00%*
Fixed Riders							
Smart Meter Riders	11.05	-	-	-	(11.05)	-	-
Stranded Meter Rider	-	1.92	1.92	-	1.92	-	*(1.92)*
Volumetric Riders							
Tax Savings	(0.40)	-	-	-	0.40	-	-
Lost Revenue (2011 & 2013 CDM Activities)	-	1.00	1.80	*0.80*	1.80	1.00	-
Dep'n/Useful Life Change	-	(14.20)	(14.20)	-	(14.20)	-	*14.20*
Total Riders	10.65	(11.28)	(10.48)	*0.80*	(21.13)	1.00	*12.28*
Total NBHDL Distribution	**65.74**	**51.78**	**53.49**	***1.71***	**(12.25)**	**64.97**	***12.88***
NBHDL distribution rate increase (%)					*-18.63%*		*25.47%*
Deferral Accounts - Power	(3.60)	0.40	0.40	-			
Global Adjustment	-	-	-	-			
Low Voltage	0.08	0.08	0.08	-			
Line Losses - COP	8.88	8.88	8.88	-			
Smart Meter Entity	0.79	0.79	0.79	-			
Total Pass Through Costs	6.15	10.15	10.15	-			
Total Distribution	**71.89**	**61.93**	**63.64**	***1.71***			
Distribution rate increase (%)			*-11.48%*				
Total bill	313.60	303.33	305.07				
		-3.27%	-2.72%				

GS>50 (192,000 kWh / 455 kW) - 1 year rider

		1 YR RIDER					
	Current	**2015 June - Board Meeting**	**2015 Sept - Proposed**	***2015 Change to Board Meeting***	**2015 Proposed Rate Increase**	**2016 Assumed**	***2016 Increase***
Service Charge	293.97	336.90	341.12	*4.22*	47.15	341.12	-
Distribution Variable	953.95	1,087.27	1,100.37	*13.10*	146.42	1,100.37	*13.10*
Total Fixed & Variable	1,247.92	1,424.17	1,441.49	*17.32*	193.57	1,441.49	*13.10*
NBHDL distribution revenue rate increase (%)					*15.51%*		*0.00%*
Volumetric Riders							
Tax Savings	(11.01)	-	-	-	11.01	-	-
Lost Revenue (2011 & 2013 CDM Activities)	-	18.97	34.85	*15.88*	34.85	18.97	-
Dep'n/Useful Life Change	-	(1,314.18)	(1,305.62)	*8.56*	(1,305.62)	-	*1,314.18*
Total Riders	(11.01)	(1,295.21)	(1,270.77)	*24.44*	(1,259.76)	18.97	*1,314.18*
Total NBHDL Distribution	**1,236.91**	**128.96**	**170.72**	***41.76***	**(1,066.19)**	**1,460.46**	***1,327.28***
NBHDL distribution rate increase (%)					*-86.20%*		*1032.49%*
Deferral Accounts - Power	(329.47)	116.79	116.53	*(0.26)*			
Global Adjustment	150.01	423.28	422.25	*(1.03)*			
Low Voltage	6.32	6.68	6.69	*0.01*			
Line Losses - COP	691.20	691.20	691.20	-			
Total Pass Through Costs	518.06	1,237.95	1,236.66	*(1.29)*			
Total Distribution	**1,754.97**	**1,366.91**	**1,407.38**	***40.47***			
Distribution rate increase (%)			*-19.81%*				
Total bill	25,184.51	24,746.00	24,791.68				
Total bill impact ('16 is approx.)		-1.74%	-1.56%				

Intermediate (1,720,000 kWh / 3,290 kW) - 1 year rider

		1 YR RIDER					
	Current	**2015 June - Board Meeting**	**2015 Sept - Proposed**	***2015 Change to Board Meeting***	**2015 Proposed Rate Increase**	**2016 Assumed**	***2016 Increase***
Service Charge	5,844.10	6,697.56	6,781.43	*83.87*	937.33	6,781.43	-
Distribution Variable	3,668.35	3,915.76	3,940.10	*24.34*	271.75	3,940.10	-
Total Fixed & Variable	9,512.45	10,613.32	10,721.53	*108.21*	1,209.08	10,721.53	-
NBHDL distribution revenue rate increase (%)					*12.71%*		*0.00%*
Volumetric Riders							
Tax Savings	(61.52)	-	-	-	61.52	-	-
Dep'n/Useful Life Change	-	(12,261.83)	(12,181.23)	*80.60*	(12,181.23)	-	*12,181.23*
Total Riders	(61.52)	(12,261.83)	(12,181.23)	*80.60*	(12,119.71)	-	*12,181.23*
Total NBHDL Distribution	**9,450.93**	**(1,648.51)**	**(1,459.69)**	***188.82***	**(10,910.62)**	**10,721.53**	***12,181.23***
NBHDL distribution rate increase (%)					*-115.44%*		*-750.38%*
Deferral Accounts - Power	(3,008.05)	1,376.53	1,373.90	*(2.63)*			
Global Adjustment	1,368.31	4,926.20	4,918.93	*(7.27)*			
Low Voltage	50.67	53.63	53.63	*(0.00)*			
Line Losses - COP	1,570.86	1,570.86	1,570.36	*(0.50)*			
Total Pass Through Costs	(18.21)	7,927.22	7,916.83	*(10.39)*			
Total Distribution	**9,432.72**	**6,278.71**	**6,457.13**	***178.42***			
Distribution rate increase (%)			*-31.55%*				
Total bill	204,192.67	200,628.64	200,830.60				
Total bill impact ('16 is approx.)		-1.75%	-1.65%				

Street Lights (168,200 kWh / 470 kW) - 1 year rider

	Current	2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
		1 YR RIDER					
Fixed Service Charge	26,444.72	30,292.21	30,671.54	*379.33*	4,226.82	30,671.54	-
Distribution Variable	12,278.99	14,072.18	14,248.43	*176.25*	1,969.44	14,248.43	-
Total Fixed & Variable	38,723.71	44,364.39	44,919.97	*555.58*	6,196.26	44,919.97	-
NBHDL distribution revenue rate increase (%)					*16.00%*		*0.00%*
Volumetric Riders							
Tax Savings	(214.60)	-	-	-	214.60	-	-
Lost Revenue (2011 & 2013 CDM Activities)	-	3,826.81	8,636.44	*4,809.63*	8,636.44	8,636.44	-
Dep'n/Useful Life Change	-	(1,202.50)	(1,194.60)	*7.90*	(1,194.60)	-	*1,194.60*
Total Riders	(214.60)	2,624.31	7,441.84	*4,817.53*	7,656.44	8,636.44	*1,194.60*
Total NBHDL Distribution	**38,509.11**	**46,988.70**	**52,361.81**	***5,373.11***	**13,852.70**	**53,556.40**	***1,194.60***
NBHDL distribution rate increase (%)					*35.97%*		*13.98%*
Deferral Accounts - Power	(294.88)	(5,717.88)	(5,717.88)	-			
Global Adjustment	134.23	423.78	423.07	*(0.71)*			
Low Voltage	5.08	5.36	5.36	-			
Line Losses - COP	710.48	710.48	710.48	-			
Total Pass Through Costs	554.91	(4,578.26)	(4,578.97)	*(0.71)*			
Total Distribution	**39,064.02**	**42,410.44**	**47,782.84**	***5,372.40***			
Distribution rate increase (%)			*22.32%*				
Total bill	65,781.51	68,032.38	75,633.48				
Total bill impact		3.42%	14.98%				

Sentinel Lights (150 kWh / 1 kW) - 1 year rider

	Current	2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
		1 YR RIDER					
Fixed Service Charge	4.42	5.07	5.13	*0.06*	0.71	5.13	-
Distribution Variable	15.44	17.69	17.91	*0.22*	2.47	17.91	-
Total Fixed & Variable	19.86	22.76	23.04	*0.28*	3.18	23.04	-
NBHDL distribution revenue rate increase (%)					*16.02%*		*0.00%*
Volumetric Riders							
Tax Savings	(0.23)	-	-	-	0.23	-	-
Dep'n/Useful Life Change	-	(2.37)	(2.35)	*0.02*	(2.35)	-	*2.37*
Total Riders	(0.23)	(2.37)	(2.35)	*0.02*	(2.12)	-	*2.37*
Total NBHDL Distribution	**19.63**	**20.39**	**20.69**	***0.30***	**1.06**	**23.04**	***2.37***
NBHDL distribution rate increase (%)					*5.40%*		*11.37%*
Deferral Accounts - Power	(0.36)	(3.81)	(3.82)	*(0.01)*			
Global Adjustment	0.17	0.78	0.78	-			
Low Voltage	0.01	0.01	0.01	-			
Line Losses - COP	0.54	0.54	0.54	-			
Total Pass Through Costs	0.36	(2.48)	(2.49)	*(0.01)*			
Total Distribution	**19.99**	**17.91**	**18.20**	***0.29***			
Distribution rate increase (%)			*-8.94%*				
Total bill	38.90	36.78	37.09				
Total bill impact		-5.45%	-4.66%				

UMSL (150 kWh) - 1 year rider								
		1 YR RIDER						
	Current	2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
Fixed Service Charge	7.03	8.06	8.16	*0.10*	1.13	8.16	-
Distribution Variable	2.43	2.79	2.82	*0.03*	0.39	2.82	-
Total Fixed & Variable	9.46	10.85	10.98	*0.13*	1.52	10.98	-
NBHDL distribution revenue rate increase (%)					*16.04%*		*0.00%*
Volumetric Riders							
Tax Savings	(0.03)	-	-	-	0.03	-	-
Dep'n/Useful Life Change	-	(1.07)	(1.07)	-	(1.07)	-	*1.07*
Total Riders	(0.03)	(1.07)	(1.07)	-	(1.04)	-	*1.07*
Total NBHDL Distribution	**9.43**	**9.78**	**9.91**	***0.13***	**0.48**	**10.98**	***1.07***
NBHDL distribution rate increase (%)					*5.06%*		*12.24%*
Deferral Accounts - Power	(0.27)	(0.13)	(0.14)	*(0.01)*			
Global Adjustment	-	-	-	-			
Low Voltage	0.01	0.01	0.01	-			
Line Losses - COP	0.54	0.54	0.54	-			
Total Pass Through Costs	0.28	0.42	0.42	*(0.01)*			
Total Distribution	**9.71**	**10.20**	**10.32**	***0.12***			
Distribution rate increase (%)			*6.31%*				
Total bill	26.66	27.14	27.27				
Total bill impact		1.80%	2.30%				

Income Statement 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013 Actual	2014 Budget	June 26th 2014 Forecast	Sept 2014 Forecast	Sept vs Budget	Notes Sept forecast vs 2014 Budget	June 26th 2015 Proposed Budget	Sept 2015 Proposed Budget	2015 Budget vs 2014 Forecast	Notes June 26th 2015 Budget prior to increase vs June 26th 2014 Forecast
Income Statement											
Revenue											
Customer Billings	61,424,212	67,407,018	69,301,357	73,723,635	70,720,163	1,418,806		70,924,290	70,708,236	(11,927)	
Cost of Power	50,412,615	56,023,658	56,086,531	60,327,076	57,307,862	1,221,331		59,597,835	59,371,782	2,063,920	
Distribution revenue	11,011,597	11,383,360	13,214,826	13,396,558	13,412,301	197,475		11,326,455	11,336,454	(2,075,847)	Smart meter disp $ 1.9m, 1576- deprecation disp $150k.
Other operating revenue	1,167,175	1,407,841	1,261,973	1,182,831	1,261,537	(435)		1,103,248	1,117,596	(143,942)	Smart meter disp$211k, RSVA $22k, Interest $22k, Bell ($312k), OPA ($185k)
Total Revenue	12,178,772	12,791,201	14,476,799	14,579,390	14,673,839	197,040		12,429,703	12,454,050	(2,219,789)	
Operating expenses											
Operations	2,324,477	2,544,722	2,438,619	2,700,543	2,677,584	238,965		3,080,884	3,195,736	518,152	Smart meter disp ($25k), tree $246k, review $100k , labour $55k
Finance	1,495,972	1,407,663	1,688,948	1,773,871	1,876,173	187,226		1,833,787	1,918,801	42,628	Smart meter disp ($104k), cost of service app $51k, Wages $84k, Postage $23k
Engineering	-	-	47,745	(0)	0	(47,745)		20,000	20,000	20,000	AM Plan
Human Resources	566,270	495,688	570,279	551,544	456,329	(113,950)		389,708	391,108	(65,221)	Union Contract ($43k), EFB IFRS ($111k), Succession Consultant 9$18k)
Administration	983,063	1,123,968	1,589,117	1,669,128	1,574,577	(14,540)		1,532,808	1,480,728	(93,849)	Smart meter disp ($283k), strategic plan $100k, IT security & mtce $53k, Insurance $20k, Navigant ($22k)
Depreciation and amortization	1,978,195	2,050,588	3,353,233	3,355,847	3,344,261	(8,972)		377,008	376,044	(2,968,217)	Smart meter disp ($951k), 1576- depreciation disp ($2.3M), offset by new capital spending
Total OM&A	7,347,977	7,622,629	9,687,941	10,050,933	9,928,925	240,983		7,234,195	7,382,418	(2,546,507)	
						-					
Income before items below	4,830,796	5,168,572	4,788,858	4,528,457	4,744,914	(43,943)		5,195,508	5,071,632	326,718	
						-					
Interest	1,171,090	1,149,551	990,317	1,019,628	1,049,475	59,158		1,291,323	1,275,307	225,832	Smart meter disp $90k, regulatory interest $26k,smart meter loan ($13k), 2014 loan $77k, 2015 loan $92k
Property taxes	57,183	62,479	64,354	64,374	66,004	1,649		66,305	69,876	3,873	
Income before other items and PILS	3,602,523	3,956,542	3,734,187	3,444,455	3,629,436	(104,750)		3,837,880	3,726,449	97,013	
								-			
Other items						-		-			
Gain/(loss) on disposal of PP&E	347,552	12,143	-	6,875	(57,415)	(57,415)		(6,289)	(78,456)	(21,041)	
Gain/(loss) on foreign exchange	(4,060)	11,365	-	19,610	14,684	14,684		-	-	(14,684)	
Charitable donation	15,550	21,050	16,050	16,050	16,550	500		16,050	18,700	2,150	
Income before PILS	3,930,465	3,959,000	3,718,137	3,454,890	3,570,155	(147,981)		3,815,541	3,629,293	59,138	
Gain/(loss) on regulatory assets	(1,132,571)	(1,164,967)	(1,139,412)	(1,152,181)	(1,147,924)	(8,512)		(2,171,924)	(2,171,924)	(1,024,000)	1576- depreciation dispostion (change in useful lives of assets)
Income before provisions for PILS	2,797,894	2,794,033	2,578,724	2,302,709	2,422,231	(156,493)		1,643,617	1,457,369	(964,863)	
				1,073,567	1,174,759	101,192		-			
Payment in lieu of taxes	660,447	536,307	710,008	685,470	473,813	(236,195)		-	(774,821)	(1,248,634)	Income for tax purposes negative
Future	-	-	-	-		-		-		-	
Income Taxes	660,447	536,307	710,008	685,470	473,813	(236,195)		-	(774,821)	(1,248,634)	
						-		-			
Net income for the period	**2,137,447**	**2,257,726**	**1,868,716**	**1,617,239**	**1,948,418**	**79,702**		**1,643,617**	**2,232,190**	**283,772**	
		-				-		-			
Retained earnings, beginning of the year	7,851,729	9,370,502	10,924,897	10,991,679	10,991,679	66,782		12,241,779	12,387,855	1,396,176	Net income $1.6m, dividends ($678k), IFRS adj $310k
Net income	2,137,447	2,257,726	1,868,716	1,617,239	1,948,418	79,702		1,643,617	2,232,190	283,772	
Dividends	(618,674)	(636,549)	(592,115)	(677,781)	(757,264)	(165,149)		(491,502)	(652,631)	104,634	2013 final $193k offset with 2015 forecast vs 2014 ($6k)
Retained earnings, end of month	9,370,502	10,991,679	12,201,498	11,931,137	12,182,833	(18,665)		13,393,893	13,967,414	1,784,581	
						-		-		-	
EBITDA	**6,736,257**	**7,135,631**	**8,061,686**	**7,803,880**	**8,006,622**	**(55,065)**		**5,490,160**	**5,359,100**	**(2,647,522)**	
EBITDA % of Revenue	***55.3%***	***55.8%***	***55.7%***	***53.5%***	***54.6%***	***-1.1%***		***44.2%***	***43.0%***	***-11.5%***	

Balance Sheet 2012 Actual - 2015 Proposed Budget

	2012 Actual	2013 Actual	2014 Budget	June 26th 2014 Forecast	Sept 18th 2014 Forecast	2014 Forecast vs 2014 Budget	June 26th 2015 Proposed Budget	Sept 18th 2015 Proposed Budget	2015 Budget vs 2014 Forecast
Balance Sheet									
ASSETS									
Current assets									
Cash and short-term investments	7,393,387	7,435,148	5,198,362	7,006,323	7,480,477	2,282,115	5,712,430	5,478,093	(2,002,384)
Restricted short term investments	-	-	-	-	-	-	-	-	-
Accounts receivable	5,571,448	7,093,372	6,086,096	8,137,834	7,855,179	1,769,083	8,042,023	7,708,387	(146,792)
Unbilled revenue	7,740,920	7,733,424	6,492,935	6,877,858	6,842,892	349,958	7,725,255	7,706,656	863,763
Inventory	579,637	448,742	549,581	454,366	454,366	(95,215)	454,366	454,366	-
Prepaid expenses	532,163	608,750	582,518	889,486	976,413	393,895	976,120	1,053,464	77,051
Payments in lieu of taxes	-	35,176	8,135	-	41,698	33,563	-	774,821	733,123
Total current assets	**21,817,555**	**24,665,391**	**18,917,626**	**23,365,867**	**23,651,025**	**4,733,399**	**22,910,193**	**23,175,786**	**(475,238)**
Restricted short term investments	**-**	**-**	**-**	**-**	**-**	**-**	**-**		**-**
Property, plant and equipment							**-**		
Electrical distribution assets	94,203,173	100,212,163	109,522,531	107,065,084	98,857,288	(10,665,243)	114,662,900	105,973,397	7,116,109
General assets	10,969,655	11,400,820	12,569,006	12,669,826	10,714,579	(1,854,427)	12,987,973	11,486,012	771,433
WIP	625,281	526,120	705,855	722,149	805,461	99,607	21,361	21,360	(784,102)
Gross Assets	105,798,108	112,139,102	122,797,391	120,457,058	110,377,329	(12,420,063)	127,672,234	117,480,769	7,103,441
Accumulated depreciation	(55,051,068)	(57,228,872)	(60,519,879)	(58,446,047)	(55,924,447)	4,595,432	(61,150,623)	(58,026,133)	(2,101,686)
	50,747,041	54,910,231	62,277,512	62,011,011	54,452,881	(7,824,631)	66,521,611	59,454,636	5,001,755
Contributions in aid of construction	(6,478,723)	(7,341,246)	(8,331,329)	(8,280,001)	(0)	8,331,329	(8,541,633)	(0)	-
Total property, plant and equipment	**44,268,318**	**47,568,985**	**53,946,183**	**53,731,010**	**54,452,881**	**506,698**	**57,979,978**	**59,454,636**	**5,001,755**
Other Assets	**6,361**	**6,361**	**6,361**	**6,361**	**6,361**	**-**	**6,361**	**6,361**	**-**
Regulatory assets	3,713,424	4,831,945	1,790,175	835,156	1,602,894	(187,280)	404,656	1,015,500	(587,395)
Future Income Taxes	6,497,137	6,075,056	2,404,643	4,588,904	4,409,750	2,005,107	4,226,329	4,140,052	(269,698)
TOTAL ASSETS	**76,302,795**	**83,147,738**	**77,064,987**	**82,527,297**	**84,122,912**	**7,057,924**	**85,527,517**	**87,792,335**	**3,669,423**
LIABILITIES									
Current liabilities									
Accounts payable and accrued liabilities	9,701,698	13,452,110	9,951,043	10,210,228	10,754,292	803,249	10,691,441	11,019,244	264,952
Operating Line	-	-	-	-	-	-	-	-	-
Deferred Revenue	275,247	614,896	402,725	455,301	396,938	(5,787)	406,634	348,271	(48,667)
Payments in lieu of taxes	153,315	-	-	85,470	-	-	-	-	-
Current portion of long-term customer deposits	87,689	80,063	87,689	80,063	80,063	(7,626)	80,063	80,063	-
Current portion of Smart Meter Capital Loan	350,000	350,000	350,000	350,000	350,000	-	350,000	350,000	-
Captital Loan 2014	-			113,658	349,574	349,574	231,111	349,450 -	124
Captital Loan 2015							256,927	528,185	
Inter Company	102,181	177,325	117,845	117,845	117,845	-	117,845	117,845	-
Total current liabilities	**10,670,130**	**14,674,394**	**10,909,302**	**11,412,565**	**12,048,712**	**1,139,410**	**12,134,022**	**12,793,059**	**744,347**
Long-term liabilities									
Customer deposits	883,091	862,925	850,653	805,356	815,932	(34,721)	805,356	815,932	-
Employee future benefits	4,405,983	4,511,393	4,606,023	4,611,413	4,300,770	(305,253)	4,289,690	4,289,689	(11,081)
Payable to Corporation of the City of North Bay	19,511,601	19,511,601	19,511,601	19,511,601	19,511,601	-	19,511,601	19,511,601	-
Deferred Revenue - Contributed Capital					1,115,543			1,588,862	
Trust Liability		353,952	352,839	355,044	356,151	3,312	-		(356,151)
Smart Meter/Capital Loan	2,566,667	2,216,667	1,866,667	1,866,667	1,866,667	-	1,516,667	1,516,667	(350,000)
Captital Loan 2014				3,772,684	3,564,806		3,424,120	3,215,479	
Captital Loan 2015							5,486,145	5,213,961	
Regulatory Liability - Future Income Taxes	6,497,137	6,075,056	2,404,643	4,588,904	4,409,750	2,005,107	4,226,329	4,140,052	(269,698)
Total long-term liabilities	**33,864,479**	**33,531,594**	**29,592,426**	**35,511,669**	**35,941,220**	**6,348,794**	**39,259,908**	**40,292,242**	**4,351,023**
Regulatory liabilities	2,886,086	4,438,473	4,850,164	4,160,329	4,233,527	(616,637)	1,228,096	1,228,021	(3,005,506)
Shareholder's equity									
Capital stock	19,511,601	19,511,601	19,511,601	19,511,601	19,511,601	-	19,511,601	19,511,601	-
Retained earnings, beginning of year	7,851,726	9,370,499	10,924,894	10,991,676	10,991,676	66,782	12,241,776	12,387,852	1,396,176
Dividends	(618,674)	(636,549)	(592,115)	(677,781)	(757,264)	(165,149)	(491,502)	(652,631)	104,634
Dividends in kind	-	-	-	-	-	-	-	-	-
Net Income	2,137,447	2,257,726	1,868,716	1,617,239	1,948,418	79,702	1,643,617	2,232,190	283,772
Retained earnings, end of year	9,370,499	10,991,676	12,201,495	11,931,134	12,387,852	186,357	13,393,890	13,967,411	1,579,559
Total shareholder's equity	**28,882,100**	**30,503,277**	**31,713,096**	**31,442,735**	**31,899,453**	**186,357**	**32,905,491**	**33,479,012**	**1,579,559**
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**76,302,795**	**83,147,738**	**77,064,987**	**82,527,297**	**84,122,912**	**7,057,924**	**85,527,517**	**87,792,335**	**3,669,423**

Cash Flow 2012 Actual - 2015 Proposed Budget

Cash Flow	2012 Actual	2013 Actual	2014 Budget	June 26th 2014 Forecast	Sept 18th '2014 Forecast	2014 Forecast vs 2014 Budget	June 26th 2015 Proposed Budget	Sept 18th 2015 Proposed Budget	2015 Budget vs 2014 Forecast
CASH PROVIDED BY (USED IN):									
OPERATING ACTIVITIES									
Net income for the period	$ 2,137,447	$ 2,257,726	$ 1,868,716	$ 1,617,239	$ 1,948,418	$ 79,702	$ 1,643,617	$ 2,232,190	$ 283,772
Adjustments for:									
Items not involving cash:									
Amortization of property, plant & equipment(net of amortization of contributions in aid of construction	1,978,195	2,050,588	2,401,809	2,401,116	2,376,996	(24,813)	2,676,821	345,376	(2,031,620)
OPA Depreciation Adjustment	4,827	-	-			-		2,301,701	2,301,701
Gain/loss on sale of property, plant and equipment	(373,907)	(12,143)	-	(6,875)	57,415	57,415	6,289	78,456	21,041
Accrual for employee future benefits	84,384	105,410	100,020	100,020	(210,623)	(310,643)	(11,081)	(11,081)	199,542
Write-down of regulatory assets	1,132,571	1,164,967	1,139,412	1,152,181	1,147,924	8,512	-	-	(1,147,924)
Future Income Taxes	-	422,081	2,700,261	1,486,152	1,665,306	(1,034,955)	362,575	269,698	(1,395,608)
Change in non-cash operating working capital:	-	-	-	-		-	-		-
Accounts receivable	(90,042)	(2,832,703)	(150,026)	266,317	548,972	698,998	95,811	146,792	(402,180)
Unbilled revenue	149,883	7,496	(180,264)	855,566	890,532	1,070,796	(847,397)	(863,763)	(1,754,295)
Inventory	178,834	130,895	50,419	(5,624)	(5,624)	(56,043)	-	-	5,624
Prepaid expenses	64,497	(76,587)	(53,927)	(280,736)	(367,663)	(313,736)	(86,634)	(77,051)	290,612
Accounts payable and accrued liabilities	(858,014)	3,750,412	(753,168)	(3,241,882)	(2,697,818)	(1,944,649)	481,213	264,952	2,962,770
Deferred Revenue	116,729	339,649	(156,924)	(159,595)	(217,958)	(61,034)	(48,667)	(48,667)	169,291
Payments in lieu of taxes	327,576	(188,491)	470,008	120,646	(6,522)	(476,530)	(85,470)	(733,123)	(726,601)
(Increase) decrease in other assets	-	-	-	-	-	-	-	-	-
Intercompany	179,055	75,144	39,628	(59,480)	(59,480)	(99,108)	-	-	59,480
Cash provided by operating activities	5,032,034	7,194,444	7,475,964	4,245,045	5,274,897	(2,201,067)	4,187,076	3,905,480	(1,369,417)
INVESTING ACTIVITIES									
Purchase of property, plant and equipment	(5,317,656)	(6,420,222)	(7,625,384)	(7,528,916)	(7,143,762)	481,622	(7,436,110)	(7,757,956)	(614,194)
Contributions received in aid of construction	675,929	1,061,939	1,250,967	1,162,638	1,128,077	(122,889)	504,033	503,987	(624,091)
Proceeds on sale of property, plant and equipment	443,898	19,171	-	6,875	8,455	8,455	-	-	(8,455)
Decrease (increase) in regulatory assets/liabilities	1,212,572	(1,153,182)	(3,192,565)	(1,116,550)	(1,984,659)	1,207,906	(2,864,308)	(2,687,810)	(703,150)
Cash used in investment activities	(2,985,257)	(6,492,294)	(9,566,982)	(7,475,953)	(7,991,889)	1,575,093	(9,796,385)	(9,941,779)	(1,949,890)
FINANCING ACTIVITIES									
Increase (decrease) in customer deposits	(6,376)	(27,792)	-	(57,569)	(46,993)	(46,993)	-	-	46,993
Deferred Revenue/Operating Loan	-	-	-	-	-	-	-	-	-
Dividends / Dividends in kind	(618,674)	(636,549)	(592,115)	(677,781)	(757,264)	(165,149)	(491,502)	(652,631)	104,634
(Increase) decrease in Note Receivable Services	2,000,000	-	-	-	-	-	-	-	-
Smart Meter Loan/Capital Loan	(350,000)	(350,000)	(350,000)	(350,000)	(350,000)	(0)	(350,000)	(350,000)	0
Capital Loan 2014	-			3,886,342	3,914,379	3,914,379	(231,111)	(349,450)	(4,263,830)
Capital Loan 2015						-	5,743,073	5,742,147	5,742,147
Trust Fund		353,952	-	1,092	2,199	2,199	(355,044)	(356,151)	(358,350)
Principal reduction of employee future benefits liability		-	-	-	-	-	-	-	-
Cash provided by financing activities	1,024,950	(660,389)	(942,116)	2,802,083	2,762,321	3,704,436	4,315,415	4,033,915	1,271,594
				-			-		
Net increase in cash	3,071,727	41,761	(3,033,134)	(428,824)	45,329	3,078,463	(1,293,893)	(2,002,384)	(2,047,713)
Cash , beginning of period	4,321,660	7,393,387	8,231,496	7,435,149	7,435,149	(796,347)	7,006,324	7,480,478	45,329
Cash , end of year	$ 7,393,387	$ 7,435,148	$ 5,198,362	$ 7,006,324	$ 7,480,478	$ 2,282,116	$ 5,712,431	$ 5,478,094	$ (2,002,384)
Represented by:									
Cash and cash equivalents	7,393,387	7,435,148	5,198,362	7,006,323	7,480,478	2,282,116	5,712,431	5,478,094	(2,002,384)
Restricted cash and cash equivalents	-	-	-	-	-	-			-
	7,393,387	7,435,148	5,198,362	$ 7,006,323	$ 7,480,478	$ 2,282,116	$ 5,712,431	$ 5,478,094	$ (2,002,384)

Financial Summary
2015 Proposed Budget with Variance to 2014 Forecast

	2014 Forecast	2015 Budget	Variance	Comments
Customer Billings	70,720,163	70,708,236	(11,927)	
Cost of Power	57,307,862	59,371,782	2,063,920	
Distribution Revenue	13,412,301	11,336,454	(2,075,847)	Smart meter disp $1.9m, 1576 - deprecation disp $150k.
Other Revenue	1,261,537	1,117,596	(143,942)	Smart meter disp $211k, RSVA($26k), Bell ($308k), OPA ($18k), Contributed Capital $18k, Collection ($23k)
Operations	2,677,584	3,195,736	518,152	Operational review $208k, Tree Triming $245k
Finance	1,876,173	1,918,801	42,628	Smart meter dis ($109k), COS Application $145k
Engineering	0	20,000	20,000	AM plan update
Human Resources	456,329	391,108	(65,221)	Union Contract ($36k),Succession Consultant ($12k), Legal ($8k), EFB ($5k)
Administration	1,574,577	1,480,728	(93,849)	Smart meter disp ($274k), Elenchus (13k), Strategic plan $100k, IT security audits $23k, IT mtce $29k, Insurance $20k
Depreciation	3,344,261	376,044	(2,968,217)	Smart meter disp ($951k), 1576- depreciation disp ($2.3M), offset by new capital spending
Other	1,174,759	1,442,339	267,580	Smart meter disp $90k, Interest $135k, w/o assets $21k, foreign exchange $16k
Gain on Reg Assets	(1,147,924)	(2,171,924)	(1,024,000)	1576- depreciation dispostion (change in useful lives of assets), offset in depreciation and other revenue
Income Prior to Taxes	2,422,231	1,457,369	(964,863)	
PILS	473,813	(774,821)	(1,248,634)	Income for tax purposes negative, loss carry back
Net Income	1,948,418	2,232,190	283,772	
EBITDA	8,006,622	5,359,100	(2,647,522)	
EBITDA	54.6%	43.0%	-11.5%	
Cash	7,480,477	5,478,093	(2,002,384)	
Capital Spending	6,015,685	7,253,969	1,238,284	
Net Fixed Assets	54,452,881	59,454,636	5,001,755	Gross capital spend, less write offs and depreciation
Borrowing	6,131,046	11,173,743	5,042,696	$6M June 2015 10 years, less principle payments on smart meter loan and 2014 capital loan
Dividends	757,264	652,631	(104,634)	

Financial Summary
2014 September Forecast Variance to June Forecast

	June 26th 2014 Forecast	Sept 18th 2014 Forecast	Variance	Comments
Customer Billings	73,723,635	70,720,163	(3,003,472)	
Cost of Power	60,327,076	57,307,862	(3,019,214)	
Distribution Revenue	13,396,558	13,412,301	15,743	
Other Revenue	1,182,831	1,261,537	78,706	Collection charges $24k, RSVA $48k, contributed capital amort $12.5k (IFRS), Bell ($4k)
Operations	2,700,543	2,677,584	(22,959)	Overheads
Finance	1,773,871	1,876,173	102,303	Postage $11k, Junior Acct $26k, customer engagement, bad debts $32k, banking RFP $18k, Smart meters $12k
Engineering	(0)	0	0	
Human Resources	551,544	456,329	(95,215)	Benefits $6k, contracted services $3k, EFB ($106k) IFRS,
Administration	1,669,128	1,574,577	(94,551)	Board legal ($35k), CustomerFirst ($32k), Navigant ($22k), Wages ($18k), smart meters ($7k), Elenchus $13k, IT mtce $5k
Depreciation	3,355,847	3,344,261	(11,586)	Contributed capital amortization $12.5k (IFRS), changes to capital spending
Other	1,073,567	1,174,759	101,192	Interest on loans($11k), RSVA $40k, loss on w/o assets $64k, offset by $5k gain on foeign exchange
Gain on Reg Assets	(1,152,181)	(1,147,924)	4,257	
Income Prior to Taxes	2,302,709	2,422,231	119,522	
PILS	685,470	473,813	(211,657)	Change in Income for taxes related to deferal accounts and CCA
Net Income	1,617,239	1,948,418	331,179	
EBITDA	7,803,880	8,006,622	202,742	
EBITDA	53.5%	54.6%	1.0%	
Cash	7,006,323	7,480,477	474,153	
Capital Spending	6,366,278	6,015,685	(350,593)	Bldg ($138k), Truck ($350k) offset Contributed Capital $123k
Net Fixed Assets	53,731,010	54,452,881	721,872	Contributed Capital to Deferred Revenue $1.1M, Spend ($358k), w/o stranded meters ($278k), w/o DA of ($65),k opening $74k.
Borrowing	6,103,009	6,131,046	28,037	$4m Sept 2014 vs August
Dividends	677,781	757,264	79,483	Increased net income

NORTH BAY HYDRO
BOARD OF DIRECTORS
NORTH BAY, ONTARIO

Resolution No: 14/16 Date: September 18, 2014

Moved by: R. Peters Seconded by: C. Gagnon

RECORD OF VOTE:

FOR AGAINST

That Management be authorized to make an application to the Ontario Energy Board for rates proposed to become effective May 1, 2015 in accordance with the terms of the updated 2015 Budget reviewed with the Board on September 18, 2014.

Carried

Secretary

Chair

NORTH BAY HYDRO
BOARD OF DIRECTORS
NORTH BAY, ONTARIO

Resolution No: 14/11 Date: June 26, 2014

Moved by: C. Gagnon Seconded by: R. Peters

RECORD OF VOTE:

FOR AGAINST

That Management be authorized to make an application to the Ontario Energy Board for rates proposed to become effective May 1, 2015 in accordance with the terms of the 2015 Proposed Budget reviewed with the Board on June 26, 2014.

Carried

Secretary

Chair

Financial Summary
2014 Revised Forecast Variance to 2014 Budget

	2014 Budget	Revised 2014 Forecast	Variance	Comments
Customer Billings	69,301,357	70,706,302	1,404,945	
Cost of Power	56,086,531	57,307,862	1,221,331	
Distribution Revenue	13,214,826	13,398,440	183,614	
Other Revenue	1,261,973	1,256,743	(5,230)	Bell ($92k), OPA $18k, Collection charges $24k, RSVA $32k, NBHS Mgt fee $5k, contributed capital amortization $12.5k (IFRS)
Operations	2,438,619	2,779,584	340,965	Less labour & overheads to capital $218k, vehicles $8k, facilities $15k, Tree triming $102
Finance	1,688,948	1,876,173	187,225	Postage $27k, Junior Acct $23k, customer engagement $50k, bad debts $41k, banking RFP $18k, Training $10k, Smart meters $12k
Engineering	47,745	0	(47,745)	AM plan
Human Resources	570,279	456,329	(113,950)	Union Contract $36k, Benefits ($43k) and EFB ($106k) IFRS
Administration	1,589,117	1,574,577	(14,540)	Elenchus $13k,Util Assist $59k, IT security audits $10k - offset labour ($36k), insurance ($11k), H.T.E. ($21k), CustomerFirst ($32k)
Depreciation	3,353,233	3,344,261	(8,972)	Capital spending changes and contributed capital to other revenue
Total OM&A	9,687,941	10,030,924	342,983	
Other	1,070,721	1,164,901	94,180	Interest on loans $20k, RSVA $29k, loss on w/o assets $58k, offset by $15k gain on foreign exchange
Gain on Reg Assets	(1,139,412)	(1,147,924)	(8,512)	
Income Prior to Taxes	2,578,724	2,311,434	(267,291)	
PILS	710,008	507,395	(202,613)	Change in Income for taxes related to deferral accounts and CCA
Net Income	1,868,716	1,804,039	(64,678)	
EBITDA	8,061,686	7,885,966	(175,720)	
EBITDA	55.7%	53.8%	-1.9%	

Financial Summary
2014 Forecast Variance to 2014 Sept 18th Forecast

	Sept 18th 2014 Forecast	Revised 2014 Forecast	Variance	Comments
Customer Billings	70,720,163	70,706,302	(13,861)	
Cost of Power	57,307,862	57,307,862	0	
Distribution Revenue	13,412,301	13,398,440	(13,861)	
Other Revenue	1,261,537	1,256,743	(4,794)	RSVA interest $1.7k, Bank interest $3.1k
Operations	2,677,584	2,779,584	102,000	Tree triming
Finance	1,876,173	1,876,173	(0)	
Engineering	0	0	-	
Human Resources	456,329	456,329	-	
Administration	1,574,577	1,574,577	-	
Depreciation	3,344,261	3,344,261	-	
Total OM&A	9,928,925	10,030,924	102,000	
Other	1,174,759	1,164,901	(9,858)	Capital loan timing
Gain on Reg Assets	(1,147,924)	(1,147,924)	-	
Income Prior to Taxes	2,422,231	2,311,434	(110,798)	
PILS	473,813	507,395	33,582	
Net Income	1,948,418	1,804,039	(144,380)	
EBITDA	8,006,622	7,885,966	(120,656)	
EBITDA	54.6%	53.8%	-0.8%	

Financial Summary
September 2015 Proposed Budget with Variance to Rate Application Budget

	Sept 18th 2015 Budget	Rate Applicatoin 2015 Budget	Variance	Changes related to rate calculation
Customer Billings	70,708,236	72,456,874	1,748,638	
Cost of Power	59,371,782	61,164,705	1,792,923	
Distribution Revenue	11,336,454	11,292,170	(44,284)	New RPP rates issued
Other Revenue	1,117,596	1,116,765	(831)	RSVA interest
Operations	3,195,736	3,029,336	(166,400)	Operational Review amortized over 5 years/Actual 2015 expenditure $208,000
Finance	1,918,801	1,933,801	15,000	Regulatory full year
Engineering	20,000	20,000	-	
Human Resources	391,108	391,108	-	
Administration	1,480,728	1,480,728	-	
Depreciation	376,044	376,044	-	
Total OM&A	7,382,418	7,231,018	(151,400)	
Other	1,442,339	1,445,804	3,465	RSVA interest
Gain on Reg Assets	(2,171,924)	(2,171,924)	-	
Income Prior to Taxes	1,457,369	1,560,189	102,821	
PILS	(774,821)	(696,697)	78,124	
Net Income	2,232,190	2,256,886	24,696	
EBITDA	5,359,100	5,465,384	106,284	
EBITDA	43.0%	44.0%	1.0%	

RESIDENTIAL (800 kWh)

		1 YR RIDER					
	Current	2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
Fixed Service Charge	14.64	16.78	16.99	*0.21*	2.35	16.99	-
Distribution Variable	10.48	12.00	12.16	*0.16*	1.68	12.16	-
Total Fixed & Variable	25.12	28.78	29.15	*0.37*	4.03	29.15	-
NBHDL distribution revenue rate increase (%)					*16.04%*		*0.00%*
Fixed Riders							
Smart Meter Riders	2.70	-	-	-	(2.70)	-	-
Stranded Meter Rider	-	0.85	**0.85**	-	0.85	-	*(0.85)*
Volumetric Riders							
Tax Savings	(0.16)	-	-	-	0.16	-	-
Lost Revenue (2011 & 2013 CDM Activities)	-	0.08	0.16	*0.08*	0.16	0.08	-
Dep'n/Useful Life Change	-	(5.68)	(5.68)	-	(5.68)	-	*5.68*
Total Riders	2.54	(4.75)	(4.67)	*0.08*	(7.21)	0.08	*4.83*
Total NBHDL Distribution	**27.66**	**24.03**	**24.48**	***0.45***	**(3.18)**	**29.23**	***4.83***
NBHDL distribution rate increase (%)					*-11.50%*		*19.40%*
Deferral Accounts - Power	(1.44)	(0.56)	(0.56)	*0.88*			
Global Adjustment	-	-	-	-			
Low Voltage	0.03	0.03	0.03	-			
Line Losses - COP	3.55	3.55	3.55	-			
Smart Meter Entity	0.79	0.79	0.79	-			
Total Pass Through Costs	2.93	3.81	3.81	*0.88*			
Total Distribution	**30.59**	**27.84**	**28.29**	***1.33***			
Distribution rate increase (%)			*-7.52%*				
Total bill	128.23	125.42	125.88				
Total bill impact ('16 is approx.)		-2.19%	-1.83%				

GS<50 (2,000 kWh) - 1 year rider

		1 YR RIDER					
	Current	2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
Service Charge	21.69	24.86	25.17	*0.31*	3.48	25.17	-
Distribution Variable	33.40	38.20	38.80	*0.60*	5.40	38.80	*0.60*
Total Fixed & Variable	55.09	63.06	63.97	*0.91*	8.88	63.97	*0.60*
NBHDL distribution revenue rate increase (%)					*16.12%*		*0.00%*
Fixed Riders							
Smart Meter Riders	11.05	-	-	-	(11.05)	-	-
Stranded Meter Rider	-	1.92	1.92	-	1.92	-	*(1.92)*
Volumetric Riders							
Tax Savings	(0.40)	-	-	-	0.40	-	-
Lost Revenue (2011 & 2013 CDM Activities)	-	1.00	1.80	*0.80*	1.80	1.00	-
Dep'n/Useful Life Change	-	(14.20)	(14.20)	-	(14.20)	-	*14.20*
Total Riders	10.65	(11.28)	(10.48)	*0.80*	(21.13)	1.00	*12.28*
Total NBHDL Distribution	**65.74**	**51.78**	**53.49**	***1.71***	**(12.25)**	**64.97**	***12.88***
NBHDL distribution rate increase (%)					*-18.63%*		*25.47%*
Deferral Accounts - Power	(3.60)	0.40	0.40	-			
Global Adjustment	-	-	-	-			
Low Voltage	0.08	0.08	0.08	-			
Line Losses - COP	8.88	8.88	8.88	-			
Smart Meter Entity	0.79	0.79	0.79	-			
Total Pass Through Costs	6.15	10.15	10.15	-			
Total Distribution	**71.89**	**61.93**	**63.64**	***1.71***			
Distribution rate increase (%)			*-11.48%*				
Total bill	313.60	303.33	305.07				
		-3.27%	-2.72%				

GS>50 (192,000 kWh / 455 kW) - 1 year rider							
		1 YR RIDER					
	Current	**2015 June - Board Meeting**	**2015 Sept - Proposed**	***2015 Change to Board Meeting***	**2015 Proposed Rate Increase**	**2016 Assumed**	***2016 Increase***
Service Charge	293.97	336.90	341.12	*4.22*	47.15	341.12	-
Distribution Variable	953.95	1,087.27	1,100.37	*13.10*	146.42	1,100.37	*13.10*
Total Fixed & Variable	1,247.92	1,424.17	1,441.49	*17.32*	193.57	1,441.49	*13.10*
NBHDL distribution revenue rate increase (%)					*15.51%*		*0.00%*
Volumetric Riders							
Tax Savings	(11.01)	-	-	-	11.01	-	-
Lost Revenue (2011 & 2013 CDM Activities)	-	18.97	34.85	*15.88*	34.85	18.97	-
Dep'n/Useful Life Change	-	(1,314.18)	(1,305.62)	*8.56*	(1,305.62)	-	*1,314.18*
Total Riders	(11.01)	(1,295.21)	(1,270.77)	*24.44*	(1,259.76)	18.97	*1,314.18*
Total NBHDL Distribution	**1,236.91**	**128.96**	**170.72**	***41.76***	**(1,066.19)**	**1,460.46**	***1,327.28***
NBHDL distribution rate increase (%)					*-86.20%*		*1032.49%*
Deferral Accounts - Power	(329.47)	116.79	116.53	*(0.26)*			
Global Adjustment	150.01	423.28	422.25	*(1.03)*			
Low Voltage	6.32	6.68	6.69	*0.01*			
Line Losses - COP	691.20	691.20	691.20	-			
Total Pass Through Costs	518.06	1,237.95	1,236.66	*(1.29)*			
Total Distribution	**1,754.97**	**1,366.91**	**1,407.38**	***40.47***			
Distribution rate increase (%)			*-19.81%*				
Total bill	25,184.51	24,746.00	24,791.68				
Total bill impact ('16 is approx.)		-1.74%	-1.56%				

Intermediate (1,720,000 kWh / 3,290 kW) - 1 year rider							
		1 YR RIDER					
	Current	**2015 June - Board Meeting**	**2015 Sept - Proposed**	***2015 Change to Board Meeting***	**2015 Proposed Rate Increase**	**2016 Assumed**	***2016 Increase***
Service Charge	5,844.10	6,697.56	6,781.43	*83.87*	937.33	6,781.43	-
Distribution Variable	3,668.35	3,915.76	3,940.10	*24.34*	271.75	3,940.10	-
Total Fixed & Variable	9,512.45	10,613.32	10,721.53	*108.21*	1,209.08	10,721.53	-
NBHDL distribution revenue rate increase (%)					*12.71%*		*0.00%*
Volumetric Riders							
Tax Savings	(61.52)	-	-	-	61.52	-	-
Dep'n/Useful Life Change	-	(12,261.83)	(12,181.23)	*80.60*	(12,181.23)	-	*12,181.23*
Total Riders	(61.52)	(12,261.83)	(12,181.23)	*80.60*	(12,119.71)	-	*12,181.23*
Total NBHDL Distribution	**9,450.93**	**(1,648.51)**	**(1,459.69)**	***188.82***	**(10,910.62)**	**10,721.53**	***12,181.23***
NBHDL distribution rate increase (%)					*-115.44%*		*-750.38%*
Deferral Accounts - Power	(3,008.05)	1,376.53	1,373.90	*(2.63)*			
Global Adjustment	1,368.31	4,926.20	4,918.93	*(7.27)*			
Low Voltage	50.67	53.63	53.63	*(0.00)*			
Line Losses - COP	1,570.86	1,570.86	1,570.36	*(0.50)*			
Total Pass Through Costs	(18.21)	7,927.22	7,916.83	*(10.39)*			
Total Distribution	**9,432.72**	**6,278.71**	**6,457.13**	***178.42***			
Distribution rate increase (%)			*-31.55%*				
Total bill	204,192.67	200,628.64	200,830.60				
Total bill impact ('16 is approx.)		-1.75%	-1.65%				

Street Lights (168,200 kWh / 470 kW) - 1 year rider

	Current	2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
		1 YR RIDER					
Fixed Service Charge	26,444.72	30,292.21	30,671.54	*379.33*	4,226.82	30,671.54	-
Distribution Variable	12,278.99	14,072.18	14,248.43	*176.25*	1,969.44	14,248.43	-
Total Fixed & Variable	38,723.71	44,364.39	44,919.97	*555.58*	6,196.26	44,919.97	-
NBHDL distribution revenue rate increase (%)					*16.00%*		*0.00%*
Volumetric Riders							
Tax Savings	(214.60)	-	-	-	214.60	-	-
Lost Revenue (2011 & 2013 CDM Activities)	-	3,826.81	8,636.44	*4,809.63*	8,636.44	8,636.44	-
Dep'n/Useful Life Change	-	(1,202.50)	(1,194.60)	*7.90*	(1,194.60)	-	*1,194.60*
Total Riders	(214.60)	2,624.31	7,441.84	*4,817.53*	7,656.44	8,636.44	*1,194.60*
Total NBHDL Distribution	**38,509.11**	**46,988.70**	**52,361.81**	***5,373.11***	**13,852.70**	**53,556.40**	***1,194.60***
NBHDL distribution rate increase (%)					*35.97%*		*13.98%*
Deferral Accounts - Power	(294.88)	(5,717.88)	(5,717.88)	-			
Global Adjustment	134.23	423.78	423.07	*(0.71)*			
Low Voltage	5.08	5.36	5.36	-			
Line Losses - COP	710.48	710.48	710.48	-			
Total Pass Through Costs	554.91	(4,578.26)	(4,578.97)	*(0.71)*			
Total Distribution	**39,064.02**	**42,410.44**	**47,782.84**	***5,372.40***			
Distribution rate increase (%)			*22.32%*				
Total bill	65,781.51	68,032.38	75,633.48				
Total bill impact		3.42%	14.98%				

Sentinel Lights (150 kWh / 1 kW) - 1 year rider

	Current	2015 June - Board Meeting	2015 Sept - Proposed	*2015 Change to Board Meeting*	2015 Proposed Rate Increase	2016 Assumed	*2016 Increase*
		1 YR RIDER					
Fixed Service Charge	4.42	5.07	5.13	*0.06*	0.71	5.13	-
Distribution Variable	15.44	17.69	17.91	*0.22*	2.47	17.91	-
Total Fixed & Variable	19.86	22.76	23.04	*0.28*	3.18	23.04	-
NBHDL distribution revenue rate increase (%)					*16.02%*		*0.00%*
Volumetric Riders							
Tax Savings	(0.23)	-	-	-	0.23	-	-
Dep'n/Useful Life Change	-	(2.37)	(2.35)	*0.02*	(2.35)	-	*2.37*
Total Riders	(0.23)	(2.37)	(2.35)	*0.02*	(2.12)	-	*2.37*
Total NBHDL Distribution	**19.63**	**20.39**	**20.69**	***0.30***	**1.06**	**23.04**	***2.37***
NBHDL distribution rate increase (%)					*5.40%*		*11.37%*
Deferral Accounts - Power	(0.36)	(3.81)	(3.82)	*(0.01)*			
Global Adjustment	0.17	0.78	0.78	-			
Low Voltage	0.01	0.01	0.01	-			
Line Losses - COP	0.54	0.54	0.54	-			
Total Pass Through Costs	0.36	(2.48)	(2.49)	*(0.01)*			
Total Distribution	**19.99**	**17.91**	**18.20**	***0.29***			
Distribution rate increase (%)			*-8.94%*				
Total bill	38.90	36.78	37.09				
Total bill impact		-5.45%	-4.66%				

UMSL (150 kWh) - 1 year rider								
		1 YR RIDER						
	Current	**2015 June - Board Meeting**	**2015 Sept - Proposed**	***2015 Change to Board Meeting***	**2015 Proposed Rate Increase**	**2016 Assumed**	***2016 Increase***
Fixed Service Charge	7.03	8.06	8.16	*0.10*	1.13	8.16	-
Distribution Variable	2.43	2.79	2.82	*0.03*	0.39	2.82	-
Total Fixed & Variable	9.46	10.85	10.98	*0.13*	1.52	10.98	-
NBHDL distribution revenue rate increase (%)					*16.04%*		*0.00%*
Volumetric Riders							
Tax Savings	(0.03)	-	-	-	0.03	-	-
Dep'n/Useful Life Change	-	(1.07)	(1.07)	-	(1.07)	-	*1.07*
Total Riders	(0.03)	(1.07)	(1.07)	-	(1.04)	-	*1.07*
Total NBHDL Distribution	**9.43**	**9.78**	**9.91**	***0.13***	**0.48**	**10.98**	***1.07***
NBHDL distribution rate increase (%)					*5.06%*		*12.24%*
Deferral Accounts - Power	(0.27)	(0.13)	(0.14)	*(0.01)*			
Global Adjustment	-	-	-	-			
Low Voltage	0.01	0.01	0.01	-			
Line Losses - COP	0.54	0.54	0.54	-			
Total Pass Through Costs	0.28	0.42	0.42	*(0.01)*			
Total Distribution	**9.71**	**10.20**	**10.32**	***0.12***			
Distribution rate increase (%)			*6.31%*				
Total bill	26.66	27.14	27.27				
Total bill impact		1.80%	2.30%				

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-2

Reference: Exhibit 1

Interrogatory:

Please provide copies of all benchmarking studies, reports, and analysis, undertaken by the Applicant itself or by a third-party, that are not already included in the application.

Response:

NBHDL is not aware of any other benchmarking reports or analyses that are relevant to the matters at issue in the Application that haven't already been included either as part of the Application or as part of an Interrogatory Response.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-3

Reference:

Interrogatory:

Does the Applicant have a corporate scorecard? If so, please provide the 2014 and 2015 version.

Response:

NBHDL does not produce a formal stand-alone scorecard. NBHDL monitors progress towards core objectives through a combination of different techniques including board reports, email, daily interaction with staff and, more recently, determining how to best integrate the OEB's new LDC scorecard, which can be found at Appendix 1-I of Exhibit 1.

<u>North Bay Hydro Interrogatory Responses</u>

<u>EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS</u>

1-SEC-4

Reference:

<u>Interrogatory:</u>

Please explain why the Applicant filed its application late.

<u>Response:</u>

There are several reasons.

First, this is NBHDL's first rebasing application filed under the Board's Renewed Regulatory Framework for Electricity Distributors (the "**RRFE**") and the first time that NBHDL has prepared a comprehensive 10 year Distribution System Plan. For example, NBHDL's delay arose in part due to the efforts necessary to respond to the RRFE driven Section 2.4.3 of the Chapter 2 Filing Requirements, which states (emphasis added):

> <u>"Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits and the impact on rates. The application should discuss any feedback provided by customers and how this feedback shaped the final application."</u>

From a sequencing perspective, this means that all of the proposals included in an Application must be formulated to a reasonable degree of certainty prior to going out to consult with customers on those proposals (otherwise the consultations won't be credible). NBHDL achieved this level of certainty on its Application during the summer of 2014. At the same time, NBHDL retained Innovative Research Group, Inc. ("INNOVATIVE") to design, collect feedback and document its customer engagement and consultation process as part of the development of the Application. This consultation effort itself took time. A complete copy of the INNOVATIVE Customer Engagement Report is attached to the Application as Appendix 1-A.7. It is dated November 2014, not long before NBHDL filed its Application.

Second, as explained elsewhere in the Application, NBHDL has managed a dramatic increase in workload across the business without greatly increasing its employee compliment. One consequence of this approach means that staff are stretched thin. There are limited resources to both run the business and complete the major undertaking of preparing a cost of service application.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-6

Note that there appears to be no question 1-SEC-5 (the numbering goes from 4 to 6).

Reference: Exhibit 1, Page 80

Interrogatory:

What is the Northern LDC Buying Consortium? Please explain the Applicant's methodology for calculating the forecasted test year savings of $115,000.

Response:

The buying consortium is known as the Northeast District Buyers Consortium (NEDBC) and includes most of the LDCs in the EDA's "Northeastern District."

The purpose of NEDBC is to facilitate the cooperative efforts of the members to obtain volume discounts from suppliers using aggregated commitments or potential commitments to purchase goods and services. In turn, such volume discounts allow members to access goods and services at lower costs. NEDBC members reach consensus on goods and services that can be procured more cost effectively through a centralized purchase. NEDBC obtains pricing through price quotations, tenders submitted in response to RFPs issued to appropriate suppliers.

The savings were calculated based on value of goods purchased forecasted to be purchased at consortium discounts, including freight reductions, versus if the purchases were made outside of the consortium. The freight savings alone are significant since shipments are made on “milk runs” made to all the northern LDC members.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-7

Reference: Exhibit 1, Page 104

Interrogatory:

The evidence states that the Applicant is to conduct its affairs, in part, "[i]n a matter consistent with the policies established by the Shareholder from time to time, and "[i]n accordance with the financial performance objectives of the Shareholder." Please provide copies of:

a) Current policies established by the Shareholder.

b) The current financial performance objectives of the Shareholder

Response:

NBHDL has confirmed the following facts with the City:

a) There are no current policies that have been established by the Shareholder.

b) The Shareholder has not provided any objectives other than those provided within the Shareholder Declaration.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-8

Reference: Exhibit. 1-Appendix 1-A.7

Interrogatory:

What modifications, if any, were made to the application as a result of the Customer Engagement Report findings?

Response:

Please refer to Exhibit 1, Pages 65-72 for a description of how NBHDL has taken the customer preferences identified in Appendix 1-A.7 into account in the operation of its business, and by extension, in the Application. Based on this, NBHDL determined that no further modifications were required to the Application.

In 2015, NBHDL has committed to continue implementing the more formal customer engagement program that commenced in 2014. This will include continued use of formal surveys to measure customer service and satisfaction levels. Lessons learned each year will be applied to make customer engagement even more effective, and the business ever more responsive to customer needs and preferences, in the future.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-9

Reference: Exhibit.1, Page 25

Interrogatory:

The Applicant indicates it has maintained the staff overtime within the industry target of <10% of hours worked per year. Please provide a reference for the industry standard.

Response:

To the best of NBHDL's knowledge there are no formal industry standards relevant to the OT measures. The "industry targets" referenced in Exhibit 1 at pg. 25 were learned through informal conversations with other LDCs. These conversations were not recorded, and were used simply to confirm whether or not NBHDL's past experience was comparable to those other LDCs.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-10

Reference: Exhibit1, Page.25

Interrogatory:

The Applicant indicates it has experienced sicktime hours that met its business target and industry target and the trend of sick days per employee per year has decreased since 2010 from 8.97 in 2010 to 5.74 in 2013. The Applicant's target is 5 sick days per employee per year.

Please provide:

a) The Applicant's historical and forecast target for each year between 2010-2015.

b) A reference for the industry targets.

Response:

a) NBHDL's historical and forecast target for each year between 2010 and 2015 are as follows:

Sick Days Per Employee	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Forecast
Historical	8.97	6.22	7.18	5.74	5.68	5
Target	5	5	5	5	5	5

b) To the best of NBHDL's knowledge there are no formal industry standards relevant to the sicktime measures. The "industry targets" referenced in Exhibit 1 at pg. 25 were learned through informal conversations with other LDCs. These conversations were not recorded, and were used simply to confirm whether or not NBHDL's past experience was comparable to those other LDCs.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-SEC-11

Reference: Exhibit1, Page 35

Interrogatory:

Please discuss the nature of the $213,239 asset management related costs in 2010 which are not required in the Test Year.

Response:

The nature of the $213,239 asset management related costs in 2010 was a mixture of planned internal and external resourcing to handle updating the out of date (6-7 years) information contained in the NBHDL GIS system that would form the basis of asset management information for the following years to come. The updating of the GIS system was planned to be a one-time undertaking, with the GIS system being maintained through normal business activities going forward. These costs were not required in the Test Year. This is shown in context in Table 2-34 of Exhibit 2 (at Page 77) which shows the variance between 2010 actual capital projects vs. 2010 board-approved capital projects.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-1

Reference: Exhibit 1, Pages 9-12

Interrogatory:

a) At the above reference North Bay sets out a number of business objectives and targets (e.g. target for overtime < 10% of hours worked). Are any of these targets/objectives incorporated into employee compensation plans? If yes, please explain.

b) Do any of these targets form a part of the rate proposal in this application? If yes, please explain how.

Response:

a) NBHDL utilizes the Hay system for managing non-union/management staff performance. Exhibit 4 page 46 identifies how compensation is tied to performance. Union compensation is established by collective agreement. This system does not currently incorporate the overtime targets/objectives. NBHDL may consider revising its system in the future.

b) NBHDL confirms that these targets do form part of the rate proposal in the Application. In general terms, the Application represents the costs associated with achieving all of these targets. For example, Table 4-2 in Exhibit #4 summarizes how OM&A spending is aligned with achievement of each of the core objectives. The narrative provided in Exhibit #4 provides further details on this alignment.

In addition, NBHDL has undertaken to provide information on the relationship between each material capital project in the test year and the core objectives in Exhibit 1 in the material project templates in Appendix Q of Appendix 2-A). For each material capital project, under the heading "Efficiency, Customer Value, Reliability (5.4.5.2.B.1)" there is a subheading titled "Related Objectives/Performance Targets" for both the main driver and the secondary driver which provides this information.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-2

Reference: Exhibit 1, Pages 43-44

Interrogatory:

a) At the above reference North Bay has identified responsibilities incremental to its 2010 cost of service application. Please assign the 2015 incremental cost for each of these categories.

Response:

NBHDL does not have the requested information. NBHDL does not track its costs in this manner.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-3

Reference: Exhibit 1, Pages 56-60

Interrogatory:

a) Please provide the costs of:

- the residential and business customer meetings (all costs including consultant/hosting etc.);
- the Utility Pulse Survey; and
- the innovative Research Customer Consultation Report.

Response:

The costs are as follows

- The cost for the residential and business customer meetings was $16,562;
- The Utility Pulse Survey cost $21,500; and
- The Innovative Research Customer Consultation Report cost $35,000.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-4

Reference: Exhibit 1, Pages 56-60

Interrogatory:

a) Please explain what follow up, reports and analysis were completed with respect to customer-utility transactions.

b) If transactional surveys or reports are undertaken please provide them.

Response:

a) Most of the customer engagement activity referenced at pages 56-60 of Exhibit 1 was completed less than a year ago, and NBHDL has not had the opportunity for complete follow up at this time. However, NBHDL confirms that customer engagement activities are ongoing in nature. In the immediate term NBHDL has concentrated on following up on CDM results with critical business customers. NBHDL has recorded some specific customer experiences which are provided on its website.

Another priority customer engagement area for NBHDL has been on the vegetation maintenance program. Over the late fall of 2014 and winter of 2015 NBHDL has been working with a local environmental group to implement a program targeted at maintaining and where possible enhancing the green canopy of the City of North Bay. Other partners are joining this initiative to make it community based. NBHDL has been working with the environmental program on implementing a new tree replacement program.

b) No new customer surveys or reports have been undertaken by NBHDL since the Application was filed.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-5

Reference: Exhibit 1, Page 66

Interrogatory:

a) What are the source, derivation and calculation of the rate impacts shown in Tables 1-29 and 1-30 for the years 2016 through 2017?

Response:

Please see 1-Energy Probe-10.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-6

Reference: Exhibit 1, Page 76 & 77

Interrogatory:

a) The evidence states North Bay has "*eliminated the provision of printed past due notices*". Please confirm that the Utility is compliant with section 4.2 of the Distribution Code which requires written notice prior to disconnection.

b) North Bay also explain that it has created an automated disconnect work order process. Please explain in more detail how these changes have affected late paying customers.

Response:

a) NBHDL confirms compliance with section 4.2 of the Distribution Code; a written disconnection notice is provided to the customer prior to disconnection. NBHDL has eliminated the provision of the printed past due notices. These notices were a first reminder that the customer's bill was past due, they were not the disconnection notice.

b) NBHDL's automated disconnect work order process does not affect late paying customer timelines or payment options. The new application allows the Customer Service Representative to review and process information related to the disconnection work order and the results of the visit to the customer electronically, instead of handling paper work orders and calling in the information to the Customer Account Specialist who then had to update the customer's account.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-7

Reference: Exhibit 1, Page 79

Interrogatory:

a) Please explain how the third-party meter-cash report has improved North Bay's understanding of its working cash requirements.

Response:

a) Please refer to 1-Energy Probe-13.

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-8

Reference: Exhibit 1, Page 100

Interrogatory:

a) In reviewing North Bay's website we were unable to find any information regarding its LEAP program or the Utility's Conditions of Service. Is this information available online? I [sic]

b) Who is North Bay's LEAP partner?

Response:

a) NBHDL's Condition of Service information and links are posted in two locations on the web site under Residential and Business new accounts. NBHDL will add it to the Home page to make it more visible to customers.

http://www.northbayhydro.com/business/new-accounts/

http://www.northbayhydro.com/residential/new-accounts/

Link to COS file from those pages:

http://www.northbayhydro.com/wp-content/uploads/2014/11/NBHDL_Conditions_of_Service1.pdf

The information relating to LEAP is currently not live/posted on NBHDL's website as NBHDL is in the midst of reviewing its presentation relating to recent changes, and improving clarity for customers. NBHDL expects the LEAP information to be re-posted by April 30/2015.

b) NBHDL's LEAP partner is North Bay's Low Income People Involvement of Nipissing (LIPI).

North Bay Hydro Interrogatory Responses

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-VECC-9

Reference: Appendix 1-G

Interrogatory:

a) Who owns the City street lighting assets?

b) Who pays for winter decorative (Christmas) lights? What was that cost in 2014?

Response:

a) The City of North Bay owns the City street lighting assets.

b) NBHDL does not pay for the winter decorative (Christmas) lights, therefore it has no ability to comment on that cost in 2014.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-Staff-1

Reference: Exhibit 2, Appendix 2-A: Distribution System Plan (DSP), Page 124

Interrogatory:

The last page of the main body of the DSP states that "the following section details all projects in 2015 that meet the materiality threshold of $65,000." The main body ends at the bottom of the page. Additionally, Appendix A of the DSP has been intentionally deleted.

a) Please confirm that section 4.5.2 of the DSP has been provided in its entirety.

b) Please provide the missing Appendix of the DSP. If North Bay Hydro is unable to provide the deleted Appendix, please explain why the Appendix was deleted and summarize its contents.

Response:

a) NBHDL confirms that section 4.5.2 of the DSP has been provided in its entirety.

b) The intentionally deleted Appendix of the DSP will not be provided. This particular Appendix of the DSP contained Operating Maps of the NBHDL distribution system that, at letter size, were not legible and therefore provided no value to the Application.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-Staff-2

Reference: Exhibit 2, Page 21

Interrogatory:

Table 2-1 of the DSP shows forecast capital spending of approximately $7.8 million in 2015. The forecast level of spending for 2016-2019 is approximately $6M each year.

a) Please explain North Bay Hydro's approach to the pacing of capital expenditures in the 2015-2019 period. Did North Bay Hydro consider delaying any of the proposed 2015 projects to have a more even spending profile throughout the forecast period? What would be the risks associated with such a decision?

Response:

a) Please refer to Sections 3.3 and 4.2 of the NBHDL Distribution System Plan found at Exhibit 2, Appendix 2-A for a comprehensive description of NBHDL's asset lifecycle optimization policies and practices together with a description of the capital expenditure planning process used to determine the pacing of capital expenditures in the 2015-2019 period.

NBHDL did consider delaying projects. NBHDL delayed four other projects as part of the 2015 budgeting process to prevent the 2015 spending profile from being higher than $7.8 million.

The main contributor to the difference in 2015 versus the 2016 to 2019 spending profile is the construction of the MS22 substation which will replace the MS9 substation in 2015 at a cost of

$1,781,297. The reasons for including this project in 2015 are well documented on page 85 in Appendix 2-A: Distribution System Plan of Exhibit 2. It should be noted that the power transformers for this project were procured in 2014 to help reduce the total project cost impact in 2015. The risks associated with delaying the substation project are also well documented in the MS22 – Substation Construction Material Capital Project Summary found in Appendix Q of Appendix 2-A: Distribution System Plan of Exhibit 2.

NBHDL has provided a comprehensive description of the risks associated with delaying each of the other material capital projects in Appendix Q of Appendix 2-A.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-Staff-3

Reference: Exhibit 2, DSP, Page 45

Interrogatory:

On page 45, North Bay Hydro states that “the operating efficiency indicators will be used as benchmarks to help guide decision making process and ensure cost control.” Please list the efficiency indicators that will be used and explain how they will help guide decision making processes and ensure cost control.

Response:

Section 5.2.3(a) of the Chapter 5 filing requirements require NBHDL to “identify and define the methods and measures (metrics) used to monitor distribution system planning process performance”. At page 38-39 of Appendix 2-A, NBHDL identifies and defines two operational efficiency indicators: (i) efficiency assessment; and (ii) operational staffing levels.

Section 5.2.3(b) of the Chapter 5 filing requirements requires NBHDL to “provide a summary of performance and performance trends over the historical”. At page 42 of Appendix 2-A, NBHDL provides past performance for both of the previously defined operational efficiency indicators.

Finally, Section 5.2.3(c) of the Chapter 5 filing requirements requires NBHDL to "explain how this information has affected the DS Plan and has been used to continuously improve the asset management and capital expenditure planning process." This is the reference to operational efficiency indicators that is cited in the question above.

The efficiency assessment indicator referenced above is the ranking of LDCs into one of five efficiency groups as determined by the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC on behalf of the Board. NBHDL is in the process of determining how best to utilize this ranking to help guide decision making and cost control in the future as it a key performance indicator included on the new LDC scorecard for which NBHDL will be measured against. NBHDL's 2013 ranking was Group 3 and NBHDL has targeted to maintain or improve its Group 3 ranking. Several of the business conditions which are inputs into the benchmarking analysis, and significantly influence the results, are outside of NBHDL's control (ex; kilometer of line, number of customers, annual usage,) however, NBHDL will endeavour to gain a better understanding of the model and its outputs and how varying business decisions can influence the variance between the predicted costs determined by the model and NBHDL's actual costs which ultimately dictate group ranking. If possible, NBHDL may also determine how best to incorporate the benchmarking model into the internal budget process in order to assist in predicting future variances between NBHDL's internal forecasted costs and the model's predicted costs. NBHDL will work towards understanding which areas of cost are causing larger variances and whether NBHDL can find process efficiencies to address potential issues within NBHDL's control.

The operational staffing levels indicator referenced above will help guide decision making processes as they relate to capital and O&M programs. The capital and O&M programs were created based on the amount of work that could be completed by the current complement, which included a reduction in the pacing of renewal projects in order to prevent the requirement for additional resources. As demonstrated by the trend from 2011 to 2013, NBHDL will endeavor to keep staffing levels constant over the rate period in efforts to control cost.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-Staff-4

Reference: Exhibit 2, DSP, Pages 74, 116 and 117

Interrogatory:

On page 74 of the DSP, North Bay Hydro states that “it does not anticipate any capacity constraints or significant O&M changes due to capital investment” for the forecast period. On page 117 of the DSP, North Bay Hydro states that it is currently unable to provide a specific or detailed forecast of the impact of its investments on system O&M costs.

a) Please explain why North Bay Hydro is unable to forecast the impact of its capital expenditures on O&M costs including a summary of the results of any attempts to do so thus far.

b) Please explain when North Bay Hydro expects to see the O&M reductions discussed on pages 116 and 117.

c) On pages 116 and 117, North Bay Hydro identifies cost benefits and avoided costs that will arise from the decommissioning of certain substations as well as the replacement of troublesome underground assets. What is North Bay Hydro’s best estimate of the current level of O&M costs associated with the items identified?

Response:

a) NBHDL is unable to forecast the impact of its capital expenditures on O&M costs because the relationships between these two concepts are incredibly complex. NBHDL does not have, and does not know of, any reliable and well tested methodology that would accurately and reliably forecast such a relationship. Attempts to forecast absent any such methodology would amount to speculative guessing and not produce in any meaningful or reliable results.

In addition, NBHDL does not have the information available to allow for such forecasts to be made. Changes required in NBHDL's accounting system to enable this type of tracking would come at a very large cost and be would be labour intensive. NBHDL would be very interested if Board staff has created a reliable and well tested predictive model or has developed a dataset that would allow for such forecasting.

b) NBHDL expects to see the O&M reductions discussed on pages 116 and 117 as follows:

- With respect to the underground projects mentioned on page 116 in Appendix 2-A: Distribution Plan of Exhibit 2, reductions will be realized immediately upon completion of the projects in 2015 and 2016.

- With respect to decommissioning of substations, mentioned on page 117 in Appendix 2-A: Distribution System Plan of Exhibit 2, MS7 is planned to be decommissioned in 2016 and will not be replaced; therefore the reductions in O&M will happen in years subsequent to 2016.

- With respect to the voltage conversion plan mentioned on page 117 in Appendix 2-A: Distribution System Plan of Exhibit 2, there is a potential reduction of O&M costs related to reduced equipment failure, the elimination of safety hazards and substandard conditions, and increased flexibility resulting in lower restoration times, however all of these statements are qualitative assessments based on probability and therefore not easily predicted in time.

c) NBHDL's best estimate of the current level of O&M costs associated with the removal of a substation from the NBHDL system that can be quantified is $2,324 per year, which is detailed on page 23 in Appendix 2-A: Distribution System Plan of Exhibit 2. There are also other costs that are eliminated, that aren't as easily quantified, such as power transformer loss, and substation employee time that can be saved or directed to other areas of the business upon the removal of a substation from the system. The station is also removed from the preventative maintenance schedule, in turn eliminating or redirecting an average $19,709.88 of O&M costs every 4 years. NBHDL's best estimate of the current level of O&M costs associated with the troublesome underground assets is between $5,000.00 and $10,000.00 per year.

North Bay Hydro Interrogatory Responses

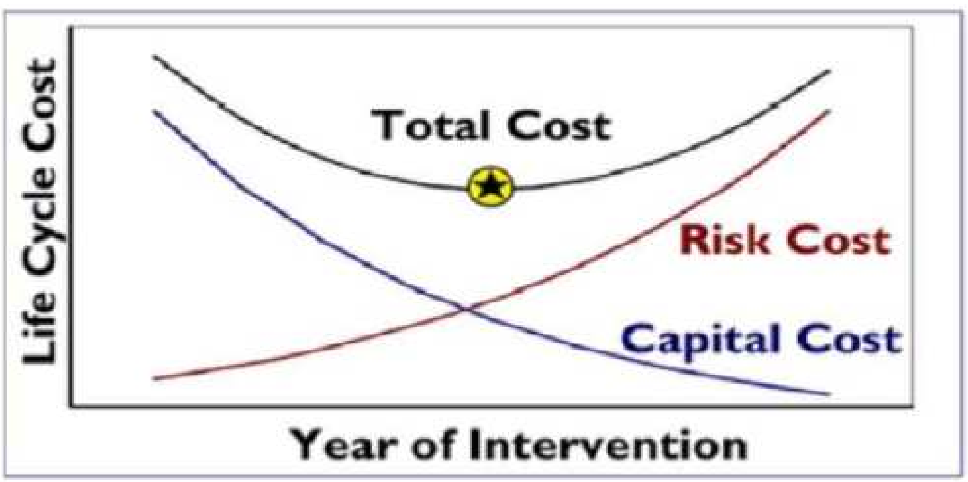
EXHIBIT 2 – RATE BASE

2-Staff-5

Reference: Exhibit 2, DSP, Pages 78 and 79

Interrogatory:

On page 78 of the DSP, North Bay Hydro states that it deployed a risk-based asset management strategy in which the risk cost is calculated for each asset and compared to its total cost. Figure 3-43, reproduced below, provides a graphical representation of this assessment.



North Bay Hydro later states that "substation assets were based on a risk based assessment, poles, and conductors based on mean life expectancy age and the risk associated with decreasing health after mean life expectancy is passed and for distribution transformers and underground cable, risk to run to failure is acceptable."

a) Are O&M costs factored in to the calculation of the total cost of an asset in the Table above? If so, how would they be captured?

b) Please explain why the risk-based approach is not applied for all asset types. If it has been applied to all asset types, please explain what would cause the evaluation to determine that distribution transformers should be run to failure whereas conductors would only be replaced after the mean life expectancy has elapsed.

Response:

a) Estimated O&M costs are factored in to the calculation of the total cost of an asset in the Table above. They are captured in the risk cost curve. The table above illustrates methodology utilized in the risk based assessment in a simplified manner showcasing the relationship between annualized capital cost, the risk cost and asset service age. In practicality a marginal cost comprised of risk and O&M costs is used and in the actual assessment as performed for NBHDL this O&M cost was estimated for the assets and included in the marginal cost stream.

b) The risk-based approach is not applied for all asset types. NBHDL commenced implementation of the risk based approach in 2014 and decided to focus on the major assets as these assets have sufficient information on condition and failure consequences.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-Staff-6

Reference: Exhibit 2, DSP, Pages 98 – 100

Interrogatory:

On pages 98 through 100 of the DSP North Bay Hydro identifies the criteria that are used to score and prioritize its 2015 capital projects.

a) Regarding the reliability criteria, please explain the difference between addressing and improving current reliability issues substantially or moderately (i.e. a score of 3 and 2). Please provide examples from North Bay Hydro's proposed 2015 capital projects that illustrate that difference.

b) Similarly, please explain how the difference between a significant, moderate and marginal increase in operational efficiency was assessed (i.e. a score of 3, 2 and 1 for the operational efficiency criteria). Please provide examples from North Bay Hydro's proposed 2015 capital projects that illustrate those differences.

Response:

a) The difference between addressing and improving current reliability issues substantially or moderately is a function of the number of customers and the length of the outages to those customers. A matrix, included below, was created to determine if reliability would be improved moderately or substantially based on outage data available relating to the specific project. The matrix was only applied if there were three (3) or more known outage issues per year in relation to the project being considered. It is important to note that reliability information is not readily available by station, feeder or specific location, and therefore the matrix was only used on projects where specific reliability issues were known.

Typical Outage related with Project

		# of Cust. Affected		
		0-50 (1)	50-500 (2)	>500 (3)
Length of Outage	< 1 min (1)	1	2	3
	1-60 min (2)	2	4	6
	>60 min (3)	3	6	9

The matrix above works as follows; if the proposed project would eliminate outages scoring in yellow (1-4) then the rating of moderate was assigned, if the proposed project would eliminate outages scoring in red (6-9) then the rating of substantial was assigned.

Examples that illustrate the difference cannot be provided as no 2015 projects received a substantial rating. There were only four 2015 projects that received a moderate rating and are as follows: MS22 – Substation Construction, Turret Complex - Madelena, Turret Complex - Melina Close, and Turret Complex - Wickstead. The majority of the projects were given a reliability rating of 1, which is provided when the project simply involves renewal that will ensure current reliability is maintained for the long term.

b) The difference between a significant, moderate, and marginal increase in operational efficiency was based on the number of possible efficiencies that would be realized upon project completion. A qualitative list of possible operating efficiency factors was created, and the number of applicable efficiencies to a specific project provided the rating. The ratings were based on the following table:

# of Applicable Efficiencies	Rating	
5 or more	3	Substantial
3 or 4	2	Moderate
1 or 2	1	Marginal
0	0	No Impact

Examples that illustrate the difference between the ratings are as follows:

All voltage conversion projects included in 2015 (McIntyre Street Rebuild, Fourth Avenue Rebuild, Fifth Avenue Rebuild, etc.) received a substantial rating, as the following six operating efficiencies will be realized upon completion of the projects:

- Increased redundancy in the system, allowing for faster restoration in outage situations;
- Decreases line loss;
- Increased flexibility of the system (enables paralleling with neighbouring stations);
- Aids in the reduction of inventory (elimination of obsolete equipment requiring spares, or non-standard rated equipment (5kV equipment));
- Increased capacity (new conductor sized larger for future requirements); and
- Improved Design (direct buried plant replaced with duct system, increased separations to allow for easier maintenance).

Whereas, by comparison, the Turret Complex - Madelena project received a moderate rating, as only four operating efficiencies will realized upon completion of the project:

- Increased redundancy in the system, allowing for faster restoration in outage situations;
- Increased access (elimination of backlot plant to the municipal right of way);
- Increased capacity (new conductor sized larger for future requirements); and
- Improved Design (direct buried plant replaced with duct system, increased separations to allow for easier maintenance).

There was only one project, Turret Complex - Wickstead, that received a marginal rating as only 2 operating efficiencies will be gained upon completion of the project:

- Increased redundancy in the system, allowing for faster restoration in outage situations; and
- Improved Design (direct buried plant replaced with duct system, increased separations to allow for easier maintenance).

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-Staff-7

Reference: Exhibit 2, Page 54

Interrogatory:

Table 2-31 shows that North Bay Hydro has used the average number of customers, as of December 31, 2013 to calculate its rate riders for recovery of stranded meter costs.

a) Please explain why North Bay Hydro has elected to use the customer numbers from 2013 to derive the rate riders when they will be recovered in 2015.

b) Please provide an updated derivation of the stranded meter rate riders using the customer numbers from North Bay Hydro's customer forecast.

Response:

a) NBHDL has elected to use the customer numbers from the 2015 customer forecast to derive the rate riders for recovery of stranded meter costs. Table 2-31 incorrectly referenced 2013 and should read "Average Number of Customers, December 31, 2015".

b) As explained in 7 a) above, Table 2-31 incorrectly referenced the 2013 fiscal year, but the customer numbers used to derive the stranded meter rate riders are based on the 2015 customer numbers from NBHDL's customer forecast.

However, as referenced in 3-Energy Probe-34, NBHDL has updated the proposed load forecast to reflect 2014 actual data and revised CDM adjustments. These changes have revised the 2015 forecasted customer count. An updated derivation of the stranded meter rate riders using the customer numbers from North Bay Hydro's updated customer forecast is as follows:

Description	Residential Class	GS<50 Class
Net Book Value, December 31, 2014	216,651	61,434
Recovery Period	1	1
Average Number of Customers, December 31, 2015	21,124	2,668
Proposed Rate Rider by Class	**$ 0.85**	**$ 1.92**

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-Staff-8

Reference: Exhibit 2, DSP, Appendix B: Asset Condition Assessment (ACA), Page 88

Interrogatory:

Page 88 of the ACA summarizes the parameters used to estimate the customer outage cost.

a) Please provide the basis of the assumed values provided in the table on page 88 of the ACA.

b) Please explain how the assumed values reflect the differences between the cost of an outage for consumers in different classes.

Response:

a) The basis of the assumed values provided in the table on page 88 of the ACA are the values that Toronto Hydro Electric Systems Limited has used for risk based approach and presented to the OEB (EB-2010-0142 and EB-2014-0116'). NBHDL retained a third party consultant, METSCO, to assist with its ACA. METSCO supplied these assumptions as appropriate for use in NBHDL's ACA.

b) NBHDL asked its third party consultant, METSCO to provide an explanation. METSCO indicated:

> "The assumption used in the analysis is that differences between the cost of an outage for consumers in different classes is reflected through the amount of load that customer

consumes. As the outage cost values are related to a load unit, consumers who consume more power would have increased consequence attributed to them. Hence, an industrial customer with a large load would have much higher outage cost than a residential customer."

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-17

Reference: Exhibit 2, Pages 4 & 89 & Exhibit 1, Page 30

Interrogatory:

In Exhibit 2, it states that in 2012 NBHDL implemented the change to depreciation rates and capitalization policies (lines 18-19 on page 4 and lines 6-15 on page 89), while in Exhibit 1 it states that NBHDL reviewed and changed its capitalization policy in fiscal 2009 (lines 8-9). Please reconcile.

Response:

The reference in Exhibit 1 was made in respect of the changes made to NBHDL's overhead capitalization policy in 2009; the change to capitalization polices referenced in Exhibit 2 in 2012 are in relation to the changes required for the componentization of capital assets and depreciation as a result of the transition to IFRS. Information on NBHDL's capitalization policy, including the overhead capitalization policy changes in 2009, can be found on pages 91 through page 95 of Exhibit 2.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-18

Reference: Exhibit 2, Pages 16-50

Interrogatory:

a) Please explain why these pages are dated October 30, 2009.

b) Are there any changes associated with these pages of correcting the date on the evidence? If yes, please explain.

Response:

a) These pages are dated October 30, 2009 in error – an oversight when utilizing the template from NBDHL's 2010 Cost of Service application.

b) No changes are required to the evidence from this oversight; it is a date error only.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-19

Reference: Exhibit 2, Tables 2-10 and 2-18

Interrogatory:

Please update the bridge year tables to reflect actual data for 2014. If actual data for all of 2014 is not yet available, please update based on the most recent year-to-date actuals available, along with an updated estimate for the remainder of the year.

Response:

Tables 2-10 and 2-18 have been updated with 2014 actuals for the full year. Please see Attachment-2-Energy Probe-19.

North Bay Hydro Distribution Limited
License Number ED-2003-0024 , File Number EB-2014-0099

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2014

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	446,565	-	-	446,565	-	-	-	-	446,565
CEC	1806	Land Rights	-	-	-	-	-	-	-	-	-
8	1808	Buildings and Fixtures	1,830,506	-	-	1,830,506	356,852	34,598	-	391,450	1,439,056
13	1810	Leasehold Improvements	-	-	-	-	-	-	-	-	-
47	1815	Transformer Station Equipment - Normally Primar	-	-	-	-	-	-	-	-	-
47	1820	Distribution Station Equipment - Normally Primary	13,013,503	646,921	-	13,660,424	4,423,215	307,837	-	4,731,052	8,929,372
47	1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers and Fixtures	21,394,561	1,954,019	298,298	23,050,282	11,472,696	337,288	264,578	11,545,406	11,504,876
47	1835	Overhead Conductors and Devices	16,392,963	761,242	107,848	17,046,356	8,739,600	222,952	89,857	8,872,695	8,173,661
47	1840	Underground Conduit	1,097,375	127,159	8,934	1,215,600	167,739	22,212	3,231	186,720	1,028,880
47	1845	Underground Conductors and Devices	7,308,072	118,969	12,591	7,414,450	4,609,132	100,233	11,314	4,698,051	2,716,399
47	1850	Line Transformers	16,518,295	553,799	62,751	17,009,344	9,432,355	252,684	59,849	9,625,190	7,384,154
47	1855	Services	18,018,316	536,867	-	18,555,183	6,925,188	408,991	-	7,334,179	11,221,004
47	1860	Meters	4,192,008	3,516,312	2,283,802	5,424,519	2,868,880	1,179,761	2,005,716	2,042,925	3,381,594
N/A	1865	Other Installations on Customer's Premises	-	-	-	-	-	-	-	-	-
N/A	1905	Land	86,551	-	-	86,551	-	-	-	-	86,551
CEC	1906	Land Rights	-	-	-	-	-	-	-	-	-
1	1908	Buildings and Fixtures	2,514,322	459,817	22,805	2,951,334	1,343,003	93,082	7,602	1,428,483	1,522,850
13	1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-
8	1915	Office Furniture and Equipment	376,560	2,726	-	379,286	309,761	10,827	-	320,588	58,698
50	1920	Computer Equipment - Hardware	824,733	128,715	-	953,448	687,364	55,786	-	743,150	210,298
50	1925	Computer Software	1,317,567	161,995	-	1,479,562	1,073,458	150,794	-	1,224,253	255,309
10	1930	Transportation Equipment	2,682,228	44,911	331,838	2,395,301	1,854,506	235,243	331,838	1,757,911	637,390
8	1935	Stores Equipment	75,196	-	-	75,196	75,196	-	-	75,196	-
8	1940	Tools, Shop and Garage Equipment	1,328,596	13,512	-	1,342,108	1,069,039	45,452	-	1,114,491	227,617
8	1945	Measurement and Testing Equipment	-	-	-	-	-	-	-	-	-
8	1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-
8	1955	Communication Equipment	169,111	5,253	-	174,364	96,405	15,377	-	111,782	62,582
8	1960	Miscellaneous Equipment	20,050	960	-	21,010	14,464	1,623	-	16,087	4,922
47	1970	Load Management Controls - Customer Premises	403,931	-	-	403,931	403,931	-	-	403,931	-
47	1975	Load Management Controls - Utility Premises	165,151	-	-	165,151	165,151	-	-	165,151	-
47	1980	System Supervisory Equipment	1,383,765	49,793	-	1,433,558	1,116,040	49,725	-	1,165,765	267,794
47	1985	Sentinel Lighting Rentals	-	-	-	-	-	-	-	-	-
47	1990	Other Tangible Property	53,060	-	-	53,060	24,894	1,630	-	26,523	26,537
47	1995	Contributions and Grants	- 9,298,809	- 1,415,412	-	- 10,714,221	- 1,957,562	- 224,601	-	- 2,182,163	- 8,532,058
	2005	Property under Capital Lease	-	-	-	-	-	-	-	-	-
		Total before Work in Process	**102,314,173**	**7,667,560**	**3,128,866**	**106,852,867**	**55,271,308**	**3,301,494**	**2,773,986**	**55,798,816**	**51,054,050**
	2070	Other utility plant	-	-	-	-		-	-		-
WIP	2055	Work in Process	526,120	1,098,849	513,661	1,111,308	-	-	-	-	1,111,308
		Total after Work in Process	**102,840,294**	**8,766,409**	**3,642,528**	**107,964,175**	**55,271,308**	**3,301,494**	**2,773,986**	**55,798,816**	**52,165,358**

Net	*4,538,693*
IFRS disposals	*490,421*
"RCGAAP"	*5,029,115*

Less: Fully Allocated Depreciation		*527,508*
Transportation	146,004	*428,829*
Communication	-	*956,337*
Loss on Disposal	61,592	
Net Depreciation	3,217,082	

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2014

CCA Class	OEB	Description	Cost: Opening Balance Jan.1/14	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance Jan.1/14	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,317,567	$ 161,995	$ -	$ 1,479,562	-$ 1,073,458	-$ 150,794	$ -	-$ 1,224,253	$ 255,309
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,830,506	$ -	$ -	$ 1,830,506	-$ 356,852	-$ 34,598	$ -	-$ 391,450	$ 1,439,056
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 13,013,503	$ 646,921	$ -	$ 13,660,424	-$ 4,423,215	-$ 307,837	$ -	-$ 4,731,052	$ 8,929,372
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 21,394,561	$ 1,954,019	-$ 298,298	$ 23,050,282	-$ 11,472,696	-$ 337,288	$ 264,578	-$ 11,545,406	$ 11,504,876
47	1835	Overhead Conductors & Devices	$ 16,392,963	$ 761,242	-$ 107,848	$ 17,046,356	-$ 8,739,600	-$ 222,952	$ 89,857	-$ 8,872,695	$ 8,173,661
47	1840	Underground Conduit	$ 1,097,375	$ 127,159	-$ 8,934	$ 1,215,600	-$ 167,739	-$ 22,212	$ 3,231	-$ 186,720	$ 1,028,880
47	1845	Underground Conductors & Devices	$ 7,308,072	$ 118,969	-$ 12,591	$ 7,414,450	-$ 4,609,132	-$ 100,233	$ 11,314	-$ 4,698,051	$ 2,716,399
47	1850	Line Transformers	$ 16,518,295	$ 553,799	-$ 62,751	$ 17,009,344	-$ 9,432,355	-$ 252,684	$ 59,849	-$ 9,625,190	$ 7,384,154
47	1855	Services (Overhead & Underground)	$ 18,018,316	$ 536,867	$ -	$ 18,555,183	-$ 6,925,188	-$ 408,991	$ -	-$ 7,334,179	$ 11,221,004
47	1860	Meters	$ 3,873,364	$ -	-$ 2,283,802	$ 1,589,562	-$ 2,822,149	-$ 100,389	$ 2,005,716	-$ 916,822	$ 672,740
47	1860	Meters (Smart Meters)	$ 318,644	$ 3,516,312	$ -	$ 3,834,957	-$ 46,731	-$ 1,079,372	$ -	-$ 1,126,103	$ 2,708,854
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,514,322	$ 459,817	-$ 22,805	$ 2,951,334	-$ 1,343,003	-$ 93,082	$ 7,602	-$ 1,428,483	$ 1,522,850
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 376,560	$ 2,726	$ -	$ 379,286	-$ 309,761	-$ 10,827	$ -	-$ 320,588	$ 58,698
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 824,733	$ 128,715	$ -	$ 953,448	-$ 687,364	-$ 55,786	$ -	-$ 743,150	$ 210,298
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,682,228	$ 44,911	-$ 331,838	$ 2,395,301	-$ 1,854,506	-$ 235,243	$ 331,838	-$ 1,757,911	$ 637,390
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,328,596	$ 13,512	$ -	$ 1,342,108	-$ 1,069,039	-$ 45,452	$ -	-$ 1,114,491	$ 227,617
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 169,111	$ 5,253	$ -	$ 174,364	-$ 96,405	-$ 15,377	$ -	-$ 111,782	$ 62,582
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 20,050	$ 960	$ -	$ 21,010	-$ 14,464	-$ 1,623	$ -	-$ 16,087	$ 4,922
47	1970	Load Management Controls Customer Premises	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,383,765	$ 49,793	$ -	$ 1,433,558	-$ 1,116,040	-$ 49,725	$ -	-$ 1,165,765	$ 267,794
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 24,894	-$ 1,630	$ -	-$ 26,523	$ 26,537
47	1995	Contributions & Grants	-$ 9,298,809	-$ 1,415,412	$ -	-$ 10,714,221	$ 1,957,562	$ 224,601	$ -	$ 2,182,163	-$ 8,532,058
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 102,314,173**	**$ 7,667,560**	**-$ 3,128,866**	**$ 106,852,867**	**-$ 55,271,308**	**-$ 3,301,494**	**$ 2,773,986**	**-$ 55,798,816**	**$ 51,054,050**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 102,314,173**	**$ 7,667,560**	**-$ 3,128,866**	**$ 106,852,867**	**-$ 55,271,308**	**-$ 3,301,494**	**$ 2,773,986**	**-$ 55,798,816**	**$ 51,054,050**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-$ 61,592			
		Total						**-$ 3,363,086**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	-$ 146,004
Stores Equipment	$ -
Net Depreciation	-$ 3,217,082

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-20

Reference: Exhibit 2, Tables 2-8 through 2-11

Interrogatory:

a) Please confirm that the WIP disposals shown in these tables reflect movement of the capital expenditures out of the WIP category and into the other accounts shown. If this is not confirmed, please explain.

b) Please explain the significant drop in WIP forecast for 2015 relative to the amounts shown for 2012 through 2014.

Response:

a) NBHDL confirms that the WIP disposals shown in these tables reflect movement of the capital expenditures out of the WIP category and into the other accounts shown once transferred in to service.

b) The WIP balance for 2015 is less than the amounts shown in 2012 through 2014 as a result of the capital projects anticipated to be in progress as of December 31, 2015 as compared to prior fiscal years. Included in the 2014 Bridge Year WIP are the costs of two substation transformers totaling $679,396 which is a significant contributor to the $784,101 decrease in 2015.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-21

Reference: Exhibit 2, Table 2-12

Interrogatory:

Please provide the 2010 Board approved capital additions to rate base.

Response:

The following tables within Exhibit 2 provide details on the 2010 Board Approved capital additions to rate base:

- Table 2-22 - Gross Assets - Detailed 1 Breakdown by Major Plant Function
- Table 2-23 – Accumulated Amortization - Detailed Breakdown by Major Plant Function
- Table 2-34 - 2010 Capital Projects vs. 2010 1 Board Approved Projects

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-22

Reference: Exhibit 2, Tables 2-12 through 2-19

Interrogatory:

a) Please provide a table that shows the total contributions and grants for each year (and updated for 2014 actuals), along with the gross addition costs associated with the projects that received contributions and grants. Please add a third line, showing the ratio of contributions and grants to the gross addition costs.

b) Please explain any significant changes in the ratio calculated in part (a) above.

Response:

a) The following table provides the total contributions and grants for each year, updated for 2014 actuals, along with the gross addition costs associated with the projects that received contributions and grants. The table provides the ratio of contributions and grants to the gross addition costs.

CAIC Details	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Test Year
Contributions in Aid of Construction (CAIC)	(905,001)	(464,129)	(675,928)	(1,061,939)	(1,415,412)	(503,987)
Gross Addition Cost related to CAIC	1,847,431	838,371	1,250,110	1,810,225	2,008,413	922,353
CAIC Ratio - CAIC Projects	**49.0%**	**55.4%**	**54.1%**	**58.7%**	**70.5%**	**54.6%**

b) The only significant change in the calculated ratios provided in part (a) above is in 2014 and this is in relation to the timing of the construction work being completed by NBHDL and the timing of the contributions being invoiced to Bell as part of the Fibre project. The Bell FSA project was completed in 2014 and there are no costs forecast for 2015.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-23

Reference: Exhibit 2, Table 2-19

Interrogatory:

The table shows an amount of $155,871 in fully allocated depreciation expense associated with transportation equipment.

a) Please show how this amount was calculated, based on the $266,797 shown as depreciation expense for this category.

b) Please show how much of the $155,871 has been capitalized and how much has been included in OM&A expenses.

Response:

a) The amount of $155,871 in fully allocated depreciation expense associated with transportation equipment was calculated as approximately 58.4% of the total deprecation amount in 2015 of $266,797. This percentage is determined by taking the total costs related to the fleet (these costs include fuel costs, repairs, parts, insurance, depreciation and all other items of expense necessary to keep the fleet in service) and determining the estimated allocation of costs between capital and OM&A. The percentage of capital and OM&A is then applied accordingly against the total depreciation amount. Additional details on the fleet rate can be found on page 91 of Exhibit 2.

b) $155,871 has been capitalized.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-24

Reference: Exhibit 2, Table 2-19 & Table 2-32 & Exhibit 1, Table 1-22

Interrogatory:

Please reconcile the capital additions shown in Table 2-19 and Table 2-32 for 2015 of 8,038,071 with the figure of $7,757,956 shown in Table 1-22 for 2015.

Response:

Table 2-32 and Table 1-22 both show $7,757,956 as capital additions for 2015. This figure represents the new capital expenditure spending in 2015 and does not include contributed capital or costs transferred out of CWIP into service. Table 2-19, the continuity schedule, is a reflection of the change in total gross assets which includes contributed capital and additions from 2014 CWIP. The following reconciliation is provided:

Description	2015
Table 2-19 - Additions	8,038,071
Table 2-32 & Table 1-22 - Additions	7,757,956
Variance	**280,114**
2014 CWIP transferred into service	805,421
2015 CWIP	(21,320)
2015 Contributed Capital	(503,987)
Variance	**280,114**

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-25

Reference: Exhibit 2, Pages 47-48

Interrogatory:

a) Does NBHDL bill all of its customers on a monthly basis? If not, please provide a breakdown by rate class of the billing frequency for customers. If one or more classes include multiple billing frequencies, please estimate the annual revenues associated with each billing frequency within that class.

b) Has the billing frequency change since NBHDL's last cost of service application? If yes, please provide details.

Response:

a) Yes, NBDHL bills all of its customers on a monthly basis.

b) No, the billing frequency has not changed since NBHDL's last cost of service application.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-26

Reference: Exhibit 2, Table 2-28

Interrogatory:

Please update Table 2-28 to reflect the most recent information available (if different from that used) for the RPP and non-RPP prices, LV charges, WMS charges, rural rate assistance charges and network and connection charges.

Response:

As indicated on page 49 of Exhibit 2, in preparing the application NBHDL utilized the most recent RPP and non-RPP price obtained from the Regulated Price Plan Price Report for the period of November 1, 2014 through October 31, 2015 published by the BOARD October 16, 2014. For the purposes of calculating the 2015 Test Year, NBHDL has used an estimate of $.09496 per kWh for RPP customers. For non-RPP customers, NBHDL has used $.09552/kWh which includes $.02064 per kWh for the Wholesale Electricity Price and $.07488 per kWh for Global Adjustment charges. LV, WMS and rural rate assistance charges are also based on the most recent information available. Subsequent to the submission of the application, UTR rate changes for Network and Connection have come into effect. The following table shows the changes to NBHDL's proposed Network and Connection amounts as a result of the rates change. As is shown, these changes are immaterial on a net basis.

Transmission Costs	Per Application	Rate Change	Impact - COP
Network:			
kW Determinant	1,023,625	1,023,625	1,023,625
Rate	$3.82	$3.78	($0.04)
Total Network Costs - IESO	**$3,910,248**	**$3,869,303**	**($40,945)**
Connection:			
kW Determinant	1,075,278	1,075,278	1,075,278
Rate	$2.80	$2.86	$0.06
Total Network Costs - IESO	**$3,010,778**	**$3,075,295**	**$64,517**
Net Transmission Costs - IESO	**$6,921,026**	**$6,944,598**	**$23,572**

However, as referenced in 3-Energy Probe-34, NBHDL has updated the proposed load forecast to reflect 2014 actual data and revised CDM adjustments. These changes have revised the 2015 forecasted kWh, kW and customer count and as a result of these changes NBHDL has updated the cost power expenses. A revised Table 2-28 is provided in Attachment-2-Energy Probe-26.

	Metric	2015 kWh - Jan~Apr	Loss Factor - Current	2015 Uplifted kWh	2015 kWh - May~Dec	Loss Factor - Proposed	2015 Uplifted kWh	2015 kW - UTR	2015 Rates	2010
Electricity - Commodity - RPP										
Class per Load Forecast										
Residential	kWh	75,493,747	1.0480	79,117,447	113,875,191	1.0471	119,238,713		$ 0.09496	$ 18,835,901
GS<50	kWh	27,058,750	1.0480	28,357,570	46,190,838	1.0471	48,366,426		$ 0.09496	$ 7,285,711
GS>50	kWh	4,469,669	1.0480	4,684,213	7,246,390	1.0471	7,587,695		$ 0.09496	$ 1,165,340
Unmetered Scattered Load	kWh	10,704	1.0480	11,218	21,340	1.0471	22,345		$ 0.09496	$ 3,187
Intermediate	kWh		1.0375			1.0366			$ 0.09496	$ -
Sentinel Lighting	kWh	129,569	1.0480	135,788	248,521	1.0471	260,226		$ 0.09496	$ 37,606
Street Lighting	kWh		1.0480			1.0471			$ 0.09496	$ -
TOTAL		**107,162,440**		**112,306,237**	**167,582,280**		**175,475,405**			**$ 27,327,745**
Electricity - Commodity - Non-RPP										
Class per Load Forecast										
Residential	kWh	5,914,643	1.0480	6,198,545	8,921,680	1.0471	9,341,891		$ 0.09552	$ 1,484,423
GS<50	kWh	4,210,477	1.0480	4,412,580	7,201,195	1.0471	7,540,371		$ 0.09552	$ 1,141,746
GS>50	kWh	67,513,898	1.0480	70,754,565	126,680,962	1.0471	132,647,636		$ 0.09552	$ 19,428,978
Unmetered Scattered Load	kWh		1.0480			1.0471			$ 0.09552	$ -
Intermediate	kWh	6,106,035	1.0375	6,335,011	11,148,775	1.0366	11,556,821		$ 0.09552	$ 1,709,028
Sentinel Lighting	kWh	9,551	1.0480	10,009	18,319	1.0471	19,182		$ 0.09552	$ 2,788
Street Lighting	kWh	778,826	1.0480	816,209	1,239,937	1.0471	1,298,338		$ 0.09552	$ 201,982
TOTAL		**84,533,429**		**88,526,920**	**155,210,868**		**162,404,238**			**$ 23,968,944**
TOTAL POWER PURCHASED - USoA 4705		**191,695,870**		**200,833,158**	**322,793,148**		**337,879,643**			**$ 51,296,689**
Wholesale Market Service										
Class per Load Forecast										
Residential	kWh	81,408,390	1.0480	85,315,993	122,796,871	1.0471	128,580,604		$ 0.0041	$ 868,013
GS<50	kWh	31,269,228	1.0480	32,770,151	53,392,033	1.0471	55,906,797		$ 0.0041	$ 359,860
GS>50	kWh	71,983,567	1.0480	75,438,778	133,927,352	1.0471	140,235,331		$ 0.0041	$ 875,226
Unmetered Scattered Load	kWh	10,704	1.0480	11,218	21,340	1.0471	22,345		$ 0.0041	$ 136
Intermediate	kWh	6,106,035	1.0375	6,335,011	11,148,775	1.0366	11,556,821		$ 0.0041	$ 72,607
Sentinel Lighting	kWh	139,120	1.0480	145,798	266,839	1.0471	279,408		$ 0.0041	$ 1,726
Street Lighting	kWh	778,826	1.0480	816,209	1,239,937	1.0471	1,298,338		$ 0.0041	$ 8,581
TOTAL WHOLESALE MARKET SERVICE - USoA 4708										**$ 2,186,148**
Rural Rate Assistance										
Class per Load Forecast										
Residential	kWh	81,408,390	1.0480	85,315,993	122,796,871	1.0471	128,580,604		$ 0.0013	$ 278,066
GS<50	kWh	31,269,228	1.0480	32,770,151	53,392,033	1.0471	55,906,797		$ 0.0013	$ 115,280
GS>50	kWh	71,983,567	1.0480	75,438,778	133,927,352	1.0471	140,235,331		$ 0.0013	$ 280,376
Unmetered Scattered Load	kWh	10,704	1.0480	11,218	21,340	1.0471	22,345		$ 0.0013	$ 44
Intermediate	kWh	6,106,035	1.0375	6,335,011	11,148,775	1.0366	11,556,821		$ 0.0013	$ 23,259
Sentinel Lighting	kWh	139,120	1.0480	145,798	266,839	1.0471	279,408		$ 0.0013	$ 553
Street Lighting	kWh	778,826	1.0480	816,209	1,239,937	1.0471	1,298,338		$ 0.0013	$ 2,749
TOTAL RURAL RATE ASSISTANCE - USoA 4730										**$ 700,327**
Transmission - Network										
Based on 2013 kW for NBHDL										
IESO	kW							1,023,625	$ 3.78000	3,869,303
Hydro One	kW							41,037	$ 3.23000	132,549
RSVA Adjustment										- 326,783
TOTAL NETWORK - USoA 4714										**$ 3,675,069**
Transmission - Connection										
Based on 2013 kW for NBHDL										
IESO	kW							1,075,278	$ 2.86000	3,075,295
Hydro One	kW							41,811	$ 2.27000	94,911
RSVA Adjustment										- 369,519
TOTAL CONNECTION - USoA 4716										**$ 2,800,687**
Low Voltage										
Based on 2013 kW for NBHDL										
Hydro One	kW							40,438	$ 0.68200	27,579
Hydro One - Fixed Charges										7,096
RSVA Adjustment										- 14,885
TOTAL LOW VOLTAGE - USoA 4750										**$ 19,789**
Smart Meter Entity Charges										
Based on 2013 customer count				# of Cust			# of Cust	# of Months		
Residential	CX #			21,124			21,124	12	$ 0.78800	199,749
General Service <50 kW	CX #			2,668			2,668	12	$ 0.78800	25,229
TOTAL SMART METER ENTITY CHARGE - USoA 4751										**$ 224,977**
TOTAL COST OF POWER EXPENSE - 2015										**$ 60,903,686**

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-27

Reference: Exhibit 2, Table 2-32 and Tables 2-12 through 2-19

Interrogatory:

a) Please add the following lines to Table 2-32 based on the figures provided in Tables 2-12 through 2-19:

- Net additions from Tables 2-12 through 2-19;
- Contributions & Grants from Tables 2-12 through 2-19;
- Resulting Gross additions from Tables 2-12 through 2-19;
- Difference between Resulting Gross additions from Tables 2-12 through 2- 19 and the Total Expenditure shown in Table 2-32.

b) Please explain any difference in the Difference line calculated in part (a) above.

c) Please update Table 2-32 to reflect actual data for 2014. If actual data for all of 2014 is not yet available, please update it to include the most recent year-to- date information for 2014, along with an updated estimated for the remainder of the year.

d) Please explain why NBHDL has not included figures for the Plan in each of 2010 through 2014.

e) Please provide a revised Table 2-32 that includes the budget (Plan) for each year that is based on the budget that is prepared annually by management and approved by the NBHDL Board of Directors (lines 21-23 on page 59).

Response:

a)

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

CATEGORY	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	Forecast Period (planned) 2015	2016	2017	2018	2019
System Access	1,283,260	1,308,483	2,022,775	1,858,535	1,800,867	1,143,704	1,166,578	1,189,909	1,213,707	1,237,982
System Renewal	5,164,759	5,055,154	2,313,746	3,997,037	4,168,904	5,469,405	4,180,343	4,235,741	4,266,049	4,054,266
System Service	396,490	289,717	200,907	141,128	206,779	373,245	214,743	127,302	89,044	135,918
General Plant	146,512	829,735	780,227	423,463	967,211	771,603	373,400	549,000	350,700	642,000
TOTAL EXPENDITURE	6,991,021	7,483,088	5,317,656	6,420,163	7,143,762	7,757,956	5,935,064	6,101,952	5,919,500	6,070,166

	2010	2011	2012	2013	2014	2015
Net additions from Tables 2-12 through 2-19	6,094,654	7,018,953	4,016,447	5,457,443	9,164,695	8,038,071
Contributions & Grants from Tables 2-12 through 2-19	(905,001)	(464,129)	(675,928)	(1,061,939)	(1,128,077)	(503,987)
Resulting Gross additions from Tables 2-12 through 2-19	6,999,656	7,483,082	4,692,375	6,519,382	10,292,771	8,542,057
Difference	**(8,635)**	**6**	**625,282**	**(99,219)**	**(3,149,009)**	**(784,101)**
Reclassified from 1945 to 1920 in '10 ('09 addition)	(8,635)	-				
CWIP costs - see Table 2-8 through 2-11:						
Capital Expenditure Spending - classified as CWIP	-	-	625,282	526,042	805,422	21,320
CWIP - transferred into service	-	-	-	(625,203)	(526,080)	(805,422)
Smart Meter Disposition	-	-	-	-	(3,428,350)	-
Immaterial variance	-	6	-	(59)	-	-
Total Difference - Table 2-32 vs. Tables 2-12 to 2-19	**(8,635)**	**6**	**625,282**	**(99,219)**	**(3,149,009)**	**(784,102)**

b) As explained on page 61 of Exhibit 2, Table 2-32 is a reflection of capital expenditure spending by fiscal year and does not include CWIP costs, 2014 smart meter costs or contributed capital. These amounts are the variances between Table 2-32 and the continuity schedules provided in Tables 2-12 through 2-19 and are itemized in the response to a) above. Please note that the 2010 variance is in relation to $8,635 being transferred from USoA 1945 to USoA 1920

– this reallocation is reflected in Table 2-12 as both an addition and disposal, but was not new capital expenditure spending in 2010.

c) Table 2-32 below has been updated to reflect actual data for all of 2014.

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2010			2011			2012			2013			2014			2015	2016	2017	2018	2019
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	N/A	1,283,260	--	N/A	1,308,483	--	N/A	2,022,775	--	N/A	1,858,535	--	N/A	1,616,199	--	1,143,704	1,166,578	1,189,909	1,213,707	1,237,982
System Renewal	N/A	5,164,759	--	N/A	5,055,154	--	N/A	2,313,746	--	N/A	3,997,037	--	N/A	3,584,280	--	5,469,405	4,180,343	4,235,741	4,266,049	4,054,266
System Service	N/A	396,490	--	N/A	289,717	--	N/A	200,907	--	N/A	141,128	--	N/A	214,952	--	373,245	214,743	127,302	89,044	135,918
General Plant	N/A	146,512	--	N/A	829,735	--	N/A	780,227	--	N/A	423,463	--	N/A	824,376	--	771,603	373,400	549,000	350,700	642,000
TOTAL EXPENDITURE	-	6,991,021	--	-	7,483,088	--	-	5,317,656	--	-	6,420,163	--	-	6,239,806	--	7,757,956	5,935,064	6,101,952	5,919,500	6,070,166

d) NBHDL did not include figures in the "Plan" for each of 2010 through 2014 as NBHDL does not have an approved DSP.

e) NBHDL does not agree with the characterization of NBHDL's internal budget being labeled (Plan). NBHDL did not have an approved DSP that it was being measured against throughout the historical period. Despite this mischaracterization, Attachment-2-Energy Probe-27 provides an updated Table 2-32 that includes NBHDL's internal budget for each year that was approved annually by management and approved by the NBHDL Board of Directors. NBHDL has used its best estimate in allocating historical capital budget costs by the DSP categories.

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Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2015*

CATEGORY	Historical Period (previous plan[1] & actual)								
	2010			2011			2012		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
System Access	1,697,037	1,283,260	-24.4%	1,591,164	1,308,483	-17.8%	2,017,341	2,022,775	0.3%
System Renewal	6,776,173	5,164,759	-23.8%	5,160,408	5,055,154	-2.0%	3,790,968	2,313,746	-39.0%
System Service	344,216	396,490	15.2%	409,288	289,717	-29.2%	242,346	200,907	-17.1%
General Plant	357,216	146,512	-59.0%	800,093	829,735	3.7%	878,976	780,227	-11.2%
TOTAL EXPENDITURE	9,174,642	6,991,021	-23.8%	7,960,953	7,483,088	-6.0%	6,929,632	5,317,656	-23.3%

CATEGORY	Historical Period (previous plan[1] & actual)										Forecast Period (planned)				
	2013			2014			2014								
	Plan	Actual	Var	Plan	Application	Var	Plan	Actual	Var	2015	2016	2017	2018	2019
System Access	1,453,913	1,858,535	27.8%		1,800,867	--		1,616,199	--	1,143,704	1,166,578	1,189,909	1,213,707	1,237,982
System Renewal	5,988,973	3,997,037	-33.3%		4,168,904	--		3,584,280	--	5,469,405	4,180,343	4,235,741	4,266,049	4,054,266
System Service	180,561	141,128	-21.8%		206,779	--		214,952	--	373,245	214,743	127,302	89,044	135,918
General Plant	601,801	423,463	-29.6%		967,211	--		824,376	--	771,603	373,400	549,000	350,700	642,000
TOTAL EXPENDITURE	8,225,249	6,420,163	-21.9%		7,143,762	--		6,239,806	--	7,757,956	5,935,064	6,101,952	5,919,500	6,070,166

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-28

Reference: Exhibit 2, Table 2-33

Interrogatory:

a) Please update Table 2-33 to include actual data for 2014. If actual data for all of 2014 is not yet available, please update it to include the most recent year-to-date information for 2014, along with an updated estimated for the remainder of the year. As part of the update, please highlight changes for the 2015 test year forecast (if any) in the revised table.

b) Please explain the difference in the net capital expenditures for 2012 through 2015 shown in Table 2-33 as compared to that in Tables 2-14 through 2-19 (for example, Table 2-19 for 2015 shows net additions of $8,038,071 while Table 2-33 shows $7,253,969).

Response:

a) Table 2-33 has been updated to include actual data for all of 2014 and changes for the 2015 test year forecast are highlighted – this table is included in Attachment-2-Energy Probe-28. Material variances between the 2014 forecast and 2014 actuals are explained in 2-SEC-12 and the revised 2015 continuity schedule is provided in 2-SEC-13 b). The changes to the 2015 test year changes are summarized as follows:

Description	2015
Table 2-33 - 2015 Projects - Application	**7,253,969**
2015 Changes:	
2014 CWIP - SR Projects	368,176
2014 CWIP - SCADA Radio	193,015
2014 Delayed - Parking Lot	75,000
	636,191
Table 2-33 - 2015 Projects - Revised	**7,890,161**

At the end of 2014, 5 material System Renewals jobs and the SCADA radio replacement project were deemed CWIP. As such, these projects came in under forecast for the 2014 Bridge Year as explained in 2-SEC-12, however, the projects will be completed in 2015 and the amounts required to complete the projects have been carried over into 2015. The parking lot project was delayed in 2014, as is explained in 2-SEC-12, but will be completed in 2015.

b) The variances between Table 2-33 and Tables 2-14 through 2-19 are highlighted below and explained in 2-Energy Probe-27 a) and b).

Description	2012	2013	2014	2015
Table 2-33 - Totals	4,641,728	5,358,224	6,015,685	7,253,969
Table 2-14 to 2-19 - Totals	4,016,447	5,457,443	9,164,695	8,038,071
Variance	**625,282**	**(99,219)**	**(3,149,009)**	**(784,101)**

Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2011 - Total Actual	2012 - Total Actual	2013 - Total Actual	2014 - Total Forecast	2014 - Total Actual	14 Variance	2015 - Total Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**		**MIFRS**
System Renewal:								
Transformer Purchases - Various Jobs	353,556	306,734	167,495	154,512	262,330	170,224	(92,106)	284,135
Major Betterment Projects								
Mercer Drive	293,011	3,255	165	-	-	-	-	-
O'Brien Street - 44kV Line Extension	210,978	-	-	-	-	-	-	-
Norman Avenue	13,779	2,296	-	916	286,402	152,376	(134,026)	78,439
Birch's Road - move 12kV to new pole line	3,156	232,480	32,287	1,251	-	-	-	-
Bond Street	-	-	-	61	142,287	223,478	81,191	-
Giroux Street	-	-	-	198,603	3,631	4,206	576	-
Turret Complex - Madelena	-	-	-	105	-	5,629	5,629	529,572
Turret Complex - Melina Close	-	-	-	105	-	-	-	293,306
Turret Complex - Lake Heights	-	-	-	210	190,380	68,289	(122,091)	79,184
Turret Complex - Wickstead	-	-	-	105	-	-	-	436,521
Voltage Conversion Projects								
Timmins & Nipissing - Upgrade Polelines for MS19	165,703	-	-	-	-	-	-	-
King Street West	-	-	-	959	167,431	39,917	(127,513)	74,172
Duke Street	111,138	103,747	-	-	-	-	-	-
Victoria Avenue	12,649	140,365	6,925	-	-	-	-	-
Queen Street, including 3PH	-	1,285	1,870	856	146,132	305,925	159,793	-
Sixth Avenue	-	65,079	234	-	-	-	-	-
Old Callander Road	-	34,240	712,070	(2,452)	-	-	-	-
Graham Drive	-	141,589	80,380	12,988	-	-	-	-
Drew Street	-	5,669	133,864	94,589	-	-	-	-
6F4 Area - Preparation for Voltage Conversion	-	-	43,382	56,580	-	-	-	-
Cassells Street	-	-	9,229	141,990	-	-	-	-
MS # 5 - 22kV & Primary Removals	73,519	35,317	37	-	-	-	-	-
Worthington Street	305,617	562,246	93,460	4,606	1,817	1,784	(32)	-
NB TS Egress - including Angus	-	245,370	17,324	-	-	-	-	-
Angus Street	-	-	184,627	49,089	-	-	-	-
6F1 - Conversion								
Brookes Street	-	-	-	363	62,811	57,896	(4,915)	-
Hardy Street	-	-	-	251	90,935	63,786	(27,149)	90,612
Maher Street	-	-	-	242	96,357	57,420	(38,937)	45,770
Laurier Street	-	-	-	83,311	-	-	-	-
Franklin Street	-	-	-	1,287	223,400	359,622	136,221	-
McGaughey Street	-	-	5,350	132,323	365	358	(6)	-
Hammond Street	-	-	10,544	187,745	52,271	53,738	1,468	-
Metcalfe Street	-	-	651	43,373	356,859	383,667	26,808	-
Chippewa Street	-	-	-	189,177	-	-	-	-
MS21 Egress Work	-	-	-	112,820	365	358	(6)	-
Fourth Avenue	-	-	-	1,400	-	-	-	147,188
Fifth Avenue	-	-	-	639	-	1,693	1,693	154,232
Fraser South - 12kV	-	-	-	-	-	-	-	116,034
McIntyre Street	-	-	-	1,050	-	-	-	452,969
Ferguson Street	-	-	-	-	636	620	(17)	278,780
First Avenue	-	-	-	-	814	792	(22)	136,126
Regina Street	-	-	-	-	785	763	(21)	81,248
Main Street West	-	-	-	-	422	411	(12)	215,217
Sherbrooke Street	-	-	-	-	-	-	-	112,822
Second Avenue	77,510	113	126	-	-	-	-	-
Pinewood Voltage Conversion - Civil & Prep	1,571,932	2,913	7,050	-	-	-	-	-
Pinewood Voltage Conversion - Electrical	1,140,594	217,726	18,053	-	-	-	-	-
Minor Betterment Projects	69,504	89,896	120,395	251,724	86,676	132,700	46,024	106,591
Porcelain Switch & Insulator Replacement	65,164	21,694	100,696	8,900	101,671	28,494	(73,177)	-
Asset Management	40,290	182,290	1,986	27,752	24,066	23,639	(427)	-
Distribution Substation Construction								
MS# 19 - Replacement MS# 5	68,468	60	20,191	-	-	-	-	-
MS# 20 - Replacement MS# 12	68,599	2,058,742	40,126	-	-	-	-	-
MS# 21 - Replacement MS# 6	-	-	73,962	1,312,184	31,907	32,279	373	-
MS# 22 - Replacement MS# 9	-	-	-	-	679,396	343,993	(335,403)	1,781,297
Distribution Substation Improvements & Rehabilitation								
MS# 8	194,134	14,480	-	-	-	-	-	-
MS# 14	7,819	160,718	104,375	-	-	-	-	-
MS# 15	-	-	-	-	226,416	294,825	68,409	-
MS# 16	-	-	9,492	798,829	84,376	85,355	979	-
Distribution Substation Transformers								
8T1 Failure - December 2008 - Insurance Proceeds	(92,392)	-	-	-	-	-	-	-
17T1 Failure - October 2010	62,526	262,229	25,727	333	-	-	-	-
13T2 Failure - October 2011	-	-	186,034	11,568	-	-	-	-
MS# 1 - Transformer Replacement - T1	-	-	-	-	278,506	254,954	(23,552)	-
MS# 13 - Transformer Replacement - T1	-	-	-	-	-	-	-	271,470
Distribution Substation SCADA								
SCADA - implementation of new radio system for SCADA	-	-	2,835	1,440	368,822	175,807	(193,015)	193,015
Misc. Projects <$65k on individual project basis	347,505	164,621	102,806	115,251	200,640	259,280	58,640	71,897
Sub-Total, System Renewal	**5,164,759**	**5,055,154**	**2,313,746**	**3,997,037**	**4,168,904**	**3,584,280**	**(584,624)**	**6,030,596**
System Service:								
Highway 11 North - Voltage Regulator Installation & Metering Upgrade	-	-	90,347	-	-	-	-	-
Copeland St. - 44kV Loadbreak Switches	64,600	-	-	-	-	-	-	-
IESO Meter Installations - 44kv Metering								
Bond St., O'Brien St., 15M1/15M2 for NBTS Conversion to 44kV	137,585	103,671	3,344	1,831	-	-	-	-
Meters Installs and Upgrades - Smart Meters	111,423	100,945	43,439	62,040	15,000	-	(15,000)	15,000
Capital Infrastructure Modernization	-	-	533	263	148,141	201,577	53,436	199,213
Misc. Projects <$65k on individual project basis								
Meters	38,028	33,544	2,760	41,352	10,000	-	(10,000)	10,000
Substations, SCADA and Misc. Projects	22,475	51,185	39,757	9,986	22,822	-	(22,822)	15,735
Major & Minor Betterment Projects	22,380	371	20,726	25,655	9,349	12,166	2,817	9,851
Feeder Conversion Projects - 5 Individual Projects <$65k/project	-	-	-	-	1,467	1,208	(258)	123,445
18F1, 18F2, 18F3, 7F2, and 1F1								
Sub-Total, System Service	**396,490**	**289,717**	**200,907**	**141,128**	**206,779**	**214,952**	**8,172**	**373,245**

Appendix 2-AA
Capital Projects Table

Projects	2010 - Total Actual	2011 - Total Actual	2012 - Total Actual	2013 - Total Actual	2014 - Total Forecast	2014 - Total Actual	14 Variance	2015 - Total Forecast
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**		**MIFRS**
System Access:								
Transformer Purchases - Various Jobs	93,439	156,988	187,612	115,377	106,872	56,875	(49,998)	95,113
Major Betterment Projects								
Aerospace Park - 44kV & 12kV Line Extension	-	-	496,321	9,125	-	-	-	-
Voodoo Cres. - 12.5kV and 44kV Line Extension	-	-	130,919	83,482	-	-	-	-
Minor Betterment Projects	292,314	207,132	268,941	288,086	198,147	302,408	104,261	230,102
Bell FSA Project	-	-	-	459,691	744,212	784,563	40,350	-
Primary Services Projects	46,683	121,508	137,329	198,663	135,952	124,747	(11,204)	217,820
Gormanville Rd - OPP 44Kv Service & Other 44Kv Work	-	78,298	74	-	-	-	-	-
Aerospace Park - Condo Development	-	-	7,833	182,307	-	-	-	-
100 Chippewa West - Memorial Gardens	-	-	-	92,019	-	-	-	-
Thompson Park - New Primary Service	-	-	-	81,213	-	-	-	-
Secondary Services	299,563	404,425	288,463	204,301	361,792	221,939	(139,853)	249,365
Subdivisions	108,129	109,429	71,948	104,729	110,975	69,026	(41,949)	100,973
Road Relocations Projects					103,218	45,732	(57,486)	212,218
Algonquin Ave. - Cassels x Copeland	246,094	164	-	-	-	-	-	-
Front St. - McLeod x Second	161,830	-	-	-	-	-	-	-
Main St.	-	48,408	184,610	6,307	-	-	-	-
John St.	-	-	90,053	177	-	-	-	-
Misc. <$65k on individual project basis	35,207	182,131	158,671	33,060	39,699	10,910	(28,789)	38,112
Sub-Total, System Access	**1,283,260**	**1,308,483**	**2,022,775**	**1,858,535**	**1,800,867**	**1,616,199**	**(184,668)**	**1,143,704**
General Plant								
Building & General Office Upgrades, including Furniture	12,656	13,858	63,237	11,532	71,116	60,675	(10,441)	26,300
HVAC System	-	-	4,200	148,769	149,427	159,036	9,609	-
Generator	-	-	-	-	166,800	171,145	4,345	-
Customer Service Entrance & Department Renovation	-	154,297	149,443	-	-	-	-	-
Operations Facility Upgrades - Garage, Yard, Driveway & Warehouse	-	-	17,800	3,945	126,995	31,243	(95,752)	111,652
Fleet Replacement - Bucket Trucks, Radial Boom Devices & Trailers	-	289,661	137,946	12,207	100,063	133,773	33,710	370,000
Fleet Replacement - Vehicles < 3 Ton	64,703	73,801	116,478	49,094	53,000	28,133	(24,867)	145,000
Work Equipment	27,751	66,985	21,427	74,019	47,000	20,070	(26,930)	46,151
Servers, PC, Other Hardware	18,783	162,087	181,608	7,832	80,600	117,239	36,639	126,500
Software	22,620	69,045	88,089	116,066	172,211	103,063	(69,148)	21,000
Sub-Total	**146,512**	**829,735**	**780,227**	**423,463**	**967,211**	**824,376**	**(142,835)**	**846,603**
Contributed Capital								
Contributed Capital from Customers	(905,001)	(464,129)	(675,928)	(1,061,939)	(1,128,077)	(1,415,412)	(287,335)	(503,987)
Sub-Total	**(905,001)**	**(464,129)**	**(675,928)**	**(1,061,939)**	**(1,128,077)**	**(1,415,412)**	**(287,335)**	**(503,987)**
Miscellaneous	-	-	-	-	-	-		-
Total	**6,086,019**	**7,018,959**	**4,641,728**	**5,358,224**	**6,015,685**	**4,824,394**	**(1,191,291)**	**7,890,161**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*	-	-	-	-	-	-		-
Total	**6,086,019**	**7,018,959**	**4,641,728**	**5,358,224**	**6,015,685**	**4,824,394**	**(1,191,291)**	**7,890,161**

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-29

Reference: Exhibit 2, Page 90

Interrogatory:

The evidence states that for rate setting purposes, in the first year of service, depreciation is calculated using the 1/2 year rule. Does NBHDL use the same 1/2 year method for financial accounting purposes? If not, please explain what NBHDL uses for financial reporting purposes and which methodology has been reflected in the continuity schedules for 2010 through 2015 shown in the evidence.

Response:

NBHDL uses the ½ year method for calculating depreciation for financial accounting purposes for distribution assets and this methodology has been reflected in the continuity schedules for 2010 through 2015 shown in the evidence. Depreciation calculated on general assets is slightly different; 2010, 2011, 2014 Bridge Year and 2015 Test Year continuity schedules reflect the ½ year methodology while 2012 and 2013 continuity schedules reflect a different methodology. In 2012, NBHDL transitioned to the use of an automated fixed asset sub ledger which calculates depreciation on General assets on an individual asset basis beginning in the first month after the asset is put into service. This methodology has been reflected in the continuity schedules for 2012 and 2013 as explained on page 79 of Exhibit 4. NBHDL has proposed the ½ year rule for determining depreciation on general assets for rate setting purposes in the 2015 Test Year as the variance between the methodologies for general assets is immaterial as can be seen in response to 4-Energy Probe-56.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-30

Reference: Exhibit 2, Appendix P

Interrogatory:

Please update the table to reflect actual data for 2014. If actual data for all of 2014 is not yet available, please update based on the most recent year-to-date actuals available, along with an updated estimate for the remainder of the year. Please also update 2015 to reflect any changes that result from the changes in 2014.

Response:

Please see 2-Energy Probe-28 a) for the updated data for 2014 actuals by project and 2015 changes that result from the changes in 2014. Exhibit 2, Appendix P and Table 2-33 are the same table.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 –RATE BASE

2-Energy Probe-31

Reference: Exhibit 2, Appendix P & Tables 2-12 through 2-19

Interrogatory:

Please explain the difference in additions shown in Table 2-12 through 2-19 with the total figures shown in Appendix 2-AA. For example, please explain the difference between the $7.25 million shown in Appendix 2-AA for 2015 with the $8.04 million shown in Table 2-19. In answering this question, please separate out the impact of the smart meters. Further, if the difference is due to work-in-progress, please provide a table that shows the impact on work-in-progress on the difference in the totals.

Response:

Exhibit 2, Appendix P (Table 2-AA) and Table 2-33 are the same table and the variances to the continuity schedules provided in Tables 2-12 through 2-19 are explained in the responses to 2-Energy Probe-27 a) and b).

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-15

Reference: Page 52, Line 1, Treatment of Stranded Assets Related to Smart Meter Deployment

Interrogatory:

"In accordance 3 with the Board's Guideline G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition 4 ("Guideline G-2011-0001"), whereby distributors are to be "held whole with respect to the cost recovery of stranded meters (i.e. conventional meters replaced as part of the smart meter initiative)", NBHDL seeks disposition of its stranded meter costs as at December 31, 2014 in the amount of $278,085."

Given the above, it is evident that the OEB seems to think that allowing LDC's to recover the undepreciated cost of analog meters is a good idea. The scrapping of these meters does not increase costs of the applicant in any way.

Given the fact that these meters were initially paid for by ratepayers and also paid for again through depreciation charges over the years they were in service and in light of the applicant's mission statement to provide "good value for money" what is the applicant's explanation for actually applying to recover these amounts from customers?

Response:

The assumption underlying this question, that "these meters were initially paid for by ratepayers and also paid for again through depreciation charges over the years they were in service" is factually incorrect. As described in Exhibit 2, Page 52, Line 2 to Exhibit 2, Page 54, Line 2, NBHDL is only seeking disposition of the pooled residual NBV of its stranded meters as at December 31, 2014, less any net proceeds from sales of the meters and all contributed capital attributable to the meters at December 31, 2014.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-16

Reference: Page 57, Line 5, Voltage Conversion

Interrogatory:

NBHDL has been undertaking a voltage conversion program which has required a large amount of capital spending. The reasons given for this program are system reliability, lower line losses and lower future maintenance costs.

The applicant states further that most plant is at the end of its useful life and must be replaced. We took six photos of a voltage conversion project undertaken in 2013 to demonstrate what NBHDL considers poles and equipment that are at the end of their useful lives.

We suggest that NBHDL may be being too aggressive in the number of projects being undertaken which are not require immediate attention and do not represent the best use of resources.

Please explain why the voltage conversation work could not be cut back and extended, for example to ten years, which would allow NBHDL to reduce delivery rates through a reduction in operations personnel and other assets required for this work?

Response:

Please refer to page 13 of the NBHDL Distribution System Plan found at Appendix 2-A of the Application, which states:

> "In continuing the implementation of the Voltage Conversion Plan, in 2013 NBHDL engaged METSCO Energy Solutions Inc. ("METSCO"), an independent power sector consulting firm, to conduct a comprehensive condition assessment of the distribution system assets. The goal of this assessment was to determine not only the condition of the assets, but also affirm NBHDL's decision to continue with the Voltage Conversion Plan. This assessment resulted in the stand-alone Asset Condition Assessment ("ACA") report attached in Appendix B (the "ACA Report").
>
> The ACA Report evaluated the risk of asset failure in service by taking into account all available information, including age, operating conditions, results of visual inspections and non-destructive testing and identifies the assets in very poor and poor condition that present unacceptably high risk of failure in service. By comparing the value of risk against the risk mitigation cost, the report also identifies the level of investments considered economically efficient.
>
> A majority of the assets determined to be in poor condition are employed on the 4.16 kV distribution lines. METSCO concluded that NBHDL's lower voltage assets presented a greater risk of failure and specifically stated the following: "Since voltage upgrade of lines offers other economic benefits in addition to reducing the risk of asset failures, poles in "very poor" and "poor" condition employed on the 4 kV lines are recommended to be given priority in conjunction with the implementation of line voltage upgrades." In addition, assets found in poor condition not only present greater risk of asset failures in service, which would degrade system reliability, but they also pose potential safety hazards to NBHDL employees and the public. As part of its capital investment plan for the next five years, NBHDL is proposing to replace the assets found in poor condition and rebuild those lines to mitigate the risk of in-service failures."

Please also refer to Sections 4.2, 4.4 and 4.5 of the NBHDL Distribution System Plan found at Appendix 2-A of the Application as well as Appendix Q and R for a detailed description of NBHDL's prioritization process and the outcome of that process for the forecast period. While

NBHDL considers impacts on rates and scaling back investment levels if needed, this is one of many competing factors used to best pace and prioritize capital investments.

NBHDL has also considered the specific images attached to 2-NBTA-16 and has the following comments:

Picture 1 and Picture 2

Pictures 1 appears to show the poles that replaced the poles in Picture 2 as part of the Cassells rebuild. The asset statistics on the first five poles from left to right in Picture 2 are as follows:

- P1804 was installed in 1960, is 40’ in length and is a class 4 pole
- P1805 was installed in 1962, is 40’ in length and is a class 4 pole
- P1806 was installed in 1960, is 40’ in length and is a class 4 pole, and houses an underslung transformer that NBH considers a safety hazard for both NBHDL workers and communication company workers as high voltage is present below the main neutral conductor.
- P1807 was installed in 1960, is 40’ in length and is a class 4 pole
- P1808 was installed in 1960, is 40’ in length and is a class 4 pole.

The statistics above are consistent with the majority of the poles that were replaced on this project, and the line was operating at 4.16kV prior to the rebuild. Aside from their age, the poles were too short to accommodate new framing standards, were not strong enough to handle 336 ASC conductor or new equipment such as transformers, and housed equipment that posed safety hazards. In order to increase the voltage to 12.47kV the separations between the conductors had to be increased as well. If anything, these poles are a prime example of assets that have been left well past their useful life and why NBHDL is in a situation where keeping up with the prescribed pace of renewal is not possible.

Picture 3 and Picture 4

Pictures 3 and 4 appear to show a pole on the corner of Olive and Cassells that was replaced as part of the Cassells rebuild.

The old pole, P1816 a 40' Class 4 installed in 1991 was replaced by a new 60' Class 2 pole. The reason the pole was replaced, is the retirement home located on Olive Street was contemplating moving forward with a service upgrade that would require servicing from the subtransmission system (44kV). If they moved forward with the upgrade four of the poles that NBHDL just replaced on Cassells would have to be replaced with 60' tall poles to accommodate servicing from the 44kV system. Therefore the incremental pole height to accommodate the servicing at a future date was included in the design of Cassells Street and the four poles that were slated to be changed to 45' poles were changed to 60' poles. This is something NBHDL looks at during design to prevent premature harvesting of pole assets and also to mitigate future costs. Imagine replacing a pole at full cost to only go back and replace the pole a year later at full cost to accommodate servicing. It should be noted that a capital contribution was provided to NBHDL for the incremental cost of the taller poles.

Picture 5 and Picture 6

Pictures 5 and 6 appear to show a pole on the corner of Chippewa and Cassells that was replaced as part of the Cassells rebuild.

The old pole, P1809 a 45' Class 3 pole installed in 1997 unfortunately had to be harvested and replaced with a 50' Class 3 pole due to the rebuild work done on Chippewa Street. There is a requirement for separations of conductors crossing in span, and due to the work on Chippewa Street which included 45' poles, the poles on Cassells that straddle Chippewa Street had to be

50’ Class 3 poles to ensure the in span crossing separation was met. At intersections were lines run perpendicular it is NBHDL standard for the poles of the supplying circuit to be 5’ taller than the poles of the tapped circuit; this is exactly the case at the intersection of Cassells and Chippewa. From time to time assets are harvested prematurely, but the situation is prevented where possible, and is only done when there is a sound reason.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-17

Reference: Page 89, Line 16

Interrogatory:

PP&E include expenditures that are directly attributable to the acquisition of the asset."

Please provide the breakdown of employee costs estimated at $5,360,185, on page 48 in Exhibit 4 – Table 4 – 10, between OM&A costs and those deemed to be direct labour to be included in PP&E.

Response:

Please refer to 4- Energy Probe-46.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-18

Reference: Page 96, Line 22

Interrogatory:

"As described previously, NBHDL does not allocate any indirect costs associated with Finance, Human Resources, Information Systems Technology, or the Administration department."

We could not find the "described previously" reference to this subject. Please provide more reference details and explain the reasoning behind not allocating all indirect costs to capital projects.

Response:

Please refer to Exhibit 2, Page 91 beginning at Line 1 and continuing to Line 28.

The Accounting Standard Board ("AcSB") deferred mandatory adoption of International Financial Reporting Standards (IFRS) for qualifying rate regulated entities to January 1, 2015. As January 1, 2015 is the mandatory year of adoption for IFRS NBDHL has filed its rate application on the basis of modified IFRS ("MIFRS"). International Accounting Standard 16 for Property, Plant and Equipment (IAS 16) provides guidance on the elements of costs that can be included in PP&E. The elements of costs can be found in IAS 16.16-20 and IAS 16.19 (d) specifies that costs can no longer include administration and other general administrative overhead costs. As explained on page 93 of Exhibit 2, lines 21 through 25, NBHDL's capitalization policy, which includes the overhead policy, has been reviewed and approved as IFRS compliant by NBHDL's external auditors.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-19

Reference: Page 104, Appendix 2 – A: Distribution System Plan, Page 7 of the DSP (second paragraph below graph)

Interrogatory:

"As of the date of this DSP, the Initial VC Plan is now 74.2 percent complete. NBHDL has since formalized its plans for voltage conversion, but this original goal of upgrading from 4.16kV to 12.47kV service remains the same."

A reduction in the scheduling for this and other system upgrade projects would allow for a reduction in front line staff and also material costs.

In the interest of maintaining lower delivery rates and given that the conversion plan is 74.2 % complete, please indicate why the final completion of the 4.16kV to 12.47 kV conversion program could not be extended over an additional few years.

Response:

Please see the response to 2-NBTA-16.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-20

Reference: Page 116, Page 12 of the DSP (second paragraph)

Interrogatory:

".. prior to the 2010 Cost of Service (COS) application (EB-2009-0270) there was not a formalized plan, nor direction in the projects selected, to achieve the actual conversion to 12.47kV and therefore the remaining capital program projects were scattered throughout the 4.16kV area."

While the existence of a plan is certainly preferable to its absence, a major factor in implementing any plan must be the overall cost and affordability from a customer point of view.

Please comment on extending the time of the plan implementation in order to reduce staff and keep delivery rates at or below current levels especially in light of the relentless rise in the costs of electricity.

Response:

Please see the response to 2-NBTA-16.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-21

Reference: Page 123, 1.3 Objectives & Scope of Work (third point)

Interrogatory:

"Delivering good value service for money while providing a fair rate of return to the City of North Bay."

Please explain how providing a "fair rate of return" supports the objectives of the proposed capital investment program.

Also, please explain how City of North Bay taxpayers benefit from a "rate of return" which is paid for by themselves through delivery rates.

Response:

Please refer to pages 24-26 *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* dated December 11, 2009 for a clear description of the benefits of providing a fair rate of return:

> **"The Cost of Capital**
>
> The Ontario Energy Board has been engaged in the rate regulation of utilities for many years. Over this extended period, the Board notes that there continues to be any of a number of misconceptions about the cost of capital concept, particularly what the cost of capital is and why it is an important consideration.

The Board is of the view that the following points articulated by Dr. Bill Cannon in his presentation at CAMPUT's 2009 Energy Regulation Conference on July 3, 2009, are principally relevant to defining and understanding the cost of capital concept.

At its simplest, the cost of capital is the minimum expected rate of return necessary to attract capital to an investment. The rate of return includes the income received during the time the investment is held plus any capital gain or loss, realized or accruing during this period, all as a percentage of the initial investment outlay.

The cost of capital can be viewed from both: (a) a company or utility perspective; and (b) from the investor's or capital provider's perspective. From the company's perspective, the cost of capital is the minimum rate of return the company must promise to achieve for investors on its debt and equity securities in order to preserve their market values and, thereby, retain the allegiance of these investors.

[There is interest] in the cost of capital…because all utilities – private or public – at some time… must raise financial capital to pay for investments, and both fairness and practical considerations dictate that the private and/or government investors who provide these capital funds must be adequately compensated. Raising capital is a competitive process. Private investors are under no obligation to buy a particular utility's securities, and government-owned utilities must compete with other government spending priorities. A utility will be able to secure new capital and replace maturing securities only if investors believe that they will be adequately rewarded for providing new capital funds. That required reward, in turn, must compensate the investors for a least two things: (1) for postponing the consumption of the goods and services that they might otherwise have enjoyed had they not made the investment; and (2) for exposing their funds to the risk that they may not get all their money back or not get it back as promptly as they anticipated. The reward demanded by investors is therefore a necessary cost of doing business from the utility's point of view, just as much as the cost of labour or fuel.

> From the viewpoint of investors as a group, however, the cost of capital can be defined more clearly and operationalized as "the expected rate of return prevailing in the capital markets on alternative investments of equivalent risk and attractiveness." There are four concepts embedded in this operational definition:
>
> First, it is forward-looking. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an expected rate of return.21
>
> Second, it reflects the opportunity cost of investment. Investors have the opportunity to invest in a wide range of investments, so the expected rate of return from a given utility-company investment must be sufficient to compensate investors for the returns they might otherwise have received on foregone investments.
>
> Third, it is market-determined. This market price - expressed as the expected return per dollar of invested capital - serves to balance the supply of, and demand for, capital for the firm.
>
> And, fourth, it reflects the risk of the investment. It reflects the expected returns on investments in the marketplace that are exposed to equivalent risks. Another way of expressing this principle is to say that the cost of capital depends on the use of the capital – or, more precisely, the risk associated with the use of the funds – and not on the source of the funds.

In Ontario, utilities regulated by the Board in the gas and electricity sectors are structured to operate as commercial entities. As such, the rate setting methodologies used by the Board apply uniformly to all rate-regulated entities regardless of ownership. The determination of rate-regulated entities' cost of capital is no exception. It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Board sees no compelling reason to adopt different methods of determining the cost of capital based on ownership."

NBHDL is of the view that for the reasons cited above, providing a "fair rate of return" supports the objectives of the proposed capital investment program.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-22

Reference: Page 127, 2.1.2 (5.2.1b) sources of cost savings expected to be achieved..... (second point)

Interrogatory:

"Specifically, implementation of a formalized asset management prioritization protocol (to be initialized in 2016) through consultation with METSCO is anticipated to allow NBHDL to have stronger and more efficient practices in determining asset health and coordinating repair and replacement efforts."

In the 2010 COS application METSCO produced an asset management plan report. In the conclusion that report, METSCO suggested that *"Due to the existing age and condition of assets, risk of in-service asset failures will remain high for the next ten years" and that "North Bay needs to ramp up the capital investment into asset renewal and replacement to a level of approximately $6 million annually, for the next ten years or so...."*

Since the 2010 report details the general methods of putting an asset management plan in place as well as a general level of CAPEX for the next ten years, please explain how an additional report will allow NBHDL to improve its practices in determining asset health and coordinating repair and replacements efforts.

Additionally, please explain why, using the 2010 report as a guideline, internal staff could not be assigned this task resulting in less cost and satisfactory results.

Response:

The asset management prioritization process used by a utility to pace, prioritize and optimize capital spending is a core requirement of the Ontario Energy Board's Chapter 5 Filing Requirements dated March 28, 2013.

The NBTA has itself questioned the existing NBHDL asset management prioritization protocol in each of 2-NBTA-16, 2-NBTA-19, 2-NBTA-20 and 2-NBTA-23. Given the questions raised by the NBTA about the existing prioritization process, one would have anticipated that the NBTA would be supportive of a plan to implement further improvements to the prioritization process with an express intent of having stronger and more efficient practices.

Please refer to Sections 4.2, 4.4 and 4.5 of the NBHDL Distribution System Plan found at Appendix 2-A of the Application as well as Appendix Q and R for a detailed description of NBHDL's current prioritization process and the outcome of that process for the forecast period.

NBHDL believes that continuously improving to its existing asset management prioritization protocol is a necessary part of its responsibility to manage its distribution system prudently. NBHDL intends to retain the expertise of third party independent engineers, METSCO, to advise on the implementation of improvements, if any, to current practices.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-23

Reference: Page 127, 2.1.2 (5.2.1b) sources of cost savings expected to be achieved..... (third point)

Interrogatory:

"The focus on the renewal of the system, specifically the replacement of assets past their useful life, is anticipated to result in less reactive based maintenance (trouble calls). The benefit may not be realized immediately, and is anticipated to help mitigate the effect of other O&M cost increases in the longer term. Less trouble calls also have the potential to result in higher reliability."

This statement concerning cost savings states the obvious regardless of the condition of the infrastructure and is too general to be helpful. In other words, if NBHDL replaced the entire infrastructure one would naturally expect fewer trouble calls and higher reliability.

However, cost considerations must be taken into account and also the point at which the law of diminishing returns come into play. Additionally, irrespective of the dire predictions made by METSCO in its 2010 report, none of the customer surveys indicated that system reliability has been a major problem.

We would like to suggest that while cost saving is a goal; cost savings come at a price which needs to be given more of a key priority.

Please comment.

Response:

NBHDL has no comment at this time.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-24

Reference: Page 129, 2.2.1.1, Customer Engagement

Interrogatory:

To meet the OEB requirements, NBHDL must demonstrate that it has coordinated infrastructure planning with customers, the transmitter, other distributors and/or OPA or other third parties.

It appears that the most of the details reported in the "2.2.1.1 Customer Engagement" section are not related to the DSP in any meaningful way.

Please explain how the engagement processes listed in this section satisfy the requirements set out by the OEB.

Response:

The content of Section 2.2.1.1 of Appendix 2-A is clearly and directly responsive to Section 5.2.2(a) of the Board's Chapter 5 Filing Requirements as it pertains to customer engagement related to the DSP. Sections 2.2.1.2 to 2.2.1.5 of Appendix 2-A is responsive to Section 5.2.2 of the Board's Chapter 5 Filing Requirements as it pertains to coordination with the transmitter (HONI), with an embedded distributor (HONI), with the IESO (formerly the OPA), as well as other third parties (e.g. the municipality).

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-NBTA-25

Reference: Page 132; Page 133

Interrogatory:

Page 132 – 1) How can we serve you better

"Reduce the cost of energy and the cost of delivery"

Page 133 - In summary business customers most important issues were:

"Better prices/lower rates"

The above survey findings from the residential and business customers indicate the main cause for concern among customers.

In the light of these facts, please explain why the preponderance of evidence in this application appears to be a single-minded adherence to increasing rates and meeting capital and replacement time schedules set by outside agencies.

Response:

Please see the response to 2-NBTA-23.

<u>North Bay Hydro Interrogatory Responses</u>

<u>EXHIBIT 2 – RATE BASE</u>

2-SEC-12

Reference: Exhibit 2

<u>Interrogatory:</u>

Please add a column to the following Board appendices for 2014 year-end actuals, and explain any material variances between the year-end 2014 forecast and actuals:

a) 2-AA

b) 2-AB

<u>Response:</u>

Board appendix 2-AA has been updated for 2014 year-end actuals as part of the response to 2-Energy Probe-28 and can be found attached to that IRR. Material variances between the 2014 forecast and 2014 actuals are highlighted in yellow and explained as follows:

<u>System Renewal</u>

<u>Transformer Purchases – ($92,106):</u>

Transformer purchases in the system renewal category are based on the transformation requirement for the planned capital program. The under spend can be attributed to 4 of the planned capital projects rolling into 2015 and the use of transformer inventory purchased in previous years on a number of projects in 2014.

<u>Norman Avenue – ($134,026):</u>

There are two contributors to the variance on this project. The first contributor to the variance is related to project timing. The project was not complete and in service at the end of 2014 as was originally forecast and costs to complete the construction has been carried over into 2015. The project is now complete and $78,439 in construction costs are included in 2015 to finish the project. The second contributor is that the scope of work changed during the design stage that eliminated the transfer of the secondary services from a backlot line to the new line constructed during the project due to the complexity involved. The work was eliminated from the project and will be undertaken separately at a later date.

<u>Bond Street - $81,191:</u>

The majority of the overrun is related to an addition to the scope of work for this project which involved replacing an existing high voltage service to a customer's premise on Bond Street. At the budgeting stage the replacement of the service was not included, but at the design stage the decision was made to include. The replacement of the service amounted to approximately $70,000 of additional cost to the project. The remainder of the variance can be attributed to materials required on the project that were not included in the estimate.

<u>Turret Complex - Lake Heights – ($122,091):</u>

There are two contributors to the variance on this project. The first contributor to the variance is related to project timing. This project was not complete and in service at the end of 2014 as originally forecasted and construction costs to the complete the work have been carried over into 2015. The project is now substantially complete, with $79,184 of costs included in 2015 for completion. The remaining variance of $42,907 is explained by the removal of two elementary school services that were planned to be replaced from the scope of work. The replacement of these services were included in a project being completed in 201 5.

<u>Queen Street, including 3PH - $159,793:</u>

The scope for this project changed substantially from the budgeting process to the design process, which included the following:

- Due to requirements by the City of North Bay, and challenging property line boundaries, a proposed 3 spans of high voltage overhead poleline had to be buried underground adding approximately $70,000 of incremental cost;

- The work required to convert a delta service to a wye service adding approximately $55,000 of incremental cost; and

- The replacement of a 44kV line pole that during construction was discovered to be rotten added approximately $10,000 of incremental cost.

The remaining variance of approximately $25,000 can be attributed to the increase in vehicle and overtime costs for the project due to the 3 items mentioned above.

<u>Franklin Street - $136,221:</u>

The majority of the variances on this project can be attributed to an addition to the scope of work and the decision by crews to convert the voltage of the line during the construction to reduce the disruption to customers and minimize costs that would be required later in the year to undertake the conversion.

A side street, Brule Street, was added to the project scope as it was overlooked during the budget process and required to be completed in order to allow voltage conversion to take place. This involved 4 additional poles, 40m of 3 phase high voltage underground cable and the replacement of low voltage servicing to 2 properties. The servicing to the properties in both cases involved the amalgamation of multiple services to one service and one of the services had to be converted from a delta to a wye. The addition of this work resulted in an extra $100,000 of costs to the project.

The conversion of the voltage while under construction resulted in an additional $15,000 of cost that in turn was eliminated from the voltage conversion project scheduled later in the year.

The remaining overrun of $21,000 can be explained by winter construction (frost, reduced working space on the street, snow removal and frigid temperatures), which slows the pace of construction, and the requirement for taller poles over a railroad crossing.

<u>Porcelain Switch & Insulator Replacement – ($73,177):</u>

This 5 year project came to a close in 2014, with the last of the porcelain switches being replaced for a total expenditure of $28,494 in 2014.

<u>MS# 22 - Replacement MS# 9 – ($335,403):</u>

A large portion of the variance relates to the procurement of the two power transformers which was budgeted at a total of $520,000 but awarded for a total of $325,488 resulting in a cost savings of $194,512. The remaining variance can be attributed to the delay of the engineering work (entire design, soil resistivity report, topographical survey and geotechnical investigation) to 2015 due to other priorities that emerged during 2014.

<u>Distribution Substation Improvements & Rehabilitation – MS# 15 - $68,409:</u>

This project was tendered and the lowest successful bid of three was $247,220 which was $67,220 more than budgeted, making up the majority of the variance. This can be partly attributed to an addition to the scope of work, which involved alterations to the substation structure, and quantities for granulars being higher than expected.

SCADA - implementation of new radio system for SCADA – ($193,015):

The entire variance for this project is related to the project rolling into 2015 due to the successful vendor running into material delivery delays. The majority of the hardware infrastructure was installed in 2014 except for a crucial fibre cable required to power up the main base station that ended up on back order for 8 weeks. Due to the time of year (November/December) it was decided to push the project into 2015 and restart in early spring. The project is forecasted to be spent to budget and completed by August 2015.

System Access

The variance of ($184,668) in this category relates to spending fluctuations in different types of demand work. Almost all demand type work was less in 2014 than the previous 5 year average, with a decrease in secondary service work being the largest contributor at ($139,853). Road relocations, transformer purchases, subdivisions, and primary services contributed ($149,433) of the variance. Minor betterment work driven by demand was up $104,261, however, the final costs of the Bell FSA project were $40,350 higher than anticipated.

General Plant

Operations Facility Upgrades - Garage, Yard, Driveway & Warehouse – ($95,752):

Included in the 2014 forecast was a project for addressing NBHDL's parking lot. This project was tendered late in the year, and when the successful contractor mobilized to start the work the weather and site conditions prevented the work from proceeding. The project was shut down for 2014 and scheduled to start back up in spring of 2015. This project resulted in a ($75,000) variance in 2014 and the costs have been carried forward into 2015. The remainder of the variance relates to immaterial individual projects.

b) Board appendix 2-AB has been updated for 2014 year-end actuals as part of the response to 2-Energy Probe-27 c). Material variances between the 2014 forecast and 2014 actuals by DSP category are explained in detail in the response above as 2-AB is a summary of 2-AA.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-13

Reference: Exhibit 2

Interrogatory:

Please update the following Board appendices/forms for 2014 year-end actuals:

a) 2-BA (2014)

b) 2-BA (2015)

c) 2-CD (2014)

d) 2-CD (2015)

e) Revenue Requirement Workform

Response:

a) Please see 2-Energy Probe-19.

b) Board appendix 2-BA (2015) has been updated to reflect 2014 year-end actuals and can be found in Attachment-2-SEC-13. A summary of the changes to the 2015 Test Year can be found in response to 2-Energy Probe-28

c) Board appendix 2-CD (2014) has been updated to reflect 2014 year-end actuals and can be found in Attachment-2-SEC-13.

d) Board appendix 2-CD (2015) has been updated to reflect 2014 year-end actuals and can be found in Attachment-2-SEC-13.

e) Please see 6-Staff-19.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2015

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance Jan.1/14**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance Jan.1/14**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,479,562	$ 28,250	$ -	$ 1,507,812	-$ 1,224,253	-$ 92,061	$ -	-$ 1,316,313	$ 191,499
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,830,506	$ 18,579	-$ 1,142	$ 1,847,943	-$ 391,450	-$ 34,784	$ 1,142	-$ 425,091	$ 1,422,852
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 13,660,424	$ 2,409,384	-$ 161,337	$ 15,908,470	-$ 4,731,052	-$ 339,080	$ 155,049	-$ 4,915,083	$ 10,993,387
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 23,050,282	$ 1,563,430	-$ 235,641	$ 24,378,072	-$ 11,545,406	-$ 371,346	$ 194,106	-$ 11,722,646	$ 12,655,426
47	1835	Overhead Conductors & Devices	$ 17,046,356	$ 803,207	-$ 91,425	$ 17,758,138	-$ 8,872,695	-$ 234,828	$ 78,342	-$ 9,029,182	$ 8,728,956
47	1840	Underground Conduit	$ 1,215,600	$ 333,627	$ -	$ 1,549,227	-$ 186,720	-$ 26,647	$ -	-$ 213,367	$ 1,335,860
47	1845	Underground Conductors & Devices	$ 7,414,450	$ 346,115	$ -	$ 7,760,565	-$ 4,698,051	-$ 105,947	$ -	-$ 4,803,998	$ 2,956,567
47	1850	Line Transformers	$ 17,009,344	$ 883,504	-$ 106,515	$ 17,786,333	-$ 9,625,190	-$ 269,766	$ 88,966	-$ 9,805,990	$ 7,980,343
47	1855	Services (Overhead & Underground)	$ 18,555,183	$ 1,491,780	$ -	$ 20,046,962	-$ 7,334,179	-$ 432,370	$ -	-$ 7,766,549	$ 12,280,413
47	1860	Meters	$ 1,589,562	$ 14,440	$ -	$ 1,604,002	-$ 916,822	-$ 102,988	$ -	-$ 1,019,810	$ 584,192
47	1860	Meters (Smart Meters)	$ 3,834,957	$ 214,955	$ -	$ 4,049,912	-$ 1,126,103	-$ 272,950	$ -	-$ 1,399,053	$ 2,650,859
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,951,334	$ 147,929	$ -	$ 3,099,263	-$ 1,428,483	-$ 82,297	$ -	-$ 1,510,780	$ 1,588,482
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 379,286	$ 6,000	$ -	$ 385,286	-$ 320,588	-$ 11,124	$ -	-$ 331,712	$ 53,574
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 953,448	$ 135,800	$ -	$ 1,089,248	-$ 743,150	-$ 82,917	$ -	-$ 826,067	$ 263,181
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,395,301	$ 631,995	-$ 83,455	$ 2,943,841	-$ 1,757,911	-$ 259,262	$ 83,455	-$ 1,933,718	$ 1,010,123
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,342,108	$ 46,151	$ -	$ 1,388,259	-$ 1,114,491	-$ 45,532	$ -	-$ 1,160,023	$ 228,236
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 174,364	$ -	$ -	$ 174,364	-$ 111,782	-$ 9,191	$ -	-$ 120,973	$ 53,391
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 21,010	$ -	$ -	$ 21,010	-$ 16,087	-$ 2,510	$ -	-$ 18,598	$ 2,412
47	1970	Load Management Controls Customer Premises	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,433,558	$ 396,515	$ -	$ 1,830,074	-$ 1,165,765	-$ 56,273	$ -	-$ 1,222,038	$ 608,036
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 26,523	-$ 1,630	$ -	-$ 28,153	$ 24,907
47	1995	Contributions & Grants	-$ 10,714,221	-$ 503,987	$ -	-$ 11,218,207	$ 2,182,163	$ 243,837	$ -	$ 2,426,000	-$ 8,792,208
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 106,852,867**	**$ 8,967,675**	**-$ 679,515**	**$ 115,141,026**	**-$ 55,798,816**	**-$ 2,589,666**	**$ 601,059**	**-$ 57,787,423**	**$ 57,353,604**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 106,852,867**	**$ 8,967,675**	**-$ 679,515**	**$ 115,141,026**	**-$ 55,798,816**	**-$ 2,589,666**	**$ 601,059**	**-$ 57,787,423**	**$ 57,353,604**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-$ 78,456			
		Total						**-$ 2,668,122**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 155,871
Stores Equipment	$ -
Net Depreciation	-$ 2,512,251

File Number:	EB-2014-0099
Exhibit:	4
Tab:	
Schedule:	
Page:	
Date:	April 24, 2015

Appendix 2-CD
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012 and will adopt IFRS for financial reporting purposes effective January 1, 2015.

2014 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Deprecation + ((d)*0.5)/(f)	2014 Depreciation Expense per Apppendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2014 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2014 Full Year Depreciation [3] (p) = 2013 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 161,995	5.00	20.00%	$ 93,718	$ 150,794	-$ 57,077	$ 32,399	$ 12,848	$ 97,070
1612	Land Rights (Formally known as Account 1906)	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ -		0.00%	$ 34,598	$ 34,598	-$ 0	$ -	$ -	$ 34,598
1810	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 646,921	33.08	3.02%	$ 331,548	$ 307,837	$ 23,711	$ 19,558	$ -	$ 341,327
1825	Storage Battery Equipment	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 1,954,019	45.00	2.22%	$ 336,300	$ 337,288	-$ 987	$ 43,423	$ -	$ 358,012
1835	Overhead Conductors & Devices	$ 761,242	60.00	1.67%	$ 222,933	$ 222,952	-$ 19	$ 12,687	$ -	$ 229,277
1840	Underground Conduit	$ 127,159	50.00	2.00%	$ 22,212	$ 22,212	$ 0	$ 2,543	$ -	$ 23,483
1845	Underground Conductors & Devices	$ 118,969	40.00	2.50%	$ 100,233	$ 100,233	$ 0	$ 2,974	$ -	$ 101,721
1850	Line Transformers	$ 553,799	40.00	2.50%	$ 246,479	$ 252,684	-$ 6,205	$ 13,845	$ -	$ 253,401
1855	Services - Overhead	$ 143,395	60.00	1.67%	$ 123,958	$ 123,982	-$ 24	$ 2,390	$ -	$ 125,153
1855	Services - Underground	$ 393,472	40.00	2.50%	$ 284,704	$ 285,009	-$ 305	$ 9,837	$ -	$ 289,622
1860	Meters	$ -	10.00	10.00%	$ 99,804	$ 100,389	-$ 585	$ -	$ 2,215	$ 97,589
1860	Meters (Smart Meters)	$ 3,516,312	10.00	10.00%	$ 200,601	$ 1,079,372	-$ 878,771	$ 351,631	$ -	$ 376,417
1905	Land	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 459,817	25.00	4.00%	$ 92,878	$ 93,082	-$ 204	$ 18,393	$ 22,414	$ 79,661
1910	Leasehold Improvements	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 2,726	10.00	10.00%	$ 10,813	$ 10,827	-$ 14	$ 273	$ 173	$ 10,776
1915	Office Furniture & Equipment (5 years)	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 128,715	5.00	20.00%	$ 61,654	$ 55,786	$ 5,868	$ 25,743	$ 6,974	$ 67,552
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment >3 ton, trailers	$ 16,778	3.04	32.90%	$ 174,268	$ 186,803	-$ 12,535	$ 5,519	$ -	$ 177,028
1930	Transportation Equipment <3 ton	$ 28,133	5.00	20.00%	$ 54,506	$ 48,440	$ 6,067	$ 5,627	$ -	$ 57,320
1935	Stores Equipment	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 13,512	10.00	10.00%	$ 45,368	$ 45,452	-$ 84	$ 1,351	$ 3,040	$ 43,003
1945	Measurement & Testing Equipment	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 5,253	10.00	10.00%	$ 7,591	$ 15,377	-$ 7,787	$ 525	$ 71	$ 7,783
1955	Communication Equipment (Smart Meters)	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 960	10.00	10.00%	$ 4,172	$ 1,623	$ 2,549	$ 96	$ -	$ 4,220
1970	Load Management Controls Customer Premises	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 49,793	20.00	5.00%	$ 49,725	$ 49,725	$ 0	$ 2,490	$ -	$ 50,970
1985	Miscellaneous Fixed Assets	$ -		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property	$ -		0.00%	$ 1,630	$ 1,630	-$ 0	$ -	$ -	$ 1,630
1995	Contributions & Grants	-$ 1,415,412	51.90	1.93%	-$ 222,655	-$ 224,601	$ 1,946	-$ 27,273	$ -	-$ 236,291
	Total	**$ 7,667,560**			**$ 2,377,038**	**$ 3,301,494**	**-$ 924,456**	**$ 524,032**	**$ 47,734**	**$ 2,591,320**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)				$ 61,592					
	Total Depreciation Expense				**$ 2,438,630**					

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Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1 2012 and will adopt IFRS for financial reporting purposes effective January 1, 2015.

2015 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2015 Depreciation Expense [1] (h)=2014 Full Year Depreciation + ((d)*0.5)/(f)	2015 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 28,250	5.00	20.00%	**$ 99,895**	$ 92,061	**$ 7,834**
1612	Land Rights (Formally known as Account 1906)	$ -		0.00%	**$ -**	$ -	**$ -**
1805	Land	$ -		0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 18,579	50.00	2.00%	**$ 34,784**	$ 34,784	**$ 0**
1810	Leasehold Improvements	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 2,409,384	45.03	2.22%	**$ 368,080**	$ 339,080	**$ 29,001**
1825	Storage Battery Equipment	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 1,563,430	45.00	2.22%	**$ 375,383**	$ 371,346	**$ 4,037**
1835	Overhead Conductors & Devices	$ 803,207	60.00	1.67%	**$ 235,970**	$ 234,828	**$ 1,142**
1840	Underground Conduit	$ 333,627	50.00	2.00%	**$ 26,820**	$ 26,647	**$ 173**
1845	Underground Conductors & Devices	$ 346,115	40.00	2.50%	**$ 106,047**	$ 105,947	**$ 100**
1850	Line Transformers	$ 883,504	40.00	2.50%	**$ 264,445**	$ 269,766	**-$ 5,321**
1855	Services - Overhead	$ 212,884	60.00	1.67%	**$ 126,927**	$ 126,915	**$ 12**
1855	Services - Underground	$ 1,278,896	40.00	2.50%	**$ 305,608**	$ 305,456	**$ 153**
1860	Meters	$ 14,440	10.00	10.00%	**$ 98,311**	$ 102,988	**-$ 4,677**
1860	Meters (Smart Meters)	$ 214,955	10.00	10.00%	**$ 387,164**	$ 272,950	**$ 114,215**
1905	Land	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 147,929	25.00	4.00%	**$ 82,619**	$ 82,297	**$ 323**
1910	Leasehold Improvements	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 6,000	10.00	10.00%	**$ 11,076**	$ 11,124	**-$ 48**
1915	Office Furniture & Equipment (5 years)	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 135,800	5.00	20.00%	**$ 81,132**	$ 82,917	**-$ 1,786**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment >3 ton, trailers	$ 526,995	8.00	12.50%	**$ 209,965**	$ 205,734	**$ 4,231**
1930	Transportation Equipment <3 ton	$ 105,000	5.00	20.00%	**$ 67,820**	$ 53,528	**$ 14,291**
1935	Stores Equipment	$ -		0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 46,151	10.00	10.00%	**$ 45,311**	$ 45,532	**-$ 221**
1945	Measurement & Testing Equipment	$ -		0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ -	10.00	10.00%	**$ 7,783**	$ 9,191	**-$ 1,409**
1955	Communication Equipment (Smart Meters)	$ -		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -		0.00%	**$ 4,220**	$ 2,510	**$ 1,710**
1970	Load Management Controls Customer Premises	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 396,515	20.00	5.00%	**$ 60,883**	$ 56,273	**$ 4,610**
1985	Miscellaneous Fixed Assets	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -		0.00%	**$ 1,630**	$ 1,630	**-$ 0**
1995	Contributions & Grants	-$ 503,987	45.00	2.22%	**-$ 241,891**	-$ 243,837	**$ 1,946**
	Total	**$ 8,967,675**			**$ 2,759,981**	**$ 2,589,666**	**$ 170,316**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)				$ 78,456	$ 78,456	
	Fully Allocated Dep'n				-$ 155,871	-$ 155,871	
	Total Depreciation expense to be included in the test year revenue requirement				**$ 2,682,567**	**$ 2,512,251**	

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-14

Reference: Exhibit 2, Page 65

Interrogatory:

Please explain the lack of AM activities in 2012 for a variance of $180,303.

Response:

The lack of AM activities in 2012 can be attributed to the one-time undertaking to update the NBHDL GIS system finishing in 2011 and no new AM initiatives being required in 2012. Refer to 1-SEC- 11.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-15

Reference: Exhibit 2, Page 65

Interrogatory:

Please explain the nature of the further reduction of $103,671 compared to 2012.

Response:

The nature of the further reduction of $103,671 compared to 2012 is a one-time project spanning across 2010 and 2011 to upgrade all NBHDL owned metering installations relating to the conversion of the HONI owned North Bay T.S. (NBTS) from 22kV to 44kV on the low voltage side of the station. This involved the full replacement of 2 existing IESO metering locations and 1 embedded metering location from 22kV to 44kV.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-16-A

Note: The SEC IRs included two questions identified as 2-SEC-16.

Reference: Exhibit 2, Page 73, Table 2-33

Interrogatory:

Please identify the discretionary projects for the Test Year.

Response:

NBHDL does not distinguish between discretionary and non-discretionary projects for the purpose of this filing. Chapter 5 filing requirements require NBHDL to prioritize and justify capital spending for the test year which is what NBHDL has done for all material capital projects. The prioritization and justification for all test year projects over the materiality threshold is provided in Appendix Q of Appendix 2-A;Distribution System Plan of Exhibit 2.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-16-B

Note: The SEC IRs included two questions identified as 2-SEC-16.

Reference: Exhibit 2, Page 98

Interrogatory:

Please explain in more details the year over year changes in overhead rates related to Engineering, Operations Administration and Store Costs.

Response:

The year over year changes in the overhead rates are a reflection of the changes in the actual costs of the Engineering, Operations Administration and Store Costs in each fiscal year. NBHDL's overhead policy for each of these departments is explained in detail on pages 91 and 92 of Exhibit 2. Changes in the overhead rates are comprised of 1) changes in department costs 2) changes in the allocation of labour time between capital and OM&A and 3) changes in the allocation of labour between capital and OM&A for the departments supported.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-17

Reference: Exhibit 2, Appendix 2-A, Page 25

Interrogatory:

With respect to Customer Engagement:

a) Please advise if the Applicant advised customers of the bill impact based on dollar or percentage increase. Please explain why the Applicant chose the method it did.

b) Please confirm if the Applicant provided the bill impact information at distribution, delivery or total bill level.

Response:

a) During the summer of 2014, NBHDL retained an expert in customer engagement and communications - Innovative Research Group, Inc. ("INNOVATIVE") -to design, collect feedback and document its customer engagement and consultation process as part of the development of the Application. NBHDL asked that customers be engaged on both NBHDL's capital infrastructure and operational plans. Customers were engaged through both a workbook facilitated discussion group and telephone surveys.

As part of the discussion group, a workbook was provided that walked through various aspects of NBHDL's business. The workbook provided customers with a summary of the bill impact based on both dollar and percentage increases so that participants would have the ability to understand the impact from both perspectives. The workbook also provided the dollar impact at the distribution level of the bill and the total bill amount in order for the customer to have comparable information and see the impact on the bottom line. Please see page 22 of the Workbook Appendix of the INNOVATIVE report provided in Appendix 1-A.7 of Exhibit 1 for the Residential example of how bill impacts were presented.

Telephone surveys were conducted and customers were walked through a series of questions and were advised on NBHDL's cost drivers. Customers were then provided with NBHDL's 2015 planned capital and OM&A spending and provided the average dollar increase over the next five years, based on the distribution portion of the bill. Please see pages 84 and 97 of the INNOVATIVE report provided in Appendix 1-A.7 of Exhibit 1 for the preamble and question that was asked in relation to bill impacts. The telephone questionnaire design methodology is described at pages 24-27 of Appendix 1-A.7 of Exhibit 1.

b) Please see a) above.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-18

Reference: Exhibit 2, Appendix 2-A, Page 37

Interrogatory:

Please advise if internal staff incentive pay is related to the planning quality indicators and if yes, please provide details.

Response:

Internal staff incentive pay is not related to the planning quality indicators.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-19

Reference: Exhibit 2, Appendix 2-A, Page 38

Interrogatory:

Is it the Applicant's goal to improve its 2013 Group 3 ranking within a specific timeframe? If so, please provide details.

Response:

No, NBHDL has not established a specific timeframe to achieve this goal. The ranking is based on a benchmark against other utilities. NBHDL has no control over those other utilities, and as a result NBHDL's performance in the benchmark is not fully within the control of NBHDL. As a result NBHDL is not in a position to create a timeframe. Rather, NBHDL has committed to controlling what is in its control – its efficiency and operational effectiveness. See Exhibit 1, Pages 73-85 for more information.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-20

Reference: Exhibit 2, Appendix 2-A, Page 39-40

Interrogatory:

With respect to reliability:

a) Please discuss if the Applicant considered setting specific reliability targets for SAIFI and SAIDI beyond the Board's requirements to be within an historic range to reflect its 5 year Distribution System Plan and associated investments.

b) Please provide the Applicant's views on the following statement - Reliability Indices provide a better indication of distribution system performance when loss of supply, major event days and scheduled outages are excluded from the calculation.

c) Please complete the following Table separately for Historical SAIFI and Historical SAIDI to provide the indicated data values.

		2007	2008	2009	2011	2012	2013	2014
1	**Total**							
2	**Excluding Loss of Supply (LOS)**							
3	**Excluding LOS and Major Event Days (MED)**							
4	**Excluding LOS, MED and Scheduled Outages (SO)**							

Response:

a) NBHDL did not consider setting specific reliability targets for SAIFI and SAIDI beyond the Board's requirement to be within an historic range to reflect its 5 year Distribution System Plan and associated investments. NBHDL believes that the Board's approach to reliability targets is reasonable and directly applicable to its business.

b) NBHDL agrees that reliability indices provide a better indication of distribution system performance when loss of supply, major event days and scheduled outages are excluded from the calculation. However, please note that NBHDL does not have records tracking major event days for the historical period.

c) The following Table has been completed separately for Historical SAIFI and Historical SAIDI to provide the indicated data values. See below.

	SAIFI	2007	2008	2009	2010	2011	2012	2013	2014
1	Total	1.83	2.70	1.63	2.86	2.37	2.68	3.07	1.17
2	Excluding Loss of Supply (LOS)	1.11	1.57	1.48	2.75	2.16	2.29	1.89	1.14
3	Excluding LOS and Major Event Days (MED)	1.11	1.57	1.48	2.75	2.16	2.29	1.89	1.14
4	Excluding LOS, MED and Scheduled Outages (SO)	0.94	1.51	1.47	2.63	2.16	2.26	1.86	1.13

	SAIDI	2007	2008	2009	2010	2011	2012	2013	2014
1	Total	1.71	2.73	1.93	2.76	2.91	2.04	2.81	1.55
2	Excluding Loss of Supply (LOS)	1.35	1.43	1.56	2.71	2.87	1.6	2.32	1.55
3	Excluding LOS and Major Event Days (MED)	1.35	1.43	1.56	2.71	2.87	1.6	2.32	1.55
4	Excluding LOS, MED and Scheduled Outages (SO)	1.04	1.33	1.53	2.59	2.86	1.54	2.26	1.54

Note that NBHDL did not track Major Event Days and therefore there is not a difference between the values in rows 2 or 3 for either SAIFI or SAIDI.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-21

Reference: Exhibit 2, Appendix 2-A, Page 41

Interrogatory:

The Applicant indicates that going forward voltage issues will be recorded so that they can be monitored and a metric reported. Please indicate the data to be gathered and the type of metric that could potentially be reported.

Response:

The data to be gathered and the type of metric that could potentially be reported is described on page 36 and page 37 in Appendix 2-A: Distribution System Plan of Exhibit 2. Please note that this metric is based solely on customer complaints. NBHDL does not have the capability or resourcing to actively monitor voltage to each and every customer, issues are managed based on complaints received in a reactionary manner.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-22

Reference: Exhibit 2, Appendix 2-A, Page 41

Interrogatory:

The Applicant indicates that going forward power quality issues will be recorded so that they can be monitored and a metric reported. Please indicate the data to be gathered and the type of metric that could potentially be reported.

Response:

The data to be gathered and the type of metric that could potentially be reported is described on page 37 in Appendix 2-A: Distribution System Plan of Exhibit 2. Please note that this metric is based solely on customer complaints. NBHDL does not have the capability or resourcing to actively monitor power quality to each and every customer, issues are managed based on complaints received in a reactionary manner.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-23

Reference: Exhibit 2, Appendix 2-A, Page 43

Interrogatory:

Does the Applicant consider Defective Equipment at 14% a major contributor to outages?

Response:

NBHDL considers defective equipment at 14% to be a significant contributor to outages. Please refer to Section 3.3 of Appendix 2-A for a comprehensive description of how NBHDL manages the risk of such outages in a cost effective and prudent manner.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-24

Reference: Exhibit 2, Appendix 2-A, Page 44

Interrogatory:

Please provide a breakdown of Tree Costs by year and work activity.

Response:

A breakdown of tree costs by year and work activity is provided in the table below:

Work Activity	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Test Year
Vegetation Management	$ 279,036	$ 411,366	$ 187,121	$ 350,991	$ 581,736	$ 656,194
Contract Adminstration	$ 7,309	$ 18,507	$ 10,044	$ 18,660	$ 78,758	$ 76,194
Cycle Tree Work	$ 227,374	$ 275,651	$ 113,942	$ 280,937	$ 421,965	$ 486,581
Off Cycle Tree Work	$ 37,882	$ 109,140	$ 50,069	$ 40,435	$ 73,879	$ 85,192
Customer Requested Tree Work	$ 5,133	$ 5,168	$ 8,492	$ 8,148	$ 1,549	$ 1,786
Trouble Calls - Tree Related	$ 1,339	$ 2,900	$ 4,573	$ 2,812	$ 5,585	$ 6,441

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-25

Reference: Exhibit 2, Appendix 2-A, Page 45

Interrogatory:

Please discuss if the Applicant considered unit costs as a potential Operating Efficiency Indicator i.e. improvement in cost) to replace a pole, transformer, switch, circuit breaker over time. If not, why not?

Response:

NBHDL did not consider unit costs as a potential Operating Efficiency Indicator to replace a pole, transformer, switch, circuit breaker over time. NBHDL didn't consider this approach due to the complexity to implement, the number of variables involved making it very hard to normalize and create useful comparisons (i.e. for poles: time of year (frost vs. no frost), earth setting conditions (rock vs. clay vs. sand), and presence of existing infrastructure (installed in greenfield, vs. installed in existing line: open space vs installed in an existing line; congested space), the changes required to the accounting system which would come at a large cost and would be very labour intensive, and the changes required in the estimating process which would also be very labour intensive. NBHDL believes implementing and meeting the planning indicator targets stated on page 38 of Appendix 2-A: Distribution System Plan of Exhibit 2 will accomplish a similar type of goal, although not as granular as unit costs, it still pushes NBHDL to execute work efficiently and as planned.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-26

Reference: Exhibit 2, Appendix 2-A, Page 45

Interrogatory:

Please provide the percentage and value of the Applicant's capital plan that is contacted out for the years 2010 to 2014 and forecasted for the Test Year.

Response:

The table below illustrates the percentage and value of NBHDL's capital plan that was contracted out for the years 2010 to 2014 and forecasted for the Test Year.

	2010	2011	2012	2013	2014	2015
Contractor Costs	$3,064,058	$2,615,821	$895,362	$2,251,502	$1,549,444	$2,781,955
Total Capital	$6,991,021	$7,483,088	$5,317,656	$6,420,163	$6,239,806	$7,757,956
% Contracted	43.83%	34.96%	16.84%	35.07%	24.83%	35.86%

The variances in the table above can be explained by the following:

- 2010 – The civil contract for the Pinewood project accounts for $1,506,400 of the contracted services

- 2011 – The contract for the construction of the MS20 substation accounts for $1,233,060 of the contracted services

- 2013 – The contract for the construction of the MS21 substation accounts for $1,234,263 of the contracted services

- 2015 – The contract for the construction of the MS22 substation is estimated at $1,253,898, and the civil contract for the Turret projects is estimated at $578,401

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-27

Reference: Exhibit 2, Appendix 2-A, Page 45

Interrogatory:

Does the Applicant track internal capital costs compared to contractor costs for the same unit of work? Please discuss.

Response:

NBHDL does not track internal capital costs compared to contractor costs for the same unit of work. NBHDL very rarely contracts out capital work that can be completed by internal staff as it is typically much more expensive to do so. The three major portions of capital work that NBHDL contracts out is civil based work, major substation construction work, and vegetation management work, all of which NBHDL cannot do internally. Over the last 5 years, only 4 line construction projects have been contracted out that could have been completed by NBHDL internal staff. In all cases, NBHDL provided the engineering work, and the material, and the contractor provided the labour and equipment to construct the project. In response to this question the tables below were created to illustrate the difference in costs for the same unit of work relating to the 4 line projects that were contracted out.

Graham Drive Line Rebuild: Contracted in 2011

Cost Description	NBHDL (estimate)	Contractor
Labour	$49,198.49	$83,392.65
Contracted Services	$11,984.00	included above
Vehicles	$12,719.52	included above
TOTAL	$73,902.01	$83,392.65

Incremental Cost to Contract $9,490.64

Victoria Street Line Rebuild: Contracted in 2011

Cost Description	NBHDL (estimate)	Contractor
Labour	$38,454.56	$94,661.60
Contracted Services	$5,870.00	included above
Vehicles	$11,497.18	included above
TOTAL	$55,821.74	$94,661.60

Incremental Cost to Contract $38,839.86

McPhail Street Line Rebuild: Contracted in 2009/2010

Cost Description	NBHDL (estimate)	Contractor
Labour	$30,615.24	$57,425.00
Contracted Services	$8,755.00	included above
Vehicles	$8,670.75	included above
TOTAL	$48,040.99	$57,425.00

Incremental Cost to Contract $9,384.01

King Street Line Rebuild: Contracted in 2009/2010

Cost Description	NBHDL (estimate)	Contractor
Labour	$8,457.29	$18,006.23
Contracted Services	$2,597.50	included above
Vehicles	$2,395.25	included above
TOTAL	$13,450.04	$18,006.23

Incremental Cost to Contract $4,556.19

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-28

Note: The SEC IRs identified this question as 2-SEC-8.

Reference: Exhibit 2, Appendix 2-A, Page 45, Future 3-5

Interrogatory:

Please provide a breakdown/listing of the units by asset type that make up the total units in the poor, very poor and fair categories that are included in the Health Index Results.

Response:

A detailed breakdown/listing of units in the poor, very poor and fair categories for each asset type is provided in section 3.2.3.1 (Pages 51-70) of Appendix 2-A: Distribution System Plan of Exhibit 2.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-29

Reference: Exhibit 2, Appendix 2-A, Page 70

Interrogatory:

With respect to assets that the Applicant runs to failure:

a) Please provide the rationale for running distribution transformers to failure.

b) Please provide a summary of all assets that the Applicant runs to failure in this application and discuss any changes in this approach since 2010.

Response:

a) For distribution transformers the consequences of failure are typically very low, they are protected by a fuse and only few customers see an outage when a failure occurs and there is not significant safety or environmental risks. Based on the consultant experience analyzing this asset class in many other utilities, the run-to-failure approach is the optimal strategy for most of the cases. Therefore, NBHDL, based on METSCO's recommendation, decided to apply run-to-failure approach for distribution transformers for the next rate filing period until the full risk based model for this asset class is developed. In this context a failure would include end-of-life deficiencies found through operation or inspection and not only failures that result in unplanned outages to customers.

b) Distribution Transformers are the only asset class that is suggested to run to failure in this application.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-30

Reference: Exhibit 2, Appendix 2-A, Page 73

Interrogatory:

Please provide a list of the asset groups that were prioritized using the Feeder Investment Model.

Response:

The asset groups that were prioritized using the Feeder Investment Model are listed below:

- Underground Cables
- Station Reclosers
- Power Transformers
- Wood Poles

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-31

Reference: Exhibit 2, Appendix 2-A, Page 77

Interrogatory:

With respect to vegetation management:

a) Please explain what is meant by topping of trees and why this practice has stopped.

b) Please explain why trees needed to be removed and provide the number of trees removed in each of the last three years and the typical tree removal cost.

Response:

(a) Please refer to the document titled, "Why Topping Hurts Trees" attached as Attachment-2-SEC-31b. The document explains what is meant by topping of trees and the negative effects topping has. Based on documents, such as the one presented, and advice from industry forums and certified utility arborists NBHDL has decided to stop practicing topping of trees due to the damage being caused to the tree and the potential for profuse regrowth that is weak and prone to breaking.

(b) In order to re-establish proper clearances throughout the NBHDL service territory major tree trimming and tree removals are required. Trimming is preferred, but in a number of situations trimming is not sufficient for a number of reasons including the need to establish the required clearance, will cause deterioration of the tree, is not the proper pruning practice, or is simply not acceptable to the property owner. In all these situations, tree removal is required.

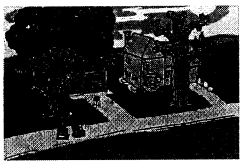
The table below illustrates the number of trees removed in each of the last 3 years and typical tree removal cost.

	2014	2013	2012
Number of Trees Removed	249	188	215
Typical Tree Removal Cost	$500	$450	$415

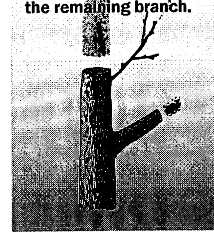
Note: Removal costs are estimated as the contract for vegetation management work is based on lump sum pricing, individual pricing/tree is not provided.

Why Topping Hurts Trees

Learn why topping is not an acceptable pruning technique and discover recommended alternatives.



Topping is perhaps the most harmful tree pruning practice known. Yet, despite more than 25 years of literature and seminars explaining its harmful effects, topping remains a common practice.



Topping is cutting branches back to stubs or lateral branches not large enough to sustain the remaining branch.

What is Topping?

Topping is the indiscriminate cutting of tree branches to stubs or to lateral branches that are not large enough to assume the terminal role. Other names for topping include "heading," "tipping," "hat-racking," and "rounding over."

Topping is often used to reduce the size of a tree. A homeowner may feel that a tree has become too large for his or her property, or that tall trees may pose an unacceptable risk. Topping, however, is not a viable method of height reduction and certainly does not reduce future risk. In fact, topping will increase risk in the long term.

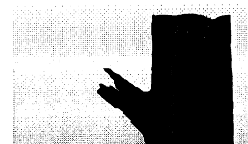
Topping Stresses Trees

Topping can remove 50 to 100 percent of a tree's leaf-bearing crown. Leaves are the food factories of a tree. Removing them can temporarily starve a tree and trigger various survival mechanisms. Dormant buds are activated, forcing the rapid growth of multiple shoots below each cut. The tree needs to put out a new crop of leaves as soon as possible. If a tree does not have the stored energy reserves to do so, it will be seriously weakened and may die.

A stressed tree with large, open pruning wounds is more vulnerable to insect and disease infestations. The tree may lack sufficient energy to chemically defend the wounds against invasion, and some insects are actually attracted to the chemical signals trees release.

Topping Leads to Decay

Correct pruning cuts are made just beyond the branch collar at the point of attachment. The tree is biologically equipped to close such a wound, provided the tree is healthy enough and the wound is not too large. Cuts made along a limb between lateral branches create stubs with wounds that the tree may not be able to close. The exposed wood tissues begin to decay. Normally, a tree will "wall off," or compartmentalize, the decaying tissues, but few trees can defend the multiple severe wounds caused by topping. The decay organisms are given a free path to move down through the branches.

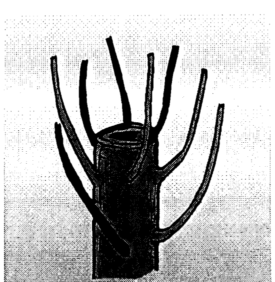


Leaving a stub maintains an open pathway to decay.

Topping Can Lead to Sunburn

Branches within a tree's crown produce thousands of leaves to absorb sunlight. When the leaves are removed, the remaining branches and trunk are suddenly exposed to high levels of light and heat. The result may be sunburn of the tissues beneath the bark, which can lead to cankers, bark splitting, and death of some branches.

Topping Can Lead to Unacceptable Risk



New shoots develop profusely below a topping cut.

The survival mechanism that causes a tree to produce multiple shoots below each topping cut comes at great expense to the tree. These shoots develop from buds near the surface of the old branches. Unlike normal branches that develop in a socket of overlapping wood tissues, these new shoots are anchored only in the outermost layers of the parent branches and are weakly attached.

The new shoots grow quickly, as much as 20 feet (6 m)in one year in some species. Unfortunately, the shoots are prone to breaking, especially during windy or icy conditions. While the original goal was to reduce risk by reducing height, risk of limb failure has now increased.

Topping Makes Trees Ugly

The natural branching structure of a tree is a biological wonder. Trees form a variety of shapes and growth habits, all with the same goal of presenting their leaves to the sun. Topping removes the ends of the branches, often leaving ugly stubs. Topping destroys the natural form of a tree. Without leaves (for up to six months of the year in temperate climates), a topped tree appears disfigured and mutilated. With leaves, it is a dense ball of foliage, lacking its simple grace. A tree that has been topped can never fully regain its natural form.

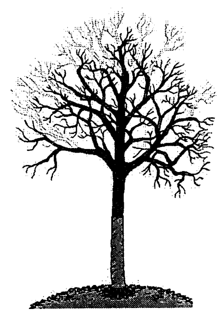
Topping Is Expensive

The cost of topping a tree is not limited to only the job cost. Some hidden costs of topping include:

- Increased maintenance costs. If the tree survives, it will likely require corrective pruning within a few years (e.g., crown reduction or storm damage repair). If the tree dies, it will have to be removed.
- Reduced property value. Healthy, well-maintained trees can add 10 to 20 percent to the value of a property. Disfigured, topped trees are considered an impending expense.
- Increased liability potential. Topped trees may pose an unacceptable level of risk. Because topping is considered an unacceptable pruning practice, any damage caused by branch failure of a topped tree may lead to a finding of negligence in a court of law.

Alternatives to Topping

Sometimes a tree must be reduced in height or spread, such as for providing utility line clearance. There are recommended techniques for doing so. Small branches should be removed back to their point of origin. If a larger limb must be shortened, it should be pruned back to a lateral branch that is large enough (at least one-third the diameter of the limb being removed) to assume the terminal role. This method of branch reduction helps to preserve the natural form of the tree. However, if large cuts are involved, the tree may not be able to close over and compartmentalize the wounds. Sometimes the best solution is to remove the tree and replace it with a species that is more appropriate for the site.



Proper branch reduction preserves natural form.

This brochure is one in a series published by the International Society of Arboriculture as part of its Consumer Information Program. You may have additional interest in the following titles currently in the series:

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Palms
Pruning Mature Trees
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Tree Selection and Placement
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Tree Values
Why Hire an Arborist
Why Topping Hurts Trees

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North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-32

Reference: Exhibit 2, Appendix B]

Interrogatory:

With respect to the Asset Condition Assessment:

a) Please confirm the assets where historic failure rates are included in the Health Index Calculation.

b) Please provide the Applicant's view on the appropriates of a level of customer outage costs used in the Feeder Investment Model and the assumed value of $30/connected kVA. (p.88)

c) The Applicant indicates assets in poor condition based on their health index are given a failure probability multiplier (p.88). Please explain how assets not in poor condition are treated in the analysis.

Response:

a) Historical failure rates were not included in any of the Health Index Calculations and are in most cases not recommended in the Health Index formulations. Instead when data is available the historical failure rates are utilized for development of failure curves that are used for the Risk Analysis. In North Bay Hydro's case historical failure data was not available and hence industry failure curves were utilized.

b) Please see IR 2-Staff-8.

c) The failure probability multiplier is not applied to assets in good or fair condition. For these assets a failure curve based on age is used as a basis. For assets in good or fair condition this approach is a good approximation for failure prediction. On the other hand for assets in poor condition their likelihood of failure may be significantly higher than the age based probability curve indicates; therefore a multiplier is used to more accurately capture the risk.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-33

Reference: Exhibit 2, Appendix 2-AA

Interrogatory:

Please complete the attached excel spreadsheet. Please also confirm the already populated data in the spreadsheet is accurate.

[See below page for excel spreadsheet.]

Interrogatory 2-SEC-33

Capital Investments Summary	2010	2011	2012	2013	2014	2015
Overhead Transformer Purchases Cost						
# of O/H Transformers Purchased						
Underground Transformer Purchases Cost						
# of U/G Transformers Purchased						
Wood Pole Replacement Cost						
# of wood poles replaced						
Substation Transformer Replacement Cost						
# of Substation Transformers Replaced						
Circuit Breaker Replacment Cost						
# of Circuit Breakers Replaced						
Low Voltage Cable Replacement Cost						
Kilometers of Low Voltage Cable Replaced						
Transformer Replacement Cost						
# of Transformers Replaced						
Overhead Distribution Switches Replacment Cost						
# of Overhead Switches Replaced						
Underground Primary Conductor Replacment Cost						
kilometers of Underground Primary Conductor Replaced						
Underground Primary Cable Replacement Cost						
Kilometers of Cable Replaced						
Capital Projects Summary	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Porcelain Switch & Insulator Replacement Cost	$65,164	$21,694	$100,696	$8,900	$101,671	-
# of Porcelain Switch & Insulators Replaced						
Meter Installs and Upgrades - Smart Meters Cost	$111,423	$100,945	$43,439	$62,040	$15,000	$15,000
# of Meters Installed						
Meters $	$38,028	$33,544	$2,760	$41,352	$10,000	$10,000
# of Meters Replaced						

Response:

At this point in time, NBHDL does not have the data at the level and category that is being requested in the above spreadsheet. Page 94 of Exhibit 2 outlines significant changes that are being made to NBHDL's internal processes in order to capture a more granular level of capital costs in the future that supports both the transition to IFRS and capital project planning and execution.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-34

Reference: Exhibit 2, Appendix 2-AA

Interrogatory:

For all Test Year material capital projects, please provide the forecasted date they are planned to go in-service.

Response:

The forecasted dates of all material capital projects are included in their individual capital project summaries found in Appendix Q – Material Capital Project Summaries in Appendix 2-A: Distribution System Plan of Exhibit 2. Please refer to the row titled "Project Timing (5.4.5.2.A.third bullet)".

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-35

Reference: Exhibit 4

NOTE: IR references Ex 4, but was called 2-SEC-35. We have retained the numbering proposed by the intervenor to ensure they can easily find the response.

Interrogatory:

Please add a column to the following Board appendices for 2014 year-end actuals, and explain any material variances between the year-end 2014 forecast and actuals.

a) 2-JA

b) 2-JB

c) 2-JC

Response:

a) Board appendix 2-JA below has been updated with a column for 2014 year-end actuals. Please refer to 2-JB and 2-JC below for explanations on material variances between year-end 2014 forecast and actuals.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year Board-Approved Less LEAP	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Operations	$ 691,316	$ 789,643	$ 942,500	$ 860,402	$ 897,622	$ 960,774	$ 828,174	$ 1,088,205
Maintenance	$ 1,270,828	$ 1,146,781	$ 1,126,685	$ 1,270,845	$ 1,397,537	$ 1,536,335	$ 1,585,026	$ 1,721,331
SubTotal	$ 1,962,143	$ 1,936,424	$ 2,069,185	$ 2,131,246	$ 2,295,158	$ 2,497,109	$ 2,413,200	$ 2,809,536
%Change (year over year)		-1.3%	6.9%	3.0%	7.7%	8.8%	-3.4%	12.5%
%Change (Test Year vs Last Rebasing Year - Actual)								45.1%
Billing and Collecting	$ 1,144,087	$ 910,353	$ 887,267	$ 1,056,107	$ 1,019,133	$ 1,604,983	$ 1,639,995	$ 1,243,810
Community Relations	$ 97,000	$ -	-$ 784	$ 35,050	-$ 6,800	$ 1,502	$ 774	$ 2,200
Administrative and General	$ 2,462,179	$ 2,158,328	$ 2,407,977	$ 2,309,976	$ 2,397,460	$ 2,704,381	$ 2,480,597	$ 2,949,298
SubTotal	$ 3,703,266	$ 3,068,681	$ 3,294,461	$ 3,401,133	$ 3,409,793	$ 4,310,866	$ 4,121,366	$ 4,195,308
%Change (year over year)		-17.1%	7.4%	3.2%	0.3%	26.4%	-4.4%	-2.7%
%Change (Test Year vs Last Rebasing Year - Actual)								36.7%
Total	$ 5,665,409	$ 5,005,105	$ 5,363,646	$ 5,532,379	$ 5,704,951	$ 6,807,975	$ 6,534,566	$ 7,004,844
%Change (year over year)		-11.7%	7.2%	3.1%	3.1%	19.3%	-4.0%	2.9%

	Last Rebasing Year Board-Approved Less LEAP	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
Operations	$ 691,316	$ 789,643	$ 942,500	$ 860,402	$ 897,622	$ 960,774	$ 828,174	$ 1,088,205
Maintenance	$ 1,270,828	$ 1,146,781	$ 1,126,685	$ 1,270,845	$ 1,397,537	$ 1,536,335	$ 1,585,026	$ 1,721,331
Billing and Collecting	$ 1,144,087	$ 910,353	$ 887,267	$ 1,056,107	$ 1,019,133	$ 1,604,983	$ 1,639,995	$ 1,243,810
Community Relations	$ 97,000	$ -	-$ 784	$ 35,050	-$ 6,800	$ 1,502	$ 774	$ 2,200
Administrative and General	$ 2,462,179	$ 2,158,328	$ 2,407,977	$ 2,309,976	$ 2,397,460	$ 2,704,381	$ 2,480,597	$ 2,949,298
Total	$ 5,665,409	$ 5,005,105	$ 5,363,646	$ 5,532,379	$ 5,704,951	$ 6,807,975	$ 6,534,566	$ 7,004,844
%Change (year over year)		-11.7%	7.2%	3.1%	3.1%	19.3%	-4.0%	2.9%

	Last Rebasing Year Board-Approved Less LEAP	Last Rebasing Year (2010 Actuals)	Variance 2010 BA - 2010 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Bridge Year	Variance 2014 Bridge vs. 2013 Actuals	2014 Actuals	Variance 2014 Actual to 2014 Bridge Forecast	2015 Test Year
Operations	$ 691,316	$ 789,643	-$ 98,327	$ 942,500	$ 152,857	$ 860,402	-$ 82,098	$ 897,622	$ 37,220	$ 960,774	$ 63,152	$ 828,174	-$ 132,600	$ 1,088,205
Maintenance	$ 1,270,828	$ 1,146,781	$ 124,047	$ 1,126,685	-$ 20,096	$ 1,270,845	$ 144,160	$ 1,397,537	$ 126,692	$ 1,536,335	$ 138,798	$ 1,585,026	$ 48,691	$ 1,721,331
Billing and Collecting	$ 1,144,087	$ 910,353	$ 233,734	$ 887,267	-$ 23,085	$ 1,056,107	$ 168,839	$ 1,019,133	-$ 36,973	$ 1,604,983	$ 585,850	$ 1,639,995	$ 35,012	$ 1,243,810
Community Relations	$ 97,000	$ -	$ 97,000	-$ 784	-$ 784	$ 35,050	$ 35,834	-$ 6,800	-$ 41,850	$ 1,502	$ 8,302	$ 774	-$ 728	$ 2,200
Administrative and General	$ 2,462,179	$ 2,158,328	$ 303,851	$ 2,407,977	$ 249,649	$ 2,309,976	-$ 98,001	$ 2,397,460	$ 87,484	$ 2,704,381	$ 306,921	$ 2,480,597	-$ 223,784	$ 2,949,298
Total OM&A Expenses	$ 5,665,409	$ 5,005,105	$ 660,304	$ 5,363,646	$ 358,541	$ 5,532,379	$ 168,733	$ 5,704,951	$ 172,572	$ 6,807,975	$ 1,103,023	$ 6,534,566	-$ 273,409	$ 7,004,844
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -
Total Recoverable OM&A Expenses	$ 5,665,409	$ 5,005,105	$ 660,304	$ 5,363,646		$ 5,532,379	$ 168,733	$ 5,704,951	$ 172,572	$ 6,807,975	$ 1,103,023	$ 6,534,566	-$ 273,409	$ 7,004,844
Variance from previous year				$ 358,541		$ 168,733		$ 172,572		$ 1,103,023		-$ 273,409		$ 196,869
Percent change (year over year)				7%		3%		3%		19%		-4%		3%
Percent Change: Test year vs. Most Current Actual								22.79%						
Simple average of % variance for all years														
Compound Annual Growth Rate for all years														
Compound Growth Rate (2013 Actuals vs. 2010 Actuals)								4.45%						

Board appendix 2-JB below has been updated with a column for 2014 year-end actuals.

Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year Board-Approved Less LEAP	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year	Total	2014 Actuals	Variance to Forecast
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS		MIFRS	MIFRS
Opening Balance	$ 5,665,409	$ 5,005,104	$ 5,363,646	$ 5,532,379	$ 5,704,951	$ 6,807,974	$ 5,665,409	$ 5,704,951	$ -
Compensation									
Employee Compensation	$80,168	$56,359	$210,733	$113,502	$166,809	$108,225	$735,797	$58,218	($108,591)
Employee Future Benefits	($32,421)	$208,128	$11,877	($59,312)	($147,341)	$2,604	($16,465)	($147,065)	$276
Sub Totals	$47,747	$264,487	$222,610	$54,190	$19,468	$110,829	$719,332	($88,847)	($108,315)
Customer Focus									
Customer Engagement	($40,000)	$7,500	($7,500)	$10,132	$110,151	$1,717	$82,000	$108,721	($1,430)
Bad Debts	($203,915)	$168,547	($120,568)	($90,481)	$167,497	$0	($78,921)	$187,745	$20,248
Bill and Collection Notice Delivery	24,221	42,616	8,421	(67,444)	(6,302)	12,124	$13,635	(4,033)	2,269
Sub Totals	($219,695)	$218,663	($119,647)	($147,794)	$271,346	$13,841	$16,714	$292,433	$21,087
Executive Financial Regulatory Professional & Insurance									
Real Time Operating Pilot	($85,000)	$0	$0	$0	$0	$0	($85,000)	$0	$0
Business and Strategic Plan	$0	$0	$18,980	($1,283)	($17,697)	$100,000	$100,000	($17,697)	$0
Regulatory Applications and OEB Assessment	($18,742)	$34,889	($8,664)	($1,115)	($60,651)	$122,476	$68,192	($63,064)	($2,413)
Banking/Audit/Legal	($10,317)	$25,125	$1,772	($6,334)	$36,979	($19,521)	$27,705	$28,181	($8,798)
Insurance	($4,131)	$15,484	($53,359)	$18,924	$19,761	$19,035	$15,715	$20,302	$541
Sub Totals	($118,190)	$75,498	($41,271)	$10,193	($21,607)	$221,990	126,612	($32,277)	($10,670)
Information & Technology									
IT Systems & Mtce	($30,990)	$19,876	$10,050	$13,013	$39,359	$46,083	$97,392	$4,286	($35,073)
Smart Meters and Meter Reading									
Smart Meter disposition	$0	$0	$0	$0	$412,548	($412,548)	$0	$412,548	$0
Sync Operator	$0	$0	$0	$38,860	$17,323	$1,389	$57,572	$20,432	$3,109
Meter Reading/ODS/Security Audits	($20,516)	($174,380)	$167,224	$56,079	$23,168	($2,395)	$49,181	$24,678	$1,510
Sub Totals	($20,516)	($174,380)	$167,224	$94,939	$453,039	($413,554)	$106,753	$457,658	$4,619
Human Resources									
Employee Costs - Recruitment/Relocation	($28,854)	$8,030	($5,551)	($4,944)	$4,291	($2,952)	($29,980)	$1,459	($2,832)
HR Consultants / Services/Legal	($11,661)	($40,167)	$3,541	($313)	$41,627	($18,926)	($25,899)	$37,095	($4,532)
Sub Totals	($40,515)	($32,137)	($2,010)	($5,257)	$45,918	($21,878)	($55,879)	$38,554	($7,364)
Operations									
Operational Review	$ -	$ -	$ -	$ -	$ -	$ 41,600	$41,600	$ -	$ -
Asset Management Annual Update	$0	$0	$0	$0	$0	$20,000	$20,000	$0	$0
Substation Preventative Mtce Contractors	($140,788)	($9,110)	$8,979	($26,413)	($2,995)	($1,281)	($171,607)	$14,782	$17,777
Vegetation Management	($30,503)	$132,330	($224,246)	$163,871	$166,839	$138,364	$346,655	$230,745	$63,905
Small Tools	($38,198)	$5,287	$1,503	($15,781)	$5,781	$361	($41,046)	$473	($5,308)
Fleet Deprecation	($9,465)	($304)	($28,914)	($1,658)	($28,335)	($793)	($69,469)	$15,796	$44,131
Sub Totals	($218,554)	$128,204	($242,677)	$120,018	$141,290	$198,252	$126,133	$261,796	$120,506
Miscellaneous									
BA ADJ - INFLATION	($18,575)						($18,575)		$0
BA ADJ - HST	($24,773)						($24,773)		$0
Miscellaneous	($15,844)	($141,669)	$174,454	$33,270	$154,210	$41,307	$245,728	($103,988)	($258,198)
Sub Totals	($59,192)	($141,669)	$174,454	$33,270	$154,210	$41,307	$202,380	($103,988)	($258,198)
Closing Balance	$ 5,005,104	$ 5,363,646	$ 5,532,379	$ 5,704,951	$ 6,807,974	$ 7,004,844	$ 7,004,844	$ 6,534,566	($273,409)

NBDL made a correction to the employee compensation line for the 2014 Bridge year and the 2015 Test Year to remove the overtime compensation related to the cost of service application. This correction does not change the closing balances since the offsetting entry was including in the miscellaneous line.

The actual 2014 employee compensation was $109k lower than forecasted mainly due to more time being allocated to recoverable work than anticipated.

The actual 2014 expenses included in miscellaneous was $258k less than forecasted. Allocated truck time was lower than forecast by $73k and all other amounts including training, travel, maintenance materials and contracted services are under the materiality threshold.

<u>Board appendix 2-JC below has been update with a column for 2014 year-end actuals.</u>

Appendix 2-JC
OM&A Programs Table

Programs (Core Objectives)	Last Rebasing Year (2010 Board-Approved)	2013 Actuals	2015 Test Year	Variance (Test Year vs. 2013 Actuals)	Variance (Test Year vs. Last Rebasing Year (2010 Board-Approved)	2014 Bridge Year	2014 Actual	2014 Actual vs 2014 Forecast
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Customer Service, Billing and Collecting (1)	$954,239	$794,512	$886,075	$91,564	($68,164)	$836,320	$808,374	($27,946)
Bad Debts (4)	$270,000	$23,582	$191,079	$167,497	($78,921)	$191,079	$211,327	$20,248
Locates (1,2)	$58,257	$238,104	$249,857	$11,753	$191,600	$218,183	$245,983	$27,800
Customer Engagement (1)	$40,000	$10,132	$122,000	$111,868	$82,000	$120,283	$118,853	($1,430)
Executive, Financial, Professional & Insurance (all)	$1,114,758	$942,990	$1,218,483	$275,493	$103,725	$1,119,602	$1,053,216	($66,386)
Regulatory Reporting and Assessments	$154,360	$243,800	$341,656	$97,856	$187,296	$193,431	$192,842	($589)
Information & Technology (4)	$369,126	$381,633	$484,962	$103,329	$115,836	$435,556	$376,310	($59,246)
Smart Meters and Meter Reading (5)	$202,308	$341,693	$383,302	$41,609	$180,995	$782,389	$797,278	$14,889
Post Employment Benefits (all)	$277,344	$405,616	$260,879	($144,737)	($16,465)	$258,275	$258,551	$276
Human Resources (all)	$217,355	$90,072	$130,229	$40,157	($87,126)	$198,053	$187,587	($10,466)
Operational Review (4)	$0	$0	$41,600	$41,600	$41,600	$0	$0	$0
Asset Management Annual Update (3,4)	$0	$0	$20,000	$20,000	$20,000	$0	$0	$0
Training / Health & Safety (2,4)	$124,518	$209,790	$222,287	$12,497	$97,769	$256,662	$207,981	($48,681)
Overhead Operations / Maintenance (3)	$452,937	$601,452	$589,640	($11,812)	$136,703	$546,153	$433,286	($112,867)
Underground Operations / Maintenance (3)	$106,575	$231,671	$222,243	($9,428)	$115,668	$232,418	$272,874	$40,456
Inclement Weather / Truck Time (4)	$171,406	$159,432	$175,868	$16,437	$4,462	$128,054	$34,192	($93,862)
Operating Tools / Equipment (4)	$124,986	$32,387	$37,948	$5,562	($87,038)	$38,409	$31,571	($6,838)
Substation Maintenance/Load Dispatching (2,3,4)	$557,294	$439,641	$510,537	$70,896	($46,757)	$448,993	$467,224	$18,231
Vegetation Management (2,3,4)	$309,539	$350,991	$656,194	$305,203	$346,655	$517,831	$581,736	$63,905
Metering - Operations / Maintenance (1,3)	$119,216	$260,585	$337,870	$77,285	$218,654	$338,082	$263,077	($75,005)
Miscellaneous (4)	$41,191	($53,131)	($77,867)	($24,736)	($119,057)	($51,796)	($7,696)	$44,100
Total	5,665,410	5,704,951	7,004,844	1,299,893	1,339,435	6,807,975	6,534,566	(273,409)

The 2014 actual for Executive, Financial, Professional & Insurance was $66k less than the 2014 forecast. Training and travel was $26k under forecast, consultants $20k, remuneration $8k, legal $6k and all other miscellaneous expenses account for the remaining $6k.

The 2014 actual for Overhead Operations / Maintenance was $113k less than the 2014 forecast. Labour and truck time was $75k under forecast, materials $29k and contracted services $9k.

The 2014 actual for Inclement Weather / Truck Time was $94k less than the 2014 forecast. Labour and truck time account for the total variance.

The 2014 actual for Metering – Operations/ Maintenance was $75k less than the 2014 forecast. Labour and truck time was $69k under forecast, contracted services and materials account for $6k.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-36

Reference: Exhibit 4, Page 6

NOTE: IR references Ex 4, but was called 2-SEC-36. We have retained the numbering proposed by the intervenor to ensure they can easily find the response.

Interrogatory:

The Applicant states that "[s]ince the cost of service application in 2010, NBHDL has gained a better understanding of the amount of labour hours that are required to support capital and maintenance activities". Please provide details.

Response:

As referenced on page 6 of Exhibit 4, the 2010 cost of service application was founded on the basis of 80% of a power line maintainer's time being allocated to capital and 20% to operations and this assumption guided the planned projects for each fiscal year.

A review of time allocation in the Lines department was undertaken and NBHDL was able to establish that to adequately service its system 35 to 40% of hours for the line department must be allocated to operations and the balance is available for the execution of capital construction programs identified through the DSP. The review provided further information that supports a higher percentage of time to OM&A in order to incorporate training, coverage, substation maintenance and line service work into the calculation of available working hours for construction projects. A review of the determination of available working hours was also done on an individual employee basis as opposed to a broader assumption of average working hours across the Lines department and this provided a more granular level of detail for which to build the resource bucket for capital construction. Page 39 of Appendix 2-A: Distribution System Plan within Exhibit 2 also highlights that adequate staffing of the Engineering department is needed to ensure that projects are designed on an on-going basis in order for capital work to continually flow to the field. Staying ahead of the design work keeps the front-line staff focused on construction, minimizes idle time and ensures NBHDL's construction is completed as planned.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-37

Reference: Exhibit 4, Page 18

NOTE: IR references Ex 4, but was called 2-SEC-37. We have retained the numbering proposed by the intervenor to ensure they can easily find the response.

Interrogatory:

Please explain the significant variance between 2010 Board-approved and actual OM&A expenses.

Response:

Please refer to the following sections of the application:

- Exhibit 1 Table 1-25 page 42 and supporting explanations pages 43-45;
- Exhibit 4 Table 4-2 and supporting explanations pages 5-17; and
- Exhibit 4 Table 4-4 (OEB 2JB) and supporting explanations pages 20-36.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-38

Reference: Exhibit 4, Page 35

NOTE: IR references Ex 4, but was called 2-SEC-38. We have retained the numbering proposed by the intervenor to ensure they can easily find the response.

Interrogatory:

Please provide a copy of the referenced Electricity Distributor Association's Emergency Task Force report.

Response:

The referenced report is not relevant to the matters at issue in this Application. In addition, it is strictly confidential information of a third party which refused to consent to disclosure as part of this proceeding when asked.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-39

Reference: Exhibit 4, Page 48

NOTE: IR references Ex 4, but was called 2-SEC-39. We have retained the numbering proposed by the intervenor to ensure they can easily find the response.

Interrogatory:

With respect to Appendix 2-K:

a) Please add rows showing the total compensation capitalized, and total charged to OM&A.

b) Please provide a version of the Appendix 2-K for showing a split between union and non-union employees.

Response:

a) Please refer to 4-Energy Probe-46.

b) Please refer to 4-VECC-39.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-40

Reference: Exhibit 4, Page 77

Note: Used IR numbering used by intervenor even though evidence reference is to Exhibit 4.

Interrogatory:

Please provide a breakdown of 'Consultants costs including Legal'.

Response:

The table below breaks down the 'Consultants costs including Legal' included in Table 4-29 - Regulatory Costs on page 77 of Exhibit 4.

NBHDL - Consultant Cost	
Util-Assist	22,129
Metsco	132,455
Piotrowski	6,200
BDO	26,650
J Saunders	2,250
Indeco	20,375
BLG (legal and consulting)	197,594
Innovative Research Group	35,000
Clarke Marketing	16,562
Total	459,215

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-SEC-41

Reference: Exhibit 5, Page 3

NOTE: IR references Ex 5, but was called 2-SEC-41. We retained the intervenors' numbering.

Interrogatory:

Please explain why the Applicant believes it is prudent to structure part of its long-term debt as a swap agreement.

Response:

In 2014, Grant Thornton assisted NBHDL in securing financing and, in the summary of findings, the most attractive fixed-rate agreement with a 10 year term was by way of Banker's Acceptances loans which are subsequently hedged by entering into an interest rate swap. Therefore, NBHDL believes it was prudent to structure its long-term debt by way of a swap agreement. Since NBHDL plans to hold the swap until maturity the risk of loss due to interest rate fluctuations is minimized.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-VECC-10

Reference: Exhibit 2, Page 20 & Page 28-29

Interrogatory:

a) Please update Table 2-17 and 2-18 (2014 Continuity Schedules in CGAAP and MIFRS format) for 2014 actual data.

Response:

Table 2-18 (2014 Continuity Schedules in MIFRS format) has been updated for 2014 actual data in 2-Energy Probe-19. Table 2-17 (2014 Continuity Schedules in RCGAAP format) has been updated for 2014 actual data and is provided in Attachment-2-VECC-10.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP Accounting Policy Changes in Effect - for comparative purposes only
Year 2014

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance Jan.1/14**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance Jan.1/14**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,317,567	$ 161,995	$ -	$ 1,479,562	-$ 1,073,458	-$ 150,794	$ -	-$ 1,224,253	$ 255,309
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,830,506	$ -	$ -	$ 1,830,506	-$ 356,852	-$ 34,598	$ -	-$ 391,450	$ 1,439,056
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 13,013,503	$ 646,921	$ -	$ 13,660,424	-$ 4,423,215	-$ 307,837	$ -	-$ 4,731,052	$ 8,929,372
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 21,394,561	$ 1,954,019	$ -	$ 23,348,580	-$ 11,472,696	-$ 337,288	$ -	-$ 11,809,984	$ 11,538,596
47	1835	Overhead Conductors & Devices	$ 16,392,963	$ 761,242	$ -	$ 17,154,204	-$ 8,739,600	-$ 222,952	$ -	-$ 8,962,553	$ 8,191,652
47	1840	Underground Conduit	$ 1,097,375	$ 127,159	$ -	$ 1,224,534	-$ 167,739	-$ 22,212	$ -	-$ 189,951	$ 1,034,583
47	1845	Underground Conductors & Devices	$ 7,308,072	$ 118,969	$ -	$ 7,427,041	-$ 4,609,132	-$ 100,233	$ -	-$ 4,709,365	$ 2,717,676
47	1850	Line Transformers	$ 16,518,295	$ 553,799	$ -	$ 17,072,094	-$ 9,432,355	-$ 252,684	$ -	-$ 9,685,039	$ 7,387,056
47	1855	Services (Overhead & Underground)	$ 18,018,316	$ 536,867	$ -	$ 18,555,183	-$ 6,925,188	-$ 408,991	$ -	-$ 7,334,179	$ 11,221,004
47	1860	Meters	$ 3,873,364	$ -	-$ 2,283,802	$ 1,589,562	-$ 2,822,149	-$ 100,389	$ 2,005,716	-$ 916,822	$ 672,740
47	1860	Meters (Smart Meters)	$ 318,644	$ 3,516,312	$ -	$ 3,834,957	-$ 46,731	-$ 1,079,372	$ -	-$ 1,126,103	$ 2,708,854
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,514,322	$ 459,817	-$ 22,805	$ 2,951,334	-$ 1,343,003	-$ 93,082	$ 7,602	-$ 1,428,483	$ 1,522,850
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 376,560	$ 2,726	$ -	$ 379,286	-$ 309,761	-$ 10,827	$ -	-$ 320,588	$ 58,698
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 824,733	$ 128,715	$ -	$ 953,448	-$ 687,364	-$ 55,786	$ -	-$ 743,150	$ 210,298
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,682,228	$ 44,911	-$ 331,838	$ 2,395,301	-$ 1,854,506	-$ 235,243	$ 331,838	-$ 1,757,911	$ 637,390
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,328,596	$ 13,512	$ -	$ 1,342,108	-$ 1,069,039	-$ 45,452	$ -	-$ 1,114,491	$ 227,617
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 169,111	$ 5,253	$ -	$ 174,364	-$ 96,405	-$ 15,377	$ -	-$ 111,782	$ 62,582
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 20,050	$ 960	$ -	$ 21,010	-$ 14,464	-$ 1,623	$ -	-$ 16,087	$ 4,922
47	1970	Load Management Controls Customer Premises	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,383,765	$ 49,793	$ -	$ 1,433,558	-$ 1,116,040	-$ 49,725	$ -	-$ 1,165,765	$ 267,794
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 24,894	-$ 1,630	$ -	-$ 26,523	$ 26,537
47	1995	Contributions & Grants	-$ 9,298,809	-$ 1,415,412	$ -	-$ 10,714,221	$ 1,957,562	$ 224,601	$ -	$ 2,182,163	-$ 8,532,058
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 102,314,173**	**$ 7,667,560**	**-$ 2,638,445**	**$ 107,343,288**	**-$ 55,271,308**	**-$ 3,301,494**	**$ 2,345,157**	**-$ 56,227,645**	**$ 51,115,643**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 102,314,173**	**$ 7,667,560**	**-$ 2,638,445**	**$ 107,343,288**	**-$ 55,271,308**	**-$ 3,301,494**	**$ 2,345,157**	**-$ 56,227,645**	**$ 51,115,643**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 3,301,494**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 127,313
Stores Equipment	$ -
Net Depreciation	-$ 3,174,181

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-VECC-11

Reference: Exhibit 2, Page15 & 38

Interrogatory:

a) Table 2-5 shows the Total Gross asset as between 2010 Board approved and 2010 actuals as $2,565,535 (i.e. $89,171,054-$86,605,519). At page 38 it states distribution assets were different by $2,115,159. Please explain this apparent discrepancy.

b) Please explain why the gross fixed asset opening value for 2010 Board approved was different from the actual 2010 opening balance.

c) Please calculate both the 2010 and 2015 revenue requirement amount for either the $2.5 or $2.1 million underspending (whichever figure North Bay believes best represents the 2010 North Bay's gross asset underspending).

Response:

a) Table 2-5 shows the Total Gross Asset variance between 2010 Board approved and 2010 actuals as $2,565,535. The page 38 reference of $2,115,159 is related to distribution assets only; lines 15 through 23 speak to the variance of general assets in the amount of $450,376. The total of these two categories reconciles to the Table 2-5 reference of $2,565,535.

b) The 2010 Board approved gross fixed asset opening value was different from the actual 2010 opening balance as the 2009 ending balance was based upon October 31, 2009 YTD actuals plus 2 months forecast. The actual gross fixed asset opening value was different from the 2010 Board approved by a net amount of $8,388.

c) As explained in response to a), the gross asset variance between Board approved and 2010 actual was ($2,565,535) and the 2015 revenue requirement already incorporates this reduced spending. The 2015 NBV of NBHDL's PP&E incorporates the 2010 actual NBV as the starting point for calculating the 2015 NBV component of NBHDL's rate base. NBHDL updated the 2010 revenue requirement model in order to reflect the 2010 actual NBV and the base revenue requirement decreased by $95,044 from $11,294,345 to $11,199,301.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-VECC-12

Reference: Exhibit 2, Appendix 2-A/DSP

Interrogatory:

a) Please explain what metrics are being implemented to measure the of the distribution system plan.

b) Please explain how these metrics relate to compensation at North Bay Hydro.

Response:

a) The metrics that are being implemented to measure the effectiveness of the distribution system plan are detailed on page 37 and page 38 in Appendix 2-A: Distribution System Plan of Exhibit 2.

b) These metrics do not relate to compensation at NBHDL.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-VECC-13

Reference: Exhibit 2, Page 74, Table 2-33

Interrogatory:

a) Please explain the difference in costs as between the Distribution stations construction of MS # 19 ($88k), MS # 20 ($2.167m), MS #21 ($1.418m) and MS #22 ($2.46m).

b) Please explain what work has been completed to on the MS #22 station.

c) Please provide the construction schedule for MS #22 station.

Response:

a) The difference in costs between the distribution stations construction of MS #19, MS #20, MS #21 and MS#22 can be explained using MS#21 as the benchmark for comparison as it represents a typical NBHDL substation which was built on an existing substation property that required minimal civil work.

The MS #19 station was built in 2009 and therefore the $88k of costs shown in Table 2-33 do not represent the majority of the construction costs but instead $68.6k of costs to complete construction of the station in 2010 and $20.2k of costs required to replace a failed recloser due to animal contact in 2012.

The MS#20 station is electrically identical to the MS#21 station, however, the MS#20 station was constructed on a site that from a civil prospective required an significant amount of work.

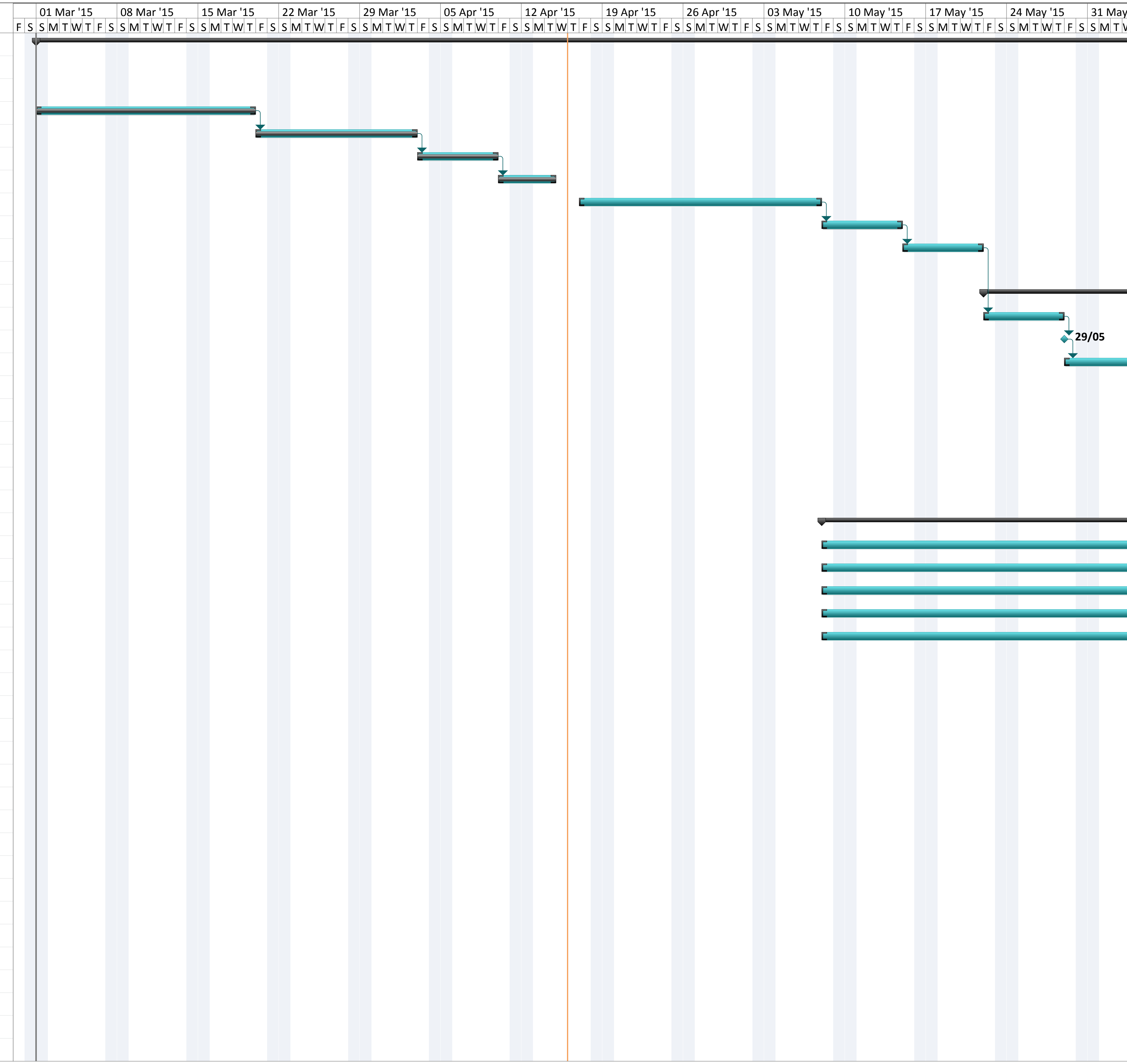
The MS#20 station was built on an undeveloped, treed, vacant piece of land that included a 6m drop from east to west. The civil portion of the project involved tree removal across the entire site, substantial fill to bring to grade, and piles to support a 6m retaining wall that spans the entire west side of the station. The entire difference from MS#20 to MS#21 can be attributed to the difference in civil work required at each station. A more ideal piece of property was available, but in order to construct on that piece of property over $1.0M of costs would have been required to rebuild and extend the distribution system. The additional $600k of civil costs versus the $1.0M or more of line costs resulted in the station being built at the non-ideal property for a lesser overall cost.

The MS#22 station electrically is basically two MS#21 stations located on the same piece of property. Therefore it has twice the electrical equipment and twice the capacity as MS#21. The cost for twice the equipment makes up the majority of the cost difference between the two stations. Another factor is the civil work required, although not as substantial as the work required at MS#20, the MS#22 property is treed, and will require a moderate amount of fill to bring to grade. There is also double the amount of equipment foundations to construct. These factors make up the $1M worth of difference between the two stations.

b) The work that has been completed on the MS #22 station includes the procurement of the two power transformers in 2014, and to date in 2015 includes conceptual design work, the completion of a topographic survey, a geotechnical investigation and the request for pricing for major equipment from selected vendors. The Engineering Services RFP for design of the station was sent out to bidders the week of April 13, 2015.

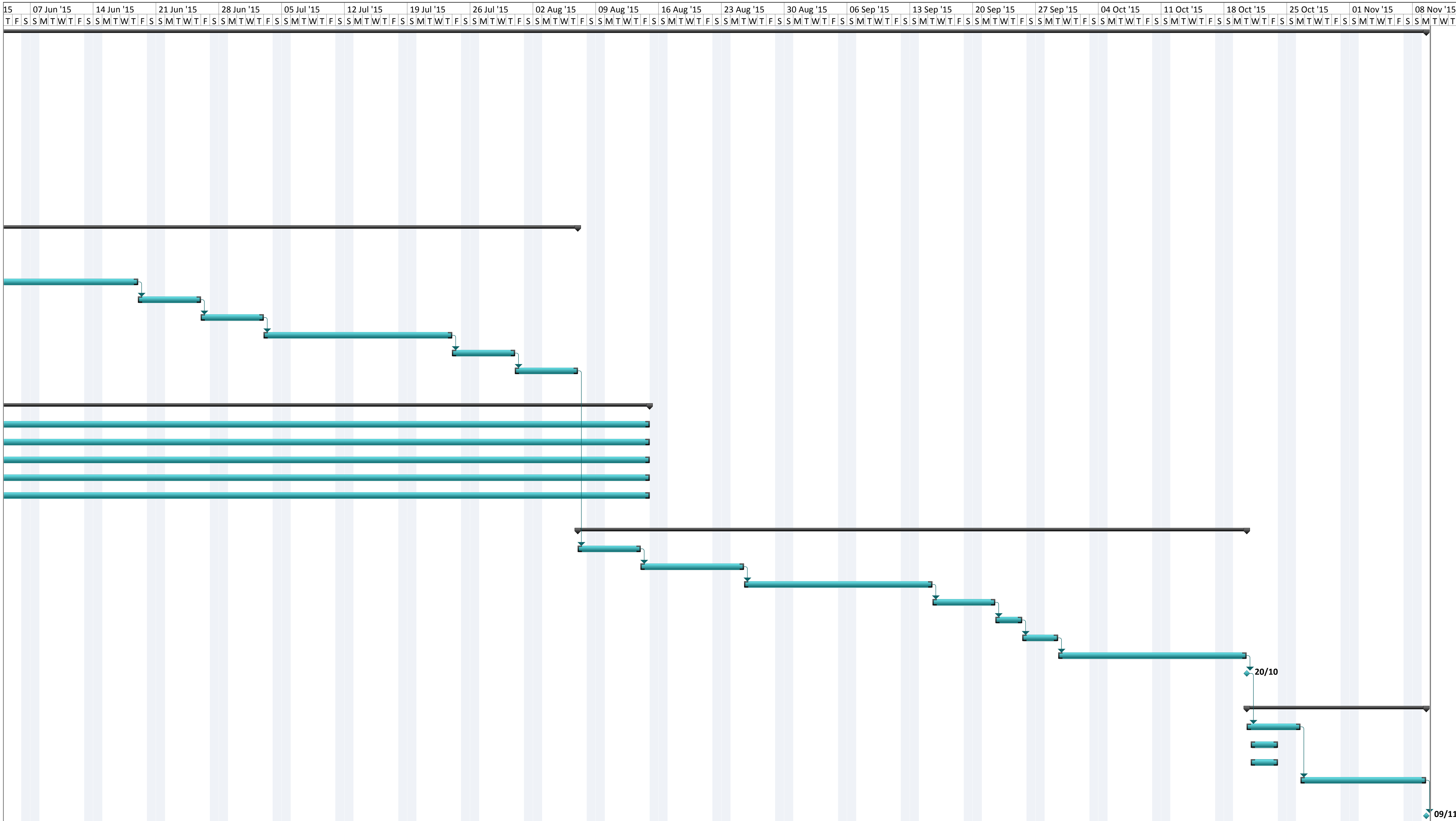
c) Please see the proposed construction schedule for the MS #22 station in Attachment-2-VECC-13c. This is a preliminary schedule and will be required to be revised when the design work and construction work are awarded, based on schedules put forward by the successful bidders.

ID	Task Name	Duration	Start	Finish	Predecessors
1	**North Bay Hydro - MS-22 Substation Project**	**180.5 days**	**Sun 01/03/15**	**Mon 09/11/15**	
2					
3					
4	Preliminary Design	3 wks	Sun 01/03/15	Thu 19/03/15	
5	Customer Review	2 wks	Fri 20/03/15	Thu 02/04/15	4
6	Finalize Design	1 wk	Fri 03/04/15	Thu 09/04/15	5
7	Develop Engineering Services Specs and Drawings	3 days	Fri 10/04/15	Tue 14/04/15	6
8	Issue Engineering Services RFP	3 wks	Fri 17/04/15	Thu 07/05/15	
9	Evaluate Proposals	1 wk	Fri 08/05/15	Thu 14/05/15	8
10	Award Order for Engineering	1 wk	Fri 15/05/15	Thu 21/05/15	9
11					
12	**Engineering**	**55 days**	**Fri 22/05/15**	**Thu 06/08/15**	
13	Startup	1 wk	Fri 22/05/15	Thu 28/05/15	10
14	Client Meeting	0 days	Fri 29/05/15	Fri 29/05/15	13
15	60% Design	3 wks	Fri 29/05/15	Thu 18/06/15	14
16	Client Review	1 wk	Fri 19/06/15	Thu 25/06/15	15
17	90% Design	1 wk	Fri 26/06/15	Thu 02/07/15	16
18	Construction Tender Issue	3 wks	Fri 03/07/15	Thu 23/07/15	17
19	Review Construction Tenders	1 wk	Fri 24/07/15	Thu 30/07/15	18
20	Award Construction Project	1 wk	Fri 31/07/15	Thu 06/08/15	19
21					
22	**Equipment Delivery**	**71 days**	**Fri 08/05/15**	**Fri 14/08/15**	
23	Reclosers	71 days	Fri 08/05/15	Fri 14/08/15	
24	46 kV Switchgear	71 days	Fri 08/05/15	Fri 14/08/15	
25	15 kV Switchgear	71 days	Fri 08/05/15	Fri 14/08/15	
26	Scada RTU	71 days	Fri 08/05/15	Fri 14/08/15	
27	Metering	71 days	Fri 08/05/15	Fri 14/08/15	
28					
29	**Construction**	**52.5 days**	**Fri 07/08/15**	**Tue 20/10/15**	
30	Mobilization	1 wk	Fri 07/08/15	Thu 13/08/15	20
31	Clearing, grubbing, grading	1.5 wks	Fri 14/08/15	Tue 25/08/15	30
32	Foundations	3 wks	Tue 25/08/15	Tue 15/09/15	31
33	Duct banks	1 wk	Tue 15/09/15	Tue 22/09/15	32
34	Ground Grid	3 days	Tue 22/09/15	Fri 25/09/15	33
35	Final grading	2 days	Fri 25/09/15	Tue 29/09/15	34
36	Electrical Installation	3 wks	Tue 29/09/15	Tue 20/10/15	35
37	Completion	0 days	Tue 20/10/15	Tue 20/10/15	36
38					
39	**Commissioning**	**14 days**	**Tue 20/10/15**	**Mon 09/11/15**	
40	Scada RTU Installation and testing	4 days	Tue 20/10/15	Mon 26/10/15	37
41	Scada Master Station programming	3 days	Wed 21/10/15	Fri 23/10/15	
42	Communications (WiMAX)	3 days	Wed 21/10/15	Fri 23/10/15	
43	Electrical Commissioning	2 wks	Mon 26/10/15	Mon 09/11/15	40
44					
45	Energization	0 days	Mon 09/11/15	Mon 09/11/15	43



Project: NBH MS-22 Project Sched
Date: Thu 16/04/15

Task, Split, Milestone, Summary, Project Summary, External Tasks, External Milestone, Inactive Task, Inactive Milestone, Inactive Summary, Manual Task, Duration-only, Manual Summary Rollup, Manual Summary, Start-only, Finish-only, Deadline, Progress



Project: NBH MS-22 Project Sched
Date: Thu 16/04/15

Task	Summary	External Milestone	Inactive Summary	Manual Summary Rollup	Finish-only
Split	Project Summary	Inactive Task	Manual Task	Manual Summary	Deadline
Milestone	External Tasks	Inactive Milestone	Duration-only	Start-only	Progress

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-VECC-14

Reference: Exhibit 2, Appendix 2-A; Page 42 & Exhibit 2, Page 103 Appendix 2-G

Interrogatory:

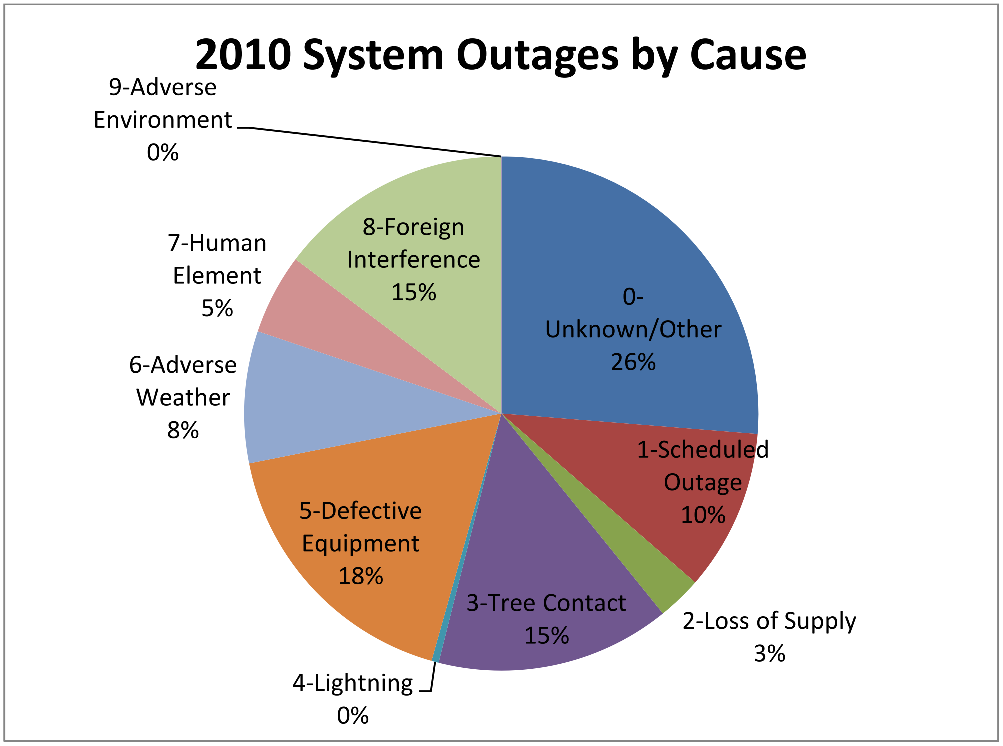
a) Please update figure 2-5 (outages by cause) for each year 2010 through 2014.

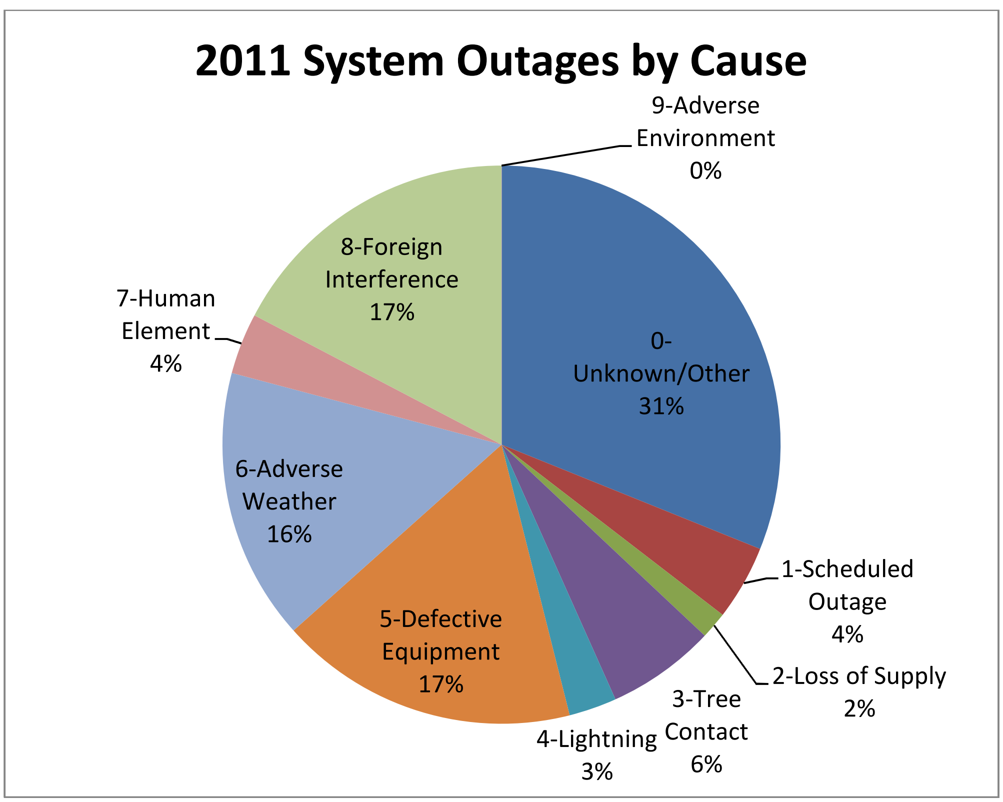
b) Please update Appendix 2-G to include 2014 data.

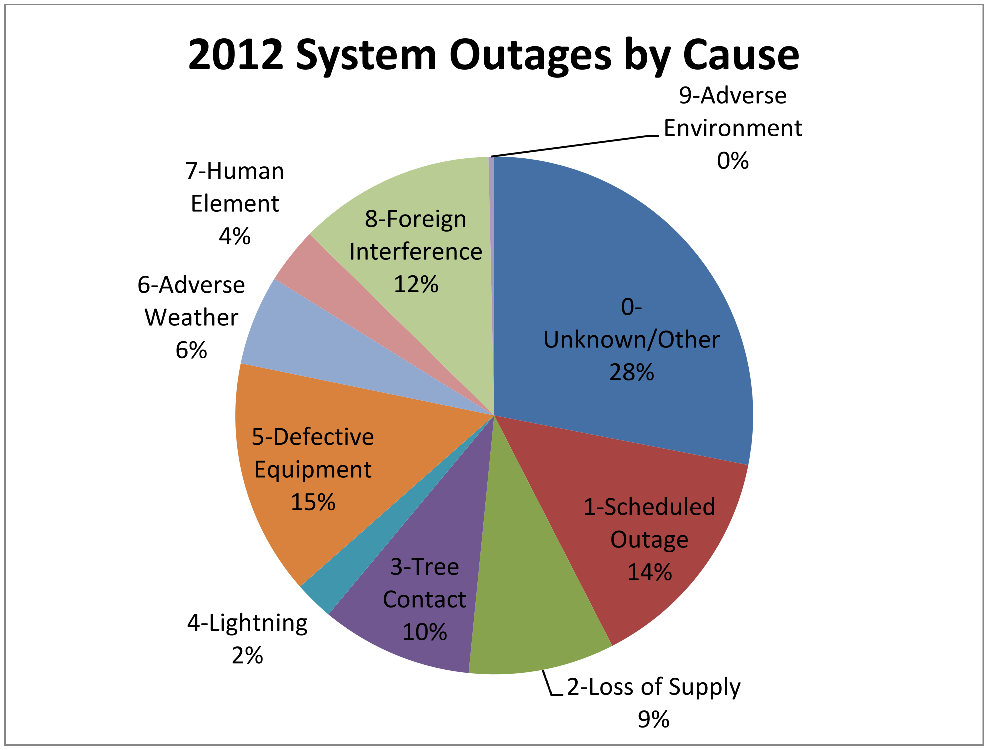
[NOTE: VECC IR doc shows points as c and d rather than a and b]

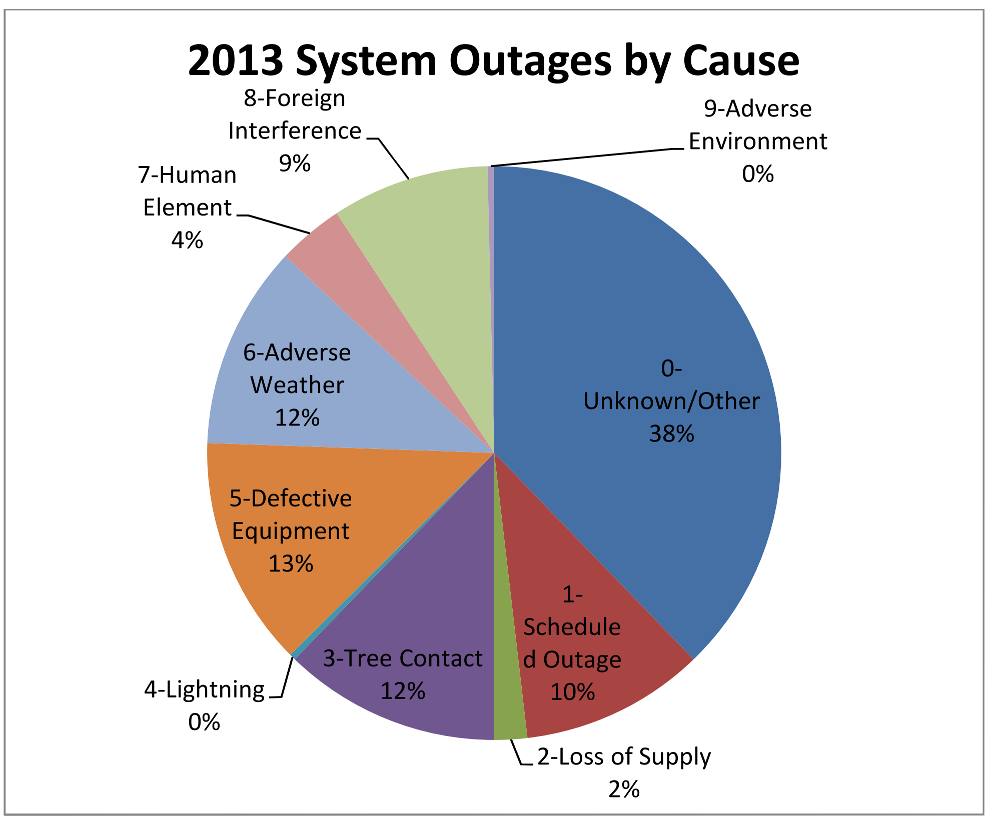
Response:

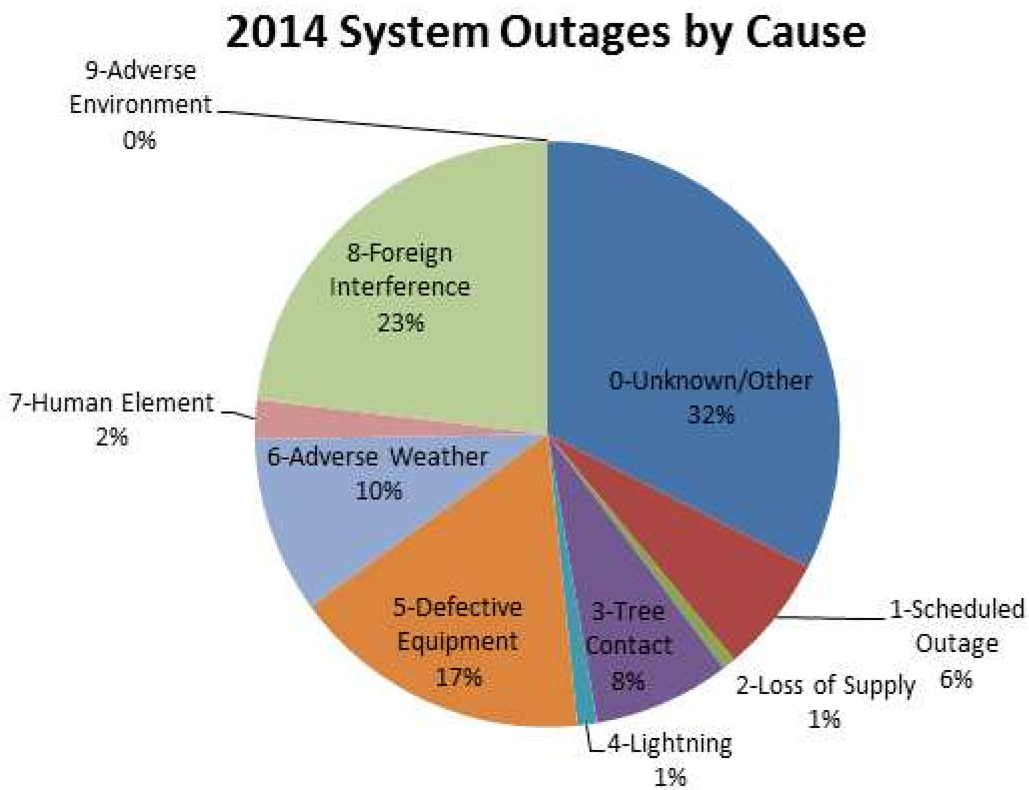
a) Figure 2-5 (outages by cause) has been updated and is included below for each year 2010 through 2014:


2010 System Outages by Cause
9-Adverse Environment 0%
8-Foreign Interference 15%
7-Human Element 5%
6-Adverse Weather 8%
0-Unknown/Other 26%
1-Scheduled Outage 10%
5-Defective Equipment 18%
3-Tree Contact 15%
2-Loss of Supply 3%
4-Lightning 0%


2011 System Outages by Cause
9-Adverse Environment 0%
8-Foreign Interference 17%
7-Human Element 4%
0-Unknown/Other 31%
6-Adverse Weather 16%
1-Scheduled Outage 4%
5-Defective Equipment 17%
2-Loss of Supply 2%
3-Tree Contact 6%
4-Lightning 3%


2012 System Outages by Cause
9-Adverse Environment 0%
7-Human Element 4%
8-Foreign Interference 12%
6-Adverse Weather 6%
0-Unknown/Other 28%
5-Defective Equipment 15%
1-Scheduled Outage 14%
3-Tree Contact 10%
4-Lightning 2%
2-Loss of Supply 9%


2013 System Outages by Cause
8-Foreign Interference 9%
9-Adverse Environment 0%
7-Human Element 4%
6-Adverse Weather 12%
0-Unknown/Other 38%
5-Defective Equipment 13%
1-Schedule d Outage 10%
3-Tree Contact 12%
4-Lightning 0%
2-Loss of Supply 2%



b) Appendix 2-G has been updated to include 2014 data and can be found in Attachment 2-VECC-14.

File Number:	EB-2014-0099
Exhibit:	2
Date:	24-Apr-15

Appendix 2-G
Service Reliability Indicators
2009 - 2013

Index	Includes outages caused by loss of supply						Excludes outages caused by loss of supply					
	2009	2010	2011	2012	2013	2014	2009	2010	2011	2012	2013	2014
SAIDI	1.930	2.760	2.910	2.040	2.810	1.554	1.560	2.720	2.870	1.600	2.320	1.551
SAIFI	1.630	2.860	2.370	2.680	3.070	1.165	1.480	2.750	2.160	2.290	1.890	1.138

6 Year Historical Average

	Includes outages caused by loss of supply	Excludes outages caused by loss of supply
SAIDI	2.334	2.103
SAIFI	2.296	1.951

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2009	2010	2011	2012	2013	2014
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	53.2%	76.5%	71.6%	77.2%	78.2%	78.4%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Call Abandon Rate	10.0%	9.0%	2.4%	2.8%	2.4%	6.1%	8.0%
Appointment Scheduling	90.0%	100.0%	100.0%	99.0%	100.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	N/A	N/A	100.0%	N/A	N/A	N/A
Reconnection Performance Standard	85.0%	N/A	N/A	100.0%	100.0%	100.0%	100.0%

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-VECC-15

Reference: Exhibit 2, Appendix 2-4; Page 43, Appendix L; Exhibit 4, Page 12

Interrogatory:

a) Please explain what, if any, analysis has been undertaken to study the relationship between tree trimming programs and outages due to tree contacts?

b) If no such analysis has been undertaken please explain what measures or metrics are being used to understand the value of increased spending on tree trimming.

c) The increase in the tree trimming budget appears to be in response to a singular incident involving a station. In addition to this event what other factors caused North Bay to reconsider its current vegetation program.

Response:

a) As described in Appendix 2-A, tree contact outages are a significant outage cause. The combination of unknown/other outages with tree contact outages makes up an average of 41.2% of all outages on an annual basis using information from 2010 to 2014. NBHDL believes the majority of unknown/other outage causes to be one of three things: trees, weather or rodents. If an assumption that 1/3 of all unknown/other outages are related just to trees, then tree contact outages would represent and average of 20.5% of all outages annually.

Additional analysis has not been undertaken to study the relationship between tree trimming programs and outages due to tree contracts because the lack of feeder based outage statistics does not allow for the cycles to be looked at independently. As mentioned on page 44 in Appendix 2-A: Distribution System Plan of Exhibit 2, NBHDL will be transitioning to an automated system for tracking of reliability metrics in 2015 which will, among other matters, allow for tracking of tree contact outages in each cycle.

b) There are three main goals associated with the increased spending on tree trimming, the first is to ensure public safety, the second is to minimize outages related to tree contact, and the third is to reduce future tree trimming costs. Until NBHDL has all of the cycles brought to a uniform standard where an actual 4.5m of space on either side of all polelines is established and maintained, the overall statistics will be difficult to track or reduce with any consistency. This is evident by the tables provided in the updated figures in the answer to 2.0-VECC-14 which do not show any trending with respect to tree contact outages. The main issue is that although reliability is improved in a given cycle the year the work is done, other cycles that have not been addressed, or are behind in the 4 year schedule start having increased tree contact outages making it hard to measure the overall effect of the program. The lack of feeder based outage statistics does not allow for the cycles to be looked at independently. As mentioned on page 44 in Appendix 2-A: Distribution System Plan of Exhibit 2, NBHDL will be transitioning to an automated system for tracking of reliability metrics in 2015 which will allow for tracking of tree contact outages in each cycle.

The most important aspect of the program that can be measured is eliminating all tree contact with high voltage lines in nominal situations (no adverse weather) and ensuring that as long as the cycle schedule is maintained that contact with high voltage lines is not possible in nominal conditions over the 4 years following tree trimming activities. As more granular outage data comes available, outages per cycle will be tracked and a downward trend relating to tree contact outages will be expected. And lastly, once the clearances are established in all cycles and the program is actually operating on a 4 year cycle, a significant reduction in the relative costs per cycle are expected, as tree removals will be reduced to almost zero (a significant portion of the cost relating to the increased spending) and the majority of the work will be standard trimming.

c) In addition to the event involving a station the other factors that caused NBHDL to reconsider its current vegetation program included:

- A number of complaints from customers located in a specific highly treed rural area about the high number of outages being experienced over the years of 2010 and 2011;

- The realization that the budgeted amounts for vegetation management activities was not allowing NBHDL to actual complete all areas in the cycle in the given year and in turn was pushing the 4 year cycle into a 6 or 7 year cycle, resulting in a large number of trees growing into high voltage lines. This not always causes an outage, but it does create a major safety issue;

- The large presence of trees throughout the service territory that were touching or within 3’ of high voltage lines, leading to outages and creating potential for an extremely unsafe and possibly fatal situation to both workers and the public;

- The realization that topping of trees was occurring despite the knowledge that it was not a proper practice, and was leading to tree damage and increased trimming costs in the future; and

- Tree contact outages are a significant outage cause. The combination of unknown/other outages with tree contact outages makes up an average of 41.2% of all outages on an annual basis using information from 2010 to 2014. NBHDL believes the majority of unknown/other outage causes to be one of three things: trees, weather or rodents. If an assumption that 1/3 of all unknown/other outages are related just to trees, then tree contact outages would represent and average of 20.5% of all outages annually.

North Bay Hydro Interrogatory Responses

EXHIBIT 2 – RATE BASE

2-VECC-16

Reference: Exhibit 2, Appendix E

Interrogatory:

a) Who is the author of the IT Assessment Report?

b) The report does not appear to include any project cost projections. Please explain if a five year IT cost plan was developed. If so please provide the spending forecast.

Response:

a) The Exhibit 2, Appendix - E title sheet should have been labelled “North Bay Hydro Information Technology Strategy”, not “IT Assessment Report”. The author of this report is NBHDL’s IT and Billing Manager. The IT Assessment and Risk Analysis Report was prepared by BDO and can be found in Appendix – 4B, of Exhibit 4.

b) The BDO IT Assessment and Risk Analysis Report did not provide project cost projections, only current state assessments, risks, and priority recommendations for remediation and mitigation. With the results from the BDO report, NBHDL prepared an IT Strategy plan forward to 2020 to address needs, risks, and recommendations. Capital budget projections were prepared through to 2019. Please see Appendix 2-A: Distribution Plan, pages 121 through 124 for details on NBHDL’s general plant spending forecasts for 2015 through 2019.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 – OPERATING REVENUE

3-Staff-9

Reference: Exhibit 3, Page 4

Interrogatory:

North Bay Hydro states that it "reviewed the data required to conduct the regression analysis on an individual rate class basis and determined that it currently does not have a method to properly convert historical billing data to monthly consumed values by rate class." Please elaborate why North Bay Hydro is unable to convert historical billing data to monthly consumed values.

Response:

NBHDL understands that in order to have data that is of the same quality as power purchased data, historical billing data by class dating back to 1999 and by calendar month would need to be utilized within the regression analysis; NBHDL does not have high quality historical billing data by class dating back to 1999 by calendar month.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 – OPERATING REVENUE

3-Energy Probe-32

Reference: Exhibit 3, Table 3-1

Interrogatory:

a) Please update Table 3-1 to reflect actual data for 2014. If actual data for all of 2014 is not yet available, please update to reflect the most recent year to date actual data available, along with the most recent estimate for any remaining months in 2014.

b) Please explain the significant reduction in distribution revenues between the 2014 bridge year and the 2015 test year at existing rates. For example, please explain the reduction in residential revenue at existing rates despite more residential customers and a higher residential kWh forecast in 2015 than in 2014, as shown in Table 3-35.

Response:

a) Table 3-1 has been updated to reflect actual data for all of 2014 below.

Description	2010 Board Approved	2010 Acutal	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Test - Existing Rates	2015 Test - Proposed Rates
Distribution Revenues								
Residential	6,302,766	5,987,720	6,235,135	6,198,440	6,396,433	8,173,859	6,507,041	7,482,238
General Service < 50 kW	2,114,489	2,046,607	2,121,536	2,098,393	2,163,428	2,533,932	2,132,984	2,452,650
General Service 50 to 2999 kW	2,430,269	2,268,244	2,154,808	1,937,243	1,946,014	1,902,710	1,799,848	2,069,588
General Service 3000 to 4999 kW	114,986	78,770	102,855	158,971	168,826	161,549	86,464	99,422
Street Lighting	35,621	32,902	383,351	476,760	580,924	504,434	464,713	534,358
Sentinel Lighting	11,495	5,090	36,752	55,522	40,859	36,140	39,410	45,316
Unmetered Scattered Load	284,721	222,314	2,746	3,011	2,668	1,598	1,447	1,664
Distribution Revenue	11,294,345	10,641,646	11,037,183	10,928,339	11,299,150	13,314,222	11,031,906	12,685,235
Other Revenue								
Late Payment Charges	137,700	160,010	143,942	130,386	125,518	142,104	136,983	136,983
Specific Service Charges	320,753	475,396	541,103	614,482	582,708	598,993	578,856	578,856
Other Distribution Revenue	259,940	245,884	289,958	280,590	282,391	283,529	282,042	282,042
Other Income and Expenses	112,223	82,487	200,993	558,239	387,748	340,789	156,053	156,053
Other Revenue	830,616	963,777	1,175,997	1,583,696	1,378,365	1,365,415	1,153,934	1,153,934
Total Operating Revenue	12,124,961	11,605,423	12,213,179	12,512,035	12,677,515	14,679,637	12,185,840	13,839,170

b) There are several components to the 2014 Bridge Year distribution revenue that are not included in the 2015 Test Year amounts. The 2014 Bridge Year revenues include the impact of the disposition of the Smart Meter costs in 2014, which includes $1,526,857 in Smart Meter Funding Adder revenues collected from 2006 through 2012. In addition, the Bridge Year includes $686,641 in revenue from the SMDR and SMIRR rate riders that are in place until April 30, 2015. 2014 totals also include $130,019 in LRAMVA revenue. The 2015 Test Year revenues are based on the proposed base revenue requirement only and these increases are offset significantly by the items listed above that do not continue into 2015.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-33

Reference: Exhibit 3, Table 3-3

Interrogatory:

Please update Table 3-3 to reflect actual data for 2014. If actual data for all of 2014 is not yet available, please update to reflect the most recent year to date actual data available, along with the most recent estimate for any remaining months in 2014.

Response:

The requested updated Table 3-3 is provided as follows:

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
Billed Energy (GWh)								
2010 Board Approved	214.9	85.0	221.4	38.8	2.7	0.5	0.3	563.7
1999 Actual	202.7	93.0	180.5	70.8	3.8	1.0	0.4	552.2
2000 Actual	200.1	93.5	189.7	73.0	3.2	0.8	0.4	560.8
2001 Actual	198.5	92.2	193.6	70.0	3.2	0.8	0.4	558.6
2002 Actual	207.7	89.8	201.0	58.9	3.2	0.7	0.4	561.7
2003 Actual	210.9	89.2	201.6	56.6	3.3	0.6	0.4	562.5
2004 Actual	210.8	90.0	203.3	58.4	3.5	0.6	0.4	566.9
2005 Actual	213.8	91.3	210.6	57.1	3.3	0.6	0.4	577.1
2006 Actual	207.2	90.2	207.1	51.6	3.3	0.6	0.4	560.3
2007 Actual	213.1	89.7	213.5	49.9	3.3	0.6	0.4	570.4
2008 Actual	213.8	88.7	215.7	44.5	3.3	0.6	0.4	567.0
2009 Actual	213.4	87.4	210.1	37.8	3.3	0.6	0.3	552.9
2010 Actual	206.5	85.0	230.0	41.0	3.3	0.6	0.2	566.7
2011 Actual	207.4	85.0	231.7	37.1	3.2	0.5	0.1	564.9
2012 Actual	200.6	84.9	223.7	35.7	2.8	0.5	0.1	548.3
2013 Actual	207.8	85.1	216.6	35.8	2.3	0.4	0.1	548.2
2014 Actual	206.0	85.4	217.2	26.9	2.0	0.4	0.1	538.0
2015 Test - Normalized	204.2	84.7	205.9	17.3	2.0	0.4	0.0	514.5

Number of Customers/Connections								
2010 Board Approved	21,075	2,645	287	2	5,680	509	21	30,218
1999 Actual	19,386	2,489	219	3	5,000	579	21	27,697
2000 Actual	19,468	2,499	229	3	5,139	579	21	27,938
2001 Actual	19,645	2,555	244	3	5,139	579	21	28,186
2002 Actual	19,973	2,562	255	3	5,287	579	21	28,680
2003 Actual	19,862	2,568	253	2	5,277	641	21	28,624
2004 Actual	19,966	2,598	253	2	5,508	574	21	28,922
2005 Actual	20,125	2,595	255	2	5,534	555	21	29,087
2006 Actual	20,555	2,678	258	2	5,510	606	21	29,630
2007 Actual	20,726	2,626	267	2	5,534	577	21	29,753
2008 Actual	20,757	2,616	273	2	5,550	521	21	29,740
2009 Actual	20,850	2,629	274	2	5,571	518	21	29,865
2010 Actual	20,952	2,633	269	2	5,572	509	19	29,956
2011 Actual	21,096	2,623	268	2	5,574	474	18	30,055
2012 Actual	21,074	2,645	254	2	5,574	447	17	30,013
2013 Actual	21,108	2,649	255	2	5,574	427	15	30,030
2014 Actual	21,117	2,657	252	2	5,419	427	11	29,885
2015 Test - Normalized	21,124	2,668	247	1	5,419	412	7	29,878

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-34

Reference: Exhibit 3, Tables 3-7 through 3-13

Interrogatory:

a) Please update Tables 3-7 and 3-10 to reflect actual data for 2014.

b) Please update Table 3-8 and 3-11 to reflect a geometric mean for 2012, 2013 and 2014.

c) Please update Table 3-9 and 3-12 for 2015 to reflect actual figures for 2014 and the forecast from 2015 that reflects the geometric means from part (b) above applied to the actual 2014 starting points.

d) Please update Tables 3-13, 3-18 and 3-23 to reflect the forecast for 2015 based on the responses to parts (a), (b) and (c) above, using the methodology employed by NBHDL.

f) What is the impact on distribution rates at current rates for 2015 of the revised forecast noted in part (d) above? Please show all calculations used to arrive at this impact.

g) Please provide a live Excel spreadsheet that utilizes 2014 figures for customer growth and average use per customer growth, in addition to 2012 and 2013, as requested above.

Response:

a) NBHDL has revised the proposed 2015 load forecast for the purposes of determining 2015 proposed rates to reflect 2014 actual power purchases and billing determinants along with revised CDM adjustments outlined in response to 3-Energy Probe-36. The information in this response as well as responses to 3-Energy Probe-33 and 3.0-VECC-20 provide the details of the revised 2015 load forecast.

The requested information is provided below:

Table 3-7 Historical Customer/Connection Data – Revised Load Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
Number of Customers/Connections								
1999	19,386	2,489	219	3	5,000	579	21	27,697
2000	19,468	2,499	229	3	5,139	579	21	27,938
2001	19,645	2,555	244	3	5,139	579	21	28,186
2002	19,973	2,562	255	3	5,287	579	21	28,680
2003	19,862	2,568	253	2	5,277	641	21	28,624
2004	19,966	2,598	253	2	5,508	574	21	28,922
2005	20,125	2,595	255	2	5,534	555	21	29,087
2006	20,555	2,678	258	2	5,510	606	21	29,630
2007	20,726	2,626	267	2	5,534	577	21	29,753
2008	20,757	2,616	273	2	5,550	521	21	29,740
2009	20,850	2,629	274	2	5,571	518	21	29,865
2010	20,952	2,633	269	2	5,572	509	19	29,956
2011	21,096	2,623	268	2	5,574	474	18	30,055
2012	21,074	2,645	254	2	5,574	447	17	30,013
2013	21,108	2,649	255	2	5,574	427	15	30,030
2014	21,117	2,657	252	2	5,419	427	11	29,885

Table 3-10 Historical Annual Usage per Customer – 2014 Actual Included

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Annual kWh Usage Per Customer/Connection							
1999	10,454	37,367	824,067	23,610,566	770	1,647	20,080
2000	10,278	37,424	828,565	24,339,658	624	1,455	18,535
2001	10,102	36,090	793,622	23,335,059	614	1,325	18,635
2002	10,398	35,050	788,257	19,646,519	597	1,194	18,585
2003	10,618	34,739	796,830	28,283,549	624	927	17,539
2004	10,558	34,638	803,426	29,191,410	626	1,099	18,469
2005	10,624	35,177	825,993	28,528,368	594	1,111	17,690
2006	10,080	33,673	802,781	25,801,506	595	954	17,606
2007	10,283	34,151	799,463	24,963,354	597	985	17,601
2008	10,301	33,916	790,147	22,264,052	600	1,090	16,727
2009	10,236	33,246	766,620	18,908,696	596	1,077	14,851
2010	9,858	32,299	855,159	20,514,052	597	1,119	8,691
2011	9,829	32,414	864,430	18,543,426	575	1,016	4,671
2012	9,520	32,117	880,663	17,861,386	501	1,091	5,222
2013	9,845	32,133	849,468	17,887,518	421	1,040	5,939
2014	9,753	32,130	862,048	13,463,278	374	993	4,601

b) The requested information is provided below:

Table 3-8 Growth Rate in Customer/Connections – Revised Load Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Growth Rate in Customers/Connections							
1999							
2000	0.4%	0.4%	4.6%	0.0%	2.8%	0.0%	0.0%
2001	0.9%	2.2%	6.6%	0.0%	0.0%	0.0%	0.0%
2002	1.7%	0.3%	4.5%	0.0%	2.9%	0.0%	0.0%
2003	(0.6%)	0.2%	(0.8%)	(33.3%)	(0.2%)	10.7%	0.0%
2004	0.5%	1.2%	0.0%	0.0%	4.4%	(10.5%)	0.0%
2005	0.8%	(0.1%)	0.8%	0.0%	0.5%	(3.3%)	0.0%
2006	2.1%	3.2%	1.2%	0.0%	(0.4%)	9.2%	0.0%
2007	0.8%	(1.9%)	3.5%	0.0%	0.4%	(4.8%)	0.0%
2008	0.1%	(0.4%)	2.2%	0.0%	0.3%	(9.7%)	0.0%
2009	0.4%	0.5%	0.4%	0.0%	0.4%	(0.6%)	0.0%
2010	0.5%	0.2%	(1.8%)	0.0%	0.0%	(1.7%)	(9.5%)
2011	0.7%	(0.4%)	(0.4%)	0.0%	0.0%	(6.9%)	(5.3%)
2012	(0.1%)	0.8%	(5.2%)	0.0%	0.0%	(5.7%)	(5.6%)
2013	0.2%	0.2%	0.4%	0.0%	0.0%	(4.5%)	(11.8%)
2014	0.0%	0.3%	(1.2%)	0.0%	(2.8%)	0.0%	(26.7%)
Geo Mean - 2012 to 2014	0.03%	0.4%	(2.0%)	0.0%	0.0%	(3.4%)	(15.1%)

Table 3-11 Growth Rate in Usage per Customer/Connection – Revised Load Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Growth Rate in Customer/Connection							
1999							
2000	(1.7%)	0.2%	0.5%	3.1%	(18.9%)	(11.7%)	(7.7%)
2001	(1.7%)	(3.6%)	(4.2%)	(4.1%)	(1.5%)	(9.0%)	0.5%
2002	2.9%	(2.9%)	(0.7%)	(15.8%)	(2.8%)	(9.9%)	(0.3%)
2003	2.1%	(0.9%)	1.1%	44.0%	4.4%	(22.4%)	(5.6%)
2004	(0.6%)	(0.3%)	0.8%	3.2%	0.4%	18.7%	5.3%
2005	0.6%	1.6%	2.8%	(2.3%)	(5.1%)	1.1%	(4.2%)
2006	(5.1%)	(4.3%)	(2.8%)	(9.6%)	0.1%	(14.2%)	(0.5%)
2007	2.0%	1.4%	(0.4%)	(3.2%)	0.4%	3.3%	(0.0%)
2008	0.2%	(0.7%)	(1.2%)	(10.8%)	0.4%	10.6%	(5.0%)
2009	(0.6%)	(2.0%)	(3.0%)	(15.1%)	(0.5%)	(1.1%)	(11.2%)
2010	(3.7%)	(2.9%)	11.5%	8.5%	0.0%	3.9%	(41.5%)
2011	(0.3%)	0.4%	1.1%	(9.6%)	(3.6%)	(9.2%)	(46.3%)
2012	(3.2%)	(0.9%)	1.9%	(3.7%)	(12.9%)	7.4%	11.8%
2013	3.4%	0.0%	(3.5%)	0.1%	(15.8%)	(4.7%)	13.7%
2014	(0.9%)	(0.0%)	1.5%	(24.7%)	(11.2%)	(4.5%)	(22.5%)
Geo Mean - 2012 to 2014	(0.3%)	(0.3%)	(0.1%)	(10.1%)	(13.4%)	(0.8%)	(0.5%)

c) The requested information is provided below:

Table 3-9 Customer/Connection Forecast – Revised Load Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	Total
Forecast number of Customers/Connections								
2015	21,124	2,668	247	1	5,419	412	7	29,878

The updated customer/connection forecast reflects the growth rate in the updated Table 3-8, but adjustments have been made consistent with the explanation in the application in Exhibit 3, page 15.

Table 3-12 Forecast Annual kWh Usage per Customer/Connection – Revised Load Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Forecast Annual kWh Usage per Customers/Connection							
2015	9,727	32,036	861,256	17,254,810	373	985	4,578

The updated usage per customer/connection forecast reflects the growth rate in the updated Table 3-11, but adjustments have been made consistent with the explanation in the application in Exhibit 3, page 17. In addition, the 2014 usage per customer in Table 3-10 for the General Service 3000 to 4999 kW class reflects the loss of a customer during the year. The load forecast process assumes the usage per customer for the General Service 3000 to 4999 kW in Table 3-12 reflects the average usage in this class before the impact of the loss of customer in this class. As a result, the usage per customer for the General Service 3000 to 4999 kW class has been held at the same level as the application.

d) The requested information is provided below:

Table 3-13 Non-normalized Weather Billed Energy Forecast – Revised Load Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	TOTAL
NON-normalized Weather Billed Energy Forecast (GWh)								
2015 (Not Normalized)	205.5	85.5	212.7	34.5	2.0	0.4	0.0	540.7

As outlined in the application, Table 3-13 assumed the number of customers for the General Service 3,000 to 4,999 kW class is 2 since the loss of a customer in this class is addressed in Table 3-18.

Table 3-18 Alignment of Non-normal to Weather Normal Forecast– Revised Load Forecast

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	TOTAL
Non-normalized Weather Billed Energy Forecast (GWh)								
2015 (Not Normalized)	205.5	85.5	212.7	34.5	2.0	0.4	0.03	540.7
Adjustment for Weather (GWh)								
2015	0.9	0.4	0.8	0.0	0.0	0.0	0.00	2.1
Adjustment for CDM (GWh)								
2015	(2.2)	(1.2)	(7.7)	0.0	0.0	0.0	0.00	(11.0)
Adjustment for Loss of Customer (GWh)								
2015	0.0	0.0	0.0	(17.3)	0.0	0.0	0.00	(17.3)
Weather Normalized Billed Energy Forecast (GWh)								
2015 Test - Normalized	204.2	84.7	205.9	17.3	2.0	0.4	0.03	514.5

Table 3-23 Summary of Billing Determinants and Variances of Actual and Forecast Data

Consistent with Appendix 2-IA – Revised Load Forecast

	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Test - Normalized
Residential							
Customers	21,075	20,952	21,096	21,074	21,108	21,117	21,124
kWh	214,923,813	206,535,118	207,358,082	200,614,424	207,806,639	205,950,080	204,205,261
Variance Analysis Compare to Board Approved							
Customers		(0.58%)	0.10%	(0.00%)	0.16%	0.20%	0.23%
kWh		(3.90%)	(3.52%)	(6.66%)	(3.31%)	(4.18%)	(4.99%)
General Service < 50 kW							
Customers	2,645	2,633	2,623	2,645	2,649	2,657	2,668
kWh	85,026,017	85,042,099	85,023,144	84,948,671	85,119,331	85,369,055	84,661,260
Variance Analysis Compare to Board Approved							
Customers		(0.46%)	(0.84%)	(0.00%)	0.15%	0.45%	0.87%
kWh		0.02%	(0.00%)	(0.09%)	0.11%	0.40%	(0.43%)
General Service 50 to 2999 kW							
Customers	287	269	268	254	255	252	247
kWh	221,440,020	230,037,737	231,667,366	223,688,453	216,614,454	217,236,187	205,910,919
kW	638,330	588,203	582,946	540,969	535,313	533,378	510,136
Variance Analysis Compare to Board Approved							
Customers		(6.17%)	(6.52%)	(11.41%)	(11.06%)	(12.10%)	(13.85%)
kWh		3.88%	4.62%	1.02%	(2.18%)	(1.90%)	(7.01%)
kW		(7.85%)	(8.68%)	(15.25%)	(16.14%)	(16.44%)	(20.08%)
General Service 3000 to 4999 kW							
Customers	2	2	2	2	2	2	1
kWh	38,784,125	41,028,104	37,086,852	35,722,772	35,775,036	26,926,556	17,254,810
kW	74,106	78,060	70,473	68,480	69,448	54,355	33,801
Variance Analysis Compare to Board Approved							
Customers		0.00%	0.00%	0.00%	0.00%	0.00%	(50.00%)
kWh		5.79%	(4.38%)	(7.89%)	(7.76%)	(30.57%)	(55.51%)
kW		5.34%	(4.90%)	(7.59%)	(6.28%)	(26.65%)	(54.39%)
Street Lighting							
Connections	5,680	5,572	5,574	5,574	5,574	5,419	5,419
kWh	2,721,605	3,324,190	3,204,123	2,790,238	2,348,268	2,026,566	2,018,762
kW	7,658	9,285	9,042	7,788	6,559	5,677	5,641
Variance Analysis Compare to Board Approved							
Connections		(1.91%)	(1.87%)	(1.87%)	(1.87%)	(4.60%)	(4.60%)
kWh		22.14%	17.73%	2.52%	(13.72%)	(25.54%)	(25.82%)
kW		21.24%	18.06%	1.69%	(14.35%)	(25.87%)	(26.34%)

	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Test - Normalized
Sentinel Lighting							
Connections	509	509	474	447	427	427	412
kWh	505,803	569,408	481,664	487,759	443,951	423,993	405,959
kW	1,382	1,541	1,287	1,601	1,224	1,179	1,193
Variance Analysis Compare to Board Approved							
Connections		0.00%	(6.88%)	(12.18%)	(16.11%)	(16.11%)	(19.06%)
kWh		12.58%	(4.77%)	(3.57%)	(12.23%)	(16.17%)	(19.74%)
kW		11.54%	(6.87%)	15.87%	(11.41%)	(14.70%)	(13.62%)
Unmetered Scattered Load							
Customers	21	19	18	17	15	11	7
kWh	337,294	165,123	84,073	88,774	89,084	50,610	32,045
Variance Analysis Compare to Board Approved							
Customers		(9.52%)	(14.29%)	(19.05%)	(28.57%)	(47.62%)	(66.67%)
kWh		(51.04%)	(75.07%)	(73.68%)	(73.59%)	(85.00%)	(90.50%)
Total							
Customer/Connections	30,219	29,956	30,055	30,013	30,030	29,885	29,878
kWh	563,738,678	566,701,778	564,905,304	548,341,092	548,196,762	537,983,046	514,489,017
kW from applicable classes	721,475	677,089	663,748	618,838	612,544	594,589	550,772
Variance Analysis Compare to Board Approved							
Customer/Connections		(0.87%)	(0.54%)	(0.68%)	(0.62%)	(1.10%)	(1.13%)
kWh		0.53%	0.21%	(2.73%)	(2.76%)	(4.57%)	(8.74%)
kW from applicable classes		(6.15%)	(8.00%)	(14.23%)	(15.10%)	(17.59%)	(23.66%)

f) The distribution rates at current rates for 2015 will move from $11,031,906 to $10,943,500 based on the revised forecast noted in part (d) above. The following provides the calculation of the $10,943,500.

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer
Residential	204,205,261		253,488		3,711,064	2,675,089	6,386,153		6,386,153
General Service < 50 kW	84,661,260		32,016		694,427	1,413,843	2,108,270		2,108,270
General Service > 50 to 2999 kW	205,910,919	510,136	2,964		871,327	1,069,551	1,940,878	85,436	1,855,442
General Service > 3000 to 4999 kW	17,254,810	33,801	12		70,129	37,689	107,818	20,281	87,537
Street Lighting	2,018,762	5,641		65,028	317,337	147,376	464,713		464,713
Sentinel Lighting	405,959	1,193		4,944	21,852	18,423	40,276		40,276
Unmetered and Scattered	32,045			84	591	519	1,110		1,110
	514,489,017	**550,772**	**288,480**	**70,056**	**5,686,727**	**5,362,490**	**11,049,217**	**105,717**	**10,943,500**

g) The requested live Excel spreadsheet which is the revised proposed load forecast is provided under file name “North Bay 2015 Load Forecast Model_EP 34”.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-35

Reference: Exhibit 3, Page 10 and Excel Forecast Spreadsheet

Interrogatory:

On page 10 the evidence states that the North Bay Economy variable has been set at 0 for all months up to and including December, 2011 and 1 for all months beyond that. However, the electronic version of the load forecast shows a value of 1 included for this variable in August, 2003.

a) Please explain why the North Bay Economy variable has a value of 1 in August, 2003 rather than 0 as is indicated in the evidence.

b) Please re-estimate the equation with the North Bay Economy variable including a value of 0 in August, 2003. Please provide a live Excel spreadsheet with this change.

c) What is the impact on the load forecast of this change?

Response:

a) The North Bay Economy variable has a value of 1 in August, 2003 to reflect the blackout that occurred in August 2003. Although the blackout cannot be classified as a slower economic event in North Bay the reduced impact on load from the blackout is similar to impact of the slower economic conditions in North Bay. In North Bay's 2010 load forecast there was a black out flag variable to address the blackout in August 2003. North Bay could have continued to use this variable along with the North Bay Economy variable but the variables were combined together since the outcome was similar.

b) A live Excel spreadsheet with the North Bay Economy variable set to 0 in August 2003 is provided in file named “North Bay 2015 Load Forecast Model_ EP 35b”.

c) The impact on the 2015 power purchased load forecast with the North Bay Economy variable set to 0 in August 2003 is a change from 566,813,952 (kWh), the power purchased amount in the revised load forecast as provided in 3-Energy Probe-34, to 567,219,734 (kWh) before any adjustments.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-36

Reference: Exhibit 3, Table 3-16

Interrogatory:

a) Please explain why there is no fall off in the persistence of 2013 CDM programs in 2014, like there was for 2011 and 2012 programs in the following years.

b) Please explain why NBHDL assumes that the savings achieved in 2014 from 2011 to 2014 CDM programs will persist into 2015 at 100%, whereas programs from the previous years show a reduction in the following years.

Response:

a) Persistence information for 2013 was received subsequent to the preparation of the Exhibit. A revised Table 3-16 incorporating persistence is as follows:

Table 3-16 4 Year (2011-2014) expected kWh target results Along with 2015 Expected results (Revised)

kWh	2011	2012	2013	2014	2015
2011 CDM Programs	2,634,934	2,597,007	2,575,709	2,504,545	2,484,385
2012 CDM Programs		2,691,068	2,667,382	2,650,992	2,473,591
2013 CDM Programs			2,576,330	2,531,398	2,468,424
2014 CDM Programs				2,670,635	2,656,334
2015 CDM Programs					14,561,027
Total in Year	2,634,934	5,288,075	7,819,421	10,357,570	24,643,761

b) NBHDL agrees persistence should be accounted for, and have revised the calculations accordingly for Table 3-16 as provided in response to a) above. The OPA has not provided persistence information for 2011 or 2014. Persistence has been estimated based on OPA reports (for 2011), and from persistence after one year, by program, in 2013 (for 2014).

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-37

Reference: Exhibit 3, Page 22

Interrogatory:

a) Please provide the annual kWh and kW figures for 2011 through 2013 for the customer that closed in 2014 in the GS 3,000 to 4,999 kW class.

b) It appears that NBHDL has assumed this lost customer was equivalent in size to the remaining customer by removing the kWh associated with the average of the two customers in this class for 2013. Is this correct?

Response:

a) The annual kWh and kW figures for 2011 through 2013 for the customer that closed in 2014 in the GS 3,000 to 4,999 kW class are as follows:

GS 3,000 to 4,999 kW	2011	2012	2013
Annual kWh	18,306,480	16,843,520	16,515,224
Annual kW	31,967	30,627	31,107

b) Please see Exhibit 3, page 22 lines 11 to 14. The referenced 17,254,810 kWh is the 2015 value in Table 3-12 for the General Service 3,000 to 4,999 kW class. This value is the 2013 average usage per customer for the General Service 3,000 to 4,999 kW class adjusted for the geo mean growth rate in Table 3-11 to arrive at the value in Table 3-12 for 2014 and 2015.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-38

Reference: Exhibit 3, Table 3-36

Interrogatory:

a) Please update Table 3-36 to reflect actual data for 2014. If actual data for all of 2014 is not yet available, please update to reflect the most recent year to date actual data available, along with the most recent estimate for any remaining months in 2014.

b) Please provide a version of Table 3-36 requested in part (a) above that removes all OPA related revenues and expenses from accounts 4375 and 4380, respectively.

Response:

a) Table 3-36 below has been updated to reflect actual data for all of 2014.

USoA	Other Revenue	2010 Board Approved	2010 Acutal	2010 Actual vs 2010 Board Approved	2011 Actual	2011 Actual vs. 2010 Actual	2012 Actual	2012 Actual vs. 2011 Actual	2013 Actual	2013 Actual vs. 2012 Actual	2014 Actual	2014 Bridge Year vs. 2013 Actual	2015 Test	2015 Test Year vs. 2014 Bridge Year
4086	SSS Administration Charge Revenue	76,632	79,656	3,024	81,266	1,610	83,258	1,992	84,210	952	84,131	(79)	83,834	(297)
4210	Rent from Electric Property	183,308	166,228	(17,080)	208,692	42,464	197,332	(11,360)	198,181	849	199,398	1,217	198,208	(1,190)
4225	Late Payment Charges	137,700	160,010	22,310	143,942	(16,067)	130,386	(13,556)	125,518	(4,868)	142,104	16,586	136,983	(5,121)
4235	Specific Service Charges	320,753	475,396	154,643	541,103	65,707	614,482	73,379	582,708	(31,774)	598,993	16,285	578,856	(20,137)
4325	Merchandising, Jobbing	12,269	5,000	(7,269)	-	(5,000)	(12)	(12)	-	12	1,208	1,208	4,400	3,192
4330	Costs and Expenses of Merchadising/Jo	(6,152)	88		5,489	5,401	(4,064)	(9,553)	21,013	25,077	(193)	(21,206)	-	193
4335	Profits and Losses from Financial Instrument Hedges										(74,674)	(74,674)		74,674
4355	Gain on disposal of property	2,500	950	(1,550)	4,975	4,025	347,552	342,577	12,300	(335,252)	15,038	2,738	-	(15,038)
4360	Loss on disposal of property	-	-		(1,328)	(1,328)	-	1,328	(157)	(157)	-	157	-	-
4375	Revenues from Non-Utility Operations	248,349	402,333	153,984	812,144	409,811	1,364,800	552,656	1,798,725	433,925	1,537,086	(261,639)	2,556,998	1,019,912
4380	Expenses of Non-Utility Operations	(209,000)	(409,054)	(200,054)	(746,164)	(337,110)	(1,242,614)	(496,450)	(1,775,798)	(533,184)	(1,481,272)	294,526	(2,505,068)	(1,023,796)
4385	Non-Utility Rental Income	(122)	-	122	-	-	-	-	-	-	-	-	-	-
4390	Miscellaneous Non-Operating Income	7,134	10,357	3,223	13,946	3,589	18,851	4,905	208,417	189,566	234,554	26,137	11,925	(222,629)
4398	4398-Foreign Exchange	-	(4,521)		8,378	12,899	(4,060)	(12,438)	11,365	15,425	9,710	(1,655)	-	(9,710)
4405	Interest & Dividend Income	57,245	77,335	20,090	103,553	26,218	77,786	(25,767)	111,883	34,097	99,332	(12,551)	87,798	(11,534)
	Other Income and Expenses	112,223	82,487	(31,454)	200,993	118,506	558,239	357,246	387,748	(170,491)	340,789	(46,959)	156,053	(184,736)
	Other Revenue	830,616	963,777	131,442	1,175,997	212,220	1,583,696	407,700	1,378,365	(205,331)	1,365,415	(12,950)	1,153,934	(211,481)

b) Table 3-36 below has been updated to reflect actual data for all of 2014 and to remove all OPA related revenues and expenses from accounts 4375 and 4380, respectively. Please refer to Appendix 2-H - Other Operating Revenue for details related to 4375 and 4380.

USoA	Other Revenue	2010 Board Approved	2010 Acutal	2010 Actual vs. 2010 Board Approved	2011 Actual	2011 Actual vs. 2010 Actual	2012 Actual	2012 Actual vs. 2011 Actual	2013 Actual	2013 Actual vs. 2012 Actual	2014 Actual	2014 Bridge Year vs. 2013 Actual	2015 Test	2015 Test Year vs. 2014 Bridge Year
4086	SSS Administration Charge Revenue	76,632	79,656	3,024	81,266	1,610	83,258	1,992	84,210	952	84,131	(79)	83,834	(297)
4210	Rent from Electric Property	183,308	166,228	(17,080)	208,692	42,464	197,332	(11,360)	198,181	849	199,398	1,217	198,208	(1,190)
4225	Late Payment Charges	137,700	160,010	22,310	143,942	(16,067)	130,386	(13,556)	125,518	(4,868)	142,104	16,586	136,983	(5,121)
4235	Specific Service Charges	320,753	475,396	154,643	541,103	65,707	614,482	73,379	582,708	(31,774)	598,993	16,285	578,856	(20,137)
4325	Merchandising, Jobbing	12,269	5,000	(7,269)	-	(5,000)	(12)	(12)	-	12	1,208	1,208	4,400	3,192
4330	Costs and Expenses of Merchadising/Jobbing	(6,152)	88		5,489	5,401	(4,064)	(9,553)	21,013	25,077	(193)	(21,206)	-	193
4335	Profits and Losses from Financial Instrument Hedges										(74,674)	(74,674)		74,674
4355	Gain on disposal of property	2,500	950	(1,550)	4,975	4,025	347,552	342,577	12,300	(335,252)	15,038	2,738	-	(15,038)
4360	Loss on disposal of property	-	-		(1,328)	(1,328)	-	1,328	(157)	(157)	-	157	-	-
4375	Revenues from Non-Utility Operations	39,349	38,048	(1,301)	38,660	612	642,840	604,180	283,171	(359,669)	53,654	(229,517)	51,931	
4380	Expenses of Non-Utility Operations	-	-		(8,064)	(8,064)	(522,388)	(514,324)	(269,384)	253,004			-	
4385	Non-Utility Rental Income	(122)	-	122	-	-	-	-	-	-	-	-	-	-
4390	Miscellaneous Non-Operating Income	7,134	10,357	3,223	13,946	3,589	18,851	4,905	208,417	189,566	234,554	26,137	11,925	(222,629)
4398	4398-Foreign Exchange	-	(4,521)		8,378	12,899	(4,060)	(12,438)	11,365	15,425	9,710	(1,655)	-	(9,710)
4405	Interest & Dividend Income	57,245	77,335	20,090	103,553	26,218	77,786	(25,767)	111,883	34,097	99,332	(12,551)	87,798	(11,534)
	Other Income and Expenses	112,223	127,257	13,315	165,609	38,353	556,505	390,896	378,608	(177,897)	338,629	(309,363)	156,054	(180,852)
	Other Revenue	830,616	1,008,546	176,212	1,140,613	132,066	1,581,963	441,350	1,369,225	(212,738)	1,363,255	(275,354)	1,153,935	(207,597)

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-39

Reference: Exhibit 3, Table 3-36

Interrogatory:

a) For 2013 actual, 2014 actual and the 2015 forecast, please provide the average interest rate used to determine the interest and dividend income in account 4405, along with the average balance to which these rates were applied in each of the years.

b) Please explain the derivation of the interest rate used in the forecast for 2015 and the amount to which it is applied relative to the balances in 2013 and 2014.

Response:

a) The table below provides the average interest rate and the average cash balance to which these rates were applied to in calculating the interest income in account 4405 for the 2013 and 2014 actual and the 2015 forecast.

	2013 Actual	2014 Actual	2015 Test Year
Interest income	111,883	99,332	87,797
Average cash balance	8,215,312	7,217,453	7,827,891
Average interest rate	0.11%	0.12%	0.09%

b) The interest rate used in the 2015 forecast was the average actual rate for March 2014-May 2014 of .09%. The balances to which this rate was applied to in calculating the interest income in account 4405 was the prior month ending balance from the 2015 monthly cash flow forecast.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-40

Reference: Exhibit 3, Table 3-36

Interrogatory:

a) Where are revenues from microfit customers shown in Table 3-36?

b) Please provide the actual number of microfit customers for each of the historical years, including 2014, along with the forecast for 2015.

Response:

a) The revenues from MicroFIT customers are shown in Table 3-36 in accounts 4235 and 4325. The table below shows the detail by account by year. Please refer to Appendix 2-H - Other Operating Revenue for details related to accounts 4235 and 4325.

USoA	Other Revenue	2010 Acutal	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Test
4235	Specific Service Charges - MicroFit	127	536	1,013	1,874		
4325	Merchandising, Jobbing - MicroFit		-		-	2,030	1,900
	Other Revenue	127	536	1,013	1,874	2,030	1,900

b) The actual number of MicroFIT customers for each of the historical years, including 2014 and the 2015 forecast are shown in the table below.

MicroFit Customers	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Test
Total MicroFit Customers	7	10	21	31	34	31

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-Energy Probe-41

Reference: Exhibit 3, Table 3-36

Interrogatory:

a) Please provide a break out of the revenue and costs shown in accounts 4375 and 4380 from each of the items included in these accounts for the years shown, but update the 2014 data to reflect actual information.

b) What is the status of the Bell Fibre project that has been included in account 4390?

c) Please explain why NBHDL has not included any gains in account 4355 for the test year when it has had such gains in all the other years shown.

Response:

a) The revenue and costs shown in accounts 4375 and 4380 from each of the items included in these accounts for the years shown with 2014 data updated to reflect actual information is shown in the tables below.

Account 4375- Revenues from Non-Utility Operations	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	Test Year
CDM Revenue OPA Incentives	$364,285	$773,484	$721,960	$1,515,554	$1,483,432	$2,505,067
Generation - Merrick Landfill			$593,485	$216,175		
Affiliate NBHS - Management Fee	$38,048	$38,660	$49,355	$66,996	$53,654	$51,931
Total	$402,333	$812,144	$1,364,800	$1,798,725	$1,537,086	$2,556,998

Account 4380 - Expense from Non-Utility Operations	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	Test Year
CDM/OPA Expenses	($409,054)	($738,100)	($720,226)	($1,506,414)	($1,481,272)	($2,505,067)
Generation - Merrick Landfill		($8,064)	($522,388)	($269,384)		
Total	($409,054)	($746,164)	($1,242,614)	($1,775,798)	($1,481,272)	($2,505,067)

b) The status of the Bell Fibre project that has been included in account 4390 is that it was considered substantially complete by both NBHDL and Bell Aliant on November 12, 2014. As of April 17, 2015, a very small amount of deficiency work is being addressed by both NBHDL and Bell Aliant. NBHDL anticipates that the project will be 100 percent complete as of May 1, 2015.

c) NBHDL has not included any gains from disposal of utility assets in account 4355 for the test year as NBHDL doesn't anticipate receiving any proceeds due to the age and condition of the assets being retired in the test year.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-NBTA-26

Reference: Page 15, Line 3

Interrogatory:

In the 2010 COS application *(EB-2009-0270 - 2010 Load Forecast.xlsm – Rate Class Customer Model tab)*, the applicant apparently used the geometric average of the growth rates for the years 2000 – 2008, (eight years) to forecast customer numbers for the years 2009 and then for 2010.

In the current application *(2015 Load Forecast Model – Rate Class Customer Model tab)*, the forecast method has been changed by applying the geometric average of the growth rates for 2012 and 2013 (two years) to forecast customer numbers for the years 2014 and then for 2015.

In addition, the worksheet notes that the averages are based on the last five years which does not seem to be the case.

Please explain the apparent anomalies and why the number of years used for forecasting has been changed in 2015.

Response:

The revised load forecast referenced in 3-Energy Probe-34 uses 2012 to 2014 consistently throughout the load forecast to determine the geometric growth rate for number of customers/connection and usage as well as the average kW/kWh factor. These three years have been chosen since they are more reflective of the slower economic conditions which are currently occurring in North Bay.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-NBTA-27

Reference: Page 15, Line 3

Interrogatory:

The use of the geometric average in calculating averages is intended to mitigate the influence of numbers in a set which are outside its general range and also in cases where the values are dependent on one another. We suggest there is no compelling reason to use the unnecessarily elaborate geomean method and that an arithmetic average is a better choice when the numbers are independent of each other and present in a narrower range.

Please support the use of a geometric average rather than an arithmetic average to forecast growth rates.

Response:

The geomean analysis is a method used to determine the compound average growth rate over a period time. Using a compound average growth rate as a forecasting tool is a better approach than using the arithmetic average since there is a compounding effect from one year to the next when a growth rate is used in the forecast.

See also the response to 8-NBTA-70.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-NBTA-28

Reference: Page 15, Line 16

Interrogatory:

In the 2010 COS application *(EB-2009-0270) in 2010 Load Forecast – Rate Class Customer Model* for the GS 3,000 to 4,999 kW class the model appears to be using a customer count of 2 when making calculations when, in fact, it was completing calculations using a factor of 1.85. This error resulted in the increase in the calculated volumetric rates for that class and the two customers in that class being overcharged.

One of the customers in that class did question NBHDL in 2012 about the error and was given incorrect information concerning the applicant's ability to change the models supplied and their obligation to verify the accuracy of the data calculated by the models.

This obligation is stated in *"Filing Requirement – Chapter 2 - page 6"* as follows:

"Likewise, the applicant bears the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses in supporting its application. The applicant is responsible for advising the Board of any concerns it may have regarding calculations flowing from the models as well as any changes that the applicant may have made to the models to address its own circumstances."

We have estimated the subsequent overcharge for the five years 2010 – 2015, depending on actual kW used, to be approximately $20,000 for each of the two customers in that class.

Please confirm that this is the case and why NBHDL refused to correct this error and failed to reimburse customers in this class for the overcharge related to the error?

Response:

NBHDL disputes the allegation that it provided any customers with “incorrect information.” NBHDL worked closely with the customer in question, provided the relevant facts, and was able to resolve the customer’s concerns.

NBHDL is not able to engage in an exercise of retroactive rate making and will not provide the confirmation requested. It is not relevant to the matters at issue in this Application.

However, in this Application, the Excel rounding feature has been used in the revised load forecast referenced in 3-Energy Probe-34 to forecast the number customer/connections for 2015. For example, in file named “North Bay 2015 Load Forecast Model EP 34”, tab Rate Class Customer Model, cell D19 the following equation is used to forecast the 2015 customers for the General Service 50 to 2999 kW class - =ROUND(D18*D42,0).

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-17

Reference: Exhibit 3, Page 4 & 5

For data for parts c) and d) see the following link:

http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=2820122&paSer=&pattern=&stByVal=1&p1=1&p2=35&tabMode=dataTable&csid=

Interrogatory:

a) As opposed to Ontario Monthly Real GDP, did North Bay test any variables, such as regional unemployment or work force levels, that provide a more local measure of economic activity?

b) If yes, please indicate the variables tested and provide the results (i.e. both the resulting regression equations and regression statistics).

c) If not, please do so using the monthly unemployment rate for Northeastern Ontario as published by Statistics Canada. Please provide the resulting equation and regression statistics. If the resulting coefficient for the variable is significant, please provide the supporting excel worksheet.

d) If not, please do so using Northeastern Ontario Employment levels as published by Statistics Canada. Please provide the resulting equation and regression statistics. If the resulting coefficient for the variable is significant, please provide the supporting excel worksheet.

Response:

a) North Bay considered using variables, such as regional employment and unemployment for the Northeastern region but the data was only available from March 2001 onwards. Since the historical data used in the regression analysis covered the period January 1999 to December 2013 employment and unemployment data was not available for January 1999 to April 2001. As a result, North Bay did not conduct the regression analysis with these two variables.

b) Not applicable, please see a).

c) Using the revised load forecast referenced in 3-Energy Probe-34, North Bay has conducted the regression analysis using the monthly unemployment rate for Northeastern Ontario as published by Statistics Canada as an additional variable. However, for the period January 1999 to April 2001 data was not available. For these months North Bay has assume the same unemployment rate as March 2001, the first month that data is available. The resulting equation and regression statistics are provided below. Since the variable is statistically significant the supporting excel worksheet is provided in file named “North Bay 2015 Power Purchased Model_VECC 17c”.

Regression Analysis Results	Value
R Square	97.7%
Adjusted R Square	97.6%
F Test	1316.4
MAPE (Monthly)	1.8%
Coefficient	
Heating Degree Days	24,698
Cooling Degree Days	82,296
Number of Days in Month	1,168,747
Spring Fall Flag	(1,858,131)
North Bay Economy	(2,214,832)
Northeastern Unemployment Rate	(128,207)
Constant	4,479,039
T-stats by Coefficient	
Heating Degree Days	64.0
Cooling Degree Days	13.4
Number of Days in Month	11.5
Spring Fall Flag	(8.9)
North Bay Economy	(10.6)
Northeastern Unemployment Rate	(1.9)
Constant	1.4

d) Using the revised load forecast referenced in 3-Energy Probe-34, North Bay has conducted the regression analysis using the monthly employment levels for Northeastern Ontario as published by Statistics Canada as an additional variable. However, for the period January 1999 to April 2001 data was not available. For these months North Bay has assume the same employment level as March 2001, the first month that data is available. The resulting equation and regression statistics is provided below. Since the variable is statistically significant the supporting excel worksheet is provided in file named “North Bay 2015 Power Purchased Model_VECC 17d”.

Regression Analysis Results	Value
R Square	97.8%
Adjusted R Square	97.7%
F Test	1370.6
MAPE (Monthly)	1.7%
Coefficient	
Heating Degree Days	25,053
Cooling Degree Days	80,954
Number of Days in Month	1,145,189
Spring Fall Flag	(1,806,302)
North Bay Economy	(2,105,878)
Northeastern Employment	40,916
Constant	(6,450,447)
T-stats by Coefficient	
Heating Degree Days	64.7
Cooling Degree Days	13.5
Number of Days in Month	11.4
Spring Fall Flag	(8.8)
North Bay Economy	(10.6)
Northeastern Employment	3.3
Constant	(1.6)

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-18

Reference: Exhibit 3, Page 10 and 20

Statistics Canada – Labour Force Statistics

http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=2820123&paSer=&pattern=&stByVal=1&p1=1&p2=35&tabMode=dataTable&csid=

Interrogatory:

Preamble: Statistics Canada reports the following employment levels and unemployment rates for Northeastern Ontario:

Table 282-0123 Labour force survey estimates (LFS), by provinces, territories and economic regions based on 2011 census boundaries, annual (persons unless otherwise noted)(1,2,3,4,5)

Survey or program details:															
Labour Force Survey - 3701															
Geograph	Labour force characteri	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Northeast	Employment (x 1,000) (	250.9	251.7	254.6	257.4	259.5	258.8	263.2	264.7	250.6	254.1	260.8	255.3	253.7	256.8
Northeast	Unemployment rate (ra	8.2	8.9	8.1	8	7.1	7.2	6.6	6.2	9.1	8.7	8	7.3	7.5	6.9
Footnotes:															

a) The employment data for Northeastern Ontario suggests that the slowing of economic conditions started in 2009. Please re-do the regression analysis setting the North Bay Economy variable at 1.0 as of this date. Based on the results, please provide the resulting equation and Tables similar to 3-5 and 3-6.

b) The employment data for Northeastern Ontario also suggests that the economy may be improving as of 2014. Please provide evidence to support the claim that slower economic conditions are expected to continue for 2014 and 2015 (similar to 2012 and 2013).

c) Please complete the following schedule of North Bay's verified CDM results for 2009 through 2013.

	CDM Results (GWh - from current and previous years' CDM Programs)				
Program Year	2009	2010	2011	2012	2013
2009					
2010	X				
2011	X	X			
2012	X	X	X		
2013	x	x	x	x	
Total					

d) Can any of the decline in electricity sales starting as of the end of 2011 be attributed to increased CDM activity?

<u>Response:</u>

a) Using the revised load forecast referenced in 3-Energy Probe-34, the regression analysis has been re-done setting the North Bay Economy variable at 1.0 for January 2009 and onward. The following provides the coefficients for the resulting equation along with Tables 3-5 and 3-6 under this assumption.

Coefficient	
Heating Degree Days	24,809
Cooling Degree Days	84,072
Number of Days in Month	1,159,544
Spring Fall Flag	(1,840,067)
North Bay Economy	(1,177,488)
Constant	3,687,619

Table 3-5 Statistical Results – Revised North Bay Economy Variable

Statistic	Value
R Square	97.0%
Adjusted R Square	96.9%
F Test	1183.6
MAPE (Monthly)	2.1%
T-stats by Coefficient	
Heating Degree Days	56.1
Cooling Degree Days	11.9
Number of Days in Month	9.9
Spring Fall Flag	(7.7)
North Bay Economy	(6.2)
Constant	1.0

Table 3-6 Total System Purchase – Revised North Bay Economy Variable

Year	Actual	Predicted	% Difference
Purchased Energy (GWh)			
1999	586.8	591.0	0.7%
2000	590.8	593.0	0.4%
2001	587.8	589.4	0.3%
2002	593.8	600.8	1.2%
2003	594.6	598.0	0.6%
2004	601.8	597.7	(0.7%)
2005	606.4	601.1	(0.9%)
2006	585.8	585.0	(0.1%)
2007	598.6	596.4	(0.4%)
2008	594.9	591.4	(0.6%)
2009	580.3	578.1	(0.4%)
2010	592.1	574.0	(3.1%)
2011	593.7	577.9	(2.7%)
2012	572.6	572.9	0.0%
2013	573.2	583.9	1.9%
2014	561.2	584.0	4.1%
2015 Test - Normalized		578.6	
2015 Test - Normalized - 20 Year Trend		577.5	

b) NBHDL's claim that slower economic conditions are expected to continue for 2014 and 2015 (similar to 2012 and 2012) are based upon the actual events that are occurring within the community directly. While NBHDL appreciates that the data suggested that the economy may be improving in 2014, North Bay experienced a wave of significant layoffs in the community from large employers and more are anticipated on the horizon. Further anecdotal evidence such as the decline in new home construction also points to continued slow economic conditions. NBHDL's 2014 actual billing is in line with that anticipated in the proposed load forecast outlined in the application which would suggest NBHDL's assumptions are aligned with the pattern being seen in the City.

c) Verified CDM results provided by the OPA are provided as follows:

	CDM Results (GWh - from current and previous years' CDM Programs)				
Program Year	2009	2010	2011	2012	2013
2009	3.8	3.4	3.4	3.4	3.4
2010	X	2.0	*	*	*
2011	X	X	2.6	*	*
2012	X	X	X	2.7	2.7
2013	x	x	x	x	2.6
Total	**3.8**	**5.5**	**6.1**	**6.1**	**8.6**

d) North Bay is unable to quantify whether or not the decline in electricity sales starting as of the end of 2011 can be attributed to CDM activity. However, CDM activity did begin in 2006 and over the period 2006 to 2011 the actual power purchased values indicate some level of variability but essentially was flat at an average level of 591 (GWh). For the period 2012 to 2014 the average has dropped to 569 (GWh) with the actual 2014 value of 561 (GWh). Based on the experience from 2006 to 2011, the decline in electricity sales starting as of the end of 2011 might be somewhat attributable to CDM activity but the impact would be minimal. The main contributor is the slower economic conditions.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-19

Reference: Exhibit 3, Page 13

Interrogatory:

a) What was the average historical loss factor for the 1999-2013 period used in the regression analysis?

b) Please explain how economic conditions are expected to affect the loss factor (per line 16).

c) Please provide the actual system purchases for 2014.

d) Please provide the actual HDD and CDD values for 2014.

e) Please calculate the weather-normalized 2014 system purchases by providing a schedule that sets out:

i. The 2014 Actual System Purchases.

ii. The difference between the actual 2014 and weather normal CDD values multiplied by 82,485.

iii. The difference between the actual 2014 and weather normal HDD values multiplied by 24,866.

iv. The 2014 Actual System Purchases – (i) – (ii).

Response:

a) The average historical loss factor for the 1999-2013 period is 1.0516.

b) The economic conditions do not affect the loss factor directly. The revised load forecast referenced in 3-Energy Probe-34 uses 2012 to 2014 throughout the load forecast to determine the geometric growth rate for number of customers/connection and usage as well as the average kW/kWh factor. These three years reflected slower economic conditions. For consistency purposes, the average loss factor used in the load forecast was also based on the average of 2012 to 2014.

c) The actual system purchases for 2014 are 561,189,732 (kWh).

d) The actual HDD and CDD values for 2014 are 5,494 and 64 respectively.

e) Using the revised HDD and CDD coefficients of 24,756 and 82,344; respectively, from the revised load forecast referenced in 3.0 –VECC -20 below, the estimated weather-normalized 2014 system purchases are as follows.

Actual Purchases (A)	561,189,732
Actual HDD (B)	5,494
Actual CDD (C)	64
Weather Normal HDD (D)	4,971
Weather Normal CDD (E)	154
HDD Difference (F) = (D) - (B)	(523)
CDD Difference (G) = (E) - (C)	90
24,756 * HDD Difference (H) =24,756 * (F)	(12,945,531)
82,345 * CDD Difference (I) =82,345 * (G)	7,374,736
Weather Normal Purchases (J) = (A) + (H) + (J)	555,618,936

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-20

Reference: Exhibit 3, Page 11-13

Interrogatory:

a) Please update the regression analysis to include actual 2014 data and provide the resulting regression equation along with updated Tables 3-5 and 3-6.

Response:

As per 3-Energy Probe-34, NBHDL has revised the proposed 2015 load forecast for the purposes of determining 2015 proposed rates to reflect 2014 actual power purchases and billing determinants along with revised CDM adjustments outlined in response to 3-Energy Probe-36. The following provides the coefficients for the resulting equation along with Tables 3-5 and 3-6 under this assumption.

Coefficient	
Heating Degree Days	24,756
Cooling Degree Days	82,345
Number of Days in Month	1,180,000
Spring Fall Flag	(1,887,542)
North Bay Economy	(2,118,010)
Constant	3,093,469

Table 3-5 Statistical Results – Revised Load Forecast

Statistic	Value
R Square	97.7%
Adjusted R Square	97.6%
F Test	1557.9
MAPE (Monthly)	1.8%
T-stats by Coefficient	
Heating Degree Days	63.9
Cooling Degree Days	13.4
Number of Days in Month	11.5
Spring Fall Flag	(9.0)
North Bay Economy	(10.4)
Constant	1.0

Table 3-6 Total System Purchase – Revised Load Forecast

Year	Actual	Predicted	% Difference
Purchased Energy (GWh)			
1999	586.8	590.5	0.6%
2000	590.8	592.7	0.3%
2001	587.8	588.8	0.2%
2002	593.8	600.2	1.1%
2003	594.6	596.5	0.3%
2004	601.8	597.3	(0.7%)
2005	606.4	600.4	(1.0%)
2006	585.8	584.5	(0.2%)
2007	598.6	595.8	(0.5%)
2008	594.9	591.1	(0.6%)
2009	580.3	591.9	2.0%
2010	592.1	587.6	(0.8%)
2011	593.7	591.5	(0.4%)
2012	572.6	561.1	(2.0%)
2013	573.2	572.2	(0.2%)
2014	561.2	572.4	2.0%
2015 Test - Normalized		566.8	
2015 Test - Normalized - 20 Year Trend		565.7	

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-21

Reference: Exhibit 3, Page 14-16

Interrogatory:

a) With respect to Table 3-8, please provide the Geo Mean growth rates for each class based on 2003-2013.

b) Given that the City of North Bay's street light retrofit program started in November 2011, why is the number of connections set out Table 3-7 constant through to the end of 2013?

c) Please provide the actual sales by class for 2014.

d) Please update Tables 3-7 through 3-11 for the 2014 actual values. For purposes of calculating the Geo Mean in Tables 3-8 and 3-11, please use 2012-2014.

e) The text on page 16 (lines 13-15) claims that North Bay's customer base is very sensitive to weather, especially during the winter months. However the values for the HDD and CDD coefficients in the regression model provided on page 11 suggest that the number of Cooling Degree days have a greater impact on load than the number of Heating Degree days. Please reconcile.

Response:

a) Consistent with information on Table 3-8, the Geo Mean growth rates for each class based on 2003-2013 are as follows:

Year	Residential	General Service < 50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Geo Mean -2003 to 2013	0.50%	0.3%	0.0%	(3.6%)	0.5%	(2.7%)	(3.0%)

b) The final count of connections was not complete and confirmed between NBHDL and the City until the retrofit was completed. Changes to the number of connections were made for billing purposes beginning in January 2014.

c) Please see 3-Energy Probe-34 d).

d) Please see response to 3-Energy Probe-34.

e) The values for the HDD and CDD coefficients in the revised regression model are 24,756 and 82,345; respectively. The annual weather normal HDD and CDD are 4,971 and 154; respectively. The HDD contribution to the 2015 load forecast is 24,756 times 4,971 or 123,063,933 (kWh). The CDD contribution to the 2015 load is 82,345 times 154 or 12,669,519 (kWh). This means the HDD contributes almost contributes almost 10 times more kWh to the load forecast than CDD which shows that the number of Heating Degree days have a greater impact on load.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-22

Reference: Exhibit 3, Page 15 & 17

Interrogatory:

a) The discussion on page 15 makes reference to a reduction in the number of street light connections (line 10) and a reduction in the number of fixtures/devices (line 13). Was there a change in the devices/connections ratio as a result of the retrofit?

b) By how much (in percentage terms) did the introduction of LED technology reduce the energy usage of each street light device?

Response:

a) No, there was not a change in the devices/connections ratio as a result of the retrofit.

b) The introduction of LED technology reduced the energy usage of each street light device by approximately 37%.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-23

Reference: Exhibit 3, Pages 19-21; Exhibit 4, Appendix 4-O, Page 7; Filing Requirements, Chapter 2, Appendix 2-I; Exhibit 4, Appendix 4-N, IndEco Report, Pages 5-6

Interrogatory:

a) Please explain why the entries in Table 3-15 differ from those in Appendix 4-O, page 7. For example, in Table 3.5 the savings in 2011 from 2011 CDM programs are shown as 2.63 GWh, where as in Appendix 4-O the amount is 2.4 GWh.

b) With reference to Appendix 2-I, please explain why North Bay is assuming that 70.71% of its 2015-2020 CDM Target will be achieved in 2015, as opposed to just 1/6th of the target.

c) With respect to page 21, please provide the derivation of the 1,241,072 kWh of CDM savings attributed to the Street Light Retrofit. {Note – Since the program started in late 2011, using 2010 as the base would yield a before retrofit usage of 3,326,484 kWh (597 kWh/connection x 5,572 connections) while the 2015 usage is projected to be 2,021,287 kWh (373/connection x 5,419 connections) – for a difference of 1,305,197 kWh}.

d) With respect to page 21, why is North Bay attributing all of the Street Lighting retrofit savings to 2015 when, as noted on page 15 of Exhibit 3, the program was implemented over the period November 2011 to January 2014 and savings from the Street Lighting Retrofit have been included in the 2012 and 2013 LRAM claim calculations (IndEco Report, pages 5-6)?

e) Based on the foregoing responses what revisions, if are required to the Application?

Response:

a) The savings in 2011 from 2011 CDM programs in Table 3-15 on page includes the adjustments to 2011 results issued by the OPA in 2012. These adjustments are included separately in 2011 on the 2012 programs line in Table 5 on page 7 of Appendix 4-O. The adjustments are listed as 0.3, which would still indicate a discrepancy when added to the 2.4 GWh, but this is simply due to a rounding error.

A revised Table 3-15 is provided below which includes corrections for persistence, as well as updated estimated results for 2014 to be consistent with NBH's 2011-2014 target.

Table 3-15 4 Year (2011-2014) Expected kWh Target Results (Revised)

4 Year (2011-2014) kWh Target: 26,100,000					
	2011	**2012**	**2013**	**2014**	**Total**
2011 CDM Programs	10.10%	9.95%	9.87%	9.60%	39.51%
2012 CDM Programs		10.31%	10.22%	10.16%	30.69%
2013 CDM Programs			9.87%	9.70%	19.57%
2014 CDM Programs				10.23%	10.23%
Total in Year	**10.10%**	**20.26%**	**29.96%**	**39.68%**	**100.00%**
kWh					
2011 CDM Programs	2,634,934	2,597,007	2,575,709	2,504,545	10,312,195
2012 CDM Programs	-	2,691,068	2,667,382	2,650,992	8,009,442
2013 CDM Programs	-	-	2,576,330	2,531,398	5,107,728
2014 CDM Programs	-	-	-	2,670,635	2,670,635
Total in Year	**2,634,934**	**5,288,075**	**7,819,421**	**10,357,570**	**26,100,000**

b) The large contribution to NBH's 2015-2020 target expected in 2015 is due to a very large cogeneration project with a completion date in 2015. The balance of the target not met by this project is distributed equally across the six years.

c) With respect to page 21, the 1,241,072 kWh of CDM savings attributed to the Street Light Retrofit was included in error for expected savings for LRAMVA purposes. The kWh/kW/connection count proposed in the revised load forecast in response to 3-Energy Probe-

36 is based on the new load profile of the street lights that was calculated upon completion of the Retrofit program. Consequently, there are no manual adjustments for CDM for this rate class or anticipated future LRAM impacts. Please see d) below for additional information.

d) The project was initiated in late 2011. There is some deviation from the actual install to what is recorded by the OPA in the database of projects (CRM). For purposes of LRAMVA, data from the CRM database was used to calculate the impact on revenues. These data understate the actual impact for two reasons: because the actual implementation schedule was faster than assumed for those projects, and because IndEco calculated net savings from the CRM reports using a net-to-gross-ratio that applies to all retrofit projects, not this one specifically. NBHDL stands by the LRAMVA claim related to this project for 2013, and will use the CRM data again for LRAMVA in 2014. There will be no LRAMVA claim for this project in 2015 or later because the full impact of the project has been incorporated into the load forecast. Street lighting is not metered, and NBHDL and the City of North Bay have reached an agreement on how to determine future demand for this rate class, and this has been incorporated into the load forecast. Consequently, there is not a requirement for any manual adjustment for CDM for this rate class.

A revised Table 3-17 is provided below showing estimated CDM savings by rate class and the manual adjustments required for CDM. NBHDL notes that the difference between the 2015 estimated savings (kWh) showing in this table and the total on Table 3-16 (3-Energy Probe-36) is the persistent savings from the Street Lighting project which, as explained in c) and d) above is dealt with separately.

Table 3-17 2015 Expected CDM Savings by Rate Class for LRAM Variance Account (Revised)

Year	Residential	General Service <50 kW	General Service 50 to 2999 kW	General Service 3000 to 4999 kW	Street Lighting	Sentinel Lighting	Unmetered Scattered Load	TOTAL
2015 manual adj. to LF for CDM (kWh)	2,177,013	1,183,729	7,654,447	-	-	-	-	11,015,189
2015 manual adj. to LF for CDM (kW)			18,715	-	-	-	-	18,715
2015 LRAMVA threshold based on full year IESO results (kWh)	3,168,898	1,733,196	14,471,949	-	-	-	-	19,374,043
2015 LRAMVA threshold based on full year IESO results (kW)			35,384	-	-	-	-	35,384

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-24

Reference: Exhibit 3, Page 21; Filing Requirements, Chapter 2, Appendix 2-I

Interrogatory:

a) Please confirm that the CDM savings included in the load forecast for 2015 due to programs implemented in 2011-2013 are all based on actual final results verified by the OPA.

b) If this is the case, why is it necessary to include the values for these years in any future LRAM variance calculation for 2015?

Response:

a) Confirmed, with adjustments discussed above in 3.0–VECC-23.

b) The OPA/IESO has a history of making adjustments to 'final' results in later years, and these adjustments will need to be captured. In the absence of adjustments, NBHDL does not anticipate that there will be any need for these years to be considered in future LRAM variance calculations. The LRAMVA claim for 2015 will consider any changes to 2013 'final' results that the IESO may release, and then, consistent with the Guidelines, will compare final results for 2013 (if adjusted), 2014 and 2015 IESO reported CDM savings to estimated savings incorporated into the load forecast.

In this regard, NBHDL has planned for LRAMVA in a way consistent with the description in the Board's CDM Guidelines (p.12):

> "Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction forecast in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual CDM results verified by an independent third party for each year of the CDM program (i.e., 2011 to 2014) in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison will result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA."

Consistent with the above quote from the Guidelines, for the LRAMVA in 2015 NBHDL will compare IESO final CDM results for the years 2013 through 2015 to the amount of CDM embedded in the load forecast.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-25

Reference: Exhibit 3, Page 22

Interrogatory:

a) For each of the years 2011, 2012 and 2013 what proportion of the total GS 3,000-4,999 class load was attributable to the customer that shut down in 2014?

Response:

Please see 3-Energy Probe-37.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-26

Reference: Exhibit 3, Page 24

Interrogatory:

a) With respect to Table 3-20, what was the historical kW/kWh ratio for each year from 2010 to 2013 for the currently remaining GS 3,000-4,999 customer?

b) Please confirm that, in Table 3-18, 0.4 GWh and 0.7 GWh were deducted from the 2014 and 2015 respective forecasts for the GS 3,000-4,999 class to account for CDM programs implemented in 2013-2015.

c) Using the ratios from Table 3-20, what billing kW reductions are associated with these CDM savings?

d) Why is it necessary to reduce the billing demand for 2014 and 2015 by a further 720 kW and 180 kW respectively (per line 7)?

Response:

a) With respect to Table 3-20, the historical kW/kWh ratio for each year from 2010 to 2013 for the currently remaining GS 3,000-4,999 customer is as follows:

2010	2011	2012	2013
0.1962%	0.2050%	0.2005%	0.1991%

b) In response to 3-Energy Probe-34, NBHDL has updated the proposed load forecast to reflect 2014 actual data and revised CDM adjustments for the 2015 Test Year. The GS 3,000-4,999 class no longer has any CDM adjustments applicable to the 2015 load forecast based on updated information.

The following tables are provided with the updated 2015 CDM adjustments incorporated into the updated proposed load forecast.

CDM Potential Impact on Load Forecast by Class

Overall kWh:	From final results	From final results	From final results	From preliminary resu	Estimated		
kWh	2011	2012	2013	2014	2015	Multiplier	Manual adjustment to Load Forecast - 2015
2011 CDM Programs	2,634,934	2,597,007	2,575,709	2,504,545	2,484,385	-	-
2012 CDM Programs		2,691,068	2,667,382	2,650,992	2,473,591	-	-
2013 CDM Programs			2,576,330	2,531,398	2,468,424	0.44	1,078,341
2014 CDM Programs				2,670,635	2,656,334	1.00	2,656,334
2015 CDM Programs					14,561,027	0.50	7,280,513
Total in Year	**2,634,934**	**5,288,075**	**7,819,421**	**10,357,570**	**24,643,761**		**11,015,189**

For most rate classes, a weighting factor of 0.5 has been used for 2013 to address that only one-half of the 2013 program results that persist into 2015 are captured in the actual load data from 2013 (because of the half-year rule). However, as street-light savings are captured separately, we have used a weighting factor of 0 for the persistence of streetlight savings from 2013 into 2015. The result is an overall weighting factor of 0.44 for 2013.

Residential kWh:	From final results	From final results	From final results	From preliminary resu	Estimated		
kWh	2011	2012	2013	2014	2015	Multiplier	Manual adjustment to Load Forecast - 2015
2011 CDM Programs	516,867	516,655	516,443	516,231	516,019	-	-
2012 CDM Programs		323,834	323,834	323,834	323,619	-	-
2013 CDM Programs			985,696	965,077	956,098	0.50	478,049
2014 CDM Programs				1,193,174	1,185,127	1.00	1,185,127
2015 CDM Programs					1,027,672	0.50	513,836
Total in Year	**516,867**	**840,489**	**1,825,973**	**2,998,316**	**4,008,536**		**2,177,013**

GS < 50 kW kWh:	From final results	From final results	From final results	From preliminary resu	Estimated		
kWh	2011	2012	2013	2014	2015	Multiplier	Manual adjustment to Load Forecast - 2015
2011 CDM Programs	856,649	836,702	815,615	774,690	754,743	-	-
2012 CDM Programs		664,057	660,988	653,971	485,438	-	-
2013 CDM Programs			562,583	562,067	512,392	0.50	256,196
2014 CDM Programs				634,888	634,262	1.00	634,262
2015 CDM Programs					586,541	0.50	293,271
Total in Year	**856,649**	**1,500,759**	**2,039,187**	**2,625,616**	**2,973,376**		**1,183,729**

GS 50 to 2,999 kW kWh:	From final results	From final results	From final results	From preliminary resu	Estimated		
kWh	2011	2012	2013	2014	2015	Multiplier	Manual adjustment to Load Forecast - 2015
2011 CDM Programs	1,261,418	1,243,650	1,243,650	1,213,623	1,213,623	-	-
2012 CDM Programs		1,094,485	1,073,869	1,064,495	1,055,842	-	-
2013 CDM Programs			716,309	692,512	688,192	0.50	344,096
2014 CDM Programs				842,573	836,944	1.00	836,944
2015 CDM Programs					12,946,813	0.50	6,473,407
Total in Year	**1,261,418**	**2,338,135**	**3,033,828**	**3,813,203**	**16,741,415**		**7,654,447**

Street Lighting kWh:	From final results	From final results	From final results	From preliminary resu	Estimated		
kWh	2011	2012	2013	2014	2015	Multiplier	Manual adjustment to Load Forecast - 2015
2011 CDM Programs						-	-
2012 CDM Programs		608,692	608,692	608,692	608,692	-	-
2013 CDM Programs			311,742	311,742	311,742	-	-
2014 CDM Programs						-	-
2015 CDM Programs						-	-
Total in Year	**-**	**608,692**	**920,434**	**920,434**	**920,434**		**-**

c) Please see b) above. The question is no longer applicable as there is no CDM adjustment for this class.

d) This adjustment is no longer being made in the revised load forecast outlined in 3-Energy Probe-34.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-27

Reference: Exhibit 3, Page 25

Interrogatory:

a) With respect to Table 3-22 what are the projected system purchases for 2014 and 2015 after all of the adjustments proposed by North Bay?

Response:

Using the revised load forecast referenced in 3-Energy Probe-34, the projected system purchases for 2015 after all of the adjustments proposed by North Bay is 537,291,034 (kWh). 2014 information is not provided since it is no longer projected in the load forecast.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-28

Reference: Exhibit 3, Page 38

Interrogatory:

a) Please update Table 3-36 with the actual results for 2014.

b) Where are the revenues from Microfit Service charges recorded and what are the actual/forecast revenues for 2013-2015?

c) Please explain why the revenue from specific service charges are projected to increase in 2014 (over 2013 actual values) but then decrease in 2015 to a value below the 2013 level.

Response:

a) Please refer to 3-Energy Probe-38.

b) Please refer to 3-Energy Probe-40.

c) The specific service charges increased in 2014 over 2013 mainly due to collection charges of $18,508. The 2015 collection charges have been forecasted to decrease to the levels of 2012 and 2013 since 2014 was an unusually high year. MicroFIT revenue was also reallocated to Account 4325 in 2015 creating a variance in specific service charges to fiscal 2013.

North Bay Hydro Interrogatory Responses

EXHIBIT 3 –OPERATING REVENUE

3-VECC-29

Reference: Exhibit 3, Page 41

Interrogatory:

a) Please provide a schedule that for 2012-2015 breaks down the Revenues from Non-Utility Operations (Acct. #4375) by source and that also does the same for Expenses of Non-Utility Operations (Acct. #4380).

b) Please provide a schedule that for 2012-2015 provides a breakdown of the various sources of Miscellaneous Non-Operating Income (Acct. #4390).

Response:

a) Appendix 2-H Other Operating Revenue tables below provide a breakdown of the various sources of Revenues from Non-Utility Operations for account 4375 and Expenses of Non-Utility Operations for account 4380.

Account 4375- Revenues from Non-Utility Operations	2010 Actual	2011 Actual	2012 Actual	2013 Actual	Bridge Year² 2014	Bridge Year² 2014	Test Year 2015
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
CDM Revenue OPA Incentives	$364,285	$773,484	$721,960	$1,515,554	$3,094,506	$3,094,506	$2,505,067
Generation - Merrick Landfill			$593,485	$216,175			
Affiliate NBHS - Management Fee	$38,048	$38,660	$49,355	$66,996	$52,862	$52,862	$51,931
Total	$402,333	$812,144	$1,364,800	$1,798,725	$3,147,368	$3,147,368	$2,556,998

Account 4380 - Expense from Non-Utility Operations	2010 Actual	2011 Actual	2012 Actual	2013 Actual	Bridge Year² 2014	Bridge Year² 2014	Test Year 2015
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
CDM/OPA Expenses	($409,054)	($738,100)	($720,226)	($1,506,414)	($3,076,276)	($3,076,276)	($2,505,067)
Generation - Merrick Landfill		($8,064)	($522,388)	($269,384)			
Total	($409,054)	($746,164)	($1,242,614)	($1,775,798)	($3,076,276)	($3,076,276)	($2,505,067)

b) Appendix 2-H Other Operating Revenue table below provides a breakdown of the various sources of Miscellaneous Non-Operating Income for account 4390.

Account 4390 - Miscellaneous Non-Operating	2010 Actual	2011 Actual	2012 Actual	2013 Actual	Bridge Year[2] 2014	Bridge Year[2] 2014	Test Year 2015
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
Miscellaneous Non Operating Income	$20	$4,561	$3,600			$0	
Sale of Scrap	$10,337	$9,385	$15,251	$11,139	$11,139	$11,139	$11,925
Bell Fibre Project				$197,278	$308,366	$308,366	
Total	$10,357	$13,946	$18,851	$208,417	$319,505	$319,505	$11,925

North Bay Hydro Interrogatory Responses

EXHIBIT 4 - OPERATING COSTS

4-Staff-10

Reference: Exhibit 4, Pages 6 and 22

Interrogatory:

On page 6, North Bay Hydro stated that its non-unionized staff received an average annual salary increase of 4.6% from 2010 forecast through 2015. North Bay Hydro stated that increases for non-unionized staff are based on performance.

a) North Bay Hydro stated that it has compared the increases of its unionized staff to those provided in other recent collective agreements. What external benchmarks have been used to compare the salaries of its non-unionized employees? How did North Bay Hydro compare to other distributors?

Response:

Please refer to Exhibit 4, Page 45, Line 18 to Exhibit 4, Page 61, Line 2 for detailed evidence to support the increase in compensation costs.

For non-union employees, the Hay system - an industry standard job evaluation system used to develop and maintain pay structures by comparing similarities and differences in the content and value of jobs. The Hay evaluation process includes a job analysis, job descriptions, job evaluation and job structure or ordering of jobs based on their relative value or content. Job evaluation factors include know how, problem solving, accountability and working conditions.

An external consultant assigns pay rates to each of the grades based on their experience and compensation from similar sized businesses in the LDC sector.

In 2013, NBHDL retained an external consultant to review the pay bands based on their experience and compensation from similar sized businesses in the LDC sector.

The consultant selects benchmark positions and establishes salary bands for each position considering pay equity legislation and salaries paid by other similar sized LDC's. Each position has a band including minimum, midpoint and maximum salary levels. Based on information provided by the consultant - other LDC's tend to have or are working towards non-unionized staff compensation being clustered around the midpoint salary level.

For NBHDL, it was found that on average management staff is clustered around the minimum point, well below the average midpoint designed by the compensation system.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-Staff-11

Reference: Exhibit 4, Pages 8 and 9

Interrogatory:

On page 8 of Exhibit 4, North Bay Hydro states:

> Ongoing business planning and specific reviews by external resources have been performed as required. For example in 2012-13 there was an external review of meter to cash processes and in 2013 an IT audit. Also in 2013-2014, [North Bay Hydro] updated its asset management plan including a new forecast of capital requirements for the next 5 years. The cost for the IT audit and the asset management plan have been included as part of the cost of service application to be recovered over a five year period.

a) Please confirm how these expenses have been included for recovery.

b) Please explain why the IT audit and the asset management plan would be eligible for recovery given that they are out of period costs.

c) Please confirm whether or not North Bay Hydro has undertaken IT audits and prepared asset management plans as part of its regular course of business in the past.

Response:

a) NBHDL confirms that the 2013 IT audit and the 2013-2014 asset management plan including a new forecast of capital requirements for the next 5 years has been included as part the cost of service application to be recovered over a five year period.

b) NBHDL considers the 2013 IT audit and the 2013-2014 asset management plan costs to be eligible for recovery as these activities were undertaken during the course of preparing the 2014 Cost of Service Application and completed in order to comply with the Filing Requirements. These are incremental costs incurred to support the application.

c) NBHDL confirms it has not undertaken IT audits or asset management plans as part of its regular course of business in the past.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-Staff-12

Reference: Exhibit 4, Pages 8 and 9

Interrogatory:

North Bay Hydro has forecasted $100,000 in ongoing business and strategic planning activities. North Bay Hydro has stated that this amount will be put towards the creation of a new strategic plan for the organization. North Bay Hydro also stated that it believes the amount of change occurring within its business (e.g. high turnover) and sector requires that ongoing business and strategic planning are required.

a) Has North Bay Hydro prepared a plan for the business and strategic planning activities that will be undertaken in 2015-2019? If so, please provide that plan along with the forecast spending in each year.

b) What is the basis for the estimated $100,000 in annual spending (e.g. historical consulting costs)?

Response:

a) NBHDL does not have an updated strategic plan for the 2015-2019 timeframe.

b) The $100,000 in annual spending is based on NBHDL's experience with the relative cost and effort expended by third party expertise recently engaged by the business for similar type activities.

In 2007/08 NBHDL last updated its strategic plan. Much has changed since this was done. A significant number of provincial policies have been implemented in the sector over the past 5 years. Exhibit #4, pages 14-15, identifies some of these changes. NBHDL fully expects the province to continue to implement new policies in the next 5 years at least at the same pace as the past 5 years. Also NBHDL will be experiencing significant retirements within the management team in the next 5 years. Given the change within the sector and within NBHDL, the past approach of a static 5 year plan no longer works without significant recalibration on an annual basis. Exhibit #4, pages 27-29 provides details with respect to the ongoing nature of planning costs. Third party expertise is important to assist with this process in order to ensure industry best practices are integrated into the process and outcomes.

The costs of more recent engagements were factored into the forecast for strategic planning, including:

- In 2012-13 there was an external review of meter to cash processes (see Exhibit 4, Appendix 4-A), which cost approximately $33,000.

- In 2013 an IT audit was conducted (see Exhibit 4, Appendix 4-B), which cost approximately $25,000.

- In 2013-2014, NBHDL updated its asset management plan including a new forecast of capital requirements for the next 5 years (see Exhibit 2, Appendix 2-A, Appendix B), which cost approximately $82,000.

- In 2014-2015, NBHDL undertook focused customer engagement for its application (see Exhibit 1, Appendix 1-A.1 to 1-A.7), which cost approximately $35,000.

- NBHDL also considered the quote of approx. $208,000 for an operational review, which quote can be found at Exhibit 4, Appendix 4-D at page 40.

Given the change within the sector and within NBHDL, the past approach of a static 5 year plan no longer works without significant recalibration on an annual basis. Exhibit #4, pages 27-29 provides details with respect to the ongoing nature of planning costs.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-Staff-13

Reference: Exhibit 4, Pages 9, 10, 75 and 76; Chapter 2 Appendices, Appendix 2-M

Interrogatory:

On page 9 of Exhibit 4, North Bay Hydro notes that its 2010 cost of service application estimated $160,000 in regulatory costs amortized over four years at $40,000 per year. North Bay Hydro also notes that the actual cost of its 2010 cost of service application was $285,232, or $71,308 per year.

For the preparation of its 2015 cost of service application, North Bay Hydro is forecasting $656,930 in costs to be recovered over five years at $131,386 per year.

North Bay Hydro states that it has forecast $459,215 in consultant costs for its application ($190k related to its DSP, $197k for legal costs, $52k for customer engagement). Appendix 2-M shows that North Bay Hydro's consultant costs were $115,000 in its last rebasing application.

North Bay Hydro states that $111,272 in one-time costs for 2015 are related to incremental costs for overtime, training and travel expenses related to the application for North Bay Hydro's employees. Appendix 2-M indicates that North Bay Hydro had zero dollars in incremental staff costs in the preparation of its 2010 cost of service application.

a) What was the cause of the variance in the estimated and actual costs for the preparation of North Bay Hydro's 2010 cost of service application?

b) Please provide a breakdown of the $111,272 in one-time incremental staffing costs related to the preparation of the North Bay Hydro's cost of service application.

c) Did North Bay Hydro use any form of tendering process in the selection of its consultants? If so, please provide the relevant documentation.

d) What procedural steps have been assumed in the forecast $197,595 in legal costs included for recovery in this application? How do the forecast procedural steps match what has been provisioned by the Board in Procedural Order No. 1?

e) Please provide a breakdown of the $189,685 in costs incurred from North Bay Hydro's consultant in the preparation of its DSP. Please confirm which, if any, of those services/analyses have been performed in the past as part of the North Bay Hydro's regular course of business.

f) Please confirm whether the $51,560 in costs related to customer engagement is incremental to the engagement activities North Bay Hydro has undertaken in the past as part of its regular course of business.

Response:

a) NBHDL has prepared the table below to outline the variances in the estimated cost of $160,000 to the actual costs of $285,232 for the preparation of NBHDL's 2010 cost of service application.

Regulatory Cost Category		USoA Account	USoA Account Balance	Ongoing or One-time Cost? 2	Last Rebasing Year (2010 Board Approved)	Last Rebasing Year Actual	Last Rebasing Year Variance to 2010 Board Approved
9	Consultants' costs for regulatory matters	5655		One-Time	$ 115,000	$ 179,735	$ 64,735
10	Operating expenses associated with staff resources allocated to regulatory matters - Overtime	5655		One-Time	$ -	$ 10,442	$ 10,442
11	Operating expenses associated with other resources allocated to regulatory matters _ Temporary Employees	5655		One-Time	$ -	$ 28,828	$ 28,828
12	Any other costs for regulatory matters -travel for the settlement conference and publications	5655			$ -	$ 4,944	$ 4,944
13	OEB Review COS	5655		One-Time	$ 35,000	$ 13,260	-$ 21,740
14	Intervenor costs	5655		One-Time	$ 10,000	$ 48,022	$ 38,022
15	Total One - Time				$ 160,000	$ 285,232	$ 125,232
16	2010 Cost of Service - Expensed over 4 years				$ 40,000	$ 71,308	$ 31,308
18	Sub Total - One Time				$ 40,000	$ 71,308	$ 31,308

b) NBHDL has prepared the table below in order to provide a breakdown of the $111,272 in one-time incremental staffing costs related to the preparation of the cost of service application.

NBHDL - One-time Incremental Staffing Costs	
NBHDL Internal Labour - overtime	100,898
Travel for training and Cost of Service application settlement conference	5,786
Training course fee	1,778
Supplies to prepare copies for application	2,811
Total	**111,273**

c) NBHDL used various forms of tendering process in the selection of its consultants. The type of work required along with the tendering process used and the basis for the award is detailed below:

- Asset Management/DSP – RFP; 2 proposals received; award based on lowest acceptable price.

- IT Assessment Report – RFP; 2 proposals received; award based on the following evaluation criteria: mandatory requirements being met, proposal merit, and price.

- Building Assessment Report – RFQ; 3 quotes received; award based on lowest submitted quote.

- Meter to Cash Report – RFP; 3 proposals received; award based on lowest acceptable price.

- Fleet Assessment Report – Sole sourced.

- Legal/Regulatory Services – Interviews by NBHDL management with prospective firms; 3 firms interviewed; award based on experience, familiarity with NBHDL, and best overall interview.

d) The $197,595 included for recovery in the application is for industry experienced legal and consulting services to prepare and submit the application as stated on page 75 (lines 35 and 36) of Exhibit 4. NBHDL retains one firm for both of these services and is billed inclusive. A settlement conference was assumed in the forecasted amount, however, expenses related to a technical conference and the possibility of an oral hearing outlined in the procedural steps by the Board in Procedural Order No. 1 have not been included in the forecast.

e) NBHDL has prepared the table below in order to provide a breakdown of the $189,685 in costs incurred from NBHDL's consultants in the preparation of its DSP for the cost of service application. NBHDL confirms that the extent of the work and analysis involved in preparing the DSP far exceed what would be done in the regular course of business.

NBHDL - DSP Consultant Costs		
Util-Assist	5 Year Metering Plan	22,129
Metsco	Asset Condition Assessment/DSP	132,455
Piotrowski	Building Assessment	6,200
J Saunders	Fleet Assessment	2,250
BDO	IT Assessement	26,650
Total		**189,684**

f) NBHDL confirms that the $51,560 in costs related to customer engagement is incremental to the engagements activities NBHDL has undertaken in the past as part of its regular course of business.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-Staff-14

Reference: Exhibit 4, Pages 26 and 38; DSP, Pages 31 and 32

Interrogatory:

On page 26, North Bay Hydro states that it needs to "continue to invest and develop its customer engagement activities." North Bay Hydro states that its engagement activities, forecasted to be $122,000 in the 2015 test year, will become a regular part of the O&M work program in 2015.

On page 31 of the DSP, North Bay Hydro discusses the results of its UtilityPULSE customer survey:

> While there is no significantly direct integration of these results into the DSP, the responses validate the direction and focus of North Bay Hydro's capital program.

On page 32 of the DSP, North Bay Hydro discusses the results of residential and small business focus group engagement activities:

> While not directly incorporated into the DSP, the results of this consultation work indicate to [North Bay Hydro] that the pacing, prioritization and focus of the 2015 capital spending and the projected infrastructure spending levels out to 2019 are aligned with customer preferences and expectations.

a) Please provide a breakdown of the engagement activities that will be undertaken on an annual basis. If available, please provide any road map of North Bay Hydro's planned future engagement activities over the forecast period.

b) Is North Bay Planning on undertaking any engagement activities to specifically investigate some of the customer preferences identified in its recent activities on a more detailed basis?

c) Given that North Bay Hydro has not directly incorporated the results of its recent engagement activities in its current planning cycle, how does North Bay Hydro believe that the proposed $122,000 in annual engagement cost will provide a direct benefit to its customers?

Response:

a) In light of the report findings, North Bay Hydro is considering a program of ongoing customer engagement activities that would help further the utility's understanding of customer perceptions, preferences and needs related to:

1. Continued delivery of high quality services
2. Reliability of service
3. Affordable electricity costs
4. Assistance to reduce consumption and thereby costs
5. Communications preferences
6. Timely service that solves customer problems
7. Professional interactions with highly skilled and experienced personnel
8. Proactive communications when there are unplanned outages

To enable this deeper understanding of customer preferences, North Bay Hydro is considering the following customer engagement activities on an on-going basis:

- Semi-annual UtilityPulse
- Semi-annual customer satisfaction (in support of OEB Scorecard requirements)
- Custom qualitative and quantitative customer research (e.g. focus group and/or surveys)

A final decision on the actual activities to be undertaken will be made in consultation with third party experts in facilitating effective engagement activities.

b) Yes. See response to part (a) for further details.

c) Continuous customer engagement is necessary to build a comprehensive understanding of customer needs and preferences. But the transition from developing that understanding and incorporating those preferences into long-term capital plans itself takes time. North Bay Hydro will incorporate the results of its continous engagement efforts into future planning cycles, which will provide customers with direct benefits. The better North Bay Hydro knows and understands its customer (including their needs and preferences) the better the utility can service its customers and provide greater value for money.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-Staff-15

Reference: Exhibit 4, Page 60

Interrogatory:

North Bay Hydro has indicated that as of December 31, 2013, the Net Benefit Liability related to its Other Post-Employment Benefits (OPEB) was $4,511,393, including $205,022 of unamortized gain. The evidence further indicates that North Bay Hydro has recognized the unamortized gain of $205,022 in its retained earnings. North Bay Hydro has recovered OPEB through its revenue requirement in prior applications before the Board.

a) Please explain how North Bay Hydro has addressed this reduction in the liability in this rate application.

b) Is North Bay Hydro going to refund the gain amount to ratepayers? If not, please explain why not.

c) In the rate proceeding EB-2011-0123 for Guelph Hydro Electric Systems Inc., the OEB approved the settlement where the Parties agreed to dispose the OPEB actuarial gain through a rate rider over the average remaining service life of the employees covered. Would North Bay Hydro agree to recording the gain in a deferral account and when the account is disposed in a future application, to amortize the gain using estimated average remaining service lives of the employees? If North Bay Hydro disagrees, please explain why such a treatment would not be fair to both customers and the company.

d) Please indicate if OPEBs were recovered on a cash or accrual accounting basis for each year since North Bay Hydro started to recover OPEBs. For example, recovery may have been on a cash basis from 2000 to 2006 when recovery was changed to accrual accounting amounts.

e) Please complete the table below to show how much more than the actual cash benefit payments, if any, have been recovered from ratepayers from the year North Bay Hydro started recovering amounts for OPEBs.

OPEBs	First year of recovery up to 2011	2012	2013	2014	2015	Total
Amounts included in rates						
OM&A						
Capital						
Sub-total						
Paid benefit amounts						
Net excess amount included in rates greater than amounts actually paid						

f) Who is responsible to fund the future payments represented by the liability of $4,511,393?

g) If North Bay Hydro believes that customers are responsible for the liability, how would North Bay Hydro expect the net excess amount in the table above to be treated for ratemaking purposes? In the event that the OEB continues to approve the OPEB amount based accrual accounting for inclusion in rates, would North Bay Hydro agree to establish an OPEB deferral account to prospectively capture the actuarial gains and losses related to OPEB?

Response:

a) NBHDL has addressed this reduction in the liability as stated below in Exhibit 4, page 60, lines 18-19.

At December 2013, the Net Benefit Liability was $4,511,393 which included $205,022 of unamortized gain; NBHDL has recognized this amount in retained earnings.

b) NBHDL has not proposed to refund the amount to ratepayers in its Application. Such an approach would be contrary to the principle that prohibits retroactive ratemaking. Rates are established on the basis of the best knowledge available at the time - they are not adjusted retroactively every time actuals deviate from forecast.

c) NBHDL would consider such a proposal in the context of a comprehensive settlement of all of the issues in this proceeding. If such a rate rider was established, NBHDL would be concerned about establishing a fair treatment for both actuarial gains (such as those arising from the net benefit liability) and actuarial losses (such as the actuarial loss in 2014 of $375,760 that under IFRS would be recorded in other comprehensive income). Please see the 2014 year end Collins Barrow evaluation in Attachment-4-Staff-15c.

d) NBHDL does not have information to confirm the basis of recovery in rates for the OPEBs from 2000-2005, since rates were set on a formula basis and not attributed to specific expenses. NBHDL confirms that the basis of recovery from the 2006 application forward was on the accrual basis.

e) Table 1 has been completed to show the OPEB amounts recovered from ratepayers from 2000 through to the 2015 forecast based on the actuarial information from the projections prepared by Collins Barrow on March 28, 2014 as included in the application, together with the actual 2014 information, and a revised 2015 forecast has been update to reflect the Collins Barrow January 23, 2015 report included as Attachment-4-Staff-15e. As discussed in response to part d) above, NBHDL cannot confirm the actual amounts recovered from ratepayers from 2000-

May 2006 and as such the assumption has been made that it was on a cash basis. May 2006 forward has been completed using rate application information.

2014 Actual						
OPEBs	2000-2011	2012	2013	2014 Actual	2015 Forecast	Total
Amounts inlcuded in rates						
OMA	4,140,543	$ 294,626	$ 294,626	$ 294,626	$ 256,255	$5,280,676
Capital	587,110	$ 12,083	$ 12,083	$ 12,083	$ 4,028	$ 627,387
Sub-total	4,727,653	$ 306,709	$ 306,709	$ 306,709	$ 260,283	$5,908,063
Paid benefit amounts	3,766,394	$ 380,544	$ 300,206	$ 251,879	$ 271,960	$4,970,983
Next excess amount included in rates greater than amounts actually paid	$ 961,260	$ (73,835)	$ 6,503	$ 54,830	$ (11,677)	$ 937,081

f) NBHDL is responsible to fund the future payments represented by the liability. This is a legitimate cost of doing business which should, in turn, be included within the calculation of just and reasonable distribution rates.

g) NBHDL’s proposal for the treatment of the net excess amount for ratemaking purposes is as described in the Application. As noted above, the amounts from 2000-2005 are based on an assumption. Rates over this period were set on a formula basis and not attributed to specific expenses. Since 2012, the variance in the accounts at times shows an asset and at times shows a liability. These are normal variances for accounts of this nature. NBHDL does not believe that these normal variances justify a departure from the principle that prohibits retroactive ratemaking.

In the event the OEB continues to approve the OPEB amount based on accrual accounting for inclusion in rates, NBHDL may or may not agree to establish an OPEB deferral account to prospectively capture the actuarial gains and losses that under IFRS would be recorded to other comprehensive income. As noted above, NBHDL would be concerned about establishing a fair treatment for both actuarial gains (such as those arising from the net benefit liability) and actuarial losses (such as the actuarial loss in 2014 of $375,760 that under IFRS would be recorded in other comprehensive income).

North Bay Hydro Distribution Limited
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Actual CY 2014	Projected** CY 2015
Discount Rate at January 1	4.60%	3.80%
Discount Rate at December 31	3.80%	3.80%
Health Benefit Cost Trend Rate at December 31		
Initial Rate	6.70%	6.40%
Ultimate Rate	4.60%	4.60%
Year Ultimate Rate Reached	2022	2022
Dental Benefit Cost Trend Rate	4.60%	4.60%
Salary Scale Rate	3.30%	3.30%
Assumed Increase in Employer Contributions	actual	expected*

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

	Actual CY 2014	Projected** CY 2015
Net Defined Benefit Liability/(Asset) as at January 1	4,306,371	4,688,803
Defined Benefit Cost Recognized in Income Statement	258,551	237,070
Defined Benefit Cost Recognized in Other Comprehensive Income	375,760	-
Benefits Paid by the Employer	(251,879)	(271,960)
Net Defined Benefit Liability/(Asset) as at December 31	4,688,803	4,653,913

B. Determination of Defined Benefit Cost
B1. Determination of Defined Benefit Cost Recognized in Income Statement

	Actual CY 2014	Projected** CY 2015
Service Cost		
- Current Service Cost	66,251	78,341
- Past Service Cost	-	-
Net Interest Cost	192,300	158,728
Defined Benefit Cost Recognized in Income Statement	258,551	237,070

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

	Actual CY 2014	Projected** CY 2015
Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	375,760	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-	
Return on Plan Assets (excluding amounts included in net interest cost)	-	-
Change in effect of asset ceiling	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	375,760	-
Total Defined Benefit Cost	634,311	237,070

C. Change in the Present Value of Defined Benefit Obligation

	Actual CY 2014	Projected** CY 2015
Present Value of Defined Benefit Obligation as at January 1	4,306,371	4,688,803
Current Service Cost	66,251	78,341
Past Service Cost	-	-
Interest Cost	192,300	158,728
Benefits Paid	(251,879)	(271,960)
Net Actuarial Loss/(Gain)	375,760	-
Present Value of Defined Benefit Obligation as at December 31	4,688,803	4,653,913

* based on estimated employer Benefits Paid for those expected to be eligible for benefits

**Projected CY2015 results are provided for informational purposes only. Significant changes in 2015 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

North Bay Hydro Distribution Limited
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Actual CY 2014	Projected** CY 2015
Discount Rate at January 1	4.60%	3.80%
Discount Rate at December 31	3.80%	3.80%
Health Benefit Cost Trend Rate at December 31		
Initial Rate	6.70%	6.40%
Ultimate Rate	4.60%	4.60%
Year Ultimate Rate Reached	2022	2022
Dental Benefit Cost Trend Rate	4.60%	4.60%
Salary Scale Rate	3.30%	3.30%
Assumed Increase in Employer Contributions	actual	expected*

D. Calculation of Component Items

	Actual CY 2014	Projected** CY 2015
Service Cost		
- Current Service Cost	66,251	78,341
- Past Service Cost	-	-
Interest Cost		
- Net Defined Benefit Liability/(Asset) as at January 1	4,306,371	4,313,043
- Benefits Paid	(125,940)	(135,980)
- Accrued Benefits	4,180,432	4,177,063
- Interest Cost	192,300	158,728
Expected Present Value of Defined Benefit Obligation as at December 31		
- Present Value of Defined Benefit Obligation as at January 1	4,306,371	4,313,043
- Current Service Cost	66,251	78,341
- Interest Cost	192,300	158,728
- Benefits Paid	(251,879)	(271,960)
- Expected Present Value of Defined Benefit Obligation as at December 31	4,313,043	4,278,152

E. Net Actuarial Loss/(Gain)

	Actual CY 2014	Projected** CY 2015
Net Actuarial Loss/(Gain) on Present Value of Defined Benefit Obligation as at December 31		
- Expected Present Value of Defined Benefit Obligation	4,313,043	4,278,152
- Past Service Cost	-	-
- Expected Present Value of Defined Benefit Obligation (after Past Service Cost)	4,313,043	4,278,152
- Actual Present Value of Defined Benefit Obligation	4,688,803	4,278,152
- Net Actuarial Loss/(Gain) on Present Value of Defined Benefit Obligation	375,760	-

* based on estimated employer Benefits Paid for those expected to be eligible for benefits.

**Projected CY2015 results are provided for informational purposes only. Significant changes in 2015 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

North Bay Hydro Distribution Limited
ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Actual Calendar Year 2014
Discount Rate - January 1	4.60%
Discount Rate - December 31	3.80%
Withdrawal Rate	Age based rate table
Assumed increase in Employer Contributions	actual

A. Determination of Benefit Expense

Current Service Cost	63,338
Interest on Benefits	195,213
Expected Interest on Assets	-
Past Service Cost	-
Transitional Obligation/(Asset)	-
Actuarial (Gain)/Loss	-
Benefit Expense	258,551

B. Reconciliation of Prepaid Benefit Asset (Liability)

Accrued Benefit Obligation (ABO) as at December 31	4,688,803
Assets as at December 31	-
Unfunded ABO	(4,688,803)
Unrecognized Loss/(Gain)	170,739
Prepaid Benefit Asset (Liability)	(4,518,065)
Prepaid Benefit/(Liability) as at January 1	(4,511,393)
Benefit Income/(Expense)	(258,551)
Contributions/Benefit Payments by the Employer	251,879
Prepaid Benefit Asset (Liability)	(4,518,065)

North Bay Hydro Distribution Limited
ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Actual Calendar Year 2014
Discount Rate - January 1	4.60%
Discount Rate - December 31	3.80%
Withdrawal Rate	Age based rate table
Assumed increase in Employer Contributions	actual

C. Calculation of Component Items

Calculation of the Service Cost	
- Current service cost	63,338
Interest on Benefits	
- ABO at January 1	4,306,371
- Current service cost	63,338
- Benefit payments	(125,940)
- Accrued benefits	4,243,769
- Interest	195,213
Expected Interest on Assets	
- Assets at January 1	-
- Funding	125,940
- Benefit payments	(125,940)
- Expected assets	-
- Interest	-
Expected ABO as at December 31	
- ABO at January 1	4,306,371
- Current service cost	63,338
- Interest on benefits	195,213
- Benefit payments	(251,879)
- Expected ABO at December 31	4,313,043
Expected Assets as at December 31	
- Assets at January 1	-
- Funding	251,879
- Interest on assets	-
- Benefit payments	(251,879)
- Expected Assets at December 31	-

North Bay Hydro Distribution Limited
ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Actual Calendar Year 2014
Discount Rate - January 1	4.60%
Discount Rate - December 31	3.80%
Withdrawal Rate	Age based rate table
Assumed increase in Employer Contributions	actual

D. Actuarial (Gain)/Loss

(Gain)/Loss on ABO as at January 1	
- Prepaid Benefit/(Liability) as at January 1	4,511,393
- Unrecognized Transitional Obligation	-
- Unamortized (Gain)/Loss	(205,022)
- Expected ABO	4,306,371
- Actual ABO	4,306,371
- Total (Gain)/Loss on ABO	-
(Gain)/Loss on assets as at January 1	
- Expected assets	-
- Actual assets	-
- (Gain)/Loss on assets	-
Total (Gain)/Loss as at January 1	(205,022)
10% of ABO as at January 1	430,637
Total (Gain)/Loss in excess of 10%	-
Expected average remaining service life (years)	13
Minimum Amortization for current year	-
Actual Amortization for current year	-
(Gain)/Loss on ABO at December 31 due to change in discount rate assumption	
- Expected ABO - December 31	4,313,043
- Actual ABO - December 31	4,688,803
- (Gain)/Loss on ABO at December 31	375,760
Unamortized (Gain)/Loss	170,739

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January 23, 2015

BY E-MAIL: CTennant@northbayhydro.com

Ms. Cindy Tennant
Finance Manager
North Bay Corporation Distribution Limited
74 Commerce Crescent
North Bay, ON P1B 8G4

Dear Ms. Tennant:

Re: North Bay Hydro Distribution Limited Actuarial Valuation Report as at December 31, 2013: Post-Retirement Non-Pension Benefit Plan – Extrapolations

This letter provides you with our calculation of the CY 2014 benefit expense and the December 31, 2014 Accrued Benefit Obligation ("ABO") for the above noted benefit plan.

The intended users of this letter and attachments include the Corporation and its auditors for financial reporting in compliance with CICA guidelines in respect of its post-retirement non-pension benefit plan.

CY 2014 Accounting Results

The calculations were performed in accordance with the guidelines set forth in Section 3461 Employee Benefits of the Canadian Institute of Chartered Accountants (CICA) Handbook Accounting Part V Pre-Changeover Accounting Standards ("CICA Section 3461").

For the post-retirement non-pension plan, the December 31, 2014 Accrued Benefit Obligation ("ABO") is approximately $4,689,000 with the supporting calculations being summarized in the actuarial valuation report hereby attached. The CY 2014 benefit expense is approximately $259,000 with the supporting calculations summarized in the accounting worksheets hereby attached.

We have performed our calculations based on the following:

- **Plan provisions**: The plan provisions are summarized in our January 1, 2013 actuarial valuation report for the post-retirement non-pension benefit plan ("Report").

- **Data**: We have used the membership data as at January 1, 2013 which is summarized in the Report.

- **Assumptions**: A discount rate assumption of 3.80% per annum as at December 31, 2014 has been selected to reflect the current yields on high quality debt instruments. In regards to the discount rate assumption for December 31, 2014, as you are aware, the Canadian Institute of Actuaries ("CIA") released an Educational Note on the "Accounting Discount Rate Assumption for Pension and Post-employment Benefit Plans" (Educational Note) in September 2011. Along with the Educational Note, the CIA has also acquired the services of Fiera Capital Investment Management Inc. (a portfolio investment management firm in Canada) to produce a monthly spot rate curve that is derived using the methodology described in the Educational Note.

  Based on the Corporation's expected projected benefit cash flows for post-retirement non-pension benefits and the most current spot rate curve published by Fiera Capital (i.e. as at December 31, 2014), a discount rate assumption of 3.80% per annum as at December 31, 2014 has been selected. For your reference, a discount rate assumption of 4.60% per annum was selected as at December 31, 2013.

  All other assumptions used in our calculations are as summarized in the Report.

- **Method**: We have done our calculations as at January 1, 2013 using the method described in the Report. The ABO's as at December 31, 2014 are based on a roll forward of the January 1, 2013 ABO using the updated membership data and management's best estimate assumptions as described above.

Results under International Financial Reporting Standards ("IFRS")

Also, included in separate accounting worksheets attached hereto, are the updated figures for 2014 and 2015 on the basis of International Financial Reporting Standards IAS 19 (Employee Benefits), including:

- Calculations of the present value of the defined benefit obligations at December 31, 2014.

- Extrapolation of the January 1, 2014 IAS 19 results for fiscal years ending December 31, 2014 and December 31, 2015.

The following is noted in regards to the attached IAS19 figures:

- The methodology, assumptions and data used in the calculation of the present value of the defined benefit obligation and current service cost is the same as outlined above in regards to the CICA disclosure provided.

- Our calculations conform to the standards as set out in International Accounting Standard 19 (Employee Benefits).

We are not aware of any subsequent events that would have a significant impact on our calculations.

If you have any questions regarding the above or the attached accounting schedules, please do not hesitate to call.

Yours truly,

Stanley Caravaggio

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North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-Staff-16

Reference: Exhibit 4, Table 4-27; Appendix 4-I – Purchasing Policy; Exhibit 4, Page 73; Chapter 2 – Filing Requirements for Electricity Distribution Rate Applications, July 18, 2014, Page 36

Interrogatory:

Page 36 of the Filing Requirements states that a distributor must provide a description of the specific methodology used in determining the vendor, including a summary of the tendering process. North Bay Hydro has provided a purchasing policy in Appendix 4-I which does not provide details regarding the tendering process. Section 9.4.07 of North Bay Hydro's purchasing policy states management has the right to waive the purchasing policy in certain situations.

Table 4-27 summarizes the North Bay Hydro's purchases from non-affiliates. The table shows three items who's method of selection is described as "Sole Source – Engineering Preference": i) G&W Canada Corporation (~155k in 2013), ii) S&C Electric Canada Ltd. (~ $172k in 2013) and iii) UTS Consultants Inc. (~ $991k in 2013).

a) Please provide a document detailing North Bay Hydro's tendering process including descriptions of the evaluation criteria for selecting vendors.

b) Please confirm whether or not North Bay Hydro has invoked the waive clause of its purchasing policy since 2010.

c) Please explain the rationale for not using a tendering process for each of the vendors identified as “Sole Source – Engineering Preference” in Table 4-27.

Response:

a) NBHDL’s tendering process is described as follows:

North Bay Hydro follows a purchasing process model. Purchases of goods or services on a value scale determine if a request for quote (phone or letter), request for proposal, or request for tender is issued. Sealed proposals/tenders are obtained for all large line vehicles and for totals over $40,000, with exceptions based on factors effecting choice of suppliers, criteria for approval and/or the waiver clauses contained in the NBHDL purchasing policy. All contracts have a start and end date and upon completion of the contract, the purchasing process restarts if the good or service is still required.

Possible bidders are identified through various means such as: previous relations, previous bid attempts, RFI’s, known businesses that offer the required good or service, businesses that have expressed interest in doing business with NBHDL and are qualified to do so. Performance Indicators are considered when selecting a vendor, indicators such as financial stability, errors in prior contracts, on time performance, and quality of product, and or service. Compliance with NBHDL terms and conditions or mutual agreement on an amended set of terms of conditions is a requisite for vendor award.

The evaluation criteria for each purchase differs based on the type of process involved, the scope of work, the duration of the contract, and the amount of the contract. In some instances the criteria is solely price, while other instances involve a complicated scoring matrix. Once the submissions are determined eligible for evaluation, a team of NBHDL employees score and evaluate each of the proponent's bids, then award based on overall score and merit. Depending on the amount of the contract, approval by senior management may be required.

b) NBHDL has not invoked the waive clause of its purchasing policy since 2010.

c) The rationale for not using a tendering process for the first two vendors, G&W Canada Corporation, and S&C Electric is that they supply substation equipment that NBHDL has standardized based on engineering requirements. Standardization allows for lower inventory, familiarity of equipment with staff installing and maintaining it, duplicated design, easy replacement in emergency conditions, and ensures quality and delivery. Quotes for the equipment are still obtained and reviewed against prior quotes for the same or similar equipment to ensure pricing is acceptable prior to purchasing. The rationale for not using a tendering process for the third vendor, UTS Consultants Inc., is that NBHDL only uses UTS to conduct 3rd Party attachment design work, which is hourly/unit based work with pricing reviewed on an annual basis. Further to that, NBHDL has standardized on the use of UTS based on engineering preference and established quality and delivery. It is important to note that all $991k of UTS cost is passed straight through to the third parties requesting attachment to NBHDL's system. The costs in 2013 are high due to the Bell fibre to the home project.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-Staff-17

Reference: Exhibit 4, Chapter 2 Appendices, Appendix 2-JA

Interrogatory:

The proposed future OM&A increases are significant, at 36.7% above 2010 actuals.

a) Please outline the outcomes and higher level of services that customers will receive for the relatively higher rates they are paying. How has the applicant communicated the benefits of these services to its customers and how did customers respond?

b) Please identify any customer engagement that supports the further increases proposed in this application.

c) Please provide the analysis that was performed to assess whether this applicant's planning decisions reflect best practices of Ontario distributors.

d) Please identify any initiatives considered and/or undertaken by the applicant, including any analysis conducted, to optimize plans and activities from a cost perspective, for example, balancing cost levels of OM&A versus capital.

e) The Board's letter of November 28, 2012, established the stretch factor assignments for 2013 rates. The applicant was assigned to Stretch Factor Group 1 out of three groups. On November 21, 2013, the Board established the stretch factor assignments for 2014 rates in the Report of the Board: Rate Setting Parameters and Benchmarking under the renewed Regulatory Framework for Ontario's Electricity Distributors. The applicant was assigned to Group III out of five groups. Please provide details on any initiatives undertaken to improve the applicant's assignment in future years.

Response:

a) Please refer to Exhibit 1, Pages 9-13 for a list of the key objectives for NBHDL, including specific targets for each objective. NBHDL developed its OM&A budget with a view to ensuring that it will have the resources necessary to able to achieve all of these targeted outcomes.

During the summer of 2014, retained an expert in customer engagement and communications - Innovative Research Group, Inc. ("INNOVATIVE") -to design, collect feedback and document its customer engagement and consultation process as part of the development of the Application.

NBHDL asked that customers be engaged on both NBHDL's capital infrastructure and operational plans. This customer engagement work and a summary of the customer preferences and NBHDL's efforts to respond to those preferences is described at Exhibit 1, Page 60, Line 7 to Exhibit 1, Page 72, Line 13.

A complete copy of the INNOVATIVE Customer Engagement Report is attached to the Application as Appendix 1-A.7.

Attached as an appendix to the Innovative Customer Engagement Report, NBHDL would refer staff specifically to page 19 of the workbook that was used to engage customers on OM&A costs. The change in costs from 2010 board approved to the 2015 budget is clearly explained, as are the key cost drivers.

Please refer to Pages 18-21 of Appendix 1-A.7 for feedback received from customers on this workbook.

Following the workbook session, INNOVATIVE conducted a telephone consultation of a larger group of customers. The telephone consultation script also covered OM&A costs, and the results of the telephone consultation are provided at Pages 22-72 of Appendix 1-A.7 (see in particular pages 55-57 for the results as it related to the operating budget).

b) All of the customer engagement work described in Exhibit 1 of the Application, including without limitation Appendix 1-A.1 to Appendix 1-A.7, has been filed as evidence in support of the proposals set out in this Application, including the proposed increase in the OM&A budget.

Customers were engaged through a workbook facilitated discussion group and telephone surveys where they learned about North Bay Hydro's proposed spending and investment plan and provided feedback on preferences and needs.

In the telephone survey, customers heard about North Bay Hydro's cost drivers and unique pressures that impact system reliability.

Customers where then read: *According to North Bay Hydro's proposed plan, the total required funding to manage the day-to-day operations and required capital investment is estimated to be **$14.7 million** in 2015.*

- ***53%** of the these funds or approximately **$7.8 million** is budgeted for capital investments required to replace aging infrastructure; to connect new customers to the electricity system; to invest in tools, IT systems, vehicles and facilities needed to manage the electricity system; and for new technologies to make the system more efficient, reliable and safe.*

- ***47%** of these funds or approximately **$7.0 million** of this proposed plan is budgeted for the day-to-day management of the company as a whole, salaries and wages, customer service and on-going maintenance of the distribution system.*

Residential Preamble: To fund this plan, **North Bay Hydro** is proposing the **average residential household's rate increase by 92 cents ($0.92)** on the distribution portion of their bill over the next five years. So, by 2019, the average residential household will be paying an **estimated $4.60 more per month** on the distribution portion of its electricity bill.

GS Preamble: To fund this plan, **North Bay Hydro** is proposing the **average small to medium sized business' rate increase by $1.10** on the distribution portion of their bill over the next five years. So, by 2019, the average **small to medium sized business** will be paying an **estimated $5.49 more per month** on the distribution portion of its electricity bill.

- 73% of residential respondents accept this proposed rate increase.

- 68% of general services respondents accept this proposed rate increase.

c) NBHDL routinely discusses its business processes and practices with other LDCs to ensure that it has adopted and is implementing industry best practices. Sharing of best practices is common throughout the industry – minimizing the need to conduct costly formal studies or reports.

In addition, NBHDL has focused on conducting more formal reviews of best practices in the areas of the business that have experienced the greatest changes, and thus represented the best opportunity for improvement or experienced the most significant amount of growth in demand for services.

A considerable amount of NBHDL's resources are involved in meter to cash activities and NBHDL engaged third party expertise in spring 2013 to review its current processes and to make recommendations on improvements in order to meet best practices in this area. The consultants recommendations were based on their experience supplemented by interviews with a cross section of other similar sized LDC's and vendors that provide services across Ontario or North America. This part of the business has experienced the most significant change given the deployment of smart meters and the implementation of new settlement processes and time of use rates. The 2015 work program is focusing on making changes in the medium and high risk areas identified by the vendor. The vendor identified "NBHDL has proven themselves adept at managing the high volume of changes that have been thrust upon them". The vendors report is included in Appendix 4-A of the Application.

Another part of the business experiencing significant change has been in the area of IT strategy and infrastructure. In late 2013 NBHDL engaged third party expertise to review IT strategy, infrastructure and governance including performance relative to industry best practices (see Appendix 4-B of the Application for their report) with a focus on identifying key risks to the business. NBHDL integrated the vendors findings into the IT strategy developed by internal resources (Appendix 4-C of the Application).

NBHDL recently updated its Asset Condition Assessment and prepared a comprehensive Distribution System Plan based on the recommendations of third party advice on best practices in the industry. This material can be found at Appendix 2-A of the Application.

NBHDL has recently consulted with other LDC's about their vegetation maintenance programs to evaluate whether further changes to the program were warranted. NBHDL also considered industry reports and LDC experience from the ice storms that hit southern Ontario just over a year ago. NBHDL engaged a third party professional arbor culturist to assess pruning, line clearing, brushing and removal practices. NBHDL's service territory is broken into cycles with the objective of undertaking activities in a specific area every 5 years. The arbor culturist reviewed the condition of each cycle and created a benchmark on the relative workload to complete a specific cycle. The results of this professional third party review were integrated into developing vegetation maintenance program costs. The arborists review was included in Appendix 4-E.

NBHDL engaged third party expertise with diverse industry experience to assess its fleet and major equipment replacement strategy. Their report is in Exhibit 2, Appendix D. Replacing vehicles at the optimum time prevent costly repairs on vehicles and equipment beyond their reliable and safe life.

NBHDL also engaged industry experts to review its operations/customer service centre and make recommendations on a maintenance and replacement for various building systems. Following this strategy helps to minimize operating costs while providing a healthy and safe work environment.

NBHDL has experienced significant increases in workload from customer phone calls, collection activities and utility locates. Details on this workload and NBHDL's approach to handling this workload is provided on page 12 of Exhibit #4. NBHDL did consult with other LDC's on how they are organized to manage customer activities, including account management, collection and billing activities. This information was collected through meetings and interviews and although no formal report exists, the information was utilized to structure job functions and work processes. NBHDL feels that this work is a contributing factor to relatively strong customer service ratings. NBHDL also engaged third party assistance to develop a computerized, mobile application for drawing and producing locates. Locates are provided in-field to ensure rapid turnaround. This work was helpful in handling the increased locate request volume.

In summary, implementing best practices happens on a regular basis and is not always the subject of formal reports or documentation. NBHDL is committed to maintaining its complement at less than 50, so new workloads must be met by continuous improvement and implementation of best practices. For example NBHDL is a member of the Sensus users group and gets access to security audits, meter testing results and AMI performance enhancements at a significant discount. NBHDL uses Sungard HTE as its billing and enterprise management system. NBHDL is in contact almost weekly with different users and the supplier to share solutions and implement best practices, including disaster recovery. Other NBHDL operational staff contact their peers in other LDC's to determine how best to utilize equipment or new technology.

As described elsewhere in the Application, NBHDL is also planning on completing an operational review of engineering and operations work activities. The third party expertise utilized for this review will bring with them additional best practices that could be applied by NBHDL.

d) NBHDL provided a list of 25 measures identified on pages 74-79 of Exhibit #1 implemented in the past to help reduce costs. For example participating in the Northern LDC Buying Group saved over $115,000 in 2013 in stores purchases. Many of the initiatives implemented have allowed NBHDL to maintain its staff complement at its objective of less than 50 despite the increase in workload in customer demand activities including customer calls, customer walk in for service, collection activities and locates.

NBHDL also identified some 20 cost saving measures that have been/will be implemented in the test year. These items are detailed on pages 80-83 of Exhibit #1. NBHDL also identified new customer service improvements that have been or will be implemented in 2015.

As stated elsewhere in the Application, NBHDL is planning on undertaking an operational review in 2015 to look at work processes, flow and execution in the engineering/operations area. NBHDL expects this review to help execute and achieve the planned work program efficiently and safely. Existing staff have challenges balancing capital and operating work programs in the busy summer season. Winters are much more severe than those experienced in the GTA often resulting in a compressed construction season.

Finally, NBHDL provided details on its budgeting process on pages 16 and 17 of Exhibit #4 as this is a key process in managing costs. Capital programs are defined by the DSP including requirements for infrastructure renewal and historical averages for delivering on demand related activities. Operating and maintenance budgets are developed from the bottom up based on forecasted activity for the year. Performance versus budget is tracked on a regular basis.

e) NBHDL has an express target to maintain or improve its current group ranking as determined using the PEG methodology (Exhibit 1, Page 12, Item 4.1). Please refer to Exhibit 1, Pages 73 - 85 for a comprehensive description of: (i) past efforts NBHDL has undertaken to achieve cost reductions and productivity improvements; and (ii) efforts NBHDL is undertaking to achieve cost reductions and productivity improvements in the test year.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-42

Reference: Exhibit 4, Page 4

Interrogatory:

a) Please update Table 4-1 to reflect actual data for 2014. If actual data for all of 2014 is not yet available, please update to reflect the most recent year to date actual data available, along with the most recent estimate for any remaining months in 2014.

b) Is there any change in 2014 and 2015 relative to 2012 and 2013 as a result of reporting under MIFRS in the bridge and test years, as compared to 2012 and 2013 which reflect changes to capitalization policies? If yes, please quantify and explain fully.

c) In Exhibit 1, page 88, NBHDL indicates it changed its capitalization of overhead. Was there a further change in capitalization that took place in 2012? If yes please quantify and explain fully.

Response:

a) Table 4-1 has been updated to reflect actual data for 2014.

OM&A	2010 Board Approved	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
Operations, Maintenance & Admin	5,665,409	5,005,105	5,363,646	5,532,379	5,704,951	6,807,975	6,534,566	7,004,844
Depreciation/Amortization	2,694,912	2,660,512	2,824,150	1,815,597	1,917,677	3,270,284	3,217,082	2,503,945
Property Taxes	64,292	60,827	58,586	57,183	62,479	66,004	66,357	69,876
Payment in lieu of Taxes	686,307	734,285	709,731	660,447	536,307	537,316	475,000	162,510
Total Operating Expenses	9,110,920	8,460,729	8,956,113	8,065,606	8,221,414	10,681,579	10,293,005	9,741,175

b) The changes made to NBHDL's capitalization policies in 2012 in relation to the transition to MIFRS impacted the componentization of assets, depreciation and contributed capital classification only. These changes did not impact the allocation of costs between OM&A and capital.

c) There were no changes to the overhead capitalization policy in 2012 and NBHDL's capitalization policy has been reviewed and approved as IFRS compliant by NBHDL's external auditors. NBHDL's capitalization policy is explained in more detail beginning on page 89 of Exhibit 2 and specific changes made to the capitalization policy are described on pages 93 to 95.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-43

Reference: Exhibit 4, Page 12

Interrogatory:

a) Please provide the 2010 Board approved amount for vegetation management, along with actual costs for 2010 through 2014 and the forecast for 2015.

b) Please provide the actual costs incurred in 2010 through 2014 and the forecast for 2015 for emergency repairs due to storm damage.

Response:

a) The table below provides the 2010 Board approved amount for vegetation management, along with the actual costs for 2010 through 2014 and the forecast for 2015.

Programs	Last Rebasing Year (2010	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
Vegetation Management	309,539	279,036	411,366	187,121	350,991	517,831	581,736	656,194

b) The table below provides the costs incurred in 2010 through 2014 for emergency repairs due to storm damage. Please note the costs below account for all storm damage and not just storm damage caused by trees. A forecast for 2015 is not available as NBHDL does not forecast labour costs at that granular a level.

2010	2011	2012	2013	2014
$54,058	$66,093	$63,603	$74,741	$4,692

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-44

Reference: Exhibit 4, Table 4-4

Interrogatory:

Please provide a breakdown of the $412,548 shown in 2014 for smart meter disposition in Table 4-4 into the years where the costs were actually incurred.

Response:

The table below breaks down the $412,548 shown in 2014 for smart meter disposition in Table 4-4 by the year where the costs were actually incurred.

2007 Actuals	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	Total
7,745	1,662	123,325	100,862	175,963	2,991	412,548

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-45

Reference: Exhibit 4, Table 4-4

Interrogatory:

a) Please explain why there is no line item in Table 4-4 for accounting changes associated with the changes in capitalization noted elsewhere in the evidence between 2011 and 2012 and between 2013 and 2014.

b) If there is an impact of the change in capitalization on OM&A between 2010 and 2015, please provide the amount on a year by year basis.

Response:

a) The changes made to NBHDL's capitalization policies in relation to the transition to MIFRS impacted the componentization of assets, depreciation and contributed capital classification only. These changes did not impact the allocation of costs between OM&A and capital and therefore there are no line items in Table 4-4 for accounting changes associated with the changes in capitalization noted elsewhere in the evidence. An explanation of the changes in NBHDL's capitalization policies can be found on pages 93 through 95 of Exhibit 2.

b) Please see the response to 4-Energy Probe-45 a) above.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-46

Reference: Exhibit 4, Table 4-10

Interrogatory:

a) Please confirm that the figures shown in Table 4-10 are the total employee costs incurred, including costs allocated to OM&A and to capital expenditures.

b) Please add lines to Table 4-10 that shows the amount of employee costs allocated to capital and the resulting level of costs allocated to OM&A for each of the years shown. In providing this response, please update Table 4- 10 to include actual data for 2014. If actual data for all of 2014 is not yet available, please update 2014 to include the most recent year to date actuals along with a current estimate of any remaining months in 2014.

Response:

NBHDL confirms that the figures shown in Table 4-10 as defined on page 47 of Exhibit 4 includes all costs paid for wages and benefits for full time employees, including costs allocated to OM&A and capital.

Table 4-10 below has been updated for the following information:

i. 2014 actuals;
ii. Temporary employees that were not included in Table 4-10 submitted with the application; and
iii. Employee costs charged to capital, OM&A and Other.

Full Time Employee Costs

	Last Rebasing Year - 2010- Board Approved	Last Rebasing Year - 2010- Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actual	2015 Test Year
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	11.0	9.0	9.3	10.9	10.0	10.0	10.0	10.0
Non-Management (union and non-union)	38.8	36.9	37.2	37.0	36.2	37.6	37.6	39.2
Total	49.8	45.9	46.5	47.9	46.2	47.6	47.6	49.2
Total Salary and Wages including ovetime and incentive pay								
Management (including executive)	$ 923,756	$ 1,019,033	$ 871,191	$ 987,388	$ 976,295	$ 1,106,605	$ 1,115,707	$ 1,099,796
Non-Management (union and non-union)	$ 2,592,132	$ 2,491,312	$ 2,646,962	$ 2,747,925	$ 2,910,427	$ 3,142,452	$ 3,069,826	$ 3,224,921
Total	$ 3,515,887	$ 3,510,345	$ 3,518,154	$ 3,735,312	$ 3,886,722	$ 4,249,057	$ 4,185,532	$ 4,324,717
Total Benefits (Current + Accrued)								
Management (including executive)	$ 213,513	$ 201,978	$ 191,079	$ 230,502	$ 241,793	$ 262,233	$ 255,695	$ 262,792
Non-Management (union and non-union)	$ 751,241	$ 634,637	$ 665,629	$ 742,703	$ 772,219	$ 776,614	$ 718,209	$ 772,676
Total	$ 964,754	$ 836,615	$ 856,708	$ 973,206	$ 1,014,012	$ 1,038,847	$ 973,905	$ 1,035,468
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$ 1,137,269	$ 1,221,011	$ 1,062,271	$ 1,217,890	$ 1,218,088	$ 1,368,837	$ 1,371,402	$ 1,362,589
Non-Management (union and non-union)	$ 3,343,372	$ 3,125,949	$ 3,312,591	$ 3,490,628	$ 3,682,646	$ 3,919,067	$ 3,788,035	$ 3,997,597
Total	$ 4,480,641	$ 4,346,960	$ 4,374,862	$ 4,708,518	$ 4,900,734	$ 5,287,904	$ 5,159,437	$ 5,360,185

Temporary Employees

Total Salary and Wages including ovetime and incentive pay								
Temporary Employees	$ 54,144	$ 63,719	$ 51,620	$ 97,810	$ 232,951	$ 120,863	$ 227,693	$ 87,938
Total Benefits (Current + Accrued)								
Temporary Employees	$ 5,448	$ 6,405	$ 4,839	$ 9,427	$ 19,299	$ 12,161	$ 16,996	$ 8,770
Total Compensation (Salary, Wages, & Benefits)								
Temporary Employees	$ 59,592	$ 70,124	$ 56,459	$ 107,237	$ 252,250	$ 133,024	$ 244,690	$ 96,708

Total Employees

Total Compensation (Salary, Wages, & Benefits)	$ 4,540,233	$ 4,417,084	$ 4,431,321	$ 4,815,755	$ 5,152,984	$ 5,420,928	$ 5,404,127	$ 5,456,893

Wages and Benefit Allocation

OM&A	2,539,261	2,619,429	2,675,788	2,886,521	3,000,023	3,166,832	3,058,241	3,275,057
Capital	1,873,206	1,462,606	1,464,396	1,451,004	1,514,915	1,721,340	1,673,640	1,805,646
Other	127,767	335,049	291,137	478,230	638,046	532,756	672,245	376,189
Total Compensation (Salary, Wages, & Benefits)	$ 4,540,233	$ 4,417,084	$ 4,431,321	$ 4,815,755	$ 5,152,984	$ 5,420,928	$ 5,404,127	$ 5,456,893

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-47

Reference: Exhibit 4, Page 21

Interrogatory:

At lines 26-27 on page 21, there is reference to a temporary increase in FTE's in 2015 related to the retirement of 2 individuals and the need for job training of new staff.

a) Are either of the 2 retirements related to positions that require apprenticeship training?

b) For each of the 2 positions, please indicate the total wages and benefits expected to be paid in 2015, along with the number of months before the positions are vacated by the current individuals.

c) For each of the 2 replacements for these positions, please indicate the total wages and benefits expected to be paid in 2015, along with the number of months that these two new individuals will be employed in 2015.

Response:

a) The 2 retirement positions do not require apprenticeship training.

b) Position 1’s total wages and benefits forecasted to be paid in 2015 are $44,024 for 7 months. Position 2’s total wages and benefits forecasted to be paid in 2015 are $81,736 for 10 months.

c) Replacement for position 1's total wages and benefits forecasted to be paid in 2015 were $51,172 for nine months. Replacement for position 2's total wages and benefits forecasted to be paid in 2015 were $92,233 for 12 months.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-48

Reference: Exhibit 4, Table 4-5

Interrogatory:

What would be the impact on total wages and benefits, and wages and benefits allocated to OM&A in 2015 if the wage increases shown in Table 4-5 for 2011 through 2015 was

a) 1.5%?

b) 2.5%?

In responding to this interrogatory, please show separately for each of (a) and (b) the impact for union and non-union employees.

Response:

a) The table below shows the impact on total wages and benefits and wages and benefits allocated to OM&A, Capital and Other by Management (non-union) and Non-Management (union) for the 2015 forecast if the rate increase was 1.5% for 2011 through 2015.

	OM&A	Capital	Other	Total
Management - non union	(101,612)	(32,839)	(23,411)	(157,862)
Non Management - union	(128,422)	(88,637)	(8,165)	(225,224)
Total - 1.5%	**(230,034)**	**(121,476)**	**(31,576)**	**(383,086)**

b) The table below shows the impact on total wages and benefits and wages and benefits allocated to OM&A, Capital and Other by Management (non-union) and Non-Management (union) for the 2015 forecast if the rate increase was 2.5% for 2011 through 2015.

	OM&A	Capital	Other	Total
Management - non union	(69,060)	(22,553)	(17,714)	(109,327)
Non Management - union	(30,069)	(23,632)	(8,165)	(61,866)
Total - 2.5%	**(99,129)**	**(46,185)**	**(25,879)**	**(171,193)**

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-49

Reference: Exhibit 4, Table 4-31

Interrogatory:

Please provide a table that shows for each of 2010 through 2015 the depreciation that has been allocated to OM&A expenses and the amount that is allocated to capital.

Response:

The following table shows for each of 2010 through 2015 the depreciation that has been allocated to OM&A expenses and the amount that is allocated to capital. This allocation applies to the fleet depreciation only and NBHDL has continued to use the same methodology for allocating fleet depreciation that was approved during the 2010 Cost of Service settlement agreement.

Cost Allocation	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year
Capital	129,022	132,845	162,597	132,911	127,313	155,871
OM&A	74,162	76,241	109,338	105,037	112,290	110,926
Total	**203,184**	**209,086**	**271,935**	**237,948**	**239,603**	**266,797**

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-50

Reference: Exhibit 4, Page 36

Interrogatory:

a) What was the impact of the capitalization changes in fiscal 2009? In particular, was there a movement from capital to OM&A or from OM&A to capital?

b) Was this change in the capitalization of overheads reflected in the last cost of service application for 2010 rates?

Response:

a) The changes to the overhead policy in fiscal 2009 resulted in more costs staying in OM&A as the costs could not be directly attributed to capital work.

b) No, the cost of service application for 2010 rates handled the capitalization of overheads differently. The methodology changes are explained on page 93 of Exhibit 2.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-51

Reference: Exhibit 4, Page 45

Interrogatory:

Please provide a table showing the 23 different settlements for 2011 through 2013 noted on line 23. For each settlement, please show the increase for each of 2011 through 2013.

Response:

The following table show the 23 different settlements for 2011 through 2013, as noted on line 23, with the increase for each. The wages settlement details are based on the agreement effective date.

Wages Settlement Details						
	Agreement Term	Agreement Effective Date	2011 Wages Settlement Percentage	2012 Wages Settlement Percentage	2013 Wages Settlement Percentage	2014 Wages Settlement Percentage
Utility #1	4yrs	1-Apr-11	2.0%	2.0%	2.0%	2%
Utility #2	4yrs	1-Apr-11	2.8%	2.9%	3.1%	3.1%
Utility #3	4yrs	1-Apr-11	2.75%	2.75%	3.25%	3.25%
Utility #4	4yrs	1-May-11	3.0%	3.0%	3.0%	3.50%
Utility #5	4yrs	1-Jun-11	3.1%	3.1%	3.1%	3.1%
Utility #6	4yrs	1-Aug-11	2.8%	2.8%	2.8%	1.25%
Average Wage Percentage			2.73%	2.75%	2.87%	2.70%
Utility #7	3yrs	1-Jan-12		2.25%	2.25%	2.50%
Utility #8	3yrs	1-Apr-12		2.80%	2.85%	2.85%
Utility #9	4yrs	1-Jun-12		2.8%	2.9%	3%
Utility #10	5yrs	1-Jul-12		2.25%	2.0%	2.50%
Utility #11	3yrs	1-Apr-12		2.0%	2.0%	2%
Utility #12	3yrs	1-Apr-12		2.75%	2.8%	2.85%
Utility #13	3yrs	1-Mar-12		3.0%	3.0%	3%
Utility #14	4yrs	1-Jan-12		2.5%	2.5%	3%
Average Wage Percentage				2.59%	2.54%	2.71%
Utility #15	3yrs	1-Jan-13			2.5%	2.50%
Utility #16	3yrs	1-Apr-13			2.0%	2%
Utility #17	4yrs	1-Apr-13			2.75%	2.75%
Utility #18	4yrs	1-Apr-13			2.75%	2.75%
Utility #19	3yrs	1-Apr-13			3.0%	3%
Utility #20	3yrs	1-Apr-13			2.5%	2.75%
Utility #21	3yrs	1-Apr-13			2.75%	2.75%
Utility #22	3yrs	1-May-13			2.0%	1.50%
Utility #23	4yrs	1-Jul-13			1.4%	2.80%
Average Wage Percentage					2.41%	2.53%
Total Wage Percentage			**2.73%**	**2.67%**	**2.60%**	**2.65%**

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-52

Reference: Exhibit 4, Table 4-10

Interrogatory:

Please update Table 4-10 to include actual data for 2014, or if actual data for all of 2014 is not yet available, update the 2014 figures to reflect the most recent year to date information available, along with a current estimate for the remainder of the year. Please add a section to the table that shows the total compensation per FTE for each of the management and non-management categories, along with the total.

Response:

Table 4 -10 is updated below to include the actual data for 2014 as well the total compensation per FTE of each of the management and non-management categories, along with the total.

	Last Rebasing Year - 2010-Board Approved	Last Rebasing Year - 2010-Actual	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actual	2015 Test Year
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	11.0	9.0	9.3	10.9	10.0	10.0	10.0	10.0
Non-Management (union and non-union)	38.8	36.9	37.2	37.0	36.2	37.6	37.6	39.2
Total	49.8	45.9	46.5	47.9	46.2	47.6	47.6	49.2
Total Salary and Wages including ovetime and incentive pay								
Management (including executive)	$ 923,756	$ 1,019,033	$ 871,191	$ 987,388	$ 976,295	$ 1,106,605	$ 1,115,707	$ 1,099,796
Non-Management (union and non-union)	$ 2,592,132	$ 2,491,312	$ 2,646,962	$ 2,747,925	$ 2,910,427	$ 3,142,452	$ 3,069,826	$ 3,224,921
Total	$ 3,515,887	$ 3,510,345	$ 3,518,154	$ 3,735,312	$ 3,886,722	$ 4,249,057	$ 4,185,532	$ 4,324,717
Total Benefits (Current + Accrued)								
Management (including executive)	$ 213,513	$ 201,978	$ 191,079	$ 230,502	$ 241,793	$ 262,233	$ 255,695	$ 262,792
Non-Management (union and non-union)	$ 751,241	$ 634,637	$ 665,629	$ 742,703	$ 772,219	$ 776,614	$ 718,209	$ 772,676
Total	$ 964,754	$ 836,615	$ 856,708	$ 973,206	$ 1,014,012	$ 1,038,847	$ 973,905	$ 1,035,468
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$ 1,137,269	$ 1,221,011	$ 1,062,271	$ 1,217,890	$ 1,218,088	$ 1,368,837	$ 1,371,402	$ 1,362,589
Non-Management (union and non-union)	$ 3,343,372	$ 3,125,949	$ 3,312,591	$ 3,490,628	$ 3,682,646	$ 3,919,067	$ 3,788,035	$ 3,997,597
Total	$ 4,480,641	$ 4,346,960	$ 4,374,862	$ 4,708,518	$ 4,900,734	$ 5,287,904	$ 5,159,437	$ 5,360,185
Total Compensation Per FTE								
Management (including executive)	$ 103,388	$ 135,668	$ 113,855	$ 111,733	$ 121,809	$ 136,884	$ 137,140	$ 136,259
Non-Management (union and non-union)	$ 86,281	$ 84,783	$ 89,144	$ 94,341	$ 101,787	$ 104,258	$ 100,746	$ 102,032
Total	$ 189,669	$ 220,451	$ 202,999	$ 206,074	$ 223,596	$ 241,142	$ 237,886	$ 238,290

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-53

Reference: Exhibit 4, Table 4-13

Interrogatory:

a) Based on the employee turnover shown in Table 4-13, did the replacements have, in general, more or less experience than those employees that they replaced? Please explain fully.

b) Based on the response to part (a) above, what was the annualized average annual wage and benefit difference associated with the replacements relative to the those being replaced?

Response:

a) Based on the employee turnover shown in Table 4-13, the replacements, in general, had less experience than those employees being replaced.

b) The annualized average wages and benefits difference associated with the replacements relative to those being replaced was a decrease of $9,423.75 for the average replacements from 2008 to 2014.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-54

Reference: Exhibit 4, Table 4-26

Interrogatory:

Most of the figures shown in Table 4-26 imply that the revenues received from affiliates are used to reduce the corresponding OM&A expenses (excluding contributed capital and electricity purchases).

However, the management fee revenue is recorded in Account 4375 rather than as an offset to OM&A expenses. What are the costs associated with providing the management services in each of 2010 through 2015 and are these costs included in the OM&A expense accounts or in Account 4380?

Response:

The highlighted OM&A costs shown in Table 4-26 below are associated with providing the Management services (management fee) in 2010 through 2015. These costs are included as a reduction in the source expense accounts stated, not in account 4380.

Item	Source/Account	Notes	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Text Year
	Appendix 2-N		2,566,217	3,710,061	4,263,996	4,446,682	3,931,536	4,225,790
Exhibit # 3- Other Revenues	4210-Rent from Electric Property	Joint Pole Attachment Fee	12,520	-	-	-	-	-
Exhibit # 3- Other Revenues	4375-Revenues from Non-Utility Operations	Management Fee	38,048	38,660	49,352	66,994	52,861	51,931
	Sub Total Other Revenue		50,568	38,660	49,352	66,994	52,861	51,931
Exhibit #4 Reduction to OM&A	5085-Miscellaneous Distribution Expenses	Human Resources	-	1,956	1,956	1,992	4,251	3,804
Exhibit #4 Reduction to OM&A	5085-Miscellaneous Distribution Expenses	Purchases of materials and contractor services	15,958	12,455	12,953	33,852	40,257	36,026
Exhibit #4 Reduction to OM&A	5085-Miscellaneous Distribution Expenses	Vehicle Charges	14	-	3,639	11,190	-	-
			15,972	14,411	18,548	47,034	44,508	39,830
Exhibit #4 Reduction to OM&A	5315-Customer Billing	Water Heater Billing	53,797	56,134	56,936	57,558	60,330	64,334
Exhibit #4 Reduction to OM&A	5615-General Administrative Salaries & Expenses	Executive Services	40,152	31,205	26,900	55,173	50,159	51,367
Exhibit #4 Reduction to OM&A	5615-General Administrative Salaries & Expenses	Financial and Administrative Services	84,053	37,657	55,966	88,930	82,941	93,168
Exhibit #4 Reduction to OM&A	5615-General Administrative Salaries & Expenses	Sentinel Light Maintenance	20,405	29,714	31,604	19,541	33,794	13,874
Exhibit #4 Reduction to OM&A	5615-General Administrative Salaries & Expenses	NBHS Payroll Services	22,056	76,648	120,166	154,010	46,694	49,204
Exhibit #4 Reduction to OM&A	5615-General Administrative Salaries & Expenses	Occupancy Cost	16,355	11,100	16,200	16,200	22,620	21,539
Exhibit #4 Reduction to OM&A	5615-General Administrative Salaries & Expenses	Information Technology Services	864	864	894	864	945	1,200
			183,885	187,188	251,730	334,718	237,153	230,352
Exhibit #4 Reduction to OM&A	5635-Property Insurance	Insurance	-	-	1,800	7,318	10,591	11,689
	Sub Total Reduction to OM&A		253,654	257,733	329,014	446,627	352,583	346,205
Exhibit #4 Reduction to OM&A (Lab/burdens/overheads) Excluding Materials	Recoverable Workorder - Revenue = Expense Net $0	Street Light Maintenance	143,416	158,299	506,064	213,116	19,305	-
Exhibit # 2- Rate Base	1955 - Contributed Capital	Construction Activity	147,828	62,344	12,330	215,739	31,675	74,820
	Total Billed - Various Revenue, Regulatory and HST	Electricity Purchases	1,970,751	3,193,025	3,367,236	3,504,206	3,475,111	3,752,834
	Total		2,566,217	3,710,061	4,263,996	4,446,682	3,931,536	4,225,790

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-55

Reference: Exhibit 4, Table 4-29 & Table 4-1

Interrogatory:

a) Please update Table 4-29 to show actual costs incurred in 2014.

b) What are the estimated cost reductions if NBHDL were to settle all issues as part of a settlement process, eliminating the need for an oral hearing?

c) Please confirm that none of the one-time costs shown in the bottom portion of Table 4-29 have been included in the historical or bridge year forecasts shown in Table 4-1. If this cannot be confirmed, please indicate the amount included in each year in Table 4-1.

Response:

a) Updated Table 4-29 to show actual costs incurred in 2014 is noted below.

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? 2	Last Rebasing Year (2010 Board Approved)	Most Current Actuals Year 2013	2014 Actual	Annual % Change	2015 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 70,780	$ 70,221	$ 68,687	-2.18%	$ 72,332	5.31%
2	OEB Section 30 Costs (Applicant-originated)			On-Going	$ -	$ -	$ -		$ -	
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 3,500	$ 3,338	$ 2,007	-39.88%	$ 3,054	52.20%
4	Legal costs for Regulatory matters	5655			$ -	$ 375	$ -		$ -	
5	Operating expenses associated with staff resources allocated to regulatory matters	5655/5610		On-Going		$ 83,073	$ 95,179	14.57%	$ 119,104	25.14%
6	Consultants' costs for regulatory matters	5655		On-Going	$ 27,200	$ 15,485	$ 1,073	-93.07%	$ 15,780	1370.64%
7	Intervenor costs	5655		On-Going	$ 12,880	$ -	$ 2,127		$ -	-100.00%
8	Sub Total - On-Going				$ 114,360	$ 172,492	$ 169,073	-1.98%	$ 210,270	24.37%
9	Consultants' costs for regulatory matters	5655		One-Time	$ 115,000	$ 139,508	$ 345,894	147.94%	$ 65,000	
10	Operating expenses associated with staff resources allocated to regulatory matters	5655		One-Time	$ -	$ 2,098	$ 68,852	3182.26%	$ 21,890	-68.21%
11	Operating expenses associated with other resources allocated to regulatory matters _	5655		One-Time	$ -	$ -	$ 21,904		$ -	-100.00%
12	Any other costs for regulatory matters (please define)	5655			$ -	$ -	$ -		$ -	
13	OEB Review COS	5655		One-Time	$ 35,000				$ 43,000	
14	Intervenor costs	5655		One-Time	$ 10,000	$ -	$ -		$ 20,000	
15	Total One - Time				$ 160,000	$ 141,606	$ 436,650	208.36%	$ 149,890	-65.67%
16	2010 Cost of Service - Expensed over 4 years				$ 40,000	$ 71,308	$ 23,769	-66.67%	$ -	-100.00%
17	2015 Cost of Service - Expensed over 5 years								$ 131,386	
18	Sub Total - One Time				$ 40,000	$ 71,308	$ 23,769	-66.67%	$ 131,386	452.76%
19	Total (8+18)				$ 154,360	$ 243,800	$ 192,842	-20.90%	$ 341,656	77.17%

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2014 Actual	2015 Test Year	Total COS	Amortized over 5 years
1	Expert Witness costs				-	
2	Legal costs				-	
3	Consultants' costs including Legal	139,508	345,894	65,000	550,402	110,080
4	Incremental operating expenses associated with staff resources allocated to this application.	2,098	68,852	21,890	92,839	18,568
5	Incremental operating expenses associated with other resources allocated to this application- Temporary Employees	-	21,904	-	21,904	4,381
6	OEB/Intervenor costs	-	-	63,000	63,000	12,600
	Total	141,606	436,650	149,890	728,145	145,629

b) There are no estimated cost reductions if NBHDL were to settle all issues as part of a settlement process, eliminating the need for an oral hearing, since NBHDL did not forecast expenses related to a technical conference or an oral hearing. Please refer to 4-Staff-13 d).

c) NBHDL confirms that none of the one-time costs shown in the bottom portion of Table 4-29 related to this cost of service application have been included in the historical or bridge year forecasts shown in Table 4-1.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-56

Reference: Exhibit 4, Page 79

Interrogatory:

The evidence indicates that for regulatory purposes, NBHDL uses the half year rule for assets added in the current year but beginning in 2012 a number of accounts were depreciated based on the month following being put in service. For each of 2012, 2013 and 2014 (assuming actuals are available), please show the depreciation expense calculated using the month in-service methodology and the amount that would have been recorded if the half-year rule had been applied in each of 2012, 2013 and 2014. If the month-in service methodology figures are different from those shown in Table 4-31, please explain fully.

Response:

The following table provides the calculation of depreciation on new additions for 2012 through 2014 (using 2014 actuals) general assets. This table shows the depreciation amount under the ½ year methodology as compared to the depreciation recorded in the continuity statements based on the month after being put in service for the applicable fiscal year. NBHDL notes that these amounts cannot be tied to Table 4-31 as that table provides the total annual depreciation for each fiscal period, not the isolated depreciation on new additions.

General Asset Additions - 2012		2012				
		Cost - New Additions	Accumulated Amortization			
USoA	Account Description		Useful Life	1/2 Year	Month in Service	Variance
1611	Computer Software (Formally Acct 1925)	125,138	5	12,514	4,324	8,190
1908	Buildings & Fixtures	231,827	25	4,637	4,940	(303)
1915	Office Furniture & Equipment (10 years)	31,051	10	1,553	1,254	298
1920	Computer Equipment - Hardware	68,005	5	6,800	1,151	5,650
1930	Transportation Equipment	254,425	5-8	19,100	20,180	(1,080)
1940	Tools, Shop & Garage Equipment	21,013	10	1,051	656	395
1955	Communications Equipment	46,452	10	2,323	500	1,822
1960	Miscellaneous Equipment	1,970	10	99	-	99
				48,075	33,004	15,071

General Asset Additions - 2013		2013				
		Cost - New Additions	Accumulated Amortization			
USoA	Account Description		Useful Life	1/2 Year	Month in Service	Variance
1611	Computer Software (Formally Acct 1925)	94,033	5	9,403	8,417	987
1908	Buildings & Fixtures	100,066	25	2,001	969	1,032
1915	Office Furniture & Equipment (10 years)	6,292	10	315	111	204
1920	Computer Equipment - Hardware	8,076	5	808	387	421
1930	Transportation Equipment	58,916	5-8	5,309	6,980	(1,671)
1940	Tools, Shop & Garage Equipment	101,630	10	5,081	2,362	2,719
1955	Communications Equipment	20,789	10	1,039	397	642
1960	Miscellaneous Equipment	-	10	-	-	-
				23,956	19,623	4,333

General Asset Additions - 2014		2014 - less Smart Meter Costs from Disposition				
		Cost - New Additions	Accumulated Amortization			
USoA	Account Description		Useful Life	1/2 Year	Month in Service	Variance
1611	Computer Software (Formally Acct 1925)	86,870	5	8,687	9,762	(1,075)
1908	Buildings & Fixtures	459,817	25	9,196	9,398	(202)
1915	Office Furniture & Equipment (10 years)	2,726	10	136	132	5
1920	Computer Equipment - Hardware	119,678	5	11,968	1,966	10,001
1930	Transportation Equipment	44,911	5-8	3,862	6,053	(2,191)
1940	Tools, Shop & Garage Equipment	13,512	10	676	550	125
1955	Communications Equipment	5,253	10	263	376	(114)
1960	Miscellaneous Equipment	960	10	48	16	32
				34,836	28,254	6,582

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-57

Reference: Exhibit 4, Appendix 4-P and Exhibit 2, Table 2-10

Interrogatory:

a) Please reconcile the additions to capital of $9,164,695 shown in Table 2-10 for 2014 with the CCA additions of $5.736,343 shown in Schedule 8 for the bridge year in Appendix 4-P. As part of the response, please reconcile the line items, and provide a mapping from the OEB accounts shown in Table 2- 10 to the CCA categories used in Schedule 8.

b) Please explain why there are no additions to CCA class 12 (computer software) in either 2014 or in previous years.

Response:

a) The following table provides the reconciliation between Table 2-10 and the 2014 CCA additions shown in Schedule 8 for the bridge year in Appendix 4-P. Reflected within the Table 2-10 additions is the disposition of the Smart Meter costs out of the DVA accounts and into the appropriate PP&E accounts. These costs are not included in the CCA schedule as 2014 additions as they were appropriately accounted for in prior fiscal periods.

CCA Class *OEB USoA*	**CCA Class Description** *OEB USoA Description*	**Table 2-10**	**Smart Meter Disposition**	**CCA Schedule**
1	Distribution System - 1988 to 22-Feb-2005			
1908	*Buildings and Fixtures*	508,280	-	508,280
	TOTAL CLASS 1	**508,280**	**-**	**508,280**
8	General Office/Stores Equip			
1915	*Office Furniture and Equipment*	57,280	-	57,280
1940	*Tools, Shop and Garage Equipment*	47,000	-	47,000
	TOTAL CLASS 8	**104,280**	**-**	**104,280**
10	Computer Hardware/ Vehicles			
1930	*Transportation Equipment*	72,163	-	72,163
	TOTAL CLASS 10	**72,163**	**-**	**72,163**
50	Computers & Systems Hardware acq'd post Mar 19/07			
1920	*Computer Equipment - Hardware*	87,266	-	87,266
1920	*Computer Equipment - Hardware - Smart Meter Disposition*	9,037	- 9,037	-
	Total Computer Equipment - Hardware	96,303	- 9,037	87,266
1925	*Computer Software*	173,211	-	173,211
1925	*Computer Software - Smart Meter Disposition*	75,126	- 75,126	-
	Total Computer Software	248,336	- 75,126	173,211
	TOTAL CLASS 50	**344,640**	**- 84,163**	**260,476**
47	Distribution System - post 22-Feb-2005			
1820	*Distribution Station Equipment - Normally Primary below 50 kV*	640,888	-	640,888
1830	*Poles, Towers and Fixtures*	2,168,186	-	2,168,186
1835	*Overhead Conductors and Devices*	734,144	-	734,144
1840	*Underground Conduit*	140,105	-	140,105
1845	*Underground Conductors and Devices*	179,671	-	179,671
1850	*Line Transformers*	667,436	-	667,436
1855	*Services*	816,567	-	816,567
1860	*Meters*	146,043	-	146,043
1860	*Meters - Smart Meter Disposition*	3,344,188	- 3,344,188	-
1980	*System Supervisory Equipment*	426,183	-	426,183
1995	*Contributions and Grants*	- 1,128,077	-	- 1,128,077
	TOTAL CLASS 50	**8,135,333**	**- 3,344,188**	**4,791,144**
	TOTAL PER TABLE 2-10, SMART METER ADJ, CCA SCHEDULE	**9,164,695**	**- 3,428,351**	**5,736,343**

b) NBHDL classifies computer software as CCA class 50.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-58

Reference: Exhibit 4, Appendix 4-P and Exhibit 2, Tab 2-11

Interrogatory:

Please explain why NBHDL has included computer software in CCA class 50 rather than class 12.

Response:

NBHDL classifies computer software as CCA class 50 for tax purposes as reflected in historical tax returns prepared by BDO.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 –OPERATING COSTS

4-Energy Probe-59

Reference: Exhibit 4, Appendix 4-P

Interrogatory:

Please confirm that NBHDL is no longer eligible for the Ontario small business credit.

Response:

NBHDL confirms that is no longer eligible for the Ontario small business credit.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-29

Reference: Page 5 - Salaries, Wages and Benefits – Line 6

Interrogatory:

Total employee costs for the 2015 test year shown in Table 4-10 at $5,360,185 compared to the actual 2010 figure of $4,346,960 represents an increase of 23.31% over the period. This represents an average per employee costs of $108,946 in 2015 compared to $94,705 in 2010 (*EB-2009-0270 – Exhibit 4 – Page 58 of 87*).

This represents an increase of $14,286 or 15.08%. Wage increases are a direct result of negotiated contract settlements and similar parallel management increases.

As evidence to support these increases, in this section, the applicant describes increased workloads caused by increased customer phone calls and numbers of walk-ins, provincial policy initiatives, staff turnovers.

While this evidence lists increases in workload it does not support the wage increase figures and especially does not support the average wage per employee figure.

Please explain the evidentiary value of these statements to support staff wages and benefit increases.

Response:

Please refer to Exhibit 4, Page 45, Line 18 to Exhibit 4, Page 61, Line 2 for comprehensive evidence on the change in compensation costs between 2010 actual and the 2015 test year.

As described in detail at Exhibit 4, Page 48, Line 3 to Exhibit 4, Page 50, Line 30 - increased workload has had a direct impact on employee staffing levels. Specifically, increased workload has driven new staffing requirements in the engineering and accounting groups, while NBHDL has been able to find efficiencies to managed increased workload in its operations group and its control group.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-30

Reference: Page 5, Line 10

Interrogatory:

"NBHDL offers the convenience of a store front operation for customer service and traffic has maintained at an estimated 15,000 – 20,000 walk-ins per year."

This would be an average of approximately 66 to 88 customers per day.

Please describe the method used to arrive at these numbers.

Response:

NBHDL tracks payments that are made in its office in the CIS computer system as a specific code and this information was obtained through a report from the system. NBHDL tracked customer traffic not related to cash payments for a 6.5 month timeframe in 2014 and prorated this information for the full year. NBHDL used the sum of these two values to arrive at the 15,000 – 20,000 walk-ins per year.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-31

Reference: Page 6, Line 31

Interrogatory:

According to Table 4-10, wages have increased from an actual $4,346,960 in 2010 to $5,360,185 budgeted in 2015. This is an average 4.67% increase each year for the five year period. The applicant's description of 2.8% union and 4.6% non-union average over the period from 2010-2015 escapes me mathematically

The evidence supporting the increase over the five years for non-unionized staff is that most have been in their roles for five years or less which in my opinion is counter intuitive.

Please provide supporting arguments for these levels of increases and how less experienced employees can cause an increase in overall wage costs?

Response:

The figures referenced in this question from Table 4-10 of Exhibit 4 reflect total compensation costs (salary, wages and benefits). Your analysis fails to account for changes in benefit costs from $836,615 in 2010 to $1,035,468 forecast in 2015.

Non-unionized staff may be promoted from time to time over the course of their career, resulting in a change in role. So while most non-unionized staff have been in their role 5 years or less, that does not correlate to the experience of that staff member at NBHDL or elsewhere in the industry.

Please refer to Exhibit 4, Page 45, Line 18 to Exhibit 4, Page 61, Line 2 for comprehensive evidence on the change in compensation costs between 2010 actual and the 2015 test year.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-32

Reference: Page 7, Line 5 - Salaries Wages and benefits

Interrogatory:

The statement "*Staff must be fairly compensated for the work they perform recognizing the industry NBHDL works in*." suggests that management and staff compensation should be measured differently from other industries. Since management and staff work in a business which is a regulated monopoly, it would seem that they do not require a lot of the skills that would be required by similar workers in other industries.

Please provide facts to support the suggestion that different realities should be applied to the electricity delivery industry and reasons to suggest that it is evidentiary in regards to this application.

Response:

NBHDL competes with other companies in its industry and with other industries to attract and retain the best talent to operate its business. In this regard, NBHDL operates in the same "reality" as companies in any industry.

NBHDL's overall compensation for all employees is designed to be competitive and equitable in order to attract and retain qualified personnel in an industry that is facing an aging workforce and is very competitive for skilled resources.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-33

Reference: Page 7, Line 7

Interrogatory:

Included in the increases in wage and benefits are increased contributions since 2010 of $189,272 to $417,659 to the OMERS pension plan. This is largely due to more funds required by OMERS to cover unfunded liabilities. This has amounted in a 16.6% per year increase in this expense since 2010. OMERS have admitted that unfunded liabilities are still an issue and more increases in contribution amounts are likely. This means that further increased costs to ratepayers resulting from higher OMERS demands are likely. This expense has increase from $122,016 in 2006 to $418,569 in 2015. That is a 243% increase in 9 years or 27% increase per year.

Any private business would consider this type of line item increase to be unacceptable and take steps to make other pension arrangements.

The applicant's peculiar description, given on page 59 of this exhibit, that the current plan is "a contributory defined pension plan" seems to be promoting the idea in readers' minds the notion that the current plan is a "defined contribution plan" which of course it is not. The current plan is a defined benefit plan.

Given those facts and given that defined benefit plans such as OMERS have been almost 100% extinct in private industry for some time, would the applicant explain why it has not converted the pension plan to a defined contribution plan rather than the defined benefit plan that now exists.

Response:

NBHDL's collective agreement with unionized staff provides for annual payroll increases, employee step progressions as well as benefits. NBHDL's current collective agreement commenced on April 1, 2014 and will expire on March 30, 2018.

NBHDL does not have the discretion to unilaterally make changes to an active collective agreement. During the collective bargaining process, various changes to the last collective agreement are considered and proposed on a case-by-case during negotiations.

NBHDL has taken steps to mitigate benefit cost increases. Changes were negotiated as part of the collective bargaining process which resulted in savings on clothing purchases and eliminating the practice of paying for winter meals. Eliminating winter meals saves NBHDL approximately $42,000 per year.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-34

Reference: Page 7, Line 12

Interrogatory:

"The 2014 Bridge Year had a one-time union contract signing bonus of $36,000"

Please explain the reasoning behind the granting of this signing bonus.

Response:

This amount falls below NBHDL's materiality threshold for this Application.

However, the one-time signing bonus of $36,000 was granted for the entire Collective Bargaining Agreement for concessions made for the winter meal buyout and mandatory generic drug substitution. The net cost savings over the four year term of $228,905 is shown in the table below.

Changes	2014 8 months	2015 full year	2016 full year	2017 full year	2018 3 months	Total
Wintermeal Buyout	$14,191	$48,132	$48,132	$48,132	$20,537	$179,124
Mandatory Generic Drug Substitution	$16,084	$21,445	$21,445	$21,445	$5,361	$85,781
Signing Bonus	($36,000)					($36,000)
Net Savings	($5,725)	$69,577	$69,577	$69,577	$25,898	$228,905

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-35

Reference: Page 7, Line 15 - Customer engagement

Interrogatory:

The *Requirements for Filing 2015 - Chapter 2 – Page 16* indicates that:

"Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application and the values of those proposals to customers i.e. costs, benefits and the impact on rates and how customer feedback to the survey shaped the final application.

Distributors should also reference any other communications sent to customers about the application such as bill inserts, town hall meetings held or other forms of outreach undertaken o engage customers and explain to them how the application serves their heed and expectations and the feedback heard from customers through these engagement activities."

In our opinion, the majority of questions in the surveys conducted do not meet any of the requirements listed above. We attended the June 2014 residential engagement session which was not attended by any NBHDL personnel and consisted of approximately 15 people being provided the results of a previous NBHDL on-line survey which asked questions such as what is your preferred method of paying your bill and would you be willing to pay more to have power lines buried.

Please provide examples where the requirements listed above were met by the surveys conducted by the applicant.

With a budget for 2015 and beyond of $122,000 per year, please explain how this expenditure provides any benefit to ratepayers and how it meets the requirements set out by the OEB.

Response:

NBHDL did not repeat its evidence on its customer engagement efforts again in Exhibit 4. Rather, NBHDL refers the reader back to the detailed evidence on customer engagement found at Exhibit 1, Page 52, Line 7 to Exhibit 1, Page 72, Line 13. Please refer also to the responses to 1-NBTA-3, 1-NBTA-4, 1-NBTA-10 and 1-NBTA-11.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-36

Reference: Page 8, Line 22 - Business and Strategic Planning

Interrogatory:

This section seems to contain contradictory statements concerning business planning exercises. For example, the applicant states that similar business planning exercises took place in 2012, 2013 and 2014 and then indicates that the strategic plan was last updated in 2007/08 and an update is needed.

Please explain exactly what costs are included in this $100,000 item and why this planning would not be something that one would expect management to do in the normal course of their paid duties?

Response:

In the test year, the money will be used to create a new NBHDL strategic plan. NBHDL last updated its strategic plan in 2007/08 and an update is needed. Since this time NBHDL has adapted to numerous changes occurring from both within and outside the business by relying on a very experienced management team and Board of Directors for strategic planning. Within the next 5 years alone, most of the experienced senior management team members will be retiring. As a result, NBHDL will no longer be able to rely solely on the experience and business judgment of its management team, and a more formalized strategic and business planning program is required at this time.

For years after the test year, the amount of change occurring within the business and the sector means that ongoing business and strategic planning is required on a case-by-case basis. This is consistent with past practice, where ongoing business planning and specific reviews by external resources have been performed as required. For example in 2012-13 there was an external review of meter to cash processes (see Exhibit 4, Appendix 4-A) and in 2013 an IT audit (see Exhibit 4, Appendix 4-B). Also in 2013-2014, NBHDL updated its asset management plan including a new forecast of capital requirements for the next 5 years (see Exhibit 2, Appendix 2-A, Appendix B).

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-37

Reference: Page 9, Line 36 – Regulatory Applications and Assessments

Interrogatory:

"New components and costs since 2010 include the development of a comprehensive Distribution System Plan, the need to engage customers on the value of the rate application and more staff time and external regulatory and legal support"

Please explain what costs are involved in "engaging customers on the value of the rate application" and what form does that activity take?

Response:

As shown in the table prepared for 4-SEC-40 the costs involved in engaging the customers on the value of the rate application are Innovative Research $35,000 and Clarke Marketing $16,562 for a total of $51,562. Also please refer to 4-Staff-13 f).

Please refer to the responses to 1-NBTA-3, 1-NBTA-9 and 1-NBTA-10 for details on this engagement.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-38

Reference: *NOTE: No reference in IR*

Interrogatory:

In addition, please explain why costs for customer engagement would be included in this line item when "Customer Engagement ..... $82,000" is a separate line item shown on page 5 in Table 4-2?

Response:

In the application there are two streams of customer engagement; one is attributable to the cost of service application which pertains to 4-NBTA-37 and the other is activities NBHDL undertakes as part of its regular course of business. As shown in Table 4-2 and as described at Exhibit 4, Page 7, Lines 15-32, NBHDL has forecasted an additional $82,000 over 2010 Board approved spending to implement formal customer engagement and communications programs and to support and monitor results on an ongoing basis.

For a description of the types of activities encompassed, please refer to Exhibit 1, Page 52, Line 7 to Exhibit 1, Page 72, Line 13.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-39

Reference: Page 10, Line 32 – Smart Meters

Interrogatory:

Please confirm if the $106,753 increase in smart meter costs between 2010 and 2015 is a onetime cost or a continuing yearly cost.

Please detail the specifics of total meter reading costs for the 2015 Test year and explain what costs are involved in the Operational Data Store to warehouse smart meter data and allow time of use settlement and to fill a new synchronization role between the smart meter system and the provincial MDM/R.

Response:

The $106,753 represents a variance in smart meter and meter reading costs in the Board Approved 2010 application versus those costs forecasted in 2015 from external sources. Please refer to 4- VECC – 32 for a further breakdown of costs.

Total smart meter and meter reading costs for the test year are $383,302; external sources of $303,313 and internal remuneration of $79,990 as shown in Exhibit 4 at page 38 (Table 4-9 – Appendix 2-JC).

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-40

Reference: Page 11, Line 32 - Operational review

Interrogatory:

The description of the benefits, to NBHDL ratepayers, of this additional expenditure is unclear to us.

Please give the specific details of "(i) formalize and optimize business processes, (ii) develop metrics to measure and manage productivity and efficiency and (iii) facilitate the transfer of knowledge and skill to achieve maximum resource leverage." which would support this expenditure.

Response:

The benefits are explained under the heading "*Continuously improve efficiency and productivity performance to provide better value-for-money*" at page 12 of Exhibit 1.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-41

Reference: Page 12, Line 7

Interrogatory:

Please confirm that the total investment of $208,000 will be used to pay outside consultants and provide details for the ledger account that contains the $41,600 yearly amount.

Response:

NBHDL confirms that an outside expert consultant will be retained to assist with this review.

The investment represents a one-time cost of $208,000 occurring in the test year. To prevent over-recovery of these costs in years beyond the test year, NBHDL has proposed to spread this cost out over 5 years resulting in a cost of $41,600 per year. The OEB account is 5005.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-42

Reference: Page 12, Line 19 - Vegetation management

Interrogatory:

The increase of $346,656 over 2010 is only supported by subjective statements detailing tree contact problems. We have also read the applicant's explanation of the tree encroachment issue on page 33 of that report.

This increase brings total vegetation management expense to over $656,000 per year and suggests a total expenditure of $3,280,000 over the next five years.

Please provide further details to support this level of expenditure on an ongoing yearly basis and provide details of the items included in this total expense.

Response:

As shown in Figure 2-5 of the NBHDL DSP (Exhibit 2, Appendix 2.A at Page 43), tree contacts and foreign interference represents key known causes of outages on the NBHDL distribution system. This figure is reproduced again below for ease of reference.

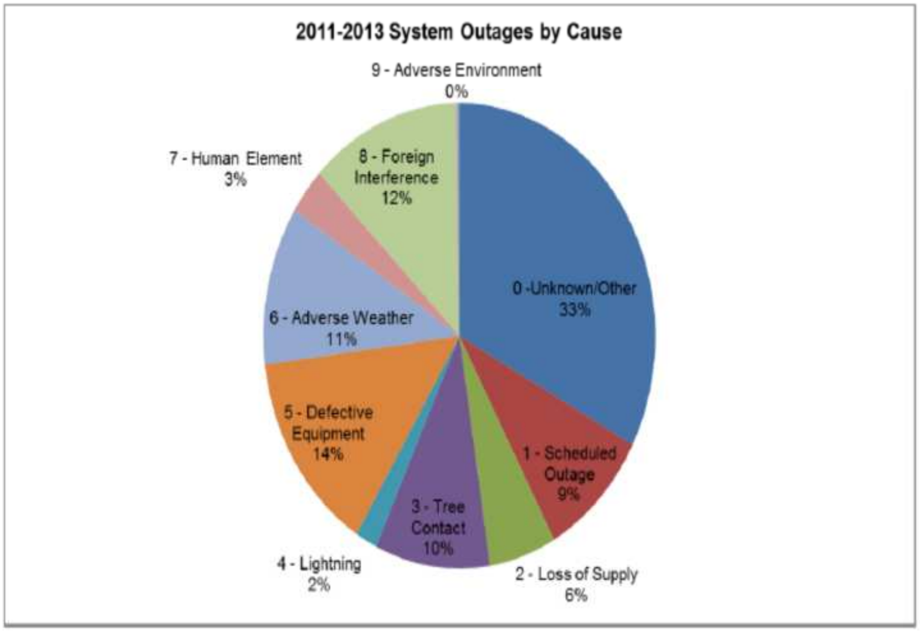

Figure 2-5: Outage Cause Summary

Please refer to Exhibit 2, Appendix 2.A at pages 43 – 44 and Exhibit 4, Appendix 4-E for further details to support the level of expenditure requested on an ongoing and yearly basis, including a detailed description of the tree trimming cycles that were used to derive the total expenditures in the forecast.

Please refer also to 2-VECC-15.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-43

Reference: Page 13, Line 28 - Inflation Rate Used

Interrogatory:

We are suggesting that there is no material link between NBHDL expenses and the CPI rate.

In order to establish a link, please provide a list of specific items that NBHDL purchases that are also included in the CPI basket discussed in TD's June 2014 quarterly report.

If inflationary impacts are not material, as the applicant suggests, why would NBHDL include the presumed effect of inflation in this application?

Response:

The evidence provided indicates that after using an inflation rate of 2%, the inflationary impacts on non-wage related expenses do not meet NBHDL's materiality threshold for this Application and are therefore the impacts are not separately identified in the Application (although they are included). Based on the foregoing, NBHDL refuses to provide the requested information on the basis that the information sought by this interrogatory is of insufficient probative value to justify such an onerous effort and the resulting delay and expense.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-44

Reference: Page 22, Line 18 - Wages

Interrogatory:

The current wage negotiation process involves management and the union referring to other contracts within the group of LDC's. This "negotiating" involves two parties whose interest are not at odds with each other. This results in an incestuous relationship where there are no parties in these wage negotiations representing ratepayers.

NBHDL has established a legal obligation through 2018 with unionized employees prior to applying for approval for a rate change with the OEB.

Please explain why NBHDL would not arrange contract talks that would allow independent parties to participate in the wage negotiation process?

Please explain what plans the applicant has if the OEB or the intervenors in this application do not agree with these compensation levels?

Response:

Management of NBHDL has an interest in maximizing shareholder value and consequently is interested in negotiating the best deal possible for the company during the collective bargaining process. By contrast, employees are interested in negotiating the best deal possible from their perspective during the collective bargaining process. These interests are not aligned.

However, a key aspect of collective bargaining negotiations is that a strike or a lock-out has a negative impact on both management and employees, providing the parties to the negotiations with an incentive pushing them both to arrive at a mutually satisfactory resolution.

In this context, NBHDL does not believe that the introduction on an independent third party into delicate collective bargaining sessions would be helpful. It would facilitate the taking of extreme positions and fundamentally disrupt the balance of vested interests that is fundamental to the collective bargaining process.

NBHDL does not believe that the Board and the intervenors will refuse the negotiated compensation levels. As described at Exhibit 4, page 46-47, NBHDL reviewed 23 different settlements over the 2011-2013 period before commencing negotiations. On average the increases with these agreements in 2014 was 2.65%. NBHDL's negotiated annual wage increase is 2.5%. Please see also the response to 4-Energy Probe-51.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-45

Reference: Page 22, Line 19

Interrogatory:

"NBHDL's overall compensation for all employees is designed to be competitive and equitable in order to attract and retain qualified personnel in an industry that is facing an aging workforce and is very competitive for skilled resources."

This statement is non-specific and not unique to NBHDL and could be applied to most industries requiring skills from the most mundane to the most skilled. Also, since this statement does not differentiate between the varied types of skills required by NBHDL employees it cannot be applied equally to all employees.

If this statement purports to provide evidentiary evidence to support the wage increases over the past five years, as shown in Table 4-5, what are the demonstrable facts supporting the claim that salaries are equitable as compared to private industry, are only competitive and have not surpassed the clearing rate for the compensated positions, actually have resulted in qualified personnel being hired and that the electricity industry workforce is aging more rapidly than any other industry and that suitably skilled employees are scarcer in the electricity industry than any other industry.

Response:

Please refer to Exhibit 4, Page 45, Line 18 to Exhibit 4, Page 61, Line 2 for detailed evidence to support the increase in compensation costs.

In particular, NBHDL would draw the reader's attention to the evidence of NBHDL's use of:

For union employees, the Stevenson Kellogg Ernst and Whinney system to evaluate job classifications and develop a wage rate progression scale using a multi-factor approach to rate jobs relative to each other, including complexity, education, experience, initiative, physical/mental demands, accountability, contacts, supervision and working conditions;

1. For non-union employees, the Hay system - an industry standard job evaluation system used to develop and maintain pay structures by comparing similarities and differences in the content and value of jobs.

2. The Hay evaluation process includes a job analysis, job descriptions, job evaluation and job structure or ordering of jobs based on their relative value or content. Job evaluation factors include know how, problem solving, accountability and working conditions. The external consultant assigns pay rates to each of the grades based on their experience and compensation from similar sized businesses in the LDC sector.

For union employees, please refer to 4-Energy Probe-51 for a comparison of wage rate increases across 23 different settlements over the 2011-2013.

Non-union employees, on average clustered around the minimum point identified by the Hay system, well below the average midpoint designed by the system.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-46

Reference: Page 22, Line 30

Interrogatory:

"An external consultant is used to develop and maintain the system."

This application reveals the use over 20 external consultants by the applicant. It appears as if some of them are, for all intents and purposes, on retainer.

Given the employee compensation levels at NBHDL and given the high regard that NBHDL holds for these employees, please explain this excess dependence on outside assistance in virtually every aspect of the business.

Response:

In the instance indicated by the reference above, NBHDL confirms that it retained an external consultant in 2004, 2009 and again in 2013 to perform an independent analysis of compensation levels for management/non-union employees. More information about the results of this work can be found at Exhibit 4, Page 46, Line 9 to Exhibit 4, Page 47, Line 8.

NBHDL does not agree that it has an "excess dependence on outside assistance in virtually every aspect of the business." NBHDL retains independent third party support on a case-by-case basis when required to prudently and efficiently operate the business.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-47

Reference: Page 23, Line 3

Interrogatory:

"Progression is not automatic, rather is performance based. The structure is updated annually with salary increases based upon market, philosophy and ability to pay."

Please provide details of the "market" based forces that support the increases for management salaries, what "philosophy" was used to support management increases and how "ability to pay" was factored into any raises for management for the periods from 2010 – 2015.

Response:

In 2013, NBHDL retained an external consultant to review the pay bands based on their experience and compensation from similar sized businesses in the LDC sector. This would be the "market" based forces.

Based on this review, it was found that on average management staff is clustered around the minimum point, well below the average midpoint designed by the compensation system. This a direct reflection of the "philosophy" (provide good value for money) and "ability to pay" considerations.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-48

Reference: Page 32, Line 23 – Asset Management Plan – Annual Update

Interrogatory:

"The plan is dynamic in that external forces result in annual updates being required and also to reflect progress toward asset performance and emerging priorities."

Given the relative lack of growth in the system and the fact that an AMP already exists and that any progress toward asset performance should be self evident, please provide additional evidence to support the need for this $20,000 yearly increase in this expense.

Response:

The amount that is the subject of this interrogatory question does not meet the materiality threshold identified for this rate application.

Variances between planned and actual capital work can occur year-to-year for a variety of reasons (for example, please refer to Exhibit 2, Page 64, Line 3 to Exhibit 2, Page 71, Line 20 for a description of year over year variances for historical costs within each of the four DSP categories of spending). Priorities must be adjusted to accommodate such variances. This is particularly important in light of the Board's focus on more formalized asset management process as described in the Chapter 5 Filing Requirements.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-49

Reference: Page 32, Line 30 – Substation maintenance

Interrogatory:

In its 2010 application NBHDL included $165,000 (4 substations @ $35,000 plus $25,000 for potential issues) for substation maintenance in its estimates (*Exhibit 4 – page 436 – line 20 – 27*) to be collected over four years. This amount was finally included in rates over five years.

As I understand the applicant's description of events following 2010, this money was never spent and the work was eventually completed by NBHDL employees.

Please confirm that I have the facts correct.

The applicant also indicates that $171,607 in external contractors' expense has been avoided since the 2010.

Please indicate if that is in addition to the $190,000.

Ledger account # 5114 balance has declined by approx $94,500 since the 2010 test year. After taking into account the removal of the $190,000 included in 2010, this would seem to indicate that in other items have increased by $95,500 or $267,107 if the $171,607 is an additional saving.

Please detail the items that make up the $226,312 included in ledger account # 5114.

Response:

In response to the first question, you do not have the facts correct. As described in Exhibit 4, Page 33, Lines 1-8 states, in part, that: “The program was fully implemented in 2012 and now the requisite number of stations is maintained each year.”

In response to the second question, the reference was intended to explain that transitioning substation maintenance in-house has avoided $171,607 in external contractors since the test year and that this savings arose because the complement in this part of the engineering department was not increased to handle these activities. You have provided no reference to or explanation of the derivation of the “$190,000”. NBHDL does not understand how the “$190,000” is being derived and is therefore unable to comment further.

In response to the third question, the table below details the items that make up the $226,312 included in ledger account # 5114.

OEB Account 5114	
Labour, Truck time and Overheads	196,531
Materials	17,681
Contracted Services & miscellaneous items	12,100
Total Account 5114	226,312

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-50

Reference: Page 36, Table 4 – 7

Interrogatory:

Increases in OM&A costs per customer have increased almost 39% since the 2010 rebasing year and those costs per FTE are up a little over 30% in the same period. The magnitude of these increases is a result of generous wage settlements. These increases have been justified by the applicant by referencing wage settlements within the industry.

Please comment on the possibility of taking into account consumers' ability to pay, the possibility that industry wage settlements are incestuous and that the asset management plan could be tempered in order to reduce staff numbers and curtail delivery cost increases.

Response:

NBHDL has no comment at this time.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-51

Reference: Page 39, Line 29 - Locates

Interrogatory:

As we understand it, the $191,600 expense variance for locates is attributable to a higher allocation of wages to that expense item.

What is the total locates expense included in the 2015 rate request and which ledger account includes this amount?

What studies has NBHDL done to ascertain the cost difference between using outside contractors to complete locates and using internal staff for this service?

Response:

The total expense for locates in the test year is $249,857. Please refer to Exhibit 4 at Page 38, Table 4-9. The OEB account specific to labour and overheads is Account 5040 and all other expenses are included in Account 5045.

Locates currently necessitate the use of in-house staff that are able to quickly respond to requests and can meet NBHDL quality requirements. As a result, NBHDL has not done such a study.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-52

Reference: Page 40, Line 19 - Executive Financial Regulatory Professional & Insurance

Interrogatory:

"The variance of $275,493 between 2015 Test Year and 2013 is a result of new accounting staff costs to assist with financial reporting, increased labour costs, management bonuses, insurance premium increases, requirement for business and strategic planning updates, travel and training of staff."

"The variance of $103,725 between 2015 Test Year and 2010 Board Approved are a result of the aforementioned, increases and banking fees."

Based on the Table 4 – 4 Cost Driver Table in this exhibit, the total increase in this line item is $126,612 not $103,725 as indicated here. In addition the total increase from 2013 to 2015, again based on Table 4 – 4, is $200,383 not $275,493 as indicated here.

Please explain the apparent anomalies.

Please detail the amount of management bonuses that were included in 2014 and are included in the 2015 Test year and also indicate the amount of bonuses that are included in rates for the next five years.

Please indicate which expenses, if any, in this line item are allocations of total employee compensation and which are additional compensation expense amounts.

Response:

Page 40, line 19, is in reference to the variances from the OM&A programs provided in Table 4-9 (Board Appendix 2-JC). Table 4-4 (Board Appendix 2-JB) referenced above is based on cost drivers. These two tables have been created based on the filing requirement direction and are two separate tables that will not match. This may be a cause of confusion and why NBTA has suggested there are anomalies. For example, within the cost driver table (Table 4-4), compensation is stated as a line item, however, on the program table (Table 4-9) compensation has been included in the appropriate program. Please refer to 4-VECC-37 for more information on Executive Financial Regulatory Professional & Insurance expenses.

Amounts paid in management staff performance bonuses in 2014 totaled $42,980, well below the materiality threshold. This was explained at Exhibit 4, Page 47, Lines 4-8.

In the 2015 test year, $45,000 was forecast for management staff performance bonuses, which is again well below the materiality threshold.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-53

Reference: Page 41, Line 17

Interrogatory:

"Labour costs for regulatory tasks were included in General and Administrative and not in the 2010 OEB approved regulatory costs of $154,300."

Since the balance shown in Account 5655 is $222,552 ($341,656 - $119,104), it appears that labour costs are included in General and Administrative once again in the application. Please confirm and explain effect on rate calculations

Please confirm that labour costs totalling $111,273 included in the total one-time charges of $656,931 shown in Table 4-29 are not included in wage expenses elsewhere in this application.

Response:

Please refer to Table 4-29 that supports the 2010 OEB approved regulatory costs of $154,300, lines 5 and 10 confirms that NBHDL did not include internal labour costs for this program.

The following table provides the details of what is included in Account 5655.

Account 5655 Details:	**2015**
OEB Annual Assessment / OEB Section 30 Costs	75,386
On-going - Consultants' costs for regulatory matters	15,780
2015 Cost of Service - Expensed over 5 years	131,386
Total - Account 5655	**222,552**

NBHDL follows the OEB's Accounting Procedures Handbook in mapping costs and on-going regulatory labour costs are included in General and Administrative and are not duplicated in Account 5655 as shown in the above table. NBHDL has not included labour costs in both accounts. There is no difference in rates if a cost is allocated to General and Administrative (5610) or Regulatory (5655).

NBHDL confirms that labour costs totalling $111,273 included in the total one-time charges of $656,931 shown in Table 4-29 are not included in wage expenses elsewhere in this application. Please refer to 4-Staff-13 and 2-SEC-35 for information related to the $111,273 included in the one-time charges of $656,931 in Table 4-29.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-54

Reference: Page 42, Line 1 – Smart meters and meter reading

Interrogatory:

The variance of $180,995 between the 2010 test year and the 2015 test year is described as the difference between 2013 and the 2015 test year.

Response:

Thank you for alerting NBHDL of this typographical error. The sentence should read:

> "The variance of $180,995 between 2015 Test Year and 2010 board approved is a result of new synchronization operator costs to support communications between the smart meter AMI system, NBHDL's CIS and provincial MDMR. Increases were also encountered for a new Operational Data Store to warehouse customer meter data, security audits, labour for reading remaining manual meters and new costs for NBHDL's AMI service provider."

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-55

Reference: Page 45, Line 2 - Metering – Operations & Maintenance

Interrogatory:

Please indicate the total costs included in 2015 delivery rates for metering operations and maintenance

Response:

The total costs for Metering – Operations / Maintenance forecast for the 2015 test year are $337,870. Please refer to Exhibit 4, Page 38 at Table 4-9.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-56

Reference: Page 48, Table 4 – 10 - Summary of Wage Increases by Year

Interrogatory:

The table shows the average 2015 wage and benefit package at approx $109,000 per employee per year compared to $90,000 in 2010 which is a 21% increase over the five year period. During the years since the 2006 COS application, wage and benefits have almost doubled and the number of employees is down from 53 to 48. Average wage in 2006 was $51,600 and nine years later is $109,000, an increase of 111% or 12.4% per year. This was during the one of the worst economic downturns in the economy that saw government bailouts, government wage freezes and loss of hundreds of thousands of jobs. NBHDL employees were obviously unaffected by this situation.

NBHDL is a monopoly delivering an essential service with a captive customer base. The Board meetings of NBHDL are not open to the public or press. The minutes of Board meetings are not made public. The names of directors are not generally known to the public and do not appear on the NBHDL's website. NBHDL revenue is not subject to normal market forces because of its monopoly status and its government protected environment. NBHDL management, who negotiate contracts, are not an independent party since they base their own compensation on the levels agreed to with CUPE who control the bulk of the settlements in the industry.

Regardless of all the outside systems and consultants (by the way its Whinney not Whitney) purchased or hired by NBHDL, this seemingly complete detachment that the applicant has from the real world is void of any semblance of protection for ratepayers.

Regardless of all the other "savings" listed in this application, please list any significant actions that the applicant has taken to lower the cost of employee wages and benefits during the past five years.

Response:

In addition to the other savings referenced throughout the Application, please refer to the response to 4-NBTA-45.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-57

Reference: Page 58, Table 4 – 21 – Benefit Expense

Interrogatory:

The table indicates total benefits for the 2015 Test year and beyond that amounts to $1,296,347 or $27,000 per employee per year.

Based on the above, will the applicant consider reducing the numbers of union and management employees and rescheduling maintenance, capital and upgrade projects on a longer time frame and if not why not?

In the alternative, will the applicant ask CUPE to reopen the contract now in place and reduce overall benefit levels by shifting to a defined cost pension plan which will reduce management benefit levels accordingly and If not why not?

Response:

NBHDL does not believe that the most effective or prudent way to manage employee benefit costs is to arbitrarily reduce union and management employees and defer necessary maintenance and capital projects.

NBHDL does not have the right to unilaterally re-open a settled collective agreement.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-58

Reference: Page 64, Line 22

Interrogatory:

NBHDL has an IT person on staff and it appears as if it also pays the City of North Bay for the services of an additional IT person to be on site. In addition, the average wage and benefit cost per IT employee at the City is over $100,000 per year

Please explain the need for two IT people on site and if the applicant has considered the possibility of using a private IT firm.

Response:

In 2013, NBHDL retained BDO Canada LLP to conduct a comprehensive IT risk analysis and assessment, which is attached at Exhibit 4, Appendix 4-B.

Based on the findings in this risk analysis and assessment, NBHDL prepared an updated IT Strategy which is attached at Exhibit 4, Appendix 4-C.

Quoting the NBHDL IT Strategy:

> "NBHDL has an Information Technology Services department on site with a current staff complement of two including the IT and Billing Manager. IT support is also augmented with support from the City of North Bay IT, and various contractors as needed.

NBHDL will be re-aligning the Billing and Customer Accounts staff to enhance customer service, provide greater redundancy (as flagged in the IT Risk Assessment Audit and the Meter to Cash Audit). One FTE with be shifted from Billing to IT centric functions.

The changing staff deployment is required due to the increased focus on IT and the need to ensure that the software applications, infrastructure, security and recoverability of the NBHDL information technology environment can be accomplished with acceptable disruption to business operations. Additionally, successful delivery of the IT Strategy as tied to the Corporate Strategy will require additional functionality in order to deliver planned work as well as normal maintenance activities – software upgrades, asset turnover and ongoing support activities to ensure that the IT environment operations in an efficient and effective manner. It will also result in a more responsive and resilient front office and billing function.

The strategic positioning of the IT department through the noted staffing changes will enable the department to transform into a more business-responsive team, positioned to deliver on the corporate needs as documented in this IT Strategic plan. The key goals of delivering more automation, enabling improved and net-new business workflows, consolidating enterprise systems through integration efforts and the standardization of IT services will enable the transformation of IT at NBHDL from a tolerated cost centre to a business enabler. These goals will be significantly impacted without the staffing realignment that can provide sufficient resources to meet the continuing challenges and need for automation that are detailed in this plan.

Industry best practices, suggest that the compliment of IT staff in the Utility sector is 6.6% of the total organizational headcount. This suggests a NBHDL IT staff compliment of approximately 3 FTE positioning NBHDL to be within industry norms and also strongly enabling delivery of improvements to operational and capital work efforts at NBHDL as outlined in the Corporate and IT Strategic plans.

The core value provided by this shift is to significantly reduce expenses from Third Party solution providers, who would otherwise provide and invoice for their services. So, this shift will assist in reducing third party costs with respect to the development of business requirements, IT functional requirements, test planning, test case development and testing support. The IT environment evolves continuously as software updates and upgrades are delivered by vendor partners – this suggests that that additional IT support will provide continuous value through testing and validating these ongoing changes, as well as continuous response to the business' directional changes and net-new deployment."

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-59

Reference: Page 66, Line 8

Interrogatory:

"Considerable effort is made by NBHDL to ensure affiliates are charged properly and do not receive any benefits as a result of their affiliation."

Please confirm that ServCo does not have access to NBHDL's customer data base.

Response:

NBHDL confirms that affiliates do not have access to NBHDL's customer database.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-60

Reference: Page 67, Page 72, Appendices 2 – N, 2010 – 2015

Interrogatory:

The Appendices indicate a service charge of 15% of purchases and services is being charged as a management fee. Some services are cost plus an administration fee and some of the other services have no service charge.

The agreement with Servco (Exhibit 1 – App 1-J) calls for charges, in addition to actual cost, of 10% for an administrative charge plus an amount as return of capital of 10%.

Please explain this apparent anomaly.

Response:

The relevant provision in Exhibit 1, Appendix 1-J, Service Schedule Number 1 to the Services Agreement provides that the payment amount shall be equal to NBHDL's actual costs plus an administrative charge of ten percent and an amount as return of capital of ten percent or such other amount as may be agreed to from time to time by Servco and Distco. Exhibit 4, Pages 67-72 shows the actual charges that were agreed to by the parties for the years 2010-2014 and the forecast for 2015. This includes charging a 15% administration fee on top of each of the charges described in Exhibit 4 at Pages 62-63.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-61

Reference: Page 78, Line 21, Tables 4 – 30

Interrogatory:

While the $2,000 is not included in the revenue requirement, the funds ultimately come from ratepayers.

Please explain the reasoning behind using funds collected from ratepayers to contribute to charitable causes.

Response:

Community and customer focus is a core objective of NBHDL. NBHDL carries on the business of distributing electricity within the City of North Bay, it is wholly-owned through its parent company by the City of North Bay, its head office is in the City of North Bay and NBHDL is firmly rooted in the local community. Giving back to its community is important for NBHDL as a good corporate citizen. The amounts in question are to the account of the shareholder, and are below the materiality threshold.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-62

Reference: Page 80, Line 1

Interrogatory:

"While NBHDL's General asset 1 sub-ledger is able to determine a more accurate depreciation expense based on actual in-service dates."

Please explain the benefit gained versus the time spent in maintaining the sub-ledger and the use made of the sub-ledger to calculate depreciation expense based on actual in-service dates.

Response:

NBHDL leveraged the existence of the fixed asset sub-ledger module within its main software platform in order to transition and comply with the componentization requirements of categorizing PP&E (IAS 16). NBHDL explains the benefit of utilizing the sub-ledger on pages 93 through 94 of Exhibit 2.

In addition, the sub-ledger is key component in monitoring the planning quality indicators explained on pages 37 and 38 of Appendix 2 1 -A: Distribution System Plan. Changes to NBHDL's construction estimation process works in parallel with the sub-ledger.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-63

Reference: Page 88, Line 9

Interrogatory:

According to information previously provided to us, the applicant does not relieve accounts of fixed asset costs relating to distribution system projects that have been rebuilt, scrapped or no longer in service.

Based on that fact, please explain how distribution assets were identified in order to estimate the remaining useful live of those assets.

Response:

NBHDL worked with BDO on the analysis of the componentization of PP&E as discussed on page 88 of Exhibit 4 and pages 93-94 of Exhibit 2.

The analysis provided, using management's best estimate, a NBV for every major component. NBHDL made assumptions based on data available through the GIS and inventory systems that including quantities, historical installation dates and historical pricing that was indexed to current pricing. Once this information was gathered an assessment was completed and costs and accumulated amortization were assessed for each component. For example, NBHDL determined asset records for poles based on vintage and pole height and then assigned all pole costs included in Account 1830, and the related accumulated amortization, accordingly based on the assessment. Based on this assessment, and the categorization of vintages, an analysis was done to estimate remaining service lives. As is reflected in Account 1576, this assessment resulted in a significant extension to the remaining depreciable term of the majority of NBHDL's distribution assets.

NBHDL's componentization and re-assessment of useful lives has been reviewed and approved by NBHDL's external auditors.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-64

Reference: Page 88, Line 18

Interrogatory:

"NBHDL confirms that the useful lives for its asset groups fall within the range allowed in the OEB sponsored Kinectrics study..."

The Kinectrics study in Table F – 2 on page 19

http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf)

indicates the useful life of a smart meter to be 5 – 15 years but it was admitted that Kinectrics did not independently assess the life span of smart meters but relied on the experience of other LDC's.

Some evidence including :

(http://www.cicorp.sk.ca/+pub/Documents/SMART%20METERS/CIC%20Smart%20Meter%20Review%202014%20complete.pdf

on page 22 suggests that the life span of a smart meter may be as long as 30 years rather than the 10 years suggest by the applicant for depreciation purposes.

Based on the above, please explain the basis for depreciating smart meters over a ten year period

Response:

NBHDL confirms that, in consultation with BDO's risk advisory services, it has adopted a useful life for smart meters of 10 years, being the mid-point of the range allowed in the Board sponsored Kinectrics study.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-65

Reference: Page 88, Line 35

Interrogatory:

"For rate setting purposes, these costs are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense."

Please explain further or reference the application where one can find a fuller explanation of the amounts of these costs.

Response:

Capital contributions are explained on pages 22, 31 and 95 of Exhibit 2. Please also refer to the "Contributed Capital from Customers" line of Table 2-33 found in Exhibit 2 at Pages 73-75.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-NBTA-66

Reference: Page 106, Line 1, Table 4 - 53 – Summary of Requested LRAM Amounts

Interrogatory:

The summary of requested LRAM amounts does not include lost revenues relating to the GS 3,000 – 4,999 kW rate class.

Please explain.

Deemed interest in the amount of $7,712 has been added to the LRAM claim. We am aware that the OEB allows these amounts to be collected from customers.

LRAM amounts are allowed to accumulate without notice to customers. Customers have no opportunity to pay these amounts as they become known and thereby avoid interest charges.

Regardless of what the OEB considers acceptable, how does the applicant explain to ratepayers why this interest was allowed to accumulate for up to three years without an indication that it was accumulating and without any request for payment?

Regardless of what the OEB considers acceptable, how does the applicant explain to ratepayers the reasoning behind adding these interest amounts in addition to the deemed interest charges calculated on the rate base which are already approximately $700,000 above NBHDL's interest expense?

Regardless of what the OEB considers acceptable, how does the applicant explain to ratepayers, who are the beneficial owners of the company, that adding these interest amounts which is equivalent to charging themselves interest is in any way "good value for money" as stated in the applicant's mission statement?

Response:

NBHDL is requesting approval for the recovery of lost revenue resulting from its CDM activities for 2011, 2012, and 2013 OPA programs; however there are no OPA verified savings relating to the GS 3,000 – 4,999 kW class for CDM programs. Please see Appendix 4-1 N - NBHDL 2011-2013 LRAMVA for details on NBHDL's LRAM claim. Please also refer to 4.0 -VECC -30.

Since disposition of variance and deferral accounts require an order of the Ontario Energy Board, there will necessarily be a lag between when amounts are accrued into these accounts and when those amounts are disposed of. During this time, carrying charges accrue on certain regulatory accounts in accordance with the rules established by the Ontario Energy Board. In some instances, the carrying charges go to the benefit of ratepayers. In other instances, the carrying charges go to the benefit of the utility. The interest amounts accrued on variance and deferral accounts is separate and distinct from the interest component of the regulatory rate of return.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-30

Reference: Exhibit 4, Appendix N-4, IndEco Report

Interrogatory:

a) Please confirm that Table B-5 sets out the impact of the 2012 CDM programs on 2012 load by customer class (as opposed to the impact of both 2011 and 2012 CDM programs on 2012 load).

b) Similarly, please confirm that Table B-6 sets out the impact of the 2013 CDM programs on 2013 load by customer class (as opposed to the impact of 2011, 2012 and 2013 CDM programs on 2013 load).

c) Please provide separate schedules for 2011, 2012 and 2013 that show the total GWh impact of the 2011-2013 CDM programs (by program year) for each year by customer class (including those that are demand billed), such that the totals reconcile with Table 5 in the OPA's 2013 Final Reported Results. For example, the schedule for the 2011 programs would be set out as follows:

2011 Programs	Calendar Year (GWh)		
	2011	2012	2013
Residential			
GS<50			
GS 50-2,999			
Street Lighting			
Total			

d) With respect to Tables B-4 to B-6, the footnote suggests that for demand billed customer classes the billing determinant impact of the CDM programs was calculated as 12x the reported impact on system peak. Please confirm that this is the case.

e) If part (d) is not confirmed, please explain how the impact on the billing determinant for these classes was determined for each program with reported results for these classes.

Response:

a) NBHDL confirms that Table B-5 of Appendix 4-N of Exhibit 4 only includes the impact of 2012 CDM programs in 2012.

b) NBHDL confirms that Table B-6 of Appendix 4-N of Exhibit 4 only includes the impact of 2013 CDM programs in 2013.

c) The following tables show the total GWh impact of the 2011-2013 CDM programs broken down by customer class:

Program year 2011

2011 Programs	**Calendar Year (GWh)**		
	2011	**2012**	**2013**
Residential	0.5	0.5	0.5
GS<50	0.9	0.8	0.8
GS 50-2,999	1.2	1.2	1.2
Street Lighting			
Total	**2.6**	**2.6**	**2.6**

Program year 2012

2012 Programs	**Calendar Year (GWh)**		
	2011	**2012**	**2013**
Residential		0.3	0.3
GS<50		0.7	0.7

GS 50-2,999		1.1	1.1
Street Lighting		0.6	0.6
Total		**2.7**	**2.7**

Program year **2013**

2013 Programs	**Calendar Year (GWh)**		
	2011	**2012**	**2013**
Residential			1.0
GS<50			0.6
GS 50-2,999			0.7
Street Lighting			0.3
Total			**2.6**

These tables differ from Table 5 on page 7 of Appendix 4-O of Exhibit 4. These tables include the adjustments to 2011 results with the 2011 results and the adjustments to 2012 results with the 2012 results. Table 5, produced by the OPA, includes 2011 adjustments with 2012 results and 2012 adjustments with 2013 results. The totals for each calendar year add up to the same values, with small differences due to rounding error.

d) It is correct that the peak demand reduction values for CDM program results allocated to customers that are billed by kW were multiplied by 12. The distributor revenue for customers billed by kW is based on the customer's peak demand in each month and the reduction in peak demand due to the CDM programs would reduce this peak demand for 12 months each calendar year.

e) Part d) has been confirmed.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-31

Reference: Exhibit 4, Page 6/Page 23

Interrogatory:

a) Please provide the number of new management staff in each of 2010 through 2015.

Response:

The following table provides the number of employees that were new to management in each of 2010 through 2015.

	2010	2011	2012	2013	2014	2015
New Management	1	2	2	0	0	0
Total	**1**	**2**	**2**	**0**	**0**	**0**

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-32

Reference: Exhibit 4, Page 11

Interrogatory:

a) Please provide the incremental cost of smart meter activities in each year 2014 and 2015. Please provide a description of the major costs.

Response:

a) The table below provides the details for the incremental cost for smart meter activities as referenced in exhibit 4, page 11, between the 2015 test year and the last rebasing board approved year (2010) in the amount of $106,753. The details are provided for the 2014 Bridge Year forecast and the actual data for all 2014. Please refer to page 42 of Exhibit 4 for a description of the major categories.

Smart Meter	Test Year vs Last Rebasing Year	2015 Test Year	Variance Test vs Last Rebasing Year Reference pg 11	2014 Bridge Year Forecast	Variance Test vs Last Rebasing Year	2014 Bridge Year Actual	Variance Test vs Last Rebasing Year
Sensus	$0	$194,538	$194,538	$183,897	$183,897	$184,342	$184,342
Sync Operator	$0	$57,572	$57,572	$56,183	$56,183	$59,292	$59,292
ODS	$0	$41,703	$41,703	$41,103	$41,103	$41,109	$41,109
Security Audits/Powerstream/Measurement Canada	$0	$9,500	$9,500	$23,121	$23,121	$24,181	$24,181
Meter Reading Services - Olameter	$196,560	$0	($196,560)	$14	($196,546)	$14	($196,546)
Total	$196,560	$303,313	$106,753	$304,319	$107,759	$308,938	$112,378

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-33

Reference: Exhibit 4, Page 18, Table 4-3

Interrogatory:

a) Please provide Table 4-3 showing 2014 actuals in both CGAAP and MIFRS formats.

Response:

a) Table 4-3 below has been updated for 2014 actuals. OM&A Values for CGAAP and MIFRS are the same as NBHDL did not have any changes to the capitalization policy that impacted OM&A as a result of the transition to IFRS and Employee Future Benefits did not have any unamortized actuarial gains/losses to be recorded for fiscal 2014.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year Board-Approved Less LEAP	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Operations	$ 691,316	$ 789,643	$ 942,500	$ 860,402	$ 897,622	$ 960,774	$ 828,174	$ 1,088,205
Maintenance	$ 1,270,828	$ 1,146,781	$ 1,126,685	$ 1,270,845	$ 1,397,537	$ 1,536,335	$ 1,585,026	$ 1,721,331
SubTotal	**$ 1,962,143**	**$ 1,936,424**	**$ 2,069,185**	**$ 2,131,246**	**$ 2,295,158**	**$ 2,497,109**	**$ 2,413,200**	**$ 2,809,536**
%Change (year over year)		-1.3%	6.9%	3.0%	7.7%	8.8%	-3.4%	12.5%
%Change (Test Year vs Last Rebasing Year - Actual)								45.1%
Billing and Collecting	$ 1,144,087	$ 910,353	$ 887,267	$ 1,056,107	$ 1,019,133	$ 1,604,983	$ 1,639,995	$ 1,243,810
Community Relations	$ 97,000	$ -	-$ 784	$ 35,050	-$ 6,800	$ 1,502	$ 774	$ 2,200
Administrative and General	$ 2,462,179	$ 2,158,328	$ 2,407,977	$ 2,309,976	$ 2,397,460	$ 2,704,381	$ 2,480,597	$ 2,949,298
SubTotal	**$ 3,703,266**	**$ 3,068,681**	**$ 3,294,461**	**$ 3,401,133**	**$ 3,409,793**	**$ 4,310,866**	**$ 4,121,366**	**$ 4,195,308**
%Change (year over year)		-17.1%	7.4%	3.2%	0.3%	26.4%	-4.4%	-2.7%
%Change (Test Year vs Last Rebasing Year - Actual)								36.7%
Total	**$ 5,665,409**	**$ 5,005,105**	**$ 5,363,646**	**$ 5,532,379**	**$ 5,704,951**	**$ 6,807,975**	**$ 6,534,566**	**$ 7,004,844**
%Change (year over year)		-11.7%	7.2%	3.1%	3.1%	19.3%	-4.0%	2.9%

	Last Rebasing Year Board-Approved Less LEAP	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
Operations	$ 691,316	$ 789,643	$ 942,500	$ 860,402	$ 897,622	$ 960,774	$ 828,174	$ 1,088,205
Maintenance	$ 1,270,828	$ 1,146,781	$ 1,126,685	$ 1,270,845	$ 1,397,537	$ 1,536,335	$ 1,585,026	$ 1,721,331
Billing and Collecting	$ 1,144,087	$ 910,353	$ 887,267	$ 1,056,107	$ 1,019,133	$ 1,604,983	$ 1,639,995	$ 1,243,810
Community Relations	$ 97,000	$ -	-$ 784	$ 35,050	-$ 6,800	$ 1,502	$ 774	$ 2,200
Administrative and General	$ 2,462,179	$ 2,158,328	$ 2,407,977	$ 2,309,976	$ 2,397,460	$ 2,704,381	$ 2,480,597	$ 2,949,298
Total	**$ 5,665,409**	**$ 5,005,105**	**$ 5,363,646**	**$ 5,532,379**	**$ 5,704,951**	**$ 6,807,975**	**$ 6,534,566**	**$ 7,004,844**
%Change (year over year)		-11.7%	7.2%	3.1%	3.1%	19.3%	-4.0%	2.9%

1

	Last Rebasing Year Board-Approved Less LEAP	Last Rebasing Year (2010 Actuals)	Variance 2010 BA – 2010 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Actuals	Variance 2012 Actuals vs. 2011 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Bridge Year	Variance 2014 Bridge vs. 2013 Actuals	2014 Actuals	Variance 2014 Actual to 2014 Bridge Forecast	2015 Test Year
Operations	$ 691,316	$ 789,643	-$ 98,327	$ 942,500	$ 152,858	$ 860,402	-$ 82,099	$ 897,622	$ 37,220	$ 960,774	$ 63,152	$ 828,174	-$ 132,600	$ 1,088,205
Maintenance	$ 1,270,828	$ 1,146,781	$ 124,047	$ 1,126,685	-$ 20,096	$ 1,270,845	$ 144,160	$ 1,397,537	$ 126,692	$ 1,536,335	$ 138,798	$ 1,585,026	$ 48,691	$ 1,721,331
Billing and Collecting	$ 1,144,087	$ 910,353	$ 233,734	$ 887,267	-$ 23,085	$ 1,056,107	$ 168,839	$ 1,019,133	-$ 36,973	$ 1,604,983	$ 585,850	$ 1,639,995	$ 35,012	$ 1,243,810
Community Relations	$ 97,000	$ -	$ 97,000	-$ 784	-$ 784	$ 35,050	$ 35,834	-$ 6,800	-$ 41,850	$ 1,502	$ 8,302	$ 774	-$ 728	$ 2,200
Administrative and General	$ 2,462,179	$ 2,158,328	$ 303,851	$ 2,407,977	$ 249,649	$ 2,309,976	-$ 98,001	$ 2,397,460	$ 87,484	$ 2,704,381	$ 306,921	$ 2,480,597	-$ 223,784	$ 2,949,298
Total OM&A Expenses	$ 5,665,409	$ 5,005,105	$ 660,305	$ 5,363,646	$ 358,541	$ 5,532,379	$ 168,733	$ 5,704,951	$ 172,572	$ 6,807,975	$ 1,103,023	$ 6,534,566	-$ 273,409	$ 7,004,844
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -
Total Recoverable OM&A Expenses	$ 5,665,409	$ 5,005,105	$ 660,305	$ 5,363,646		$ 5,532,379	$ 168,733	$ 5,704,951	$ 172,572	$ 6,807,975	$ 1,103,023	$ 6,534,566	-$ 273,409	$ 7,004,844
Variance from previous year				$ 358,541		$ 168,733		$ 172,572		$ 1,103,023		-$ 273,409		$ 196,869
Percent change (year over year)				7%		3%		3%		19%		-4%		3%
Percent Change: Test year vs. Most Current Actual								22.79%						
Simple average of %variance for all years														
Compound Annual Growth Rate for all years														
Compound Growth Rate (2013 Actuals vs. 2010 Actuals)								4.46%						

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-34

Reference: Exhibit 4, Page 20, Table 4-4

Interrogatory:

a) Please identify all the 2015 cost driver amounts that are for one-time costs.

b) Please identify the retirement costs in 2015 and the one-time training and succession costs in that year.

Response:

a) Please refer to Table 4-28 - One–Time Costs on page 74 of Exhibit 4.

b) Please refer to 4-Energy Probe-47 for the salary and benefit information related to succession costs in 2015. The training costs included in 2015 for succession is $7,416. NBHDL does not consider the succession costs, or the related training costs, as one-time costs as eleven more employees are eligible to retire during rate application timeframe.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-35

Reference: Exhibit 4, Page 26 & 39

Interrogatory:

a) Please provide the bad debt amounts for each of 2010 through 2015 (forecast).

b) Please explain how the 2015 forecast is derived.

Response:

a) The chart below provides the bad debt amounts for each year 2010 through to the 2015 Test Year forecast.

2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
66,085	234,632	114,063	23,582	191,079	211,327	191,079

b) NBHDL used the same value for the 2015 Test Year forecast as the amount forecasted for 2014 as 2014 was not forecasted to have any unusual write offs or adjustments. NBHDL forecasted 2014 by taking the actual June year-to-date value and forecasted the remaining six months for a total of $191,079. NBHDL made the assumption that focused collection activities would offset the increases expected in TOU rates anticipated in 2015 forward.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-36

Reference: Exhibit 4, Page 41 & Page 74, Appendix 4-27

Interrogatory:

a) Please provide the annual EDA fees paid in each of 2010 through 2015 (forecast).

b) Please provide cost of locates for 2010 through 2015.

Response:

a) The table below provides the annual EDA fees paid in each year 2010 through to the 2015 Test Year forecast.

2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
38,800	40,520	42,200	44,300	46,200	46,200	48,181

b) The table below provides the costs of locates for 2010 through to the 2015 Test Year forecast.

2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
140,105	226,757	209,629	238,104	218,183	245,983	249,857

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-37

Reference: Exhibit 4, Page 41 & Appendix 2-JC

Interrogatory:

a) Please provide a breakdown of the line labeled "Executive, Financial, Regulatory & Insurance" to show Insurance and Regulatory costs separate from the other categories and for the years 2010 through 2015 (forecast).

b) Does North Bay purchase from the MEARIE group? If yes please show the premiums for each of 2010 through 2015 and indicate when the last time this contract was competitively tendered.

c) Please provide the insurance premium costs for 2010 through 2015.

Response:

a) The line labeled "Executive, Financial, Regulatory & Insurance" should not have included "Regulatory" since the expenses related to this program were included in the line below in Appendix 2-JC included in the application. Therefore the table below provides a breakdown of the line labeled "Executive, Financial, Regulatory & Insurance" in Appendix 2-JC excluding Regulatory for the years 2010 through to the 2015 forecast.

Executive, Financial, Regulatory, Professional & Insurance	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actual	2015 Test Year
NBHDL - Admin - Liability, Property, Travel	145,513	160,997	107,637	126,562	146,323	146,864	165,358
EDA	38,800	40,520	42,200	44,300	46,200	46,200	48,181
Wholesale Settlement	48,204	42,191	44,019	44,019	45,329	44,019	46,683
Meter to Cash, Banking RFP, Strategic Planning	-	-	18,980	17,697	18,190	16,050	100,000
Banking, Audit, Legal	59,128	84,253	86,026	79,692	98,481	91,823	97,150
Renumeration, Facility and all Other	757,671	678,206	660,533	630,720	765,079	708,260	761,111
Total	1,049,315	1,006,167	959,395	942,990	1,119,602	1,053,216	1,218,483

b) NBHDL purchases insurance from the MEARIE group. The table below shows the premiums for each of 2010 through 2015. The premiums shown include amounts for the affiliated companies and the breakdown by company is provided in the 2nd chart. NBHDL has included the Holdco and Generation amounts totaling $2,160 in the OM&A costs for the years 2010 through to 2015 in error; however, this amount is immaterial. The last time this contract was competitively tendered was 2008.

Insurance Premiums	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Forecast	2014 Actual	2015 Test Year	2015 Actual
Liability	28,076	50,844	40,844	46,527	56,819	56,820	62,413	61,139
Cyber	-	-	10,642	10,201	11,364	11,364	12,732	12,563
Director's & Officers	10,421	9,791	10,642	10,201	11,364	11,364	12,732	12,563
2015 Premium reduction			(21,547)					(20,955)
Total Liability	**38,497**	**60,635**	**40,582**	**66,928**	**79,547**	**79,548**	**87,877**	**65,310**
Property	105,396	97,242	69,156	68,965	76,357	76,357	88,139	84,189
Vehicle	23,108	22,702	24,072	25,291	26,588	26,590	26,590	26,594
Other - Business Travel Accident Insurance	1,620	3,120	1,500	1,500	-	500	-	540
Total	**168,621**	**183,699**	**135,310**	**162,684**	**182,492**	**182,995**	**202,606**	**176,633**

Total Insurance Cost by Company								
Company	**2010 Actuals**	**2011 Actuals**	**2012 Actuals**	**2013 Actuals**	**2014 Forecast**	**2014 Actual**	**2015 Test Year**	**2015 Actual**
NBHDL - Admin - Liability, Property, Travel	143,353	158,837	107,277	124,402	144,163	144,664	163,198	134,687
NBHDL - Ops - Vehicle	23,108	22,702	24,072	27,360	25,577	25,579	25,559	25,563
Sub Total NBHDL	**166,461**	**181,539**	**131,349**	**151,762**	**169,740**	**170,243**	**188,757**	**160,250**
NBHS	-	-	1,800	8,007	10,592	10,592	11,689	14,223
HOLDCO	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Generation	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
HST Error				755				
Total	**168,621**	**183,699**	**135,309**	**162,684**	**182,492**	**182,995**	**202,606**	**176,633**

c) Please refer to b) above for premium costs 2010 through 2015.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-38

Reference: Exhibit 4, Page 43 & Appendix 2-JC

Interrogatory:

a) Please provide the Training/Health & Safety line broken down for (a) training outside workers (b) all other training and conferences; and for years 2010 through 2015 (forecast).

Response:

The following table provides the Training/Health & Safety line broken down for training outside workers (which is referenced in Appendix 2-JC) and all other training and conferences for years 2010 through 2015 (forecast).

Department	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2014 Actuals	2015 Test Year
Customer Service							
Labour	2,053	9,325	11,181	8,172	12,773	12,582	7,046
Training - Meals/Course Fees/Travel	-	3,000	3,114	764	1,295	1,295	-
Sub Total	2,053	12,325	14,295	8,936	14,068	13,877	7,046
Line Department							
Labour	135,110	163,140	99,769	84,267	129,620	102,086	95,107
Training - Meals/Course Fees/Travel	26,848	65,558	26,805	27,409	25,996	16,720	25,371
Health & Safety - Tools/Clothing/Misc.	31,519	23,603	27,949	26,811	30,395	39,003	32,717
Sub Total	193,478	252,300	154,522	138,488	186,011	157,809	153,195
Substation Department							
Labour	18,517	18,470	11,780	11,652	12,680	9,508	13,003
Training - Meals/Course Fees/Travel	11,615	6,148	6,968	7,398	7,020	878	6,000
Health & Safety - Tools/Clothing/Misc.	-	-	-	925	-	919	-
Sub Total	30,132	24,617	18,748	19,975	19,700	11,305	19,003
Metering Department							
Labour	12,336	10,167	22,277	25,443	30,659	22,499	34,145
Training - Meals/Course Fees/Travel	168	7,069	10,804	16,939	6,109	2,491	8,775
Health & Safety - Tools/Clothing/Misc.	33	-	-	9	114	-	123
Sub Total	12,537	17,237	33,082	42,391	36,882	24,990	43,042
Total Training - Outside Workers - per Appendix 2-JC	**238,199**	**306,479**	**220,647**	**209,790**	**256,662**	**207,981**	**222,287**
All Other Training:							
Labour	23,966	38,691	24,766	19,403	17,870	39,227	16,026
Training - Meals/Course Fees/Travel	57,765	45,676	25,897	38,899	60,999	41,124	77,845
Health & Safety - Tools/Clothing/Misc.	6,008	12,866	10,178	8,376	7,826	8,607	8,499
Total Training - Other	**87,739**	**97,233**	**60,841**	**66,678**	**86,695**	**88,958**	**102,370**
Total Training	**325,938**	**403,712**	**281,488**	**276,468**	**343,356**	**296,939**	**324,657**

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-39

Reference: Exhibit 4, Page 48

Interrogatory:

a) Please amend Appendix 2-K so as to show Management, non-union, and union employee information separately.

Response:

a) The version of Appendix 2-K provided in the application is split between union and non-union employees; NBHDL Management employees are all non-union and all Non-Management employees are union.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-40

Reference: Exhibit 4, Page 62 & 66, Table 4-26

Interrogatory:

a) Please explain why a 15% administration fee is not applied to North Bay's streetlight services provided to the City.

b) Please provide a table showing the street light maintenance costs for each of 2010 through 2015.

c) Please explain the variation in these costs, specifically the increase to $506k in 2012 and the absence of any costs in 2015 (as shown in Appendix 2-N).

Response:

a) NBHDL bills the City of North Bay as a recoverable work order for actual costs since there is no service agreement in place that would refer to a 15% administration fee.

b) Please refer to Table 4-26 on page 66 of Exhibit 4 for the street light maintenance costs for each of 2010 through 2015.

c) Lines 7-12 on page 64 of Exhibit 4 explain the variation in street light cost for the requested years. NBHDL has worked with the City to convert all of its street lights to LED. This was the key driver of the variation in costs. The City of North Bay is one of the first communities in North America to convert its streetlights entirely to LED fixtures. Since this program is complete, this level of support is not expected in 2015.

North Bay Hydro Interrogatory Responses

EXHIBIT 4 – OPERATING COSTS

4-VECC-41

Reference: Exhibit 4, Page 77, Appendix 2-M

Interrogatory:

a) Please explain how the amount of $111,272 in incremental operating expenses related to regulatory activities of this application was derived.

b) Please explain if the resources were North Bay staff or outside contract or consulting staff.

c) Please explain the rationale for recovering this cost over 5 years.

Response:

a) The table below shows the components of the $111,272 incremental operating expenses related to regulatory activities of this application.

NBHDL - One-time Incremental Staffing Costs	
NBHDL Internal labour - overtime	100,898
Travel for training and Cost of Service Application settlement conference	5,786
Training course fee	1,778
Supplies to prepare copies of the application	2,811
Total	111,272

b) The resources were NBHDL staff.

c) NBHDL would not have incurred this cost in the normal course of business and the costs should not be handled any differently than outside consulting, legal or cost awards related to this application. This rationale supports the recovering of this cost over 5 years.

North Bay Hydro Interrogatory Responses

EXHIBIT 5 –COST OF CAPITAL AND RATE OF RETURN

5-Staff-18

Reference: Exhibit 5, Page 2

Interrogatory:

On page 2 of Exhibit 5, North Bay Hydro indicates that it has used the cost of capital parameters for 2014 cost of service applications in its evidence. North Bay Hydro states that it will update its rates to reflect the latest cost of capital parameters prior to the issuance of the Board's decision for its application. When responding to 6-Staff-19, please include an update to the cost of capital parameters used to calculate North Bay Hydro's revenue requirement.

Response:

NBHDL has updated the cost of capital parameters used to calculate NBHDL's revenue requirement and all changes are reflected in 6-Staff-19.

North Bay Hydro Interrogatory Responses

EXHIBIT 5 –COST OF CAPITAL AND RATE OF RETURN

5-Energy Probe-60

Reference: Exhibit 5

Interrogatory:

a) Please update the cost of capital, including Appendix 2-OA and Appendix 2- OB to reflect the cost of capital parameters issued by the Board on November 20, 2014.

b) With regard to the SWAP agreement with the TD Bank to be effective June 30, 2015 for $6,000,000, please update the expected interest rate for a 10 year term based on current interest rates.

Response:

a) The revised Appendix 2-OA and 2-OB are provided below and reflect the cost of capital parameters issued by the Board on November 20, 2014 and updated expected interest rate of 2.45% for a 10 year term based on current interest rates for the SWAP agreement with the TD Bank to be effective June 30, 2015.

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2015 Test

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$35,304,187	4.24%	$1,497,335
2	Short-term Debt	4.00%	(1)	$2,521,728	2.16%	$54,469
3	**Total Debt**	60.0%		$37,825,914	4.10%	$1,551,804
	Equity					
4	Common Equity	40.00%		$25,217,276	9.30%	$2,345,207
5	Preferred Shares			$ -	0.00%	$ -
6	**Total Equity**	40.0%		$25,217,276	9.30%	$2,345,207
7	**Total**	100.0%		$63,043,191	6.18%	$3,897,011

Appendix 2-OB
Debt Instruments

Year 2015 Test

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Shareholder loan	City of North Bay	Affiliated	Fixed Rate	17-Mar-03		$ 19,511,601	4.77%	$ 930,703	
2	Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Apr-11	10	$ 2,056,450	3.90%	$ 80,202	
3	Captial Loan 2014	TD	Third-Party	Fixed Rate	2-Oct-14	10	$ 3,784,136	3.10%	$ 117,119	
4	Captial Loan 2015	TD	Third-Party	Fixed Rate	30-Jun-15	10	$ 2,946,397	2.45%	$ 72,187	
Total							$ 28,298,584	4.24%	$ 1,200,211	

b) On April 13, 2015 NBHDL's relationship manager at TD Commercial Bank provided an indicative interest rate SWAP for the $6,000,000 2nd tranche at June 30, 2015 at 2.45%. It was also noted that this rate is subject to change.

North Bay Hydro Interrogatory Responses

EXHIBIT 5 –COST OF CAPITAL AND RATE OF RETURN

5-NBTA-67

Reference: Page 2, Line 8

Interrogatory:

Although the OEB sets limits for return on capital and ROE rates, these are calculated amounts and not required by the OEB to be added to delivery rates. While useful in protecting customers in cases where the company and customers operate on an arm's length basis they are not beneficial to NBHDL customers. The applicant appears to have been using the fact that limits are in place in an opportunistic way which penalizes NBHDL owners/customers rather than rewards them.

Please explain why the applicant has chosen to penalize its captive customers and beneficial owners by including amounts in rates that are in excess of actual interest paid and an amount for return on equity in excess of what is required to service debt?

Please explain how this course of action benefits customers in any way.

In addition, please explain why the applicant has chosen to exclude these items from the description of delivery charges shown on customers hydro bills?

Response:

Please refer to the responses to 1-NBTA-1, 1-NBTA-2 and 2-NBTA-21.

NBHDL's billing format conforms with industry standards, a description of which can be found at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+Bill.

The Ontario Energy Board is also considering ways to make items on the bill, such as the delivery and electricity line items, more understandable and meaningful. See: http://www.ontarioenergyboard.ca/oeb/Consumers/Electricity/Your%20Electricity%20Bill/Improving%20Your%20Electricity%20Bill.

Detailed information about the distribution component of the delivery charge, including the application of the Board's cost of capital policies, is made available to the general public through this public hearing process.

North Bay Hydro Interrogatory Responses

EXHIBIT 5 –COST OF CAPITAL AND RATE OF RETURN

5-NBTA-68

Reference: Page 3, Line 19; Page 3, Line 25; Page 3, Line 30

Interrogatory:

Page 3 – Line 19

The “principle” balance at the end of the 2015 Test Year is $1,866,667. The average principal amount owing.....

Page 3 – Line 25

The “principle” balance at the end of the 2015 Test Year is $3,594,480. The average principal amount owing...

Page 3 – Line 30

The “principle” balance at the end of the 2015 Test Year is $5,741,992. The average principal amount owing in 2015 on this loan is expected to be $2,946,397.

This error appears throughout this application and is embarrassing. Doesn’t anyone have a dictionary over there?

Response:

We apologize for any confusion this may have caused.

North Bay Hydro Interrogatory Responses

EXHIBIT 5 –COST OF CAPITAL AND RATE OF RETURN

5-NBTA-69

Reference: Page 6, Table 2 – OB - Debt Instruments

Interrogatory:

Since blended principal and interest payments are being made on some loans, the formulas used in the Excel workbook to calculate interest amounts do not apply and the 2015 interest amounts shown for the Smart Meter, 2014 Capital and 2015 Capital loans are incorrect. The Shareholder loan actual interest rate is 5%.

It seems that this table and the related worksheet are superfluous and do not affect rates since the long term debt ratio has been calculated by the OEB and is being used to calculate rates

If the calculations will affect delivery rates, please the correct interest amounts in the worksheet and change the Long-term Debt Cost Rate where applicable.

If, as I suspect, they do not, a brief explanation of the purpose of Table 2-OB would be appreciated.

Response:

Table 2-0B is used to calculate the weighted average cost of debt applicable in the 2015 test year. This weighted average cost of debt is then applied against the deemed long-term debt component of the capital structure (see line no. 1 of Appendix 2-OA) to calculate a total cost of capital which is then included in rates.

When calculating the weighted average cost of debt for the test year, the Ontario Energy Board's policy is that for affiliate debt that is callable on demand (such as the City loan), an applicant must use the lesser of the actual debt rate contained in the instrument and the deemed long-term debt rate set by the Board. As described at Exhibit 5, Page 3 Lines 1-15, the applicant used the Board's deemed long-term debt amount for the City loan for the purpose of calculating rates.

North Bay Hydro Interrogatory Responses

EXHIBIT 5 –COST OF CAPITAL AND RATE OF RETURN

4-VECC-42

Reference: Exhibit 5, Page 3, Appendix
NOTE: IR references Ex 5, but is titled 4-VECC-42

Interrogatory:

a) With respect to the 2015 TD Loan please provide the source of the forecast interest rate.

b) Please update this rate for the most recent available forecast.

Response:

a) a) The source for the 2015 TD loan forecasted interest rate was the actual rate from the 2014 TD Swap agreement. The agreement included an option for a 2nd tranche of $6,000,000 in 2015. Please refer to Exhibit 5 page 3 lines 29-32.

b) On April 13, 2015, NBHDL’s Relationship Manager at TD Commercial Banking provided an indicative interest rate SWAP for the $6,000,000 2nd tranche at June 30, 2015 of 2.45%. It was also noted that this rate is subject to change.

North Bay Hydro Interrogatory Responses

EXHIBIT 6 - CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

6-Staff-19

Reference: Exhibit 6

Interrogatory:

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Response:

An updated RRWF in working Microsoft Excel format is provided in file named "North Bay 2015_Rev_Reqt_Work_Form_V5_6-Staff-19". The adjustments made to the Application version are documented in Sheet 10 Tracking Sheet. The adjustments reflect the following:

- Step 1: Application with 2014 actual capital
- Step 2: Step 1 with Nov 20th 2014 cost of capital parameters and new rate on 2015 SWAP
- Step 3: Step 2 with updated load forecast as per 3-Energy Probe-34

The results of step 3 have also been included in the middle column of the updated RRWF.

North Bay Hydro Interrogatory Responses

EXHIBIT 6 - CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

6-Energy Probe-61

Reference: Exhibit 6

Interrogatory:

Upon completion of the interrogatory responses, please provide an updated Table 6-1, Table 6-2 and RRWF that reflects any and all changes made as a result of the responses to the interrogatories and any updates or corrections made to the evidence. Please include a live Excel version of the RRWF, including the tracking form that shows the changes made, the source of each change and the impact of each change.

Response:

Please see response to 6-Staff-19.

North Bay Hydro Interrogatory Responses

EXHIBIT 7 – COST ALLOCATION

7-Staff-20

Reference: Exhibit 7, Page 5

Interrogatory:

On page 5 of Exhibit 7, North Bay Hydro stated that costs were assigned to each class in determining the weighting factors for billing and collecting. North Bay Hydro states that "the labour costs for a specific employee who is responsible for all GS > 50 billing were assigned to the GS > 50, Intermediate and Street Light class based on the number of customers per class."

a) Please provide the details of North Bay Hydro's analysis and derivation of the weighting factors for billing and collection. Please include an explanation of the additional complexities in the billing of GS 50 to 2,999 kW, GS 3,000 to 4,999 kW and Street Lighting classes that would cause the weighting factors of 23.8, 14.7 and 14.7, respectively.

b) Please clarify whether the employee identified is also responsible for Street Light class billing. If not, please explain why the costs for an employee responsible for GS > 50 kW customer billing would be allocated to the Street Light class.

Response:

a) The following table has been prepared to provide the details of NBHDL's analysis and the derivation of the weighting factors for billing and collection.

Description	Allocator	Residential	GS < 50 kW	GS > 50 to 2,999 kW	GS >3,000 to 4,999 kW	Street Lighting	Sentinel	Unmetered Scattered Load	Total Costs
Billing Costs - Account 5315:									
Postage / Delivery Costs	# of bills/year	165,079	20,908	1,899	8	8	3,001	55	190,958
Sync Operator / ODS Costs	# of customers	88,115	11,160	-	-	-	-	-	99,275
Internal Staffing Costs	# of customers	77,195	9,777	81,289	335	335	1,404	26	170,360
		330,389	41,846	83,188	342	342	4,405	80	460,593
Other	% per Class	31,718	4,017	7,986	33	33	423	8	44,218
Total Billing Costs by Class		**362,107**	**45,863**	**91,175**	**375**	**375**	**4,828**	**88**	**504,811**
Collecting Costs - Acct 5320:									
Late Payment Average by Class		176,165	39,967	56,153	-	-	-	-	272,285
based on late pymt charges/class - 2011~2013									
Total Collecting Costs by Class		**176,165**	**39,967**	**56,153**	**-**	**-**	**-**	**-**	**272,285**
Total Billing & Collecting Costs by Class:									
Total Costs		538,272	85,831	147,327	375	375	4,828	88	
# of bills issued / year - (I6.2-CA Model)		253,440	32,100	2,916	12	12	4,608	84	
Cost / bill		2.12	2.67	50.52	31.27	31.27	1.05	1.05	
Weighting factor - relative to Resi Class		**1**	**1.3**	**23.8**	**14.7**	**14.7**	**0.5**	**0.5**	

While there is an additional level of complexity in the billing of >50 customers, the weighting factors of 23.8, 14.7 and 14.7 are reflective of the billing costs per class divided by the # of customers billed each month and this is then taken as a relative weighting to 1 (Residential) class. The additional level of complexity in the billing of >50 customers is reflected in the dedication of one employee who is responsible for all GS > 50 billing; this represents approximately 245 customers as compared to the other billing employee who handles the residential and GS <50 class which has approximately 23,795 customers.

b) The employee identified is also responsible for billing the Street Light class.

North Bay Hydro Interrogatory Responses

EXHIBIT 7 – COST ALLOCATION

7-Staff-21

Reference: Cost Allocation Model – Sheet I7.1

Interrogatory:

On Sheet I7.1 North Bay Hydro has provided a list of 14 meter types. Many of the types of meters identified in this list show that there are zero meters of that type installed in North Bay Hydro's service area.

Please confirm which meter types indicated in Sheet I7.1 are installed and being used in North Bay Hydro's service area. If necessary, please file an updated cost allocation model reflecting any changes.

Response:

The list of 14 meters types is the list of meters used in the NBHDL 2010 Cost Allocation model plus three additional meter types that reflect current specific costing as explained on page 4 of Exhibit 7, lines 11 through 20. The list was provided for comparison purposes to show the change between the NBHDL's 2010 and 2015 Cost Allocation models. Meter quantity has only been input into meter types that are applicable to NBHDL in 2015.

North Bay Hydro Interrogatory Responses

EXHIBIT 7 – COST ALLOCATION

7-Staff-22

Reference: Cost Allocation Model – Sheet I7.1 and Sheet I7.2

Interrogatory:

Sheet I7.1 of the cost allocation model indicates that there are 3 types of meters installed for the GS 50 to 2,999 kW class. On sheet I7.2, all meters for the GS 50 to 2,999 kW class have been given a meter reading weighting of 39.34.

Please explain how meter reading costs for all meter types in the GS 50 to 2,999 kW class are identical given that not all of the meters possess interval metering functionality (as described on Sheet I7.1).

Response:

There are 3 different types of meters installed for the GS 50 to 2,999 kW class in sheet I7.1 of the Cost Allocation model, however, NBHDL's understanding is that sheet I7.2 determines the weighting factors to be utilized in order to appropriately allocate the costs of meter reading (USoA 5310) by class in sheet O2. Based on this interpretation, NBHDL assigned the costs included in USoA 5310 by class and the allocation of internal labour costs took varying interval metering functionality into consideration. The following table has been prepared to provide the details of NBHDL's analysis and the derivation of the weighting factors for meter reading.

Description	Residential	GS < 50 kW	GS > 50 to 2,999 kW	GS >3,000 to 4,999 kW
Meter Reading Costs - Account 5310:				
Smart Meter Costs	167,201	21,177	-	-
Internal Staffing Costs - manual meter reading	4,363	4,363	77,659	873
Total Meter Reading Costs by Class	171,563	25,540	77,659	873
# of customers/meters (I7.1)	21,120	2,675	243	1
Cost per customer/meter	8.12	9.55	319.58	872.57
Weighting factor - relative to Resi Class	**1**	**1.18**	**39.3**	**107.4**

The resulting weighting factors as shown above were not determined based on meter type, but instead are reflective of the total cost by class. For example (sheet I7.2), based on a weighting of 39.34, the GS 50 to 2,999 kW class calculates a total ‘weighted factor’ of 9,560 which represents approximately 28.2% of weighted average costs – this translates to $77,659 in sheet O2 for Account 5310 which is what NBHDL proposes is the appropriate cost of meter reading for the GS 50 to 2,999 kW class.

North Bay Hydro Interrogatory Responses

EXHIBIT 7 – COST ALLOCATION

7-Energy Probe-62

Reference: Exhibit 7, Page 3

Interrogatory:

The evidence states that the street lights are connected to NBHDL's secondary buss and are captured outside of Account 1855.

a) Please indicate which account these costs are included in.

b) What is the amount of these costs?

c) How are these costs allocated to the street lighting class?

Response:

a) NBHDL would like to clarify this comment further: the costs included in Account 1855 are related to secondary services and incorporate the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformers or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel. There are no such connection costs associated with street lights recorded in account 1855 or any other account as all incremental costs to connect street lights are charged directly to the City of North Bay.

b) As explained in part a) above, there are no distinct costs attributed to the connection of street lights.

c) Since there are no connection costs associated with street lights the process of having the weighting factor for services set to zero for street lights means no connection costs included in account 1855 are allocated to the street light class.

North Bay Hydro Interrogatory Responses

EXHIBIT 7 – COST ALLOCATION

7-VECC-43

Reference: Exhibit 7, Page 3

Interrogatory:

a) The Application states that North Bay "charges customers for all new and upgraded service unless the change to servicing falls under an internal capital project and involved correcting non-standard or outdated servicing". Does this include services for Residential and GS<50 customers?

b) If yes, why are costs in Account #1885 virtually all assumed to be associated with the Residential and GS<50 classes?

c) If not, please clarify the quoted statement in part (a).

d) The Application states that Street Light assets are connected to North Bay's secondary buses. Who owns the connection assets and, if it is North Bay, in what USOA account are the costs recorded?

Response:

a) Yes, this applies to Residential and GS<50 customers.

b) Please see lines 17 through 21 on page 3 of Exhibit 7. The costs included in Account 1855 are related to secondary services and incorporate the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformers or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel. Due to the ownership rules for these services, NBHDL does not own the assets that would be charged against the Services account 1855 for General Service 50 to 2999 kW and General Service 3000 to 4999 kW classes and therefore these classes have been assigned a weighting factor of 0.0.

c) Please see response to b) above.

d) Please see 7-Energy Probe-62.

North Bay Hydro Interrogatory Responses

EXHIBIT 7 – COST ALLOCATION

7-VECC-44

Reference: Exhibit 7, Page 4

Interrogatory:

a) Are all of North Bay's customers billed on a monthly basis?

b) If not, how many customers in each class are billed on an alternative basis and what on what basis are they billed?

c) Is fact that the IESO undertakes meter data verification for those customers with smart meters whereas for larger customers this function must be performed by North Bay taken into account in the billing and collection weighting factors?

Response:

a) Yes, all of North Bay's customers are billed on a monthly basis.

b) Please see response to a) above.

c) Please see 7-Staff-20.

North Bay Hydro Interrogatory Responses

EXHIBIT 7 – COST ALLOCATION

7-VECC-45

Reference: Exhibit 7, Page 9

Interrogatory:

a) Please confirm that Hydro One Networks is not registered as a market participant at either delivery point and that North Bay's power purchases (per Exhibit 3) include the power delivered to Hydro One Networks.

Response:

NBHDL confirms that Hydro One Networks is not registered as a market participant at either delivery point. NBHDL's power purchases (per Exhibit 3) include the power delivered to Hydro One Networks.

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-Staff-23

Reference: Exhibit 8, Table 8-5, Page 5; Chapter 2 – Filing Requirements for Electricity Distribution Rate Applications, July 18, 2014, Page 53

Interrogatory:

Table 8-5 shows that the current monthly service charges for the GS 50 to 2,999 kW and GS 3,000 and 4,999 kW classes are above the ceiling fixed charges calculated in North Bay Hydro's cost allocation model. North Bay Hydro is proposing to increase both of these fixed charges further in 2015.

Page 53 of the Filing Requirements states that distributors are not expected "to raise the fixed charge further above the ceiling."

Please explain why North Bay Hydro is proposing to increase the monthly service charges for classes that are already above the ceiling charge calculated in cost allocation model.

Response:

The Board's policy and past practice on setting the monthly service charge is simply not as cut and dry as suggested in the referenced filing requirement. The referenced filing requirement relates to the Board's Report on the Application of Cost Allocation for Electricity Distributors dated November 28, 2007 (EB-2007-0667). Since the November 28, 2007 report was issued, the Board has frequently approved distribution rate design proposals which do allow the fixed charge to increase further above the ceiling in circumstances where the applicant is proposing to maintain the same fixed and variable split for various rate classes.

To illustrate this point, North Bay Hydro has identified six cases in Exhibit 8 of the application where the Board has allowed the fixed charge to increase above the ceiling for one or more rate classes. The six cases have been repeated below.

- Centre Wellington Hydro Ltd. - 2013 Cost of Service Rate (EB-2012-0113)
- Atikokan Hydro Inc. - 2012 Cost of Service Rate (EB-2011-0293)
- Espanola Regional Hydro Distribution Corporation - 2012 Cost of Service Rate (EB-2011-0319)
- Horizon Utilities Corporation - 2011 Cost of Service application (EB-2010-0131)
- Hydro One Brampton Networks Inc. - 2011 Cost of Service application (EB-
- 2010-0132)
- Kenora Hydro Electric Corporation Ltd.- 2011 Cost of Service application (EB-2010-0135)

In Horizon Utilities Corporation's ("Horizon") recent decision on their 2015 rates (EB-2014-0002) the Board approved Horizon's proposal to maintain the fixed/variable split. The following outlines the Board finding with regards to proposed fixed/variable split.

- *The Board accepts Horizon's proposal. While the Board's current policy direction is to move toward an increased fixed charge, this consideration was not the sole basis upon which the Board reached its Decision. The Settlement Agreement contains a re-opener provision which would address any policy change related to an increased fixed charge.*

- *A fixed/variable split above the ceiling was approved in Horizon's last cost of service proceeding. In this application, Horizon has maintained the fixed/variable split.*

- *The Board notes that a principle of rate design is that in most circumstances rate stability is desirable. Counter-direction in rates can be confusing to ratepayers. Horizon has chosen to maintain a fixed/variable split that moves above the ceiling. Intervenors argue that this is contrary to the Board's report in EB-2007-0667.*

On April 2, 2015, the Board released the Board's Policy on A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410). Under the new policy, electricity distributors will structure residential rates so that all the costs for distribution service are collected through a fixed monthly charge. The Board has determined that the best approach to implement the new residential rate structure is a four-year transition for all distributors. Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue-neutral. The transition period will be from 2016 to 2019.

As indicated in the April 2, 2015 report, the Board has decided that it will not implement the policy for small general service customers at this time. It will undertake a consultation to consider alternative approaches to implementing its rate design policy for the general service classes

Based on above information, North Bay Hydro submits it would be appropriate to maintain the current fixed/variable proportions for 2015 rates.

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-Staff-24

Reference: Exhibit 8, Page 9

Interrogatory:

North Bay Hydro has provided its estimated Low Voltage expenses for 2015 but, has not provided actual costs for the historical years and forecast costs for the base year. North Bay Hydro states that it has estimated the Low Voltage expense by utilizing current approved LV rates applies to the 2015 load forecast.

a) Please provide the historical and bridge year Low Voltage costs and explanations for any variances.

Response:

Low Voltage costs for the historical years 2010 – 2013 and 2014 actual are provided below.
Variances year over year are immaterial.

Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual
Low Voltage Expense	20,013	27,135	35,511	34,493	34,504

In providing the details in response to this question it was determined that there was an oversight in calculating the Low Voltage costs for the purposes of determining new rates as shown in Table 8-8. Based on NBHDL's load forecast data, the correct Low Voltage should be $34,675, not $19,930. The following table provides the correct LV amount to determine new rates.

2015 Estimated Hydro One (HON) Low Voltage Charges:		
Variable Charges		
2015 Estimated kW - based on 2013 kW		40,438
2015 Rate / kW	$	0.682
Total Common ST Line Charges - Variable	**$**	**27,579**
Fixed Charges		
2015 Rate / Month	$	295.68
Charge / Month	$	591.36
Total Common ST Line Charges - Fixed	**$**	**7,096**
Total Low Voltage Expense - 2015	**$**	**34,675**

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-Staff-25

Reference: [NOTE: IR does not include reference]

Interrogatory:

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50, etc.).

Response:

An updated Appendix 2-W in working Microsoft Excel format is provided in file named "North Bay 2015 Bill Impacts - Appendix 2-W_8-Staff-25". The impacts reflect the Step 3 case outlined in 6-Staff-19. In addition, the following rates have been updated

- EDDVAR rate riders as per 9-Staff-31
- Stranded meter charge to reflect revised load forecast
- RTSR rates as per 8.0-VECC-46
- LV rates as per 8.0–VECC-47

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-Energy Probe-63

Reference: Exhibit 8, Table 8-5

Interrogatory:

a) Please explain why NBHDL proposes to increase the monthly fixed charges for those classes where the existing charge is already higher than the ceiling.

b) What is NBHDL's understanding of the Board's policy with respect to increasing the monthly fixed charge for those rate classes where the existing fixed charge is already above the ceiling?

Response:

a) Please see response to 8-Staff-23.

b) Please see response to 8-Staff-23.

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-Energy Probe-64

Reference: Exhibit 8, Pages 7 – 9

Interrogatory:

Please update any of the tables shown on these pages that have changed due to changes in transmission, wholesale market or LV rates from those used in the evidence.

Response:

Changes have been made to the RTSR and LV rates. The revised RTSR are provided in response to 8.0-VECC-46 and revised LV rates are provided in response to 8.0-VECC-47.

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-NBTA-70

Reference: Page 4, Table 8 - 4 – Proposed monthly service charge

Interrogatory:

Residential annualized customers shown in the table as 253,440 is the result of calculations made using the geometric mean in *2015 Load Forecast Model* workbook in the *Rate Class Customer Model* tab.

In the 2010 COS application, the applicant used the arithmetic mean of growth rates for 8 years to determine the customer connection count for the bridge year and the test year.

In the 2015 COS application, the applicant is using the geometric mean of growth rates for two years to determine the customer connection count for the bridge year and the test year.

A note on the *2015 Load Forecast Model* workbook in the *Rate Class Customer Model* tab indicates that the averages were calculated using the last 5 years when in fact only two years have been used.

Please explain this change in method and the apparent anomalies between the note and the calculations

There is also a reference in the note to a change, for calculation purposes, to the geometric mean from the arithmetic mean in the 2010 COS application. I see no evidence of that in the 2010 decision.

Please provide a reference to the change made in the 2010 application or explain note.

Response:

The note in the *2015 Load Forecast Model* is incorrect in suggesting the geometric mean was calculated using the last 5 years. As described at Exhibit 3, Page 15, the geometric mean analysis for 2012 and 2013 were used as they will be more reflective of what is expected in 2014 and 2015.

The very same note in the *2015 Load Forecast Model* goes on to say “10 COS settlement had NBHDL agree to use geomean”.

The Settlement Agreement filed March 26, 2010 in respect of the 2010 COS application (EB-2009-0270) provided at page 10 that:

> “The Parties agree for the purposes of settlement of this Application that the load and customer forecasts used by NBHDL are appropriate, with one adjustment: While the Parties agree with the purchased forecast of 590.8 GWh (see Exhibit 3, page 18, Table 3-9), the use of a geometric mean approach to the forecast rather than the arithmetic mean approach used in the Application results in a decrease in revenue deficiency in the amount of $13,300.”

This was agreed to by the parties to EB-2009-0270 (NBHDL, EP, SEC, VECC and Mr. Rennick) and was approved by the Board.

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-NBTA-71

Reference: Page 4, Table 8-4 – Proposed monthly service charge

Interrogatory:

The calculation of the proposed monthly service charges shown in the table do not seem to appear in any of the Excel workbooks submitted. Please provide the workbook containing the calculation, if one was used, or indicate if the rates were calculated manually.

Response:

Table 8-4 has been revised as follows to explain the calculation of the proposed monthly service charges:

Rate Class	Total Base Revenue Requirement - From Table 8-2 (A)	Fixed Revenue Proportion - From 8-3 (B)	Fixed Revenue (C) = (A) * (B)	Annualized Customers / Connections - Number of Customers/ Connections from Load Forecast times 12 (D)	Proposed Monthly Service Charge (E) = (C) / (D)
Residential	$7,488,001	57.0%	$4,269,712	253,440	$16.85
General Service < 50 kW	$2,454,539	32.6%	$801,211	32,100	$24.96
General Service 50 to 2999 kW	$2,103,877	47.6%	$1,002,017	2,916	$343.63
General Service 3000 to 4999 kW	$99,498	81.1%	$80,701	12	$6,725.12
Street Lighting	$502,662	68.3%	$343,251	65,028	$5.28
Sentinel Lighting	$45,351	51.7%	$23,438	4,608	$5.09
Unmetered Scattered Load	$1,078	40.8%	$440	84	$5.24
Total	**$12,695,006**		**$6,520,770**	**358,188**	

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-NBTA-72

Reference: Page 7, Table 8 - 8 – Proposed Retail Transmission Rates

Interrogatory:

Our understanding of the system is that IESO bills transmission network and line connection charges to Hydro One. Hydro One then passes the cost of those charges to NBHDL and other LDC's.

Since there are both IESO and Hydro One network and connection rate charges included in delivery rates, we presume we are mistaken. Please explain the billing method.

Response:

The IESO bills the entity that is identified as the transmission customer for each point where the NBHDL system connects to the provincial transmission grid.

NBHDL is the transmission customer at seven delivery points where the NBHDL system connects to the provincial transmission grid. NBHDL is billed Uniform Transmission Rates by the IESO on all capacity delivered through these seven points.

NBHDL is embedded in Hydro One's 44 kV sub transmission system at the City of North Bay water treatment plant located at 248 Lakeside Drive and at Substation #17, which is located in North Bay's rural area at 20 Peninsula Road. Hydro One is the transmission customer of the IESO at these two points. For these points, Hydro One pays the IESO wholesale transmission charges calculated at the Ontario Uniform Transmission Rates and then passes them on to NBHDL at Hydro One's approved rates.

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-VECC-46

Reference: Exhibit 8, Page 7

Interrogatory:

a) Please update the RTSR calculations to reflect the OEB approved 2015 UTRs and Hydro One Networks proposed 2015 RTSR's per its EB-2013-0416 Application.

b) Please provide a schedule that contrasts North Bay's proposed RTSRs and the RTSR's resulting from part (a) with its approved 2014 RTSRs.

Response:

a) The RTSR calculations have been updated to reflect the OEB approved 2015 UTRs and Hydro One Networks proposed 2015 RTSR's per its EB-2013-0416 Application. The following provides the updated RTSR's

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	**kWh**	**$**	**0.0075**	**$**	**0.0059**
General Service Less Than 50 kW	**kWh**	**$**	**0.0071**	**$**	**0.0053**
General Service 50 to 2,999 kW	**kW**	**$**	**2.8142**	**$**	**2.0810**
General Service 3,000 to 4,999 kW	**kW**	**$**	**2.9852**	**$**	**2.2998**
Unmetered Scattered Load	**kWh**	**$**	**0.0071**	**$**	**0.0053**
Sentinel Lighting	**kW**	**$**	**2.1330**	**$**	**1.6423**
Street Lighting	**kW**	**$**	**2.1224**	**$**	**1.6086**

b) The following schedule contrasts North Bay's proposed RTSRs and the RTSR's resulting from part (a) with its approved 2014 RTSR.

Rate Class	Unit	Current RTSR Network	Current RTSR Connection	Proposed RTSR Network - Application	Proposed RTSR Connection - Application	Proposed RTSR Network - VECC 46	Proposed RTSR Connection - VECC 46
Residential	kWh	0.0073	0.0057	0.0076	0.0057	0.0075	0.0059
General Service Less Than 50 kW	kWh	0.0069	0.0052	0.0072	0.0052	0.0071	0.0053
General Service 50 to 2,999 kW	kW	2.7265	2.0265	2.8421	2.0309	2.8142	2.0810
General Service 3,000 to 4,999 kW	kW	2.8921	2.2396	3.0147	2.2445	2.9852	2.2998
Unmetered Scattered Load	kWh	0.0069	0.0052	0.0072	0.0052	0.0071	0.0053
Sentinel Lighting	kW	2.0665	1.5993	2.1541	1.6028	2.1330	1.6423
Street Lighting	kW	2.0562	1.5665	2.1434	1.5699	2.1224	1.6086

North Bay Hydro Interrogatory Responses

EXHIBIT 8 – RATE DESIGN

8-VECC-47

Reference: Exhibit 8, Page 9

Interrogatory:

a) Please provide a schedule that contrasts North Bay's actual 2014 LV rates with its proposed 2015 LV rates.

b) What were the actual Low Voltage charges billed by Hydro One Networks in each of 2013 and 2014?

Response:

a) A schedule that contrasts North Bay's actual 2014 LV rates with its proposed 2015 LV rates is as follows:

Rate Class	Unit	Current LV Rates	Proposed LV Rates
Residential	kWh	0.00004	0.00007
General Service Less Than 50 kW	kWh	0.00004	0.00007
General Service 50 to 2,999 kW	kW	0.0139	0.0258
General Service 3,000 to 4,999 kW	kW	0.0154	0.0285
Unmetered Scattered Load	kWh	0.00004	0.00007
Sentinel Lighting	kW	0.0110	0.0204
Street Lighting	kW	0.0108	0.0200

b) Please see 8-Staff-24.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Staff-26

Reference: Exhibit 9, Table 9-17 (Appendix 2-EB), Table 9-15 and Table 9-16; Chap. 2 Appendices Appendix 2-BA – revised CGAAP for years 2013 and 2014

Interrogatory:

a) North Bay Hydro has not provided the Fixed Asset Continuity Schedules under the old CGAAP for years 2013 and 2014. Since the net additions and depreciation numbers are material, these schedules are required to verify the numbers used in the calculation of the balance in Account 1576. Please provide the Appendices 2-BA under the old CGAAP for years 2013 and 2014.

b) The net additions in Appendix 2-EB do not match Appendix 2-BA for the following years:

i. 2012 – old CGAAP

ii. 2012 – revised CGAAP

iii. 2013 – revised CGAAP

iv. 2014 – revised CGAAP.

Please explain the differences, and provided amended schedules as necessary.

c) The Closing net PP&E for each of the years 2012, 2013, and 2014 shown on Appendix 2-EB does not match the Appendix 2-BA for those years under revised CGAAP. This is also the case for the number shown under the old CGAAP for 2012. OEB staff was not able to verify the Closing net PP&E numbers shown for years 2013 and 2014 under old CGAAP as these schedules were not provided. It appears that North Bay Hydro may have included the CWIP as part of PP&E when calculating the balance in Account 1576. Please explain, and provide the amended schedules as necessary.

Response:

a) Appendices 2-BA under the old CGAAP for 2013 and 2014 is provided in Attachment-9-Staff-26. NBHDL has updated 2-BA 2014 to include actuals for all of 2014.

b) In the completion of Appendix 2-EB provided in the application, NBHDL included CWIP in the net additions calculation. The following table provides an explanation of the differences.

	2012	2013	2014
Appendix 2-EB:			
Additions	4,641,727	5,983,486	9,970,116
Disposals	(316,355)	(704,431)	(3,166,720)
Net Additions	4,325,372	5,279,055	6,803,396
Appendix 2-BA:			
Additions	4,016,447	5,457,443	9,164,695
Disposals	(316,355)	(79,228)	(2,640,640)
Net Additions	3,700,091	5,378,215	6,524,055
Variance	**625,281**	**(99,161)**	**279,341**
CWIP Additions	625,281	526,042	805,422
CWIP Disposals	-	(625,203)	(526,080)
Variance	**625,281**	**(99,161)**	**279,341**
CWIP disposals = assets reclassified 'in-service'			

NBHDL has amended Appendix 2-EB (please see Attachment-9-Staff-26) to exclude CWIP and include actuals for all of 2014. The amended Appendix 2-EB reconciles to Appendix 2-BA for 2012, 2013 and 2014 actuals and, as per a) above, Appendix 2-BA for 'old CGAAP' for 2013 and 2014 has also been provided and reconciles to amended Appendix 2-EB. Appendix 2-EB has also been updated to reflect NBHDL's updated cost of capital. An updated Appendix 2-BA for 2014 actuals under MIFRS has been provided in response to 2-Energy Probe-19.

NBHDL has updated the EDDVAR model to reflect the changes to the Account 1576 balance to reflect 2014 actuals and changes to the WACC %.

c) Please see response to b) above. Updated Appendix 2-BA for 2014 actuals has been provided along with Appendix 2-BA for 2013 and 2014 under 'old CGAAP'. NBHDL has also provided an amended Appendix 2-EB.

File Number:	EB-2014-0099
Exhibit:	2
Tab:	
Schedule:	
Page:	
Date:	April 24, 2015

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP **'Old' CGAAP - for comparative purposes only**
Year **2013**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,223,533	$ 94,033	$ -	$ 1,317,567	-$ 1,000,712	-$ 80,963	$ -	-$ 1,081,674	$ 235,892
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,728,007	$ 112,435	-$ 9,936	$ 1,830,506	-$ 333,981	-$ 33,865	$ 9,936	-$ 357,909	$ 1,472,597
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 11,016,436	$ 2,057,224	-$ 60,158	$ 13,013,503	-$ 4,283,406	-$ 381,166	$ 53,350	-$ 4,611,221	$ 8,402,281
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 20,054,943	$ 1,345,153	-$ 5,535	$ 21,394,561	-$ 11,504,486	-$ 640,273	$ -	-$ 12,144,758	$ 9,249,803
47	1835	Overhead Conductors & Devices	$ 15,639,134	$ 753,828	$ -	$ 16,392,963	-$ 8,811,047	-$ 504,228	$ -	-$ 9,315,275	$ 7,077,688
47	1840	Underground Conduit	$ 791,323	$ 306,052	$ -	$ 1,097,375	-$ 166,450	-$ 37,773	$ -	-$ 204,223	$ 893,153
47	1845	Underground Conductors & Devices	$ 6,918,226	$ 389,846	$ -	$ 7,308,072	-$ 4,637,167	-$ 209,977	$ -	-$ 4,847,144	$ 2,460,928
47	1850	Line Transformers	$ 16,002,784	$ 519,110	-$ 3,599	$ 16,518,295	-$ 9,429,941	-$ 457,557	$ -	-$ 9,887,499	$ 6,630,797
47	1855	Services (Overhead & Underground)	$ 17,526,406	$ 491,910	$ -	$ 18,018,316	-$ 6,758,505	-$ 628,523	$ -	-$ 7,387,028	$ 10,631,287
47	1860	Meters	$ 3,823,010	$ 50,354	$ -	$ 3,873,364	-$ 2,715,458	-$ 90,529	$ -	-$ 2,805,987	$ 1,067,377
47	1860	Meters (Smart Meters)	$ 256,341	$ 62,304	$ -	$ 318,644	-$ 18,078	-$ 21,670	$ -	-$ 39,749	$ 278,896
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,414,256	$ 100,066	$ -	$ 2,514,322	-$ 1,261,439	-$ 81,683	$ -	-$ 1,343,122	$ 1,171,200
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 370,268	$ 6,292	$ -	$ 376,560	-$ 298,319	-$ 11,674	$ -	-$ 309,993	$ 66,567
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 816,657	$ 8,076	$ -	$ 824,733	-$ 639,644	-$ 54,491	$ -	-$ 694,135	$ 130,598
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,623,313	$ 58,916	$ -	$ 2,682,228	-$ 1,616,558	-$ 237,948	$ -	-$ 1,854,506	$ 827,722
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,226,966	$ 101,630	$ -	$ 1,328,596	-$ 1,028,453	-$ 42,849	$ -	-$ 1,071,302	$ 257,294
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 148,322	$ 20,789	$ -	$ 169,111	-$ 90,756	-$ 8,224	$ -	-$ 98,981	$ 70,131
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 20,050	$ -	$ -	$ 20,050	-$ 9,931	-$ 2,005	$ -	-$ 11,936	$ 8,113
47	1970	Load Management Controls Customer Premises	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	-$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,342,401	$ 41,364	$ -	$ 1,383,765	-$ 1,047,133	-$ 34,166	$ -	-$ 1,081,299	$ 302,466
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 23,264	-$ 1,630	$ -	-$ 24,894	$ 28,167
47	1995	Contributions & Grants	-$ 8,236,870	-$ 1,061,939	$ -	-$ 9,298,809	$ 1,892,665	$ 346,078	$ -	$ 2,238,743	-$ 7,060,066
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 96,935,958**	**$ 5,457,443**	**-$ 79,228**	**$ 102,314,173**	**-$ 54,426,341**	**-$ 3,215,115**	**$ 63,286**	**-$ 57,578,169**	**$ 44,736,004**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 96,935,958**	**$ 5,457,443**	**-$ 79,228**	**$ 102,314,173**	**-$ 54,426,341**	**-$ 3,215,115**	**$ 63,286**	**-$ 57,578,169**	**$ 44,736,004**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 3,215,115**			
			$ -				-$ 1,133,421				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 132,911
Stores Equipment	$ -
Net Depreciation	-$ 3,082,204

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard CGAAP **'Old' CGAAP - for comparative purposes only**
Year **2014**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally Acct 1925)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1611	Computer Software (Formally Acct 1925)	$ 1,317,567	$ 161,995	$ -	$ 1,479,562	-$ 1,081,674	-$ 145,198	$ -	-$ 1,226,873	$ 252,689
CEC	1612	Land Rights (Formally Acct 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 446,565	$ -	$ -	$ 446,565	$ -	$ -	$ -	$ -	$ 446,565
47	1808	Buildings	$ 1,830,506	$ -	$ -	$ 1,830,506	-$ 357,909	-$ 34,631	$ -	-$ 392,540	$ 1,437,966
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 13,013,503	$ 646,921	$ -	$ 13,660,424	-$ 4,611,221	-$ 426,221	$ -	-$ 5,037,442	$ 8,622,981
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 21,394,561	$ 1,954,019	$ -	$ 23,348,580	-$ 12,144,758	-$ 691,965	$ -	-$ 12,836,723	$ 10,511,856
47	1835	Overhead Conductors & Devices	$ 16,392,963	$ 761,242	$ -	$ 17,154,204	-$ 9,315,275	-$ 522,631	$ -	-$ 9,837,906	$ 7,316,299
47	1840	Underground Conduit	$ 1,097,375	$ 127,159	$ -	$ 1,224,534	-$ 204,223	-$ 46,437	$ -	-$ 250,660	$ 973,874
47	1845	Underground Conductors & Devices	$ 7,308,072	$ 118,969	$ -	$ 7,427,041	-$ 4,847,144	-$ 209,813	$ -	-$ 5,056,958	$ 2,370,083
47	1850	Line Transformers	$ 16,518,295	$ 553,799	$ -	$ 17,072,094	-$ 9,887,499	-$ 457,913	$ -	-$ 10,345,412	$ 6,726,683
47	1855	Services (Overhead & Underground)	$ 18,018,316	$ 536,867	$ -	$ 18,555,183	-$ 7,387,028	-$ 640,250	$ -	-$ 8,027,278	$ 10,527,904
47	1860	Meters	$ 3,873,364	$ -	-$ 2,283,802	$ 1,589,562	-$ 2,805,987	-$ 100,389	$ 2,005,716	-$ 900,659	$ 688,903
47	1860	Meters (Smart Meters)	$ 318,644	$ 3,516,312	$ -	$ 3,834,957	-$ 39,749	-$ 1,056,499	$ -	-$ 1,096,247	$ 2,738,709
N/A	1905	Land	$ 86,551	$ -	$ -	$ 86,551	$ -	$ -	$ -	$ -	$ 86,551
47	1908	Buildings & Fixtures	$ 2,514,322	$ 459,817	-$ 22,805	$ 2,951,334	-$ 1,343,122	-$ 91,723	$ 7,602	-$ 1,427,243	$ 1,524,091
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 376,560	$ 2,726	$ -	$ 379,286	-$ 309,993	-$ 10,861	$ -	-$ 320,853	$ 58,433
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equipment - Hardware	$ 824,733	$ 128,715	$ -	$ 953,448	-$ 694,135	-$ 65,795	$ -	-$ 759,930	$ 193,518
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 2,682,228	$ 44,911	-$ 331,838	$ 2,395,301	-$ 1,854,506	-$ 235,243	$ 331,838	-$ 1,757,911	$ 637,390
8	1935	Stores Equipment	$ 75,196	$ -	$ -	$ 75,196	-$ 75,196	$ -	$ -	-$ 75,196	$ -
8	1940	Tools, Shop & Garage Equipment	$ 1,328,596	$ 13,512	$ -	$ 1,342,108	-$ 1,071,302	-$ 45,590	$ -	-$ 1,116,892	$ 225,217
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 169,111	$ 5,253	$ -	$ 174,364	-$ 98,981	-$ 9,526	$ -	-$ 108,507	$ 65,858
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 20,050	$ 960	$ -	$ 21,010	-$ 11,936	-$ 2,053	$ -	-$ 13,989	$ 7,020
47	1970	Load Management Controls Customer Premises	$ 403,931	$ -	$ -	$ 403,931	-$ 403,931	$ -	$ -	-$ 403,931	$ -
47	1975	Load Management Controls Utility Premises	$ 165,151	$ -	$ -	$ 165,151	-$ 165,151	$ -	$ -	-$ 165,151	$ -
47	1980	System Supervisor Equipment	$ 1,383,765	$ 49,793	$ -	$ 1,433,558	-$ 1,081,299	-$ 33,485	$ -	-$ 1,114,784	$ 318,774
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ 53,060	$ -	$ -	$ 53,060	-$ 24,894	-$ 1,630	$ -	-$ 26,523	$ 26,537
47	1995	Contributions & Grants	-$ 9,298,809	-$ 1,415,412	$ -	-$ 10,714,221	$ 2,238,743	$ 395,625	$ -	$ 2,634,368	-$ 8,079,853
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
						$ -				$ -	$ -
		Sub-Total	**$ 102,314,173**	**$ 7,667,560**	**-$ 2,638,445**	**$ 107,343,288**	**-$ 57,578,169**	**-$ 4,432,227**	**$ 2,345,157**	**-$ 59,665,240**	**$ 47,678,048**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total PP&E	**$ 102,314,173**	**$ 7,667,560**	**-$ 2,638,445**	**$ 107,343,288**	**-$ 57,578,169**	**-$ 4,432,227**	**$ 2,345,157**	**-$ 59,665,240**	**$ 47,678,048**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						$ -			
		Total						**-$ 4,432,227**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	-$ 127,313
Stores Equipment	$ -
Net Depreciation	-$ 4,304,915

File Number:	EB-2014-0099
Exhibit:	9
Tab:	
Schedule:	
Page:	
Date:	April 24, 2015

Appendix 2-EB
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

	2010 Rebasing Year	2011	2012	2013	2014	2015 Rebasing Year
Reporting Basis	**CGAAP**	**IRM**	**IRM**	**IRM**	**IRM**	**MIFRS**
	Forecast	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**
			$		$	$
PP&E Values under former CGAAP						
Opening net PP&E - Note 1			41,679,603	42,509,617	44,736,004	
Net Additions - Note 4			3,700,091	5,378,215	5,029,115	
Net Depreciation (amounts should be negative) - Note 4			-2,870,077	-3,151,829	-2,087,071	
Closing net PP&E (1)			42,509,617	44,736,004	47,678,048	
PP&E Values under revised CGAAP (Starts from 2012)						
Opening net PP&E - Note 1			41,679,603	43,643,038	47,042,865	
Net Additions - Note 4			3,700,091	5,378,215	5,029,115	
Net Depreciation (amounts should be negative) - Note 4			-1,736,656	-1,978,388	-956,337	
Closing net PP&E (2)			43,643,038	47,042,865	51,115,643	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			-1,133,421	-2,306,861	-3,437,595	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	- 3,437,595		**WACC**	6.28%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	- 216,004		**# of years of rate rider disposition period**	1
Amount included in Deferral and Variance Account Rate Rider Calculation	- 3,653,598			

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2012, the PP&E values as of January 1, 2012 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:

the variance account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Staff-27

Reference: Exhibit 9, Page 8-9

Interrogatory:

The rate riders for the Disposition and Recovery Refund of Regulatory Balances (2012) – Account 1595 expired in April 2014. North Bay Hydro is proposing disposition of the unaudited residual balance in this sub-account. OEB staff notes that according to the OEB's EDDVAR report, only audited balances are to be disposed. Account 1595 is a Group 1 account and is eligible for annual review and disposition by the OEB.

a) Since the amount is material, please explain why North Bay Hydro is proposing to dispose of an unaudited balance?

b) Please provide a revised calculation of the deferral and variance account rate riders by removing the balance in this sub-account of Account 1595, in the event the Board does not accept North Bay Hydro's proposal.

Response:

a) The rate rider for the 2012 RSVA expired in April 2014 and NBHDL proposed to dispose of the balance in order to address all DVA balances within the rate application that related to DVA balances prior to 2013. The disposition amount included an estimate of 2014 amounts collected from January through April of 2014. Subsequent to the submission of this application, BDO has provided NBDHL with an unqualified or 'clean' opinion for the 2014 financial statements; the final 2014 balance for this account, including carrying charges, is $189,778.48 – a variance of $14,788.11. NBHDL continues to request disposition of this account and has updated the EDDVAR model to reflect 2014 actual data.

b) In the event the Board does not accept North Bay Hydro's proposal, a revised calculation of the deferral and variance account rate riders with the balance this sub-account of Account 1595 removed, is as follows:

Please indicate the Rate Rider Recovery Period (in years) | **1**

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Balance (excluding 1589)**	**Rate Rider for Deferral/Variance Accounts**	
RESIDENTIAL	kWh	213,486,948	-$ 210,655	- **0.0010**	$/kWh
GENERAL SERVICE LESS THAN 50 KW	kWh	86,032,032	$ 5,556	**0.0001**	$/kWh
GENERAL SERVICE 50 TO 2,999 KW	**kW**	490,350	$ 163,630	**0.3337**	**$/kW**
GENERAL SERVICE 3,000 TO 4,999 KW	**kW**	31,718	$ 11,823	**0.3727**	**$/kW**
UNMETERED SCATTERED LOAD	kWh	52,860	-$ 128	- **0.0024**	$/kWh
SENTINEL LIGHTING	**kW**	1,234	-$ 5,609	- **4.5475**	**$/kW**
STREET LIGHTING	**kW**	5,641	-$ 82,378	- **14.6033**	**$/kW**
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 117,762**		

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Staff-28

Reference: Exhibit 9, Pages 9 and 16-17

Interrogatory:

North Bay Hydro is proposing disposition of $43,057 for Account 1508 – Sub-account IFRS Transition costs. This amount includes projected costs in the amount of $26,960 with respect to costs incurred in the bridge and test years.

a) Please indicate whether North Bay Hydro has any amounts embedded in rates with respect to IFRS transition costs in the test year.

b) Please confirm that no further amounts will be recorded in this sub-account in the future.

c) If the answer to part b. is "no", please explain why North Bay Hydro is proposing to dispose of an amount that is below its materiality threshold.

Response:

a) NBHDL does not have any IFRS transition costs embedded in rates for the test year.

b) NBHDL confirms that no further amounts will be recorded in this sub-account in the future.

c) Section 2.12.3 of the Chapter 2 Filing Requirements states:

"An applicant should file a request for review and disposition of the balance in Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs or Account

> 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance. The balance requested should include actual audited incremental transition costs to date, the unaudited actuals for the bridge year and a forecast of any remaining costs to be incurred for the test year. Given that applicants are expected to adopt IFRS effective January 1, 2015, costs forecasted to be incurred in the test year are expected to be minimal."

This requirement does not give NBHDL discretion. NBHDL is proposing to dispose of the amount in this DVA in accordance with the Filing Requirements. NBHDL is seeking to discontinue this account following its disposal as the issue that gave rise to the establishment of the sub-account has been concluded.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Staff-29

Reference: Exhibit 9, Page 32

Interrogatory:

North Bay Hydro is proposing disposition of an immaterial amount of $379 with respect to Account 1508, Sub-account OEB Cost Assessments from January 2009 through April 2011. OEB staff notes that this Sub-account of Account 1508 was discontinued effective May 1, 2006, and distributors were to cease recordings in this account after April 30, 2006.

Please explain why North Bay Hydro has continued to use this account despite the fact that it has been discontinued. In the revised calculation of the deferral and variance account rate riders requested in 9-Staff-30, please also remove the balance in Account 1508, sub-account OEB Cost Assessments.

Response:

From January 2009 to April 2011, NBHDL recorded the amounts invoiced by Hydro One Networks for HON Regulatory Rate Riders for (2006 & 2008) to Account 1508. NBHDL was unaware of the discontinued use of this account in 2006. In the revised calculation of the deferral and variance account rate riders requested in 9-Staff-31, the balance in Account 1508, sub-account OEB Cost Assessments, has been removed from the EDDVAR model continuity schedule.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Staff-30

Reference: Exhibit 9, Page 32

Interrogatory:

North Bay Hydro has proposed disposition of the balance of $36,278 in its Miscellaneous Deferred Debits Account, 1525. North Bay Hydro has stated that the amounts recorded in this account are related to the initial work related to the new 2011 – 2014 CDM framework, development of CDM strategy, and anticipated implementation of the Board approved programs that did not materialize as OPA programs became the tool used for achieving the CDM targets.

The Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) dated April 26, 2012, page 10, state that "if the applied for programs are not approved, the development costs would not be recoverable".

The description in the APH for Account 1525, states that "this account shall include all debits not elsewhere provided for which will benefit future periods and shall be carried forward and charged to expense over the term of the benefit."

a) Since the programs were not approved, please provide justification for the proposed recovery of the program development costs.

b) Since the programs did not materialize, and the incurred costs would not benefit any future periods, please provide justification for recording the costs in Account 1525.

c) In the revised calculation of the deferral and variance account rate riders requested in 9-Staff-30, please also remove the account balance in Account 1525.

Response:

a) Upon further review and consideration of the information provided in this Board Staff interrogatory, NBHDL withdraws its request for disposition of this amount. In the revised calculation of the deferral and variance account rate riders requested in 9-Staff-31, the balance in Account 1525, Miscellaneous Deferred Debits, has been removed from the EDDVAR model continuity schedule.

b) Please see the response to a) above.

c) Please see the response to a) above.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Staff-31

Reference: Exhibit 9, Page 39

Interrogatory:

North Bay Hydro has stated that the Smart Grid rate adders were collected from the residential, GS<50, GS>50 and Intermediate class based customers on a monthly fixed charge basis. North Bay Hydro has used the number of customers as the allocator for the Funding Adder Deferral account in its EDDVAR model, which allocates costs to all rate classes. North Bay Hydro has further stated that the costs related to the Smart Grid Capital and OM&A deferral accounts were for initiatives undertaken for the GS>50 and Intermediate classes. However, using the EDDVAR model, North Bay Hydro has allocated the costs to all demand classes. North Bay Hydro has indicated that it would support a more refined cost allocation methodology to allocate Account 1536 based on the proportion collected by the four impacted classes and would propose allocating the costs to the GS<50 and Intermediate classes based on the number of customers within the classes.

Please provide the alternative allocation calculation within the EDDVAR model referred to by North Bay Hydro and file the appropriate schedules as necessary.

Response:

NBHDL has updated the EDDVAR model to reflect NBHDL's proposed cost allocation of the net Smart Grid amounts. The following table provides the details of the calculations made.

	Total Disposition Request	Residential	GS < 50 kW	GS > 50 to 2,999 kW	GS >3,000 to 4,999 kW	UMSL	Sentinel Lights	Street Lights
Per EDDVAR model - Application:								
Account 1536 - Smart Grid Funding Adder	(72,681)	(51,426)	(6,513)	(592)	(2)	(17)	(935)	(13,195)
Account 1534 - Smart Grid Capital	2,758	-	-	2,557	165	-	6	29
Account 1535 - Smart Grid OM&A	58,808	-	-	54,518	3,526	-	137	627
Net Smart Grid Disposition by Class	**(11,114)**	**(51,426)**	**(6,513)**	**56,483**	**3,689**	**(17)**	**(791)**	**(12,538)**
Proposed Allocation - IRR:								
Account 1536 - Smart Grid Funding Adder:								
Amounts Collected by Class	(69,183)	(60,635)	(7,778)	(764)	(6)	-	-	-
% of Funds Collected by Class		88%	11%	1%	0%	0%	0%	0%
Proposed Disposition Amounts - 1536	**(72,681)**	**(63,701)**	**(8,172)**	**(802)**	**(6)**	-	-	-
Account 1534 - Smart Grid Capital								
Number of Customers - 2015 Load Forecast	244	-	-	243	1.00	-	-	-
% of Costs by Class		0%	0.0%	99.6%	0%	0%	0%	0%
Proposed Disposition Amounts - 1534	**2,758**	-	-	**2,747**	**11**	-	-	-
Account 1535 - Smart Grid OM&A								
Number of Customers - 2015 Load Forecast	244	-	-	243	1.00	-	-	-
% of Costs by Class		0%	0%	100%	0%	0%	0%	0%
Proposed Disposition Amounts - 1535	**58,808**	-	-	**58,567**	**241**	-	-	-
Account 1536 - Smart Grid Funding Adder	(72,681)	(63,701)	(8,172)	(802)	(6)	-	-	-
Account 1534 - Smart Grid Capital	2,758	-	-	2,747	11	-	-	-
Account 1535 - Smart Grid OM&A	58,808	-	-	58,567	241	-	-	-
Net Smart Grid Disposition by Class	**(11,114)**	**(63,701)**	**(8,172)**	**60,512**	**246**	-	-	-

An updated EDDVAR model has been provided under a file name "North Bay 2015_EDDVAR_Continuity_Schedule_CoS_v2_4_20141212 - Staff 31" and the following changes have been made:

- kWh, kW, customer/connection counts have been change to reflect the revised load forecast – 3-Energy Probe-34;

- Account 1576 has been updated to reflect the changes to the Account 1576 balance to reflect 2014 actuals and changes to the WACC % - 9-Staff-26b);

- Disposition and Recovery Refund of Regulatory Balances (2012) – Account 1595 has been updated to reflect the 2014 audited balance – 9-Staff-27;

- The balance in Account 1508, sub-account OEB Cost Assessments, has been removed – 9-Staff-29;

- The balance in Account 1525, Miscellaneous Deferred Debits, has been removed - -9-Staff-30; and

- The cost allocation of the Smart Grid accounts have been revised for NBHDL's proposed cost allocation as explained above.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Staff-32

Reference: Exhibit 9, EDDVAR model – Billing Determinants

Interrogatory:

The allocator percentages for Account 1595 for 2011 and/or 2012 may not be correct. For example, the recovery share of the residential customers in 2011 was 55%, and in 2012, it fell to 17%. Please confirm that the recovery share percentages shown are correct or provide an update to the model as necessary.

Response:

NBHDL confirms that the recovery share percentages shown are correct. NBHDL utilized different weightings based on the specifics of the accounts. The allocator percentages are explained on page 38 (lines 23-27) and page 39 (lines 1-4) of Exhibit 9.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Staff-33

Reference: *NOTE: IR does not include reference*

Interrogatory:

Please confirm whether or not North Bay Hydro serves any Class A or Wholesale Market Participant customers.

a) If North Bay Hydro has Class A customers, please explain how balances in Account 1589 – Global Adjustment have been allocated to these customers.

b) If North Bay Hydro has any Wholesale Market Participant Customers, please confirm that these customers have been excluded from the disposition of RSVA account balances as they settle these charges directly with the IESO.

Response:

a) NBHDL does not have any Class A customers.

b) NBHDL does not have any Wholesale Market Participant customers.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-Energy Probe-65

Reference: Exhibit 9, Table 9-17

Interrogatory:

Please update Table 9-17 to reflect the updated cost of capital and any change to the 2014 net closing balance as the result of update the 2014 capital expenditures to reflect actual data for the bridge year.

Response:

NBHDL has updated Table 9-17 to reflect the updated cost of capital and the changes to the 2014 net closing balance as the result of the update of 2014 capital expenditures to reflect actual data for the bridge year. Please see 9-Staff-26, part b).

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-NBTA-73

Reference: Page 2, Line 15

Interrogatory:

The applicant indicates that it is using OEB prescribed rates to add interest to DVA balances.

Please confirm that internal interest charges charged to DVA account balances are credited to GL Account # 4405.

If not please give the details of how those interest charges are handled on the company's books.

The OEB publishes the prescribed interest rates to be used in calculating interest on DVA balances.

Please reference the mandate issued by the OEB that requires the addition of interest to DVA balances.

Response:

Carrying charges assessed on DVA account balances are credited to GL Account # 4405 if the corresponding DVA is in a debit balance.

NBHDL calculates carrying in accordance with the OEB's Accounting Procedures Handbook. NBHDL would refer you to "Article 490 – Accounting for Specific Items – Retail Services and

Settlement Variances” for the specific guidance surrounding DVA accounts. Please also refer to 4-NBTA-66.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-NBTA-74

Reference: Page 9, Table 9 - 3

Interrogatory:

In the table, Account # 1562 is described as *"RSVA – Wholesale market charge"* and in the Excel workbook *EDDVAR - Tab 2. Continuity Schedule* it is described as "Deferred Payments in Lieu of Taxes"

Please explain.

Response:

There is an error in Table 9-3. Account # 1580 is RSVA – Wholesale market charge and Account #1562 is Deferred Payments in Lieu of Taxes, as specified in the Board's Accounting Procedures Handbook revised July 31, 2007.

An updated Table 9-3 with the error corrected is provided below:

Account 1595 (2012) Detail	USoA #	Principal Disposition - 2012	Interest Disposition - 2012	Total Disposition (May 2012)
Decision and Order - EB-2011-0187				
Group 1 Accounts:				
LV Variance Account	1550	30,070	924	30,994
RSVA - Wholesale Market Service Charge	1580	(749,839)	(18,492)	(768,331)
RSVA - Retail Transmission Network Charge	1584	590,978	15,488	606,466
RSVA - Retail Transmission Connection Charge	1586	320,707	8,748	329,455
RSVA - Power (excluding Global Adjustment)	1588	(56,643)	245	(56,398)
RSVA - Global Adjustment	1589	561,975	16,620	578,595
RSVA - Disposition of Regulatory Balances (2010)	1595	(666,077)	699,055	32,978
Subtotal - Group 1 Accounts		**31,171**	**722,588**	**753,760**
Other Accounts:				
Special Purpose Charge	1521	5,139	1,039	6,178
Deferred Payments In Lieu of Taxes	1562	554,291	241,572	795,863
Subtotal - Other Accounts		**559,430**	**242,611**	**802,040**
Total DVA Disposition - 2012 IRM		**590,601**	**965,199**	**1,555,800**
Account 1595 (2012) - Cell "AK35" - EDDVAR model Continuty Schedule				
2012 STS Refund	1595	56,285	-	56,285
2012 Disposition	1595	(590,601)	(965,199)	(1,555,800)
Disposition and Recovery - 1595 (2012)		**(534,316)**	**(965,199)**	**(1,499,515)**

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-NBTA-75

Reference: Page 25, Line 25

Interrogatory:

"NBHDL's PP&E including WIP is expected to decrease by $3,452,455 as of December 31, 2014 as a result of these changes as indicated in Table 9-14 below."

It appears as if this line should read "NBHDL's PP&E including WIP is expected to "increase" by $3,452,455 as of December 31, 2014 as a result of these changes as indicated in Table 9-14 below.

Please confirm or explain.

Response:

NBHDL confirms that this line should read "NBHDL's PP&E including WIP is expected to increase as shown in Table 9-14 below." Thank you for alerting NBHDL of this error.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-NBTA-76

Reference: Page 30, Line 16

Interrogatory:

"In considering the disposition period of this rate rider, NBHDL weighed the financial impact of such a significant refund on the business as well as bill impact considerations for customers and is proposing a disposition period of one year."

The impact of the Account 1576 rate rider for 2015 will be significant and will be a prelude to see bills increase in the following year by approximately 4.77% for a customer using 1,000 kWh per month. This is a major difference and in opposition to the applicant's oft repeated goal of rate mitigation.

We believe the disposition period should equal the collection period of three years which would see an increase a residential 1,000 kWh customers bill by approximately .85% over 2014 and provide a dampening effect on those customers' bills for the next two years equal to approximately 1.7%

Using this method, we calculate refund to be approximately $4.5 million or $1.5 million over three years.

Please comment.

Response:

NBHDL has no comment at this time.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-NBTA-77

Reference: Page 30, Line 26

Interrogatory:

"NBHDL believes it is appropriate that customers receive credit based on their proportion of system utilization and submits that kWh is an appropriate allocator for Account 1576"

We agree with NBHDL on this issue and suggest that, where possible, customers who were overcharged for their portion of system utilization should be reimbursed for those amounts.

In the *"Filing Requirements Chapter 2 Appendices workbook – Tab App.2-V Rev Reconciliation"*, the applicant has recorded the number of connections in the GS 3,000 to 4,999 rate class for 2015 as one which effectively returns the entire refund in that rate class amounting to $118,007 to one customer when in reality it was collected from two customers.

Since the two customers who were included in the GS 3,000 to 4,999 rate class are readily identifiable, we suggest that an even-handed way of apportioning the refund would be to reimburse those two particular customers even though one or them, after operating in North Bay for many years, closed up operations during 2014. This closure was at least in part a result of high electricity costs.

Response:

There does not appear to be a question in this interrogatory. The rate rider is calculated based on 2015 kWh - that is to say the rate rider is allocated on the basis of prospective consumption based on system utilization. This is consistent with the forward-test year methodology used throughout the balance of this cost of service application.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-NBTA-78

Reference: Page 37, Table 9 – 23

Interrogatory:

Please provide the calculations used to arrive at the interest figures shown in the "Projected Interest (Jan. 1, 2014 – Apr. 30, 2015) column.

Response:

The calculation used to arrive at the interest figures shown in the "Projected Interest (Jan. 1, 2014 – Apr. 30, 2015) column is determined using simple interest applied to the monthly opening balances in the RSVA account in accordance with the OEB's APH. The interest rates used by NBHDL are provided on page 11 of Exhibit 9, in Table 9-4 - Interest Rates Applied to Deferral and Variance Accounts, and are applied against the 2013 principal balance in the applicable DVAs. NBHDL notes that the total projected interest for this period is $6,626.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-NBTA-79

Reference: Page 40, Line 1

Interrogatory:

In the "EDDVAR workbook - Tab 4 - Billing Determinants", please explain how the breakdown of the LRAM claim was arrived at and why there has been no lost revenue amount assigned to the 3000 – 4,999 kW rate class

Response:

Please refer to Exhibit 4, Pages 105-107 (including Table 4-53), Appendix 4-N, and the response to 4-NBTA-66.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-NBTA-80

Reference: Page 42, Table 9 – 26

Interrogatory:

Please note our suggestion regarding the GS 3,000 to 4,999 rate class rate rider noted above.

Response:

Your suggestion has been noted.

North Bay Hydro Interrogatory Responses

EXHIBIT 9 – DEFERRAL & VARIANCE ACCOUNTS

9-VECC-48

Reference: Exhibit 9, Page 12

Interrogatory:

a) Please provide the current IFRS transition cost balance.

Response:

a) NBHDL sought clarification of this question from VECC and was advised that the question is in relation to the most recent balance for Account 1508 IFRS Transition costs (referenceE9/pgs. 9, 16-17). The balance in this account is as of December 31, 2014 is $36,594.38.

North Bay Hydro Interrogatory Responses

APPENDIX 2: FILING REQUIREMENTS - CHAPTER 2

Chapter 2-NBTA-81

Filing_Requirements_ Chapter 2_ Appendices.xlsm

Reference: Tab – Appendix 2 – CB New CGAAP DepExp – 2012

Interrogatory:

Note 5 indicates that NBV must exclude assets which have been fully amortized or depreciated.

In "*EB-2009—0270 North Bay IRR NBTA.pdf*", NBHDL explained that "For distribution system assets, NBHDL uses the 'pooled' or 'grouped asset' method of accounting.

Since NBHDL does not record all asset disposals, gross asset values and related accumulated depreciation remains on its records, please explain how NBHDL met the requirements to exclude assets that have been fully amortized or depreciated?

Response:

Please refer to Exhibit 2, Pages 89 – 95 for a description of the NBHDL capitalization policy, and the changes that have been made since the EB-2009-0270 application.

In 2012, NBHDL reviewed its capitalization policy in anticipation of transitioning to IFRS; componentization of assets, depreciation changes and overheads were the focus of the review. In parallel with this analysis, the capitalization policy was also reviewed in light of the July 17, 2012 Board letter indicating that changes to depreciation expense and capitalization policies were permitted in 2012. NBHDL elected to make these changes in 2012 as a substantial amount of work had gone into the analysis for componentization and depreciation changes. NBHDL confirms that the changes to its capitalization policy are consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0040 , the Kinectrics Report, and the APH, effective January 1, 2012. NBHDL's external auditors have also deemed NBHDL's capitalization policy, including the overhead policy, to align with IFRS standards.

Under the 'pooled' method of accounting for distribution assets asset disposals are not recorded, however, the gross cost of the asset remains in PP&E as does the full amount of accumulated amortization. These two amounts offset each in full in PP&E and account for $0 in NBV which in effect accounts for the impact of fully depreciated assets. A full explanation of Table 4-42, which is the appendix referenced above, begins at line 25 on page 91. In particular, NBHDL would draw attention to the opening net book value used in the computation of this table. NBHDL has considered the impact of fully depreciated assets by utilizing the NBV as the opening balance. Please also refer to pages 91 - 93 of Exhibit 4 for an explanation of the depreciation tables referenced. 4-NBTA-63 also addresses this issue.

North Bay Hydro Interrogatory Responses

APPENDIX 2: FILING REQUIREMENTS - CHAPTER 2

Chapter 2-NBTA-82

Filing_Requirements_ Chapter 2_ Appendices.xlsm

Reference: Tab – Appendix 2-V Rev Reconciliation – Column L

Interrogatory:

Please explain how the $104,467 total transformer credits are factored into the delivery rates when this worksheet appears to show them as increasing revenues.

Response:

In Tab – Appendix 2-V Rev Reconciliation – Column K there is a Class Specific Revenue Requirement of $12,695,006 which ties directly to information in Exhibit 8, Page 2 of 14, Table 8-1 and 8-2. This distribution revenue requirement reflects the cost of providing distribution service to NBHDL customer.

NBHDL provides a transformer allowance to those customers that own their transformation facilities. NBHDL proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. However, in order to ensure NBHDL collects the proposed distribution revenue assigned to the rate class that provides a transformer allowance, the total amount or "cost" of the transformer allowance for the rate class needs to be collected in the distribution volumetric rates from all customers in the class. This process, which has been in place for a number of years, allows NBHDL to collect distribution revenue from the rate class at the "gross" level and then provide a transformer allowance which will reduce the gross distribution revenue to a "net" level. In total, the net level amount will be equivalent to the proposed revenue requirement mentioned above of $12,695,006.

As a result, $85,436 in “cost” of the transformer allowances for the General Service 50 to 2999 kW class is collected from that class. Similarly, $19,031 is collected form the General Service 3000 to 4999 kW class for a total of $104,467.