PUBLIC INTEREST ADVOCACY CENTRE
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North Bay Hydro Distribution Limited (NBHDL)
2021 Rates Application

EB-2020-0043

Submission of the
Vulnerable Energy Consumers Coalition
(VECC)

July 14, 2021

Vulnerable Energy Consumers Coalition

Public Interest Advocacy Centre
613-562-4002
piac@piac.ca

Mark C Garner Digitally signed by Mark C Garner
Date: 2021.07.14 23:22:29 -04'00'

Introduction

We have organized our submissions to the Board's approved issue list and the outstanding issues subsequent to partial settlement accepted by the Board (as commented upon and conditioned) in its Decision of May 31, 2021.

From the outset we would be remiss not to state how exceptional we found the OM&A request to be in this Application. VECC has been a party to if not every, almost every electricity distribution application over the past 10 years. In that time, it would be hard to recall a more substantive ask with such little evidence in its support. Frankly in our view North Bay Hydro's new executive management has presented a case of shotting for the stars in the hope the Board will grant it the moon. It is up to the Board to demonstrate that this is not how regulation works and that what is expected are reasonable proposals for it to consider.

Issue 1.2 Operations, Maintenance and Administration (OM&A) Costs

The problem with North Bay Hydro's OM&A proposal is that it is a big increase. Or perhaps better said it is a massive 33% increase - or about 38% from what was actually spent on OM&A in 2015. And this large ask is not associated with any equally startling incremental responsibility. This Utility is not growing. There are no new significant activities being undertaken. One notable event is that the request is coincidental with a change in senior management at North Bay Hydro.

We consider the increase in three ways: (1) efficiency as measured by OM&A costs per FTE and the Board's sponsored benchmarking; (2) by programs and the increases since the last period; and finally (3) by compensation both in terms of the increase in staff and the amount of compensation per FTE. By any of these measures our conclusion is that NBHDL cannot even remotely justify the proposed OM&A increase.

<u>Efficiency</u>

The proposed increase is not associated with an expanding utility. In fact, NBHDL has grown by less than 2% as measured by the residential customers increase since 2015.[1] The result, as shown below, is a dramatic decline in efficiency as measured by the total OM&A per customer between 2015 and 2020. This metric would further degrade if the Board were to approve the Utility's request[2].

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[1] Exhibit 3, page 6 of 45

[2] Appendix 2-L, Excel Model NBHDL_IRR_Ch2 Appendices_20210401.XLMS

	Last Rebasing Year 2015 - OEB Approved	Last Rebasing Year 2015 - Actual	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Reporting Basis								
OM&A Costs								
O&M	2,502,736	2,368,931	2,499,939	2,369,875	2,297,928	2,755,008	2,981,844	3,642,089
Admin Expenses	3,926,993	3,844,278	3,907,005	4,061,219	3,941,884	3,933,873	4,470,983	4,923,849
Total Recoverable OM&A from Appendix 2-JB [5]	6,429,729	6,213,210	6,406,945	6,431,094	6,239,812	6,688,882	7,452,827	8,565,938
Number of Customers [2,4]	24,040	24,023	24,086	24,107	24,142	24,197	24,234	24,271
Number of FTEs [3,4]	49	46	46	46	45	45	49	53
Customers/FTEs	489	524	529	521	542	540	494	458
OM&A cost per customer								
O&M per customer	104	99	104	98	95	114	123	150
Admin per customer	163	160	162	168	163	163	184	203
Total OM&A per customer	267	259	266	267	258	276	308	353
OM&A cost per FTE								
O&M per FTE	50,889	51,644	54,932	51,174	51,616	61,537	60,742	68,719
Admin per FTE	79,849	83,808	85,849	87,696	88,542	87,869	91,077	92,903
Total OM&A per FTE	130,739	135,453	140,781	138,871	140,157	149,405	151,820	161,621

Nor does North Bay Hydro have a particularly efficient starting point. In fact, it remains a Group 3 utility in the Board's ranking and teeters into falling into Group 4.[3]

Cost Benchmarking Summary	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test	2022 Forecast	2023 Forecast	2024 Forecast
Actual Total Cost	16,186,108	15,860,761	16,206,020	16,794,774	17,721,539	18,140,531	20,137,386	20,616,137	21,105,474	21,641,273
Predicted Total Cost	15,094,161	15,355,279	15,341,396	16,251,685	16,873,219	17,511,504	18,240,438	18,981,727	19,748,207	20,548,780
Difference	1,091,947	505,482	864,624	543,089	848,320	629,027	1,896,948	1,634,411	1,357,268	1,092,493
% Difference (Performance)	7.0%	3.2%	5.5%	3.3%	4.9%	3.5%	9.9%	8.3%	6.6%	5.2%
Three-year Average Performance			5.2%	4.0%	4.6%	3.9%	6.1%	7.2%	8.3%	6.7%
Stretch Factor Cohort										
Annual Result	3	3	3	3	3	3	3	3	3	3
Three-year Average			3	3	3	3	3	3	3	3

As measured by efficiency metrics NBHDL fails on all accounts.

[3] Undertaking J1.1

OM&A Programs

A noteworthy fact is that NBHDL considerably underspent its 2020 forecast. This can be seen in the table below which compares the 2020 Bridge amounts provided as part of the original filing[4].

Programs	Last Rebasing Year (2015 OEB-Approved)	Last Rebasing Year (2015 Actuals)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	*2020 Bridge Year*	2020 Actuals	2021 Test Year
Reporting Basis									
Customer Services, Billing & Collecting (1,4,5)	874,281	852,944	951,084	913,856	856,418	809,381	*932,859*	811,497	931,903
Bad Debts (4)	191,079	131,849	72,850	163,484	167,985	121,132	*200,000*	113,333	200,000
Locates (1,2)	249,857	281,031	342,115	271,936	189,340	293,933	*183,361*	241,077	172,430
Customer Engagement (1,4,5)	62,000	33,590	51,273	57,655	67,979	108,844	*66,790*	23,695	164,820
Executive, Financial, Regulatory, Professional, Insurance (all)	1,197,087	1,260,162	1,228,678	1,220,284	1,132,601	1,139,758	*1,325,767*	1,368,387	1,382,287
Regulatory Reporting & Assessments (5)	222,552	163,255	275,338	270,027	269,009	270,260	*140,496*	140,142	270,679
Information & Technology (1,4,5,6)	453,162	411,146	455,611	605,282	579,942	600,795	*669,547*	550,301	712,558
Smart Meters, Meter Reading (4,5)	377,808	376,075	374,498	302,500	316,606	314,485	*328,463*	293,275	342,707
Human Resources (all)	376,108	401,609	335,128	439,642	355,030	425,209	*491,812*	441,971	568,201
Corporate Policies, Initiatives, and Strategy (all)	0	0	0	0	0	0	*110,000*	56,220	150,000
Training, Health & Safety (2,4)	215,387	238,322	266,588	166,018	251,168	218,912	*288,647*	122,273	294,009
Overhead Operations & Maintenance (2,3,4)	711,686	705,682	755,322	731,007	740,328	866,065	*853,864*	967,556	1,141,750
Underground Operations & Maintenance (2,3,4)	276,014	448,112	328,702	317,505	309,295	331,735	*383,846*	466,963	462,900
Substation Maintenance, Load Dispatching, SCADA (2,3,4)	510,537	398,805	413,185	396,446	418,110	516,528	*706,996*	468,846	840,861
Vegetation Management (2,3,4)	456,194	438,897	541,345	516,229	515,994	550,373	*685,609*	596,124	773,437
Metering - Operations & Maintenance (2,3,4)	330,670	252,727	301,221	306,947	240,739	292,249	*322,179*	321,663	362,170
Miscellaneous (4)	(74,692)	(180,997)	(285,992)	(247,722)	(170,733)	(170,777)	*(237,408)*	(205,727)	(204,775)
Total	**6,429,729**	**6,213,210**	**6,406,945**	**6,431,094**	**6,239,812**	**6,688,882**	***7,452,827***	**6,777,595**	**8,565,938**

[4] CCC-29

It is somewhat jarring to consider that on January 5, 2021 when North Bay Hydro filed its application it was reporting to the Board that its 2020 OM&A spending would be $7.45 million. Then 3 months later the costs were found to be actually $680k lower than that amount. When this application all 2020 amounts were historical. The inaccuracy of this estimate as compared to the actual amounts speaks either to the credibility or competency of management of this Utility.

Furthermore, the lower than estimated spending in 2020 are not all from what might be described as "pandemic impacted" programs. Certainly, there are some items where the association between pandemic events and underspending are clear. For example, in 2020 spending on training was about one-half of its historical amount. This makes sense given the restrictions on physical interaction during the pandemic. On the other hand, customer billing, collection and bad debt costs (notwithstanding the pandemic) were lower than originally estimated. Rather the opposite then what would be expected. And we note vegetation management – an outdoor activity generally less impacted by the pandemic – was considerably less than the 2020 estimate and the 2021 proposed amounts. In fact, vegetation management in 2020 was in line with the prior 4 years. Giving little credence to the long and convoluted arguments about how this new management team discovered that the prior management team's vegetation management plan was deficient.

As it turns out the 2020 spending of $6.777 million was relatively consistent with the prior 5 years at about $6.4 million.

One program for which NBHDL is truly an outlier at is regulatory costs as demonstrated in the table below[5].

Table CCC-27 – Comparison of Regulatory Costs for NBHDL and other LDCs

Cost Category	NBHDL (2015)	NBHDL (2020)	ERHDC (2020)	PUC (2018)	Sudbury (2019)	NPEI (2020)	WNH (2019)	OPUCN (2020)
Legal / Consultants	722,331	626,300	507,539	366,829	280,000	489,451	525,000	532,786
Intervenors & OEB Costs	84,494	85,000	70,000	55,620	60,000	94,000	115,000	155,000
Internal Labour	114,073	82,250	-	405,760	110,000	-	10,000	-
Other	-	-	5,000	10,000	-	-	-	-
Total Costs	**920,899**	**793,550**	**582,539**	**838,209**	**450,000**	**583,451**	**650,000**	**687,786**

[5] CCC-27

With the exception of PUC (Sault Ste. Marie) NBHDL significantly outpaces the spending of similar sized utilities. In our submission there are no compelling reasons why this should be so. In fact, it seems to us the Applicant has a rather prolific sense of regulatory costs. They suggest the need for $150,000 in legal costs for the effort of a one-day hearing (which we presume includes review of the Applicant's written arguments and reply to those of intervenors). Based on the Board's allowed consultant/legal costs for intervenors ($330/hr) that would purchase about 455 hours work. We can only hope our argument is worth that effort.

Revised COS Application Costs:	
Legal Costs	210,713
Consultant Costs	180,126
Legal/Consultant Costs	390,839
Cost Awards	85,000
Incremental Labour	60,006
Total Application Costs	535,846
Oral Hearing Costs:	
Legal Costs	150,000
Cost Awards	25,000
Estimated Oral Hearing Costs	175,000
Total Application/Hearing Costs	710,846

NBHDL also suggests that is bad debt in 2021 will exceed the bad debt in the 2020 which was actually less than the pre-pandemic year of 2019. In our submission the unreasonableness of these estimates calls into question the veracity of the entire program OM&A forecasting of this Utility.

<u>Compensation</u>

Another way to look at the issue of the inordinate OM&A request of NBHDL is from the perspective of compensation. The proposed compensation increase is set out in the table below.

Table SEC-16 – Updated Table 4-13/Appendix 2-K /Employee Costs

	Last Rebasing Year - 2015-Board Approved	Last Rebasing Year - 2015-Actual	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	10.0	9.0	9.6	10.2	9.9	10.0	11.0	13.0
Non-Management (union and non-union)	39.2	36.9	36.0	36.1	34.6	34.8	38.1	40.0
Total	49.2	45.9	45.5	46.3	44.5	44.8	49.1	53.0
Total Salary and Wages including overtime and incentive pay								
Management (including executive)	$ 1,099,796	$ 979,953	$ 1,164,976	$ 1,311,168	$ 1,409,417	$ 1,255,530	$ 1,390,483	$ 1,678,677
Non-Management (union and non-union)	$ 3,224,921	$ 2,956,975	$ 3,007,910	$ 3,041,437	$ 2,930,546	$ 2,968,695	$ 3,335,071	$ 3,482,832
Total	$ 4,324,717	$ 3,936,928	$ 4,172,886	$ 4,352,605	$ 4,339,963	$ 4,224,225	$ 4,725,554	$ 5,161,508
Total Benefits (Current + Accrued)								
Management (including executive)	$ 262,792	$ 224,320	$ 267,451	$ 296,192	$ 318,365	$ 289,892	$ 326,695	$ 410,522
Non-Management (union and non-union)	$ 772,676	$ 726,635	$ 742,759	$ 746,253	$ 724,583	$ 726,492	$ 831,494	$ 891,859
Total	$ 1,035,468	$ 950,955	$ 1,010,210	$ 1,042,446	$ 1,042,948	$ 1,016,384	$ 1,158,188	$ 1,302,381
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$ 1,362,589	$ 1,204,273	$ 1,432,427	$ 1,607,361	$ 1,727,782	$ 1,545,422	$ 1,717,178	$ 2,089,199
Non-Management (union and non-union)	$ 3,997,597	$ 3,683,610	$ 3,750,669	$ 3,787,691	$ 3,655,129	$ 3,695,187	$ 4,166,565	$ 4,374,690
Total	$ 5,360,185	$ 4,887,883	$ 5,183,096	$ 5,395,051	$ 5,382,911	$ 5,240,609	$ 5,883,743	$ 6,463,889
Capital Labour - *per Financial Statements*	**$ 1,805,642**	**$ 1,424,347**	**$ 1,520,518**	**$ 1,768,901**	**$ 1,586,002**	**$ 1,573,628**	**$ 1,655,284**	**$ 1,781,639**

In 2015 total compensation costs not capitalized were $3,463,536 of a total OM&A spending of $6,213,210 or about 55% of all OM&A costs. In 2021, if approved, compensation costs not capitalized would be $4,682,250 of a proposed $8,565,938 in OM&A costs - or about the same 55%. Similarly, Appendix 2-D - overhead expense capitalized -shows a steady state of approximately 7% in capitalization rates. This is important because NBHDL in its Argument-in-Chief (AIC) suggests that the Board needs to consider changes in capitalization in order to get an “apples-to-apples” comparison of OM&A from the last Board approved. Capitalization is not an issue in this proceeding.

NBHDL is seeking to recover the costs of an additional 4 FTEs from the last Board approved amount. What is more it is seeking to recover the cost of an additional 8 FTEs from what it has operated under between 2015 and 2019?

In considering the value to customers of these FTE additions one needs to look at their responsibilities. Table 4-14 shows the changes from the last Board approved to the proposed number of FTEs to be funded in rates[6].

[6] Exhibit 4, page 43 of 114

Table 4 - 14- Full-Time Employees by Department

Department	2015 Board Approved	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge Year	2021 Test Year	2021 vs 2015 Board Approved	2019 Actual vs 2021 Test Year
Operations										
Operations Administration	3	3	3	3	3	3	3	5	2	2
Lines	14	14	14	12	12	12	12	12	(2)	-
Customer Services	2	2	2	2	2	1	-	-	(2)	(1)
Stores	1	1	1	1	1	1	2	2	1	1
Substations	2	2	2	2	2	2	3	3	1	1
Metering	2	2	2	2	2	2	2	2	-	-
Total	24	24	24	22	22	21	22	24	-	3
Engineering										
Engineering	9	7	9	8	8	9	9	9	-	-
Total	9	7	9	8	8	9	9	9	-	-
Finance										
Accounting/Finance	5	5	5	5	5	5	6	6	1	1
Billing	2	2	2	2	1	1	2	2	-	1
CAS	5	5	5	4	4	4	4	4	(1)	-
Total	12	12	12	11	10	10	12	12	-	2
Administration										
Administration	1	1	1	2	1	2	2	2	1	-
Human Resources	1	1	1	1	1	1	1	2	1	1
CDM	1	-	-	-	-	-	-	-	(1)	-
IT	1	1	1	1	2	3	4	4	3	1
Total	4	3	3	4	4	6	7	8	4	2
Total	49	46	48	45	44	46	50	53	4	7
Increase over prior year			2	(3)	(1)	2	4	3		
Increase 2021 over 2015 Board Approved								4		

There are no increases in the area of Operations where in 3 of the past 5 years the Utility operated under complement in this area. Nor is there any change proposed for Engineering or Finance, which includes the billing function and where again the Utility has managed to operate with less than its approved complement for a number of years.

What there is a 100% increase in administrative FTEs from the four approved for funding in 2015 to 8 in the test year. In large part the increase comes in the area of information technology (IT) which has an increase of 3 FTEs. This particular increase is difficult to understand given, as shown below, the actual total IT systems costs do not increase dramatically.[7]

[7] 4.0-VECC-31

Table 4 - 7: IT Systems & Maintenance

IT Systems & Maintenance Costs	2015 Board Approved	2020 Bridge Year	2021 Test Year	2021 vs. '2015 Board Approved	2021 vs. '2020 Bridge Year
Central Square (NBHDL's Software Platform)	120,850	173,849	173,849	52,999	-
CNB IS Services	104,903	-	-	(104,903)	-
Cyber Security	6,047	62,149	40,442	34,395	(21,707)
Internet (including redundancy)	40,926	33,960	51,828	10,902	17,868
Software Licenses / Support / Maintenance	22,956	37,613	80,523	57,567	42,910
Network Mtnc	-	-	3,054	3,054	3,054
Server Mtnc	18,837	6,168	7,776	(11,061)	1,608
IT Items	1,300	10,908	10,625	9,325	(283)
Total	**315,819**	**324,647**	**368,097**	**52,278**	**43,450**

"*It is important to note that the majority of cyber security related costs are allocated to internal labour which is not represented in Table 4-7 below. The table represents external costs only*."

The important proviso shown in this table is that cyber security internal costs are not included from which one might conclude that FTEs for cyber security are the driving force for the increase. However, that does not seem to be the case. When cross-examined on this issue NBHDL did not clarify that the $34,395 was only a very small part of the increase for Cyber Security.[8] Moreover, as shown in the table below the increase in IT FTEs does not appear to be related to cyber security at all.

Table 4 - 15: New Positions 1 Since 2015 Actual

Driver	Number of Employees
Growth in Administrative Functions Administrative Assistant	1
Growth in Customer Engagement requirements Communications Officer	1
Growth in Health and Safety Compliance, Purchasing, Planning, Project Management, and Risk Management Operations Coordinator	1
Operations Department Succession Planning Operations Manager / Operations Supervisor	1
Growth in IT - Cyber Security, Network, Digital Transformation, and Billing IT Analyst IT Specialist - created position in-house and	1

[8] Transcript (TC). June 22, 2001, pages 121-123

eliminated external contractor	1
IT Specialist (meter to cash)	1
Growth in Financial and Regulatory Reporting and Analysis	
Customer Accounts Specialist	(1)
Accountant	1
Operations Efficiencies	
Powerline Maintainers	(2)
Customer Services Representative	(2)
Substation Electrician Learner	1
Storekeeper Assistant	1
Elimination of Position	
CDM Position	(1)
Total	**4**

In 2015 the Board approved compensation per FTE was 109k. In 2019 (the last actual shown in the table above) this amount had increased to 117k. For 2021 the comparable figure is 122k. Not only are the actual FTEs increasing but so is the compensation per FTE by an amount of approximately 12%.

Other than the Board's requirements for improved cyber security there few real actual incremental costs facing this Utility. It is not a growing utility. The one adjustment that should be made in our submission is with respect to the Board's annual assessment costs. In 2020 these were $102,904 (approximately 103k)[9]. The amount build into rates in the last application was $72,332.[10] (approximately 73k). The Board should therefore allow an increase of $30k to be passed through in rates. Along with cyber security costs the actual costs related to truly incremental costs are then 65k.

<u>Affordability</u>

In cost of service proceedings parties and the Board focus on the costs of safely and efficiently running the utility. Much time is spent on "inside the beltway" arguments as to whether the utility is being compensated in rates sufficient to allow it to earn a fair rate of return. Almost no time is spent considering issues of affordability. This is the other side of the regulatory coin and one that is seldom discussed in practice or theory. Companies which are not monopolies spend considerable time and effort on understanding their market. Electricity distributors are spared this exercise. The reason being that they are the only one game in town. The question

[9] 4.0-VECC-33
[10] Appendix 2-M

for low-income consumers is not whether they will pay their electricity bill. Their question is what will have to be given up to make that payment.

It is incumbent on the Board, as proxy for market forces, which is what a regulatory of a monopoly is, to fill that gap. And to its credit the Board has made effort in that direction with the inclusion of customer engagement requirements. However, it is usually the case, as it is in this application, that customer engagement is perfunctory. Surveys are made, leading information is provided to survey participants and customers are provided false choices and veiled ultimatums which ask whether it is better to spend more or to have unreliable service.

In this proceeding VECC attempted in hearing cross-examination to go beyond this. North Bay Hydro makes the claim (as do most utilities) that "nobody knows their customers better them themselves." Yet when quired Utility executives did not even have the basic understanding of the affordability of its service as measured by something as simple and accessible as the median income of North Bay customers.

Yet, NBHDL's own customer engagement survey shows that 35% of customers with an income of less than $30k worry about paying for electricity. As it turns out in 2015 the median employment income in North Bay was about $30k. In 2019 the average salary (without benefits) of an NBHDL employee was just over $94k ($4,224,255/44.8 FTEs). In 2015 out of a total population age 15 and over of 42,725 only 2,800 people, or about 6.5% of income earners in North Bay could lay claim to a salary as good as that paid by the Utility.

Clearly these figures are imprecise. The Statistics Canada data VECC presented at the hearing are from 2015. Given inflation the disparities would therefore be worse at today's value. And of course, FTEs are not employees nor have we have included benefits or considered after-tax income. None of which detracts from the main point. Employees of NBHDL can count themselves among a privileged in the City of North Bay. There is nothing wrong with employees of NBHDL being properly compensated but it does, we submit, inure them somewhat from the understanding that more of their customers then they would like to admit have affordability issues.

Change in Management

A disturbing fact in this case is the clear correlation between the change in management in 2018 with the hiring of a new CEO and new VPs in finance and engineering and the subsequent increase in spending. The picture painted both in the written evidence and at the hearing (taking an unusual hour of opening statements to explain to the Board) is that this new management team "discovered" the utility as being mismanaged. This notwithstanding that both the CEO and VP of finance are long-time employees with at least 10 years prior experience prior to their elevation to senior positions.

This new management team began in 2018 to go on a spending spree. From 2015 to 2018 the OM&A budget had waivered between $6.2 and $6.4 million each year. In 2019 and 2020 the spending increased to around $6.7 million and kept increasing even in the face of a pandemic.

This management teams wants the Board to accept their story they are overworked and under resourced. To us this seems likely the same story they told their former bosses who ran the utility at a lower cost base (and yet still in the less efficient Group 3 cohort). Yet if the previous management was inept how is proven? Are their major reliability problems? No. Outpouring of complaints about the Utility? No. What actual evidence has been presented to support the story of a mismanaged utility now being rescued by formerly underlings of the old management? We submit none.

One big thing though is missing. Where is the presentation to the Board of Directors setting out this crisis? VECC explored this missing link at the hearing and could find nothing to support the notion of a utility in trouble[11]. It simply unfathomable that a new CEO of a small utility could go from spending $6.2 to $8.5 million in the course of 3 years without explaining this to its Board of Directors. Not only is there no explanation – no smoking gun of crisis presented to the Board of Directors, there is also no comprehensive strategic or operational plan to put it all right again. To anyone who has run a non-regulated business this is very strange indeed. A new CEO goes on a spending spree without explaining to their Board of Directors why. We suppose that works if you are regulated and can charge what you want - if the regulator acquiesces. It works much less if you have to compete against better qualified and efficient operators. Quite simply there is no evidence to support management's contention that they are rescuing the Utility from disaster.

<u>Reduction in OM&A</u>

In our submission the question for the Board is not whether to reduce the OM&A but by how much. First let it be said that NBHDL has the ability to absorb a reduction. We note that there are currently 4 vacancies at the Utility. NBHDL also has an employee churn rate of on average 14.5%[12] which, as far as we can understand, is not built into the OM&A estimate. Its bad debt figure for 2021 exceeds the 2020 Covid-19 actual bad debt. NBHDL has also included $150,000 in the Test Year for ongoing annual costs related to corporate initiatives, health and safety, and departmental process. Whatever the merits of those activities we think the costs excessive and unusual for small utility such as NBHDL. As we also noted the regulatory costs are simply out of line with others and it is unlikely that some of what is preposed would be spent in any event.

[11] TC, page 105-107
[12] 4.0-VECC-39

Finally, the Utility's CEO admitted that the increase being sought is not currently being spent pending the Board's approval of its request.[13]

The usual way VECC considers OM&A is to do three things. As a starting point we consider both the 2015 Board approved and the actual amounts spent. Generally, we take the lower of the two as the starting point on the assumption that if a utility can work within that amount, it is reasonable. In this case the 2015 actual spending was about 200k lower than approved. However as mentioned above, the amounts in each year tended to fluctuate between the $6.4 million and $6.2 million.

Next, we inflate these figures by CPI using the Bank of Canada's inflation calculator.[14] Inflating 2015 Board approved to 2021 would provide an amount of $7,144,143. Using 2015 actuals would provide a figure today of $6,903,566. To this we would add $65k for increased cyber security and Board assessment cost.

However, NBHDL as a Group 3 utility has had a productivity stretch factor offset of 0.3% in each year of its IRM. Over the course of the rate plan term this should result in a decline over the entire period of approximately 1.5%. If the Board does not make an adjustment for this productivity offset then these amounts are reclaimed by the utility and the net effect is that all prior productivity benefits are lost to consumers. In this case the stretch factor offset would be about $107k using the 2015 Board approved (1.5% x 7,144,143) or $103k using the 2015 actuals.

In our view the Board should not embody spurious accuracy to any calculation of an OM&A reduction. We would say, to the benefit of the Utility, that the stretch factor offset roughly offsets any truly incremental responsibilities such as cyber security and the Board's increase in assessments. In fact, it is a bit generous but we think there can be other incremental costs that should be allowed to be recovered in rates. All in all, we conclude the stretch factor adjustment and the truly incremental costs to be a wash.

The average of the two 2015 figures (Board approved and actual spent) inflated to 2021 is $7,023,854. **This is a reduction of $1,542,083 which we would round to $1,550,000**. This reduction still results in a generous 3.6% increase over the actual spending in 2020. That is, it is higher than inflation. Frankly we believe a higher reduction could be calculated (especially in consideration of the breach of the Board's order as discussed below) but our goal here is to provide a reasonable compromise so as to allow this Utility to do some of its desired administrative initiatives.

[13] TC, page 42

[14] https://www.bankofcanada.ca/rates/related/inflation-calculator/

Finally, we must add one thing in response to NBHDL Argument-in-Chief. There is a suggestion in that argument (par. 63) to the effect that if its request is not granted certain things will not happen. In this reference the negative impacts are in not hiring a position. Whatever the merits of that specific argument it is important for the Applicant to be reminded that the Board does not approve positions, or their responsibilities or, for that matter, what furniture to buy or what colour to paint the utility building. The Board approves a dollar amount to be recovered in rates. It does so on the basis of what it believes are necessary for the safe reliable operation of the system which also would allow an efficient working utility to earn its approved rate of return. It is incumbent upon the Utility's management to work within the implied envelope (it is implied since all costs and revenues are estimates) so as to make the best decision for both ratepayers and shareholders. This can be difficult but not as hard as competing against Amazon.ca.

Issue 3.3
Cost Are North Bay Hydro's proposals, including the proposed fixed/variable splits, for rate design appropriate?

For 2021 rates North Bay Hydro is proposing to maintain the current fixed/variable split (i.e., the fixed variable split based on 2021 approved rates and the forecast 2022 billing determinants) for all customer classes [15]. In the case of the Residential class, North Bay Hydro notes that, in accordance with the Report of the Board: A New Distribution Rate Design for Electricity Residential Customers (EB-2012-0410), it completed the transition to a fully fixed rate effective May 1, 2019[16].

The following Table sets out the fixed-variable splits used for each class and the resulting rates for 2021[17].

[15] Exhibit 8, page 4
[16] Exhibit 8, page 8
[17] Settlement Proposal, RRWF, Tab 13

Customer Class	Current Fixed/Variable Split Percentages		2021 Proposed Rates Monthly Service Charge	2021 Proposed Rates Volumetric Rate	
	Fixed	Variable			
Residential	100%	0%	$ 34.44	$ -	/kWh
GS<50	34%	66%	$ 28.32	$ 0.0217	/kWh
GS>50	45%	55%	$ 364.40	$ 3.0145	/kW
GS>3000<5000	82%	18%	$ 7,628.28	$ 1.3225	/kW
Street Lighting	68%	32%	$ 1.53	$ 8.2150	/kW
Sentinel Lights	82%	18%	$ 5.78	$ 20.1498	/kW
UMSL	54%	46%	$ 6.26	$ 0.0144	/kWh

For the subsequent IR period after 2021 and until the rebasing Application, the approved fixed and variable charges for the previous year will each be adjusted by the same percentage as determined by the Board's Rate Generator model, unless the Board approves otherwise. North Bay Hydro has not applied for or indicated it will be seeking a departure from this standard practice during the IR period.

VECC has no issues with North Bay Hydro's proposed rate design for its Residential class. North Bay Hydro's proposal to continue with a fully fixed charge for this class conforms with Board policy.

The Board's policy with respect to rate design for non-Residential customer classes was first addressed in EB-2005-0317, re-examined in EB-2007-0667 and is currently the subject on an ongoing consultation (EB-2015-0043).

North Bay Hydro has used the OEB's Cost Allocation Model (CAM) to assign costs to customer classes for the purpose of designing rates for the 2021 Test Year. One of the outputs of the CAM[18] is three scenarios that provide, by customer class, the monthly cost of servicing a customer under three sets of assumptions: Scenario 1 - avoided customer costs plus general administration, Scenario 2 -directly related customer costs plus general administration, and Scenario 3 - minimum system costs adjusted for PLCC. According to the Board's Report – "Cost Allocation Review: Board Directions on Cost Allocation Methodology for Electricity Distributors (EB-2005-0317)" the results from Scenarios 1 and 3 provide reasonable cost-based lower and upper end customer unit costs per month.

In its EB-2007-0667 Report – "Application of Cost Allocation for Electricity Distributors" – the Board indicated[19] that it remained of the view that the use of avoided costs, as defined in the Methodology (i.e., Scenario 1), is an appropriate basis for establishing the minimum or floor amount for the Monthly Service Charges. It also confirmed that the results of Scenario 3

[18] Tab O2 in the CAM
[19] Page 12

continued to be an appropriate basis for setting the upper found for the Monthly Service Charge. In its Report the Board stated further that[20]:

> *"The Rate Review will also examine the role of rate design in achieving various objectives, including conservation of energy. Both of these undertakings will have determinative impacts on the fixed/variable ratio policy.*
>
> *In the interim, the Board does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC. Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level at this time*."

The following Table sets out North Bay Hydro's current 2020 current monthly fixed charge for each non-residential customer class, the 2021 proposed monthly fixed charged for non-residential each customer class and the upper and lower end unit customer unit costs per month (per Scenarios 1 and 3) as calculated by the CAM.

Customer Class	2020 Monthly Service Charge	Proposed 2021 Monthly Service Charge	Scenario 3 - Minimum System with PLCC Adjustment (Ceiling)	Scenrio 1 -Avoided Cost (Floor)
GS<50	$25.00	$28.32	$37.16	$9.94
GS>50	$315.75	$364.40	$86.21	$48.23
GS>3000<5000	$6,734.18	$7,628.28	$226.65	$116.07
Street Lighting	$5.06	$1.53	$1.75	$0.00
Sentinel Lights	$5.10	$5.78	$10.17	$0.79
UMSL	$5.53	$6.26	$8.58	$1.65
Sources:	1) Exhibit 8, page 6			
	2) Settlement Proposal, RRWF, Tab 13			
	3) Settlement Proposal, Cost Allocation Model, Tab O2			

With respect to North Bay Hydro's proposed 2021 rates for its non-residential customer classes, VECC notes that for the GS<50, Street Light, Sentinel and UMSL classes the proposed 2021 monthly fixed charges fall within the range established by the Cost Allocation model. VECC further notes that the reduction in the monthly fixed charge for Street Light arises solely due to the planned adjustment in the revenue to cost ration for the class. VECC has no issues with North Bay Hydro's rate design proposals for these classes.

However, for the GS50-2999 and GS3000-4999 classes, the 2020 monthly service charge is above the range established by the Cost Allocation model and North Bay Hydro proposes to further increase the values in 2021. North Bay Hydro's rationale for doing so is that[21]: i) it is consistent with past decisions of the Board and ii) it is supported by the Board's Report: A New

[20] Page 12
[21] Exhibit 8, pages 4-5.

Distribution Rate Design for Electricity Residential Customers (EB-2012-0410). These same two points were reiterated in North Bay's Argument in Chief (AIC) [22].

With respect to the point that the proposals regarding the larger GS classes are consistent with past Board decisions, VECC has the following observations and submissions.

First, it is noted that the majority of the decisions referenced are from the proceedings dealing with rates for either 2011, 2012 or 2013 – almost 10 years ago. VECC has reviewed the referenced decisions and in virtually[23] every case the reasoning offered by the Board was that maintaining the current fixed-variable proportions was consistent with previous Board decisions. VECC further notes that the earliest of these decisions (Brampton, EB-2010-0132) makes reference to an even earlier Lakeland decision (EB-2008-0234). In that Lakeland decision the Board's rationale for maintaining the fixed-variable split was that it "*is consistent with the Board's report on cost allocation* (EB-2007-0667") [24].

As noted earlier, the Board's EB-2007-0667 Report set out its expectations with the respect to the setting of the monthly service charge as follows:

> *"In the interim, the Board does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC. Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level at this time."*

In VECC's view while the policy as set out in EB-2007-0667 indicated that distributors were not expected to increase monthly service charges that were currently below the "ceiling" to a value greater than the ceiling, the policy did not specifically deal with situations where the charge was already in excess of the ceiling, other than to indicate there was no requirement to lower the charge to the ceiling value, leaving some room for interpretation. However, in the Board's Filing Guidelines for 2021 Cost of Service Applications provide further clarification by stating[25]:

> *"If a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling,* ***nor are distributors expected to raise the fixed charge further above the ceiling for any non-residential class****."* (emphasis added)

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[22] Pages 25-26
[23] The one exception is Horizon's EB-2010-0131 Decision where no reasons were provided for maintaining the F-V split for the GS classes and the Board treated the Large Use class as a "special circumstance:
[24] Page 30
[25] Page 54

Furthermore, this issue has been the just recently dealt with in Hydro Ottawa's 2021 Rate Application (EB-2019-0261). In its Decision the Board stated[26]:

> "*Hydro Ottawa's approach was that, for 2021, if the calculated fixed charge based on its standard approach is above the ceiling, it would maintain it at the 2020 level. The OEB agrees with that approach*".

VECC submits that the much earlier Decisions cited by North Bay Hydro do not provide a useful precedent for the Board to apply with respect to North Bay Hydro's current Application as they have been superseded by more recent events. First, the 2021 Filing Guidelines provide additional clarification regarding the Board's requirements with respect to the setting of the monthly service charge, specifically stating that in cases where the charge already exceeds the ceiling it is expected that it will not be increased further. In addition, there are more recent precedents (e.g., the Hydro Ottawa Decision) that confirm this requirement.

Second, in the more recent Horizon Utilities' case (EB-2014-0002) referenced by North Bay Hydro, the Board decision to approve the application of the current fixed-variable split in circumstances where the monthly service charge already exceeded the ceiling referenced not only previous decisions and the Board's EB-2007-0667 Report but also the "Board's current policy direction is to move toward an increased fixed charge" a part of the rationale.

The Board's consultation regarding Rate Design for Commercial and Industrial Customers (EB-2015-0043) is still ongoing. However, the most recent Staff Report specifically states[27] the current "*rates are based on good rate design principles and are cost reflective of fixed and demand charges*" and then goes on to indicate[28] that "*staff are now proposing that there be no change to the underlying rate classes, basis for fixed charge, or rate design and allocations for these customers*". As result, VECC submits that the current policy direction with respect to the GS rates is not as evident as assumed in the Horizon decision and still a matter of debate.

Furthermore, in VECC's view, where consultations are ongoing and the outcome is still unknown, prejudgement of the outcome, particularly when it changes current policy, should not be used as a basis for justifying an Applicant's proposals. In its EB-2019-0261 Decision regarding Hydro Ottawa the Board agreed[29] with this view:

> "*The OEB finds that consideration of changes to rate design for the affected rate classes based on assumptions associated with the current consultative process is not appropriate*

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[26] Page 22
[27] Page 35
[28] Page 36
[29] Page 23

given the ongoing nature of the consultation process and the uncertainty regarding its outcome."

As result, VECC submits that the Horizon Decision is also not a relevant precedent. In its AIC North Bay Hydro also makes reference to the Board's EB-2016-0085 Decision regarding InnPower. However, this Decision[30] relies on the Board's finding from the Horizon case and, therefore, is also not a relevant precedent.

With respect to the Board's Report - : A New Distribution Rate Design for Electricity Residential Customers (EB-2012-0410), North Bay Hydro makes reference[31] to the following statement in support of its proposed rate design:

> "*The current rate design for distribution service is not reflective of the costs to distribute electricity, because costs that are mostly fixed are being recovered through charges which vary with usage*."

In VECC's view the Board's approach towards Residential Rate Design does not provide any precedent or direction with respect to the rate design for larger industrial and commercial customers. The nature of large commercial/industrial customers and their current rate design are different from that of Residential customers as evidenced by the fact the Board currently has an ongoing consultation – Rate Design for Commercial and Industrial Customers (EB-2015-0043) – which is dealing directly with this issue.

Furthermore, the Board has expressed the view that "*consideration of changes to rate design for the affected rate classes based on assumptions associated with the current consultative process is not appropriate given the ongoing nature of the consultation process and the uncertainty regarding its outcome*"[32]. However, to the extent such deliberations were relevant, VECC again notes that the most recent Staff Report in the consultation indicates[33] "*staff are now proposing that there be no change to the underlying rate classes, basis for fixed charge, or rate design and allocations for these customers*".

Overall, the most relevant considerations for the Board in determining the approach to be used in designing North Bay Hydro's rates for its large GS classes are the 2021 Filing Guidelines and the Board's more recent Hydro Ottawa decision regarding this issue. As discussed above, both the Guidelines and the Hydro Ottawa Decision support a rate design that, in instances where the current monthly service charge exceeds the "ceiling" value, maintains the monthly service charge at its current level for the test year. As a result, VECC submits that the Board should

[30] Page 27
[31] Exhibit 8, pages 4-5
[32] Decision, EB-2019-0261, page 23
[33] Staff Report to the Board-Rate Design for Commercial and Industrial Electricity Consumers, February 21, 2019, page 36

direct North Bay Hydro to maintain the 2021 monthly service charges for its GS50-2999 and GS3000-4999 classes at their current 2020 values.

For the post 2021 IR period, the models used for the annual IR adjustment increase both the fixed and variable charges by the same amount (effectively maintaining the current fixed-variable split). However, the models are not determinative of Board policy. This is evident from Board's Decision regarding Hydro Ottawa's rate application which also addressed[34] the determination of the monthly fixed charge during the subsequent IRM period for those instances where the current monthly charge exceeds the "ceiling" as follows:

"*For the GS > 50 to 1,499 kW, GS 1,500 to 4,999 kW, and Large Use classes, the OEB finds that fixed charges should be set by comparing the fixed charge resulting from Hydro Ottawa's standard rate design approach with the previous year's level for the five year rate term. In years where maintaining the current fixed/variable revenue split results in a higher fixed charge than the previous year, Hydro Ottawa shall maintain the fixed charge at the previous year's level. In years where maintaining the current fixed/variable revenue split results in a lower fixed charge than the previous year, Hydro Ottawa shall maintain the fixed charge at the lower value*."

VECC submits that the Board should direct North Bay Hydro to apply a similar approach when setting its rates for the GS50-2999 and GS3000-4999 classes during the post-2021 IR period.

Issue 5.1
Is the proposed effective date (i.e., May 1, 2021) for 2021 rates appropriate?

In order to have rates effective for May 1 of the following year the Board requires that utilities file a complete application by August 31 of the prior year. On August 31, 2020 NBHDL wrote the Board stating that due to the disruption of the pandemic it would be delayed in submitting an application until November 30, 2020. The Board granted that extension but noted in its letter that the "*extension does no ensure that a May 1, 2021 effective date will be approved for North Bay Hydro*".[35] On November 18, 2020 NBHDL wrote the Board indicating it would be unable to file an application until December 31, 2020 and the following day the Board wrote a letter granting that extension with a similar proviso. The application was finally filed on January 5, 2021.

Had the pandemic not occurred it would, it our submission, be clear based on the Board's past practice that a utility filing significantly passed the due dates would be unable to retroactively recoup amounts before the final rates were approved. However, the pandemic has been disruptive to many businesses and **many customers**. In our view the question is not whether

[34] Page 23
[35] OEB, September 3, 2020 EB-2020-0043

the delay in filing was reasonable or unreasonable, but whether this Utility should benefit from the delay. In our submission they should not.

It is our view that the principle that should be adopted in considering the rate consequences of a delay in filing should be similar to those adopted by the Board in its study of the regulatory treatment of COVID-19 costs. In its Report[36] the Board observed that:

> *The utilities that the OEB regulates are providers of essential services. They are required to maintain operations despite any challenges that they are presented with. The utilities in Ontario have responded swiftly and effectively and maintained service to their customers in the wake of the pandemic. At the same time, as essential service providers, natural gas and electric utilities have been spared from being faced with the most disruptive and severe types of economic constraints that many other non-essential industries and businesses have been burdened with*.

The Report then goes on to outline a series of test to determine whether a pandemic related costs has had a material impact on a utility's long-run ability to earn a reasonable rate of return.

Should the Board be able to render a decision in this case in August then, based on our observation of most utility's billing capabilities the new rates could be in place for August 1 and certainly no later than September 1. In our submission the financial impact of a 3-month delay in having new rates put in place is immaterial to the long-run ability of NBHDL to earn its regulated rate of return. The actual cost of each month delay is unknown given the Board has yet to render its decision however one can extrapolate from the monthly loss of revenue of approximately $15,000 when NBHDL delayed implementing its May 1, 2020 rate change.[37] In any event the delay in increasing rates it seems to us is in keeping with the delay of many of its customers in having gainful employment during this pandemic.

Issue 5.2 :
Has North Bay Hydro responded appropriately to the requirements and agreements set out in its previous cost of service application EB-2014-0099, namely:

- **exploring the possibility of better aligning North Bay Hydro's incentive pay structure with the metrics and outcomes described in EB-2014-0099**

[36] Report of the Ontario Energy Board, Regulatory Treatment of Impacts Arising from the COVID-19 Emergency, EB-202-0133, June 17, 2021, page 1.
[37] See 4-Staff-42. In this response NBHDL notes that a delay in its 2020 was 100k over 6 months.

It is crystal clear that NBHDL did not meet its commitment made and approved by the Board in EB-2014. That commitment was[38]:

> *NBHDL further agrees to explore the possibility of better aligning its incentive pay structure with the metrics and outcomes described in this Application and mandated by the Board. NBHDL also agrees to explore the possibility of further improving the alignment between the Board's mandated outcomes and metrics with its distribution system planning process. NBHDL will present the results of its efforts in this regard during its next cost of service or custom IR rate application. If NBHDL identifies opportunities to improve its incentive pay structure or its distribution system planning requirement to balance in the in-service test year of $775,173,482. That is, the account should be asymmetrical in favour of ratepayers. processes before then, it will not delay any potential implementation until its next cost of service or custom IR rate application.*

NBHDL admits it did not do this and apologies apart, offers only COVID-19, an event that took place almost 5 years after the commitment, as an excuse. What makes this blatant disregard to a Board order (which the settlement agreement became upon acceptance by the Board) was that the commitment to consider ways to tie compensation with outcomes is intrinsically tied to the current proposal to substantively increase OM&A spending. That is, in support of such an unusually large proposed increase in OM&A one might have expected an accompanying proposal to show how the increase met with new metrics developed as part of this commitment. Instead, we have all of the ask and none of the metrics to measure the effectiveness of that request.

What is the Board to do about it? The last such clear breach of a Board order we can recall was with respect to SEC in an Ontario Power Generation application and where Mr. Shepherd inadvertently breached the Board's confidentiality rules. This was in 2010. In that case the Applicant OPG, sought a sanction of $5,000. In the event the Board ordered Mr. Shepherd to make a personal payment of $10,000 (equivalent to around $12,000 today)[39]. That is, the Board took very seriously the breach of its rules and notwithstanding the actual harm made a lesson of the matter.

We are not suggesting a similar personal or corporate penalty. That would serve little purpose in moving this Utility in the direction of higher efficiencies for the benefit of its ratepayers. What we would say is that it would be patently unfair for the Board to apply stiff penalties to intervening parties for innocuous events that are not even fervently argued against by the offended party and then let a regulated utility simply walk away from a clear breach of a Board order. We would also say that the lack of prior notification to the Board that the Utility would

[38] Decision and Order, EB-2014-0099, North Bay Hydro Distribution Ltd., July 16, 2015
[39] See EB-2010-0008, Board letter of December 20, 2010

be unable to meets its Board commitment shows a disregard and lack of respect for the regulatory process.

Rather than be punitive we suggest the Board consider the breach in light of its determination of a just and reasonable OM&A amount to be included for recovery of customers in rates. It is not, in our view, necessary for the Board to delineate a certain amount as a penalty. It is sufficient in our submission that the Board reference its consideration of the matter in making its determination. We are confident of the Board's exercise of that discretion.

Reasonably Incurred Costs

These are our respectful submission. VECC submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

July 14, 2021