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July 28, 2017

Delivered by Email, RESS and Courier

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

Dear Ms. Walli:

**Re: Thunder Bay Hydro Electricity Distribution Inc.
EB-2016-0105 – Reply Submissions**

Pursuant to Procedural Order No 6, please find enclosed the Reply Submissions in regards to the above-noted proceeding.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original signed by Shane Freitag per John A.D. Vellone

John A.D. Vellone

CC: Parties in EB-2016-0105

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, (Schedule B) (the “Act”);

AND IN THE MATTER OF an Application by Thunder Bay Hydro Electricity Distribution Inc. under Section 78 of the Act for an order or orders approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2017.

**REPLY SUBMISSIONS OF
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.**

July 28, 2017

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**REPLY SUBMISSIONS OF
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.**

DELIVERED: JULY 28, 2017

A. INTRODUCTION

1. Thunder Bay Hydro Electricity Distribution Inc. (“**Thunder Bay Hydro**”) makes these written submissions in reply to the submissions of the School Energy Coalition (“**SEC**”) received July 13, 2017 and the submissions of OEB staff (“**OEB Staff**”), the Vulnerable Energy Consumer Coalition (“**VECC**”) and the Association of Major Power Consumers in Ontario (“**AMPCO**”) received July 14, 2017 in respect of an Application filed by Thunder Bay Hydro on September 9, 2016 under Section 78 of the *Ontario Energy Board Act, 1998* (the “**Act**”) seeking an order of the Ontario Energy Board (the “**OEB**”) approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2017 (the “**Application**”, Board file number EB-2016-0105). OEB Staff, AMPCO, SEC, and VECC shall be referred to collectively as the “**Parties**”.

B. GENERAL THEMES

2. Thunder Bay Hydro’s submissions are organized around five general themes.

B.1 *The rate minimization model*

3. First, Thunder Bay Hydro is unlike any other utility that the OEB regulates. This is because Thunder Bay Hydro operates under a shareholder imperative known as the “*Rate Minimization Model*.” As explained in Thunder Bay Hydro’s Argument-in-Chief filed July 5, 2017 (“**AIC**”), this has resulted in rates in the test year that are \$1,213,660 lower than they otherwise would be had the utility used the Board’s deemed long-term debt rate of 3.91% for affiliate debt.¹
4. The Rate Minimization Model is more than a shareholders’ optional forbearance of dividends and interest. The Rate Minimization Model also forms the foundation of a

¹ AIC at para. 11.

philosophy that permeates the entire organizational culture at Thunder Bay Hydro. This was best explained by Mr. Wilson:

“We do have a long-standing commitment to efficiencies and cost improvements at the utility. Cost control at our utility comes from the top. Our CEO, Mr. Mace, and our CFO, Ms. Speziale, have made it abundantly clear for at least the last ten years that all decisions made with respect to the utility operations really need to consider the customer in the sense of how can we do things better, how can we do things for less cost, can we defer certain items in the present or in the future and in doing so, you know, avoid some cost impact for our customers.”²

5. Rate minimization is an imperative for every major external stakeholder of Thunder Bay Hydro: its shareholder, its customers, and its regulator (the OEB). As a result of this clear alignment of interests, it is not surprising that rate minimization and cost controls are an organizational imperative for Thunder Bay Hydro staff as well.
6. This frames Thunder Bay Hydro’s commitment to achieve continuous improvements in productivity and cost performance, and to ensure that savings from operational effectiveness are sustainable. Thunder Bay Hydro has demonstrated this commitment throughout the evidence, with a representative sample of quantifiable cost control initiatives totalling \$1,079,484 in savings for ratepayers (AIC paras 45-46).
7. **Correction:** Thunder Bay Hydro has identified one error in the calculation of its annual savings projection in its AIC. Specifically, and as discussed in further detail below, it has come to the attention of Thunder Bay Hydro that the approximately \$570,000 in OM&A cost savings arising due collective agreement wage increases less than industry average was a cumulative savings which occurred between 2013-2017. The actual OM&A savings which occur in the 2017 test year, and which will recur annually into the future are \$178,000. Adjusting the \$1,079,484 by reducing it by the value of this cumulative savings of approximately \$570,000, and then increasing it by \$178,000 in annual savings, results in actual annual OM&A savings of **\$687,484**. These savings are sustainable savings, that will recur year over year to benefit ratepayers.

² Transcript Vol. 2 dated June 29, 2017 at pg. 13, lines 9-19.

8. These savings are only a representative sample. They are in addition to numerous other cost savings efforts that occurred, but were too difficult to quantify in a meaningful way on the evidentiary record.
9. Is \$687,484 in annual savings meaningful? Contrary to the submissions of various Parties – the answer is undoubtedly yes.
 - a. These savings represent 4.33% of the total OM&A budget in the test year.
 - b. Using the OEB's 4GIRM rate setting formula, the 0.3% stretch factor embedded in that formula reduces the 2017 revenue requirement for Thunder Bay Hydro by a \$50,797. Adding this to the annual recurring savings embedded in the 4GIRM formula across 2014-2017 period, the 4GIRM formula includes embedded savings over this period of \$416,458. Thunder Bay Hydro's quantified savings are 63.7% higher than the efficiencies assumed in the 4GIRM formula.
 - c. Another comparator is the productivity assumptions embedded directly in the Aiken model³ which uses a Group 3 stretch factor of 0.3% to calculate total estimated OM&A efficiencies in the 2014-2017 period of \$411,949 in cumulative savings.⁴ By comparison, Thunder Bay Hydro has produced quantified evidence of annual savings in the test year that are more than 50% higher than the efficiencies assumed in the Aiken model.
10. In view of Thunder Bay Hydro's rate minimization philosophy and in consideration of the Parties submissions, which expressed a clear preference for a slower pacing of increases to System Renewal spending, Thunder Bay Hydro is voluntarily willing to reduce its System Renewal spending in the test year by an amount that is equal to \$400,000 if the OEB deems it appropriate. Specifically, and as described further below:

³ Exhibit K3.4, SEC Cross-examination materials, at page 62.

⁴ Specifically, starting with Thunder Bay Hydro's actual 2013 OM&A results, this is the sum of the calculated stretch factor (0.3%) efficiencies in 2014 of \$39,699, in 2015 of \$80,753, in 2016 of \$123,493, and in 2017 of \$168,004. These are the efficiencies that are embedded in the very model that was proposed by SEC during cross-examination.

- a. Thunder Bay Hydro has carefully reviewed its System Renewal plan to identify if there are any opportunities for deferring System Renewal spending without affecting lower priority projects.
 - b. Thunder Bay Hydro has identified one such opportunity, which relates to the "*McDougall-Court Voltage Conversion*" (project number B1298). This project is priority #19 of 21 in the test year.
 - c. Thunder Bay Hydro engineering staff have determined that without cancelling the project entirely, they are able to defer up-to a maximum of \$400,000 in spending on this project from 2017 into future years.
 - d. The deferral of this project is unlikely to affect the planned retirement of the Algoma station transformer, which is classified as being in "very good" condition and is not flagged for action until year 14.⁵
 - e. This deferral will delay the ultimate completion of this project out into future years. Because the Algoma substation will continue to have low interconnectivity and no back up transformation should the substation transformer fail,⁶ this will result in an increased risk of failure and service outages for certain customer loads, including a district jail, a seniors centre, a high school and 41 commercial customers.⁷
11. Finally, in view of Thunder Bay Hydro's rate minimization philosophy and in consideration of the Parties submissions, Thunder Bay Hydro believes that no reductions in its proposed cost of capital or OM&A expenses in the test year are appropriate.

B.2 Mr. Tsimberg's expertise

12. Second, the Parties' submissions demonstrate a fundamental misunderstanding of Thunder Bay Hydro's capital program, specifically the system renewal component of the capital program. It is perhaps not surprising. None of the Parties are electrical engineers by training. And none of the Parties are experienced with operating and maintaining a

⁵ Exhibit 2, Appendix 2-B Distribution System Plan (hereinafter, the "**DSP**"), Appendix C – Kinectrics Asset Condition Assessment (hereinafter, the "**ACA**"), at Table 1-7.

⁶ The DSP, Appendix J – Material Capital Project Summaries, Project number B1298, "Project Summary" heading.

⁷ Undertaking J3.1.

distribution system in a northern environment like Thunder Bay on a day-to-day basis. As a result, the Parties' submissions on Thunder Bay Hydro's system renewal plan are peppered with errors.

13. Thunder Bay Hydro attempted to address this issue in advance by retaining a widely recognized and independent expert in asset management and distribution system planning – Mr. Yury Tsimberg – to provide the OEB and the Parties with the benefit of expert opinion evidence on best practice as it relates to distribution system planning and asset management. Thunder Bay Hydro's intent was to ensure the OEB panel had access to the best information available upon which to make its decision on Thunder Bay Hydro's proposed capital plan. Thunder Bay Hydro's concern was that this OEB panel might otherwise be deceived by the apparent simplicity of some of the Parties' submissions, which are premised on false assumptions and misleading arguments.
14. Unfortunately, none of the Parties took full advantage of Mr. Tsimberg's expertise to ensure their submissions were rooted in a firm understanding of best practices for system renewal and distribution system asset management. In fact, rather than encouraging the OEB to make decisions on a capital program based on industry best practices, some of the Parties attempted instead to discredit Mr. Tsimberg and his evidence. Their approach appears to be: why let expert evidence and best practices get in the way of a good argument?

B.3 There is no such thing as perfect data

15. Third, the Parties all cite certain data limitations in the Kinectrics Asset Condition Assessment (ACA) to support proposed reduced spending. Thunder Bay Hydro is fully aware of, and has been completely transparent throughout this proceeding, about the data limitations it faces. Thunder Bay Hydro has repeatedly committed to improving its data for its next asset condition assessment. However, some of these data challenges are difficult to resolve. And the data will never be 100% perfect. There will always be room for improvement. As a result, the real question facing this OEB panel is:

Should Thunder Bay Hydro completely ignore all of the good work that has been done, and the results that are available, from the detailed Asset Condition Assessment that Kinectrics has performed?

16. Each of the Parties proposed System Renewal spending in the test year suggest that the answer is: yes. In Thunder Bay Hydro's submission, the answer is no. Management cannot stop doing its job, prudently operating and maintaining the distribution system, until perfect data is available. Perfect data will never be available. Rather, management must use the information it does have available to make prudent and informed decisions. This is exactly what Thunder Bay Hydro has done with its proposed system renewal spending.

B.4 Theory vs. reality

17. Fourth, the Parties submissions on OM&A expenditures are rooted heavily in theoretical models (such as the "Aiken model") and assumptions. However, none of the Parties have taken the time to assess their theories against the facts available on the evidentiary record. And the facts tell a very different story.
18. As explained in AIC (para. 15 and Table 1), Thunder Bay Hydro's achieved return on equity in 2016 was a mere 1.4%, more than 700 basis points less than the OEB's maximum permitted ROE and more than 500 basis points less than the ROE that is currently included in rates. In fact, Thunder Bay Hydro's achieved ROE was more than 300 basis points less than the OEB's maximum permitted ROE in each of 2014, 2015 and 2016.
19. Achieved ROE is a very good indicator of the overall financial health of a utility. Because of this, if 2017 were not a re-basing year, the OEB would be asking whether Thunder Bay Hydro should come in for an early rebasing (ROE has fallen outside of the 300 basis point deadband). Why? Because the OEB's rate setting methodology recognizes an inherent truth: that the theory embedded in the 4GIRM formula is not appropriate in all circumstances – that certain cost drivers might be truly unavoidable and may exceed the formulaic assumptions over the short term. This is what the evidence indicates is true for Thunder Bay Hydro. And this is why the OEB has adopted a cost of service methodology for rebasing years.

20. By assessing the actual costs of providing service during rebasing, the OEB ensures that its formulaic 4GIRM approach is periodically refreshed with evidence of actual costs. Theoretical costs are periodically refreshed with evidence of actual costs. If the OEB adopts the Parties' proposals, and applies a top-down formulaic approach to the test year OM&A budget – the OEB will never actually true-up OM&A costs to reflect reality.
21. Thunder Bay Hydro submits that in circumstances where there is evidence of historical and material under earnings at a utility (i.e. ROE performance below the 300-basis point deadband) the OEB should depart from theoretical formulas and instead assess cost forecasts based on the actual evidence and the rationale provided (i.e. a true "cost of service" assessment).
22. By contrast, an ongoing and rigid adherence to theoretical formulas, as is advocated by the Parties, risks putting the ongoing financial viability of an already low earning utility at risk. This is not in the public interest.
23. This problem may not happen immediately in the test year, but can occur later during the 4GIRM term. This, in-turn, could result in achieved ROE falling once again below the 300 basis point deadband, triggering yet another cost of service review where the evidence of the cost drivers would mostly likely be very similar to what they are today. This too is not in the public interest.

B.5 Customer engagement

24. Fifth, several of the Parties have made various recommendations about how Thunder Bay Hydro's customer engagement activities can be improved in the future. Each of these Parties appear to ignore the detailed evidence of the extensive customer engagement activities Thunder Bay Hydro undertook to better understand customer feedback and to ensure the application was responsive to customer preferences.⁸ Thunder Bay Hydro made changes to its Application, including targeting its grid modernization plan, directly in response to customer needs and preferences.

⁸ Exhibit 1 at pages 10-36, 37-51; Attachment 1-E; Attachment 1-G; Attachment 1-H; Attachment 1-J; Attachment 1-K; Exhibit 2, Attachment 2-B; Transcript Vol. 2 dated June 29, 2017 at page 12, line 7 to page 17 at line 5.

25. Thunder Bay Hydro also provides evidence in Exhibit 1 of its plans to move beyond these minimum engagement requirements with the creation and implementation of a Local Advisory Committee. This committee of key customer stakeholders will be able to learn about and weigh in on current and future utility plans on a regular basis, improving the quality of dialogue and ensuring all of Thunder Bay Hydro's actions are better aligned with customer needs and preferences.
26. That said, customer engagement by its very nature will never be perfect. Customers have limited time, and it is difficult to talk about every issue that might arise in a rate case when engaging with customers before that rate case even begins. This is made more difficult by the complicated, and interconnected, nature of Ontario's electricity industry, and the complexities of the OEB's rate setting process. However, all of this said Thunder Bay Hydro has taken note of each of the Parties comments and will make continuous improvements to these efforts in the future.

C. COST OF CAPITAL (ISSUE 2.1)

27. No Party opposed Thunder Bay Hydro's proposed cost of capital.
28. This is not surprising given:
- a. Thunder Bay Hydro's proposed cost of capital for the test year complies strictly with the Report of the Board on the *Cost of Capital for Ontario's Regulated Utilities* issued December 11, 2009 with Board File No. EB-2009-0084 (the "**2009 CoC Report**").
 - b. Thunder Bay Hydro voluntarily agreed to use a lower weighted average cost of debt as calculated in Undertaking J3.5, which reflects the best information available about Thunder Bay Hydro's actual cost of long-term debt and which benefits ratepayers with even lower rates.⁹ This is a tangible reduction in rates which further demonstrates Thunder Bay Hydro's ongoing commitment to its Rate Minimization Model.

⁹ AIC at para. 7.

- In response to a request from OEB Staff,¹⁰ Thunder Bay Hydro confirms that the holder of the newly issued third party debt is Infrastructure Ontario.
- c. Prior to the reduction in Undertaking J3.5, Thunder Bay Hydro's rates were already \$1,213,660 lower than they otherwise would be had the utility used the Board's deemed long-term debt rate of 3.91% for affiliate debt.¹¹ This savings is a direct result of Thunder Bay Hydro's Rate Minimization Model.
- d. Thunder Bay Hydro's rates are currently and will, if the OEB approves the requested cost of capital and test-year OM&A and capital budgets, remain within the lowest quartile (25%) of monthly bills in the Province of Ontario.¹²
- e. Thunder Bay Hydro is legally entitled to earn a fair rate of return by way of "*the fair return standard*".¹³ In the 2009 CoC Report, the OEB affirms its view that the fair return standard frames the discretion of the regulator. In the words of the OEB: "Meeting the standard is not optional, it is a legal requirement."
- f. In the course of developing the 2009 CoC Report, the OEB was informed by numerous experts to establish a regulated utility's cost of capital and based on this expert input, and the submissions of numerous stakeholders across the industry, the OEB determined that it would use a deemed capital structure, a formula-based equity risk premium approach for ROE, and an approach to long-term debt that relies on the actual cost for existing long-term debt instruments.
- g. Finally, on January 14, 2016, OEB staff published an OEB Staff Report (with Board File No. EB-2009-0084 titled *Review of the Cost of Capital for Ontario's Regulated Utilities* (the "**Review**"). In the Review, OEB staff reviewed the OEB's current cost of capital policy as set out in the 2009 CoC Report and assessed cost of capital

¹⁰ OEB Staff submissions at pg. 21.

¹¹ AIC at para. 11.

¹² AIC at para. 13 and Figure 1. See also 1-Staff-3 at pg. 14.

¹³ *TransCanada PipeLines Limited v. National Energy Board et al.* [2004] F.C.A 149, *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia et. al.* 262 U.S. 679 (1923), *Northwestern Utilities Limited v. City of Edmonton*, [1929] S.C.R. 186, and *Federal Power Commission v. Hope Natural Gas* 320 U.S. 591 (1944).

outcomes between 2010 and 2015. Following this review, OEB staff concluded “OEB staff is of the view that the current cost of capital policy has worked as it was intended. Movement in the parameters have followed macroeconomic trends and activity, and have not resulted in excessive or anomalous volatility.”

29. Finally, we would refer the panel to three prior decisions on cost of capital: (i) the Board’s Decision and Order in EB-2009-0139 dated April 9, 2010; (ii) the Board’s Decision and Order in EB-2009-0259 dated March 1, 2010; and (iii) the Board’s Decision and Order in EB-2013-0116 dated August 14, 2014. The principle established by the OEB in these decisions is that any party proposing a departure from the Board’s policy on cost of capital must support it with evidence (at pg. 12 of EB-2009-0139, pg. 18 of EB-2009-0259, and pg. 9 of EB-2013-0116). There is simply no evidence on the record that would support a departure from the Board’s policy on cost of capital for Thunder Bay Hydro as it relates to allowable Return on Equity.

D. CAPITAL PROGRAM (ISSUES 1.1 AND 2.1)

30. Thunder Bay Hydro’s proposed capital program is broken down into four categories: System Access, System Service, General Plant and System Renewal.
31. In Figure 2 of its AIC, Thunder Bay Hydro illustrated how its proposed test year capital expenditures are broken down into a prioritized list of material capital projects that fall within each of the four categories (this list was taken from Table 5.4.5-5 of the DSP, and was developed following Thunder Bay Hydro’s prioritization process found at Section 5.4.2.3 of the DSP). It is reproduced again below for ease of reference.

OEB Category	Thunder Bay Hydro Project	Project Description	Total Expenditure	Driver	Priority Level	Overall Priority
System Access	A 01	PCB Transformer Replacements	\$118,655	Mandated Obligations	P3	8
	A 02	Customer Recoverable System Modifications	\$281,092	Customer Requests	P3	10
	A 11	Customer Driven System Expansions	\$209,034	Customer Requests	P3	5
	A 12	Residential Service Connections	\$445,213	Customer Requests	P3	6
	A 13	General Service Connections	\$926,898	Customer Requests	P3	7
	A 14	Expansions for Residential Subdivisions	\$230,530	Customer Requests	P3	4
	A 15	System Relocations	\$164,881	Third Party Requests	P3	9
	A 21	Meter Installations	\$286,129	Mandated Obligations	P3	11
System Renewal	A 16	Small Pole Replacements	\$342,512	OH Renewal	P2	3
	A 17	Lines Safety Reports	\$761,834	Safety	P2	1
	A 18	Transformer and Switch Replacements	\$756,484	Asset Failure Renewal	P2	2
	B11140	25kV Pole Replacements	\$584,384	OH Renewal	P4	12
	B12111	Black Bay-Dewe Voltage Conversion	\$1,174,112	OH Renewal	P4	14
	B12112	Dewe-Rita Voltage Conversion	\$1,489,302	OH Renewal	P4	15
	B1270	Cumming-Brodie Voltage Conversion	\$580,677	OH Renewal	P4	16
	B1277	Donald-Mountdale Voltage Conversion	\$310,256	OH Renewal	P4	13
	B1298	McDougall-Court Voltage Conversion	\$789,716	OH Renewal	P4	19
	B12135	Finlayson - Brodie Voltage Conversion	\$893,725	OH Renewal	P4	17
	B14129	Underground Replacements	\$376,868	UG Renewal	P4	18
System Service	A	Grid Modernization	\$230,375	Reliability	P5	21
General Plant	C	Fleet - Double Bucket Replacement	\$450,000	System Maintenance Support	P5	20

Table 5.4.5-5 2017 Material Capital Projects and Programs

Figure 1: Material Capital Projects and Programs (Table 5.4.5-5 of the DSP)

32. It is important to note that project prioritization cannot be done using a narrow or single-factor lens. Rather, an assessment of priority should take into consideration all of the considerations relevant to a utility management's decision making. The evidence in the DSP demonstrates that when assessing project prioritization Thunder Bay Hydro weighs impact on safety or property, legislative and regulatory requirements, impact on customers and service, importance to risk mitigation, financial and operational impacts (including

coordination with other projects and work resources) and strategic alignment, to name but a few of the considerations identified in Section 5.4.2.3 of the DSP.

33. Thunder Bay Hydro confirmed during the oral hearing that if the OEB approved a lower capital expenditure than requested in the Application, Thunder Bay Hydro would cut projects starting with the lowest overall priority (Grid Modernization) and working up the priority list.¹⁴

D.1 System Service (lowest priority)

34. If the OEB cuts Thunder Bay Hydro's capital program in the test year, the first project that will be cut is the proposed System Service expenditures in the test year. These expenditures are more fully detailed in the Grid Modernization Plan found at Appendix D of the DSP.
35. Despite this, none of the Parties opposed Thunder Bay Hydro's proposed System Service expenditures in the test year.
36. OEB Staff note that "this expenditure is for distribution automation expenditures intended to enhance Thunder Bay Hydro's ability to provide improved reliability to small commercial and large use customers" and "the project also includes investments in improved SCADA infrastructure and was developed in response to customer preferences" and that "there were no system service expenditures in the 2012 to 2016 period, and the current expenditures are now minor."¹⁵
37. AMPCO goes a step further to argue that the System Service expenditures should be prioritized differently, and that the OEB "should approve this project given the benefits it delivers to customers."¹⁶ This not surprising given AMPCO's role representing large use customers that would benefit directly from this particular project.
38. What is noteworthy is that AMPCO also observed that "Thunder Bay Hydro's reliability statistics for the five-year period 2011 to 2015 indicate that for both SAIDI and SAIFI,

¹⁴ Transcript Vol. 2 dated July 29, 2017 at page 33, line 11 to line 21.

¹⁵ OEB Staff submissions at pg. 5

¹⁶ AMPCO submissions at pg. 15.

Thunder Bay Hydro's reliability has improved. In 2016, SAIDI improves but SAIFI was slightly worse."¹⁷

39. Thunder Bay Hydro does not debate its historical reliability performance. This forms part of the reason why a project that is aimed at further improving reliability performance for some (not all) customers has a lower priority.
40. In this context, Thunder Bay Hydro submits that the OEB should not make arbitrary and myopic changes to Thunder Bay Hydro's project prioritization methodology. Certainly, the OEB should not make changes that are advanced by a single customer group (AMPCO) that wish to see a particular project proceed because it directly benefits their constituency (large users). A single powerful constituency (like large industrial users) should not be permitted to exercise undue influence in the regulatory process to advance their narrow interests.
41. In this context, Thunder Bay Hydro notes that none of the Parties have the expertise necessary to make prudent project prioritization decisions. To do this, you would need an electrical engineering background, years of experience operating and maintaining the Thunder Bay distribution system, knowledge of committed and available worker resources (whether in-house or contractors), knowledge of prior, existing and future projects, and an ability to make informed business decisions and trade-offs against competing priorities and objectives. This is what management of Thunder Bay Hydro bring to bare in their formalized project prioritization methodology found at Section 5.4.2.3 of the DSP.
42. In the spirit of continuous improvements, Thunder Bay Hydro also committed to improving its prioritization methodology in the future. In this context, Thunder Bay Hydro did receive helpful recommendations from Mr. Tsimberg.
43. Thunder Bay Hydro also takes comfort in Mr. Tsimberg's opinion that there is no perfect prioritization process.

"I think they do have prioritization. I have not seen an ideal one yet; every different utility has a different prioritization methodology. Some are some more subjective,

¹⁷ AMPCO submissions at pg. 1.

some less subjective, and I am assuming that the next version of Thunder Bay's prioritization will be less subjective.”¹⁸

44. Thunder Bay Hydro submits that its proposed System Service spending in the test year is appropriate. Further, Thunder Bay Hydro submits that its prioritization process is appropriate and must not be arbitrarily modified to satisfy specific vested interests.

D.2 General plant (the second lowest priority projects)

45. If the OEB cuts Thunder Bay Hydro's capital program further, the next projects that will be deferred are both General Plant projects. The only projects in this category that exceed Thunder Bay Hydro's materiality threshold relate to fleet replacements. The first is a \$325k expenditure for the completion of the purchase of a boom and body for a double bucket truck whose cab and chassis were expensed in 2016 (as a replacement for truck #5, a 2002 double bucket) and the second is a \$125k expenditure for the initial purchase of the cab and chassis portion of a new double bucket truck (a replacement for truck #3, a 2001 double bucket).¹⁹
46. Only one party, AMPCO, objected to Thunder Bay Hydro's the proposed General Plant expenditures. AMPCO argues that “*given the uncertainty in the General Plant category*” an 11%, or \$138,000, reduction in general plant budget is appropriate. AMPCO specifically questions the timing for the truck #3 replacement, which in AMPCO's view could be deferred.²⁰
47. AMPCO cited no evidence of the purported “uncertainty in the General Plant category”. This is because General Plant expenditures have the lowest degree of uncertainty of any part of the capital program. These expenditures are entirely within the control of Thunder Bay Hydro, are based on known information about existing fleet, buildings, IT, and tools and equipment assets and business needs, and are generally addressed through measured long-term plans that help appropriately pace spending. See, for example, the *Fleet Plan*

¹⁸ Transcript Vol. 2. Pg. 127 lines 16-21.

¹⁹ DSP Appendix J

²⁰ AMPCO submissions at page 16.

included at Appendix E of the DSP (the “**Fleet Plan**”) and the *IS and IT Strategy* included at Appendix I of the DSP.

48. Thunder Bay Hydro does not agree with an arbitrary reduction in General Plant expenditures in the test year. As confirmed by OEB Staff at pgs. 6-7 of its submissions, Thunder Bay Hydro has proposed test year General Plant expenditures that are less than what was it actually spent in each of 2015 and 2016. In addition, Thunder Bay Hydro’s average proposed General Plant expenditures over the forecast period is \$1.1 million, which is slightly less than its average level of expenditures in the 2012-2016 period (with 2013 removed). Further deferral of General Plant expenditures will adversely affect Thunder Bay Hydro’s levelized approach to General Plant expenditures.
49. Thunder Bay Hydro also does not agree with the suggested deferral of Double bucket truck #3. This vehicle is already 16 years old (2001 vintage),²¹ which exceeds the expected useful service life of 15 years.²² Replacement is identified in the test year, as part of a comprehensive, measured and paced approach to overall fleet management until 2027.²³ The deferral of this one replacement will cause a ripple effect, that will delay future replacements and affect the entire plan.
50. In addition, deferring this needed truck replacement will increase the probability of vehicle breakdown and failure. This will adversely affect customer service, since most speciality vehicles are not readily available for rent in Thunder Bay and expected lead times for a rental range from 3-4 weeks (at best) to 2-6 months (more realistically). In addition, rental of double bucket trucks are costly (\$7,000 in delivery/pick fees plus \$6,100 monthly).²⁴
51. The evidence demonstrates that when deciding to replace a fleet vehicle, Thunder Bay Hydro considers repair costs, total kms and vehicle age.²⁵ However, in the experienced judgement of Thunder Bay Hydro’s staff who work with these vehicles every day, vehicle age remains the most reliable measure of service life.

²¹ Fleet Plan at pg. 9.

²² Fleet Plan at pg. 4.

²³ Fleet Plan pages 9-11.

²⁴ Fleet Plan at pgs. 6-7.

²⁵ 2-AMPCO-18.

52. Finally, Thunder Bay Hydro agrees with AMPCO's suggestion that it begin to collect, track and manage utilization rates of vehicles, in addition to repair costs, kms and age.

D.3 System Renewal (the third lowest priority projects)

53. Thunder Bay Hydro's proposed System Renewal spending attracted the most attention from the Parties in their submissions.
54. This is not surprising. Thunder Bay Hydro is proposing a \$1.2 million dollar increase in System Renewal spending in the test year, which is the latest step in a long-term, measured and paced plan to increase System Renewal spending gradually to achieve an appropriate and sustainable level for Thunder Bay Hydro which began back in 2008.²⁶
55. In this context:
- a. VECC argues that there is no compelling reason for the OEB to consider adding more than 10% increase to the past five-year trend capital budget, which would have the effect of reducing the 2017 forecast by \$500,000.²⁷
 - b. OEB Staff argues that any increase in spending in the System Renewal category should be limited to the rate of inflation (1.9%). OEB Staff explain that this would result in a System Renewal budget of \$7,320,496, a reduction of \$1,059,500 from the proposed 2017 forecast.²⁸
 - c. SEC argues that System Renewal budget should be limited to the average of the last four years' of actual spending (\$6.671M), a reduction of \$1.709M from the 2017 forecast.²⁹
 - d. AMPCO argues that System Renewal budget should be reduced by \$1,815,378 from the 2017 forecast. This represents the sum of various reductions in six (6) specific System Renewal projects.³⁰

²⁶ AIC paras. 31-33 and Transcript Vol. 2 dated June 29, 2017 at page 25, lines 15-28.

²⁷ VECC submissions at para. 3.24. While VECC takes an envelope approach to capital spending, its specific criticisms and concerns centre on the proposed System Renewal spending.

²⁸ OEB Staff submissions at pg. 12.

²⁹ SEC submissions at para. 4.5.2.

³⁰ AMPCO at page 17.

56. In general terms, most of the Parties are not opposed to the general direction of System Renewal program being undertaken by Thunder Bay Hydro. Notably:
- a. *“VECC’s submission is straight forward. We are not opposed to the general direction in capital planning being taken by TBH. In fact, we agree that a distribution system plan based on remedial and proactive addressing of assets might be desirable.”*³¹
 - b. *“OEB staff submits that the DSP filed by Thunder Bay Hydro is responsive to the OEB’s filing requirements and in general was clearly written. Some of the projects and proposed expenditures are well supported. OEB staff supports Thunder Bay Hydro’s move towards a more condition-based asset management strategy through the engagement of Kinectrics to produce the ACA. It appears to OEB staff that the utility is striving to implement best asset management practices, and this new approach should support system reliability and resilience.”*³²
 - c. *“AMPCO supports Thunder Bay Hydro’s approach to better understand the conditions of its assets. Kinectrics’ ACA provides Thunder Bay Hydro with a good baseline and reference point for the current condition of its assets.”*³³
57. There is general consensus that the direction Thunder Bay Hydro is going with respect to its System Renewal spending is the right one. However, each of the Parties have raised concerns with Thunder Bay Hydro’s proposed pacing of System Renewal spending.
58. The Parties’ submission in this regard demonstrate a fundamental misunderstanding of Thunder Bay Hydro’s system renewal program. Thunder Bay Hydro is sympathetic. Not everyone has the engineering expertise or experience to understand these complicated programs. Thunder Bay Hydro attempted to address this issue in advance by retaining a widely recognized and independent expert in asset management and distribution system

³¹ VECC submissions at para 3.22.

³² OEB Staff submissions at pgs. 11-12.

³³ AMPCO submissions at pg. 5.

planning – Mr. Yury Tsimberg – to provide the OEB and the Parties with the benefit of expert opinion evidence on best practice as it relates to distribution system planning and asset management. Thunder Bay Hydro’s intent was to ensure the OEB panel had access to the best information available upon which to make its decision on Thunder Bay Hydro’s proposed capital plan.

59. Sadly, none of the Parties took full advantage of Mr. Tsimberg’s expertise to ensure their submissions were rooted in a firm understanding of best practices for system renewal and distribution system asset management.
60. Indeed, several Parties found fault with the fact that Kinectrics used, as an input into their asset condition assessment, inspection and other data that was gathered by Thunder Bay Hydro employees. The implicit suggestion is that the data is for some reason not reliable. Thunder Bay Hydro had an opportunity to respond to this directly during the oral hearing:

“MR. VELLONE: And I think the implication of that was that the utility data was no good that went to Kinectrics. And I would just like to put to the utility itself, would you agree with that statement, that the data that was given to Kinectrics was somehow no good or of poor quality?”

MS. BAILEY: I would not classify the data as no good.

MR. VELLONE: Why not?

MS. DUFF: You make decisions based on it?

MS. BAILEY: Yes, we make decisions based on it and we are continually trying to improve that data. So from our last 2013 application, we have updated how we collect it, ensuring it's consistent across subject matter experts, ensuring that the criteria that's collected is enhanced to provide us a better view into how the assets are visually inspected.

We ensure that the people that are doing the inspections are qualified, they have the experience needed to do that inspection.

So in terms of the actual inspections and the data that we are collecting, the data is what we feel good. There are areas of improvement, definitely. We can do more pole testing and we are committing, as my boss’s boss just told me, committing to ensuring that we gather better data than we have in the past.”³⁴

61. Thunder Bay Hydro submits that there is no evidence to support the suggestion made by several of the parties that Thunder Bay Hydro should spend even more money to hire (yet

³⁴ Transcript Vol. 3 at pg. 78, line 15 to pg. 79, line 10.

another) third-party consultant to complete an audit on inspection data. This data is already collected by qualified and experienced staff, and are verified by Thunder Bay Hydro through their own internal controls and processes. Ms. Bailey confirms, based on her review of the data that it is of good quality. And Ms. Bailey confirms that Thunder Bay Hydro is committed to ensuring continuous improvements into the future.

62. Each of Parties cite certain data limitations to support the proposed reduced spending. These data limitations include the lack of asset removal data, challenges with failure statistics, low Data Availability Index (DAI) for some (not all) asset classes, high data gaps for some (not all) asset classes.
63. This is not surprising. Thunder Bay Hydro is fully aware of, and has been completely transparent throughout this proceeding, about the data limitations it faces. Thunder Bay Hydro has repeatedly committed to improving its data for its next asset condition assessment, including recording asset removal data, standardizing the collection of failure statistics, addressing low DAI for specific asset classes, and resolving data gaps for some asset classes.
64. However, some of these data challenges are difficult to resolve.
65. For example, the way failure statistics are recorded – an individual must identify a single primary cause of a failure. This approach to recording failure statistics (which is mandated by the OEB reporting requirements) is in direct contradiction to reality: failures are often due to a number of different but interrelated causes. This is illustrated by an example explored by Mr. Tsimberg during the oral hearing:

“But at the same time, vegetation management and outages due to vegetation management is also linked with condition of assets. A simple example would be if you have a storm and a tree falls on your conductor [...] if a conductor is not in a good condition a tree will break the conductor, so it's not just a matter of removing the tree. It's also, you also have to repair the conductor itself, and if conductor falls it's possible that adjacent structures will fall as well.”³⁵

In this factual scenario, the individual who first arrives at the scene must make a decision. Does she record the outage as a bad weather event? It was as a result of a storm. Does she

³⁵ Transcript Vol. 2 pg. 66, line 13-24.

record it as a tree contact? A tree did fall on the conductor. Or does she record it as an equipment failure? The conductor did break because it was not in a good condition.

66. Regardless of what decision she makes, the failure statistics will not show the complete picture of what happened. Because of this, failure statistics cannot be read in isolation. They must be interpreted by qualified staff that have a full understanding of the distribution system together with what actually happened, to be able to accurately interpret and draw conclusions from these statistics. This is what Mr. Tsimberg means when he concludes his example by saying:

“So I think when it comes to reliability it's more art than science, and there are many different components, so the best one can hope for, identify those components, qualitatively assess the impact on reliability, and one of the things to do is probably have some measures in place that track impact on your investments, on reliability attributable to those assets that investments were made into.”³⁶

67. As another example, Thunder Bay Hydro has a relatively low DAI and a high data gap for its underground conductors. The reason for this is obvious, it is difficult to conduct visual or other inspections on conductors which are buried underground. There are processes and equipment which can be used to assess the health of underground conductors, however processes take time to implement, equipment is expensive, and staff would need to be trained. Despite these challenges, this is exactly what Thunder Bay Hydro has committed to do. And in recognition of existing data limitations and the high costs of replacing underground cable, Thunder Bay Hydro is holding investments in these assets at 2.4km of replacement in the test year (much less than the 7km recommended).³⁷

68. In this context, Mr. Tsimberg's views on the topic are instructive.

“MS. LAU: Yeah, no worries.

So on pages 48 to 49 of VECC's compendium in response to interrog ER-VECC-7 Thunder Bay Hydro sets out some ways it intends to address these data gaps through its DSP, so Mr. Tsimberg, would these solutions or proposals adequately address your concerns about data gaps?

MR. TSIMBERG: Well, I am never totally satisfied. I like to have all the gaps closed and data availability indicator be 100 percent. It's fairly continuous process, because closing data gaps and increasing data availability indicator, it's

³⁶ Transcript Vol. 2 pg. 66, line 24, to pg. 67, line 4.

³⁷ AIC at para. 41.

not free, so it does entail some O&M costs, and so it's really utility's prerogative how you want to do it.

To me what's important is anytime we do assessment, asset condition assessment, which is a snapshot in time, that there improvements, improvements in data availability scores. Some of the data gaps are closed and more information is collected, so -- and also sample size increased, so basically from year to year it's impossible to jump from where you are today to immediately have a perfect asset condition assessment, but the intent is every year you improve it, so it's important to have continuous improvement of the process.”³⁸

69. Thunder Bay Hydro is committed to making continuous improvements and achieving best practices. However, Thunder Bay Hydro recognizes that the data will never be 100% perfect. There will always be room for improvement. Technological innovation and new testing and inspection methods are being continuously created. Data that couldn't be collected just a few years ago is now available.
70. The real question facing this OEB panel is: Should Thunder Bay Hydro completely ignore all of the good work that has been done, and the results that are available from the detailed Asset Condition Assessment that Kinectrics has performed?
71. Each of SEC, AMPCO and Board Staff argue that the answer to this question is: yes. The reductions in System Renewal spending proposed by SEC and AMPCO would result in a absolute reduction in total System Renewal spending from 2016 and prior years. AMPCO's reductions would make 2017 the System Renewal lower than the four-year historical average. Rather than taking steps to address the backlog of work that needs to be done, AMPCO and SEC would recommend that this backlog of poor and very poor assets should be allowed to increase – to artificially keep rates lower for consumers today. This, in Thunder Bay Hydro's submission, is not in the public interest.
72. In-fact, Thunder Bay Hydro submits that this is exactly the opposite of what prudent utility management should be doing in the circumstances, which is to gradually increase System Renewal work in response to clear evidence of a large backlog of poor and very poor condition assets that are in need of renewal in the next five years, as shown in the Levelized Flagged for Action Plan in the ACA.

³⁸ Transcript Vol. 2 at pg 144 line 28, line 145, line 22.

73. Even Board Staff's recommendation, which proposes an inflationary increase in 2016 System Renewal spending, will result in a net reduction in the total amount of work that can be accomplished in 2017. Why? Because this does not keep pace with Thunder Bay Hydro's cost drivers. The evidence on the record is that negotiated union wage increases for 2017 are 2.0%. While this increase is less than industry average, it does exceed inflation.
74. Thunder Bay Hydro submits that steady and paced increases in System Renewal spending are necessary in the test year, to proactively address the large backlog of poor and very poor condition assets that were identified in the Levelized Flagged for Action Plan in the ACA.
75. The importance placed on increasing System Renewal investments by management of Thunder Bay Hydro has been evidenced throughout this proceeding. Notably:
- a. Thunder Bay Hydro has gradually been increasing its System Renewal spending since 2008. It does this even though 4GIRM formula does not fund new capital investments until they are eventually added into rate base. Thunder Bay Hydro management explains this fact directly to its Board of Directors, not because Thunder Bay Hydro objects to the OEB's IRM formula as has been alleged, but rather to ensure that its Board of Directors are fully informed about the financial consequences of increased System Renewal spending. Despite the financial disincentive to increasing capital spending in this way, Thunder Bay Hydro continues to do so because it is the right thing to do.
 - b. Thunder Bay Hydro's prioritization process reflects the importance the utility places on achieving a sustainable level of System Renewal spending. If required by the OEB, Thunder Bay Hydro will first defer System Service and needed General Plant spending rather than sacrifice System Renewal that is needed to ensure the long-term health and sustainability of the system.
76. Despite all of this, Thunder Bay Hydro has heard the Parties submissions. The Parties have expressed a clear preference for a slower pacing of increases to System Renewal spending, despite evidence to the contrary.
77. Thunder Bay Hydro has carefully reviewed its System Renewal plan to identify if there are any opportunities for deferring System Renewal spending without affecting lower priority

projects. Thunder Bay Hydro has identified one such opportunity, which relates to the "McDougall-Court Voltage Conversion" (project number B1298). This project is priority #19 of 21 in the test year. Thunder Bay Hydro engineering staff have determined that without cancelling the project entirely, they are able to defer up-to a maximum of \$400,000 in spending on this project from 2017 into future years, if the OEB deems it appropriate.

78. The deferral of this project is unlikely to affected the planned retirement of the Algoma station transformer, which is classified as being in "very good" condition and is not flagged for action until year 14.³⁹ This deferral will delay the ultimate completion of this project out into future years. Because the Algoma substation will continue to have low interconnectivity and no back up transformation should the substation transformer fail,⁴⁰ this will result in an increased risk of failure and service outages for certain customer loads, including a district jail, a seniors centre, a high school and 41 commercial customers (each as described in Undertaking J3.1).

The Kinectrics Evidence

79. While most Parties raise concerns with the proposed pacing of System Renewal spending, or the data limitations in the ACA, in final submissions, counsel to SEC resorts to attacking the credibility of Mr. Tsimberg, his conclusions as found in the Kinectrics ACA and the spending implications of those conclusions.⁴¹
80. There is an adage in legal profession: If the facts aren't in your favour, attack credibility.
81. Counsel for SEC has a well known and public disdain for the engineering profession. He has written entire blog articles on the topic.⁴² His view can be summarized as: the only thing you can trust engineers to do is spend more money. This general bias against an entire profession is difficult to understand. But this bias surfaces again at paragraphs 4.3.1-4.3.33 of the SEC submissions (a full 8 pages are dedicated to attacking Mr. Tsimberg).

³⁹ Exhibit 2, Appendix 2-B Distribution System Plan, Appendix C – Kinectrics Asset Condition Assessment, at Table 1-7.

⁴⁰ Exhibit 2, Appendix 2-B Distribution System Plan, Appendix J – Material Capital Project Summaries, Project number B1298, "Project Summary" heading.

⁴¹ SEC submissions at paras 4.3.1-4.3.33

⁴² <https://jayshepherdwriting.wordpress.com/2017/03/18/energy-16-the-big-build/>

82. The core of SEC's concern appears to be that Kinectrics' has recommended higher levels of capital spending in other ACAs completed for various other Ontario LDCs. These other ACAs are not on the evidentiary record in this proceeding. And Thunder Bay Hydro has not reviewed them. These other ACAs are not relevant to this application.
83. However, let us assume for a moment that SEC's theory might be true – that Mr. Tsimberg has a "history of spending bias." When confronted with this allegation during cross-examination, Mr. Tsimberg responded directly in a measured and respectful way to refute this allegation:

MR. SHEPHERD: That's all very nice to say, but I asked a very specific question. Have you ever recommended less action than the utility was already doing? The answer is no, right? You have always recommended they should be doing more than they are doing.

MR. TSIMBERG: Well, first of all, you are asking me questions that I can't provide you an answer because it's not my starting point. I don't start with saying look how much money you guys are spending in the past, and let me see how can I help you to spend more. That is really not my objective.

I would like them to spend the right amount of money and to help them determine what this right amount of money is, I am providing them with useful input of what their condition based requirements are. This is where my expertise comes in, not in looking at how much they were spending before and trying to bring it up. That's nothing to do with what we do.

Most of the time, I don't even consider what they spent before; it's irrelevant to me.

⁴³

84. This makes sense. By sticking to his knitting, asset management best practices, Mr. Tsimberg creates an impartial and useful input into a much more difficult business decision that must be made by utility management of how to manage the utility and its limited resources.
85. Of course, there is another more plausible explanation for why recent ACA results might recommend increased emphasis on system renewal: that current and historical spending levels are and were too low, and that an increased focus on system renewal is actually needed.

⁴³ Transcript Vol. 3 at pg. 28, line 18 to pg. 29, line 9.

86. Prior to market restructuring and the introduction of the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, distribution systems were operated by municipal electric utilities (MEUs). MEUs were operated as branches of municipal councils under the control of municipal politicians, much like municipal water and wastewater systems are today. Some of these politicians took pride in promising no rate increases (thereby ensuring their re-election). Denied even inflationary rate increases, during this era (which lasted for decades), MEUs were forced to defer much needed system renewal spending into the future in favour of supporting artificially low rates.
87. Because of this systemic history of underspending across Ontario, it is hardly surprising that many of the ACAs being completed today are uncovering evidence of an accumulated backlog in needed system renewal.
88. In this context, Thunder Bay Hydro submits that Mr. Tsimberg and his team at Kinectrics are widely recognized, reputable and independent third-party asset management experts.
89. Mr. Tsimberg was a member of the international advisory panel revising Asset Management PAS 55 specifications developed by the British Institute of Asset Management and a member of the NERC committee developing North American planning standards. Mr. Tsimberg is currently the Canadian representative on CIGRE Study Committee SC1 “System Development and Economics” and a member of the Committee’s management team as Asset Management Group Convener.
90. Mr. Tsimberg and his team have been retained by numerous different stakeholders across the industry in both the US and in Canada (not just utilities). Mr. Tsimberg has nothing to gain, and everything to lose (a reputation of integrity, an entire livelihood), by producing anything other than results that are rooted in asset management best practices and principles.
91. Mr. Tsimberg has signed the OEB’s Form A – Acknowledgement of Experts Duty, wherein he acknowledges his duty to provide opinion evidence that is fair, objective and non-partisan, that is related only to matters that are within his area of expertise, and to provide

such additional assistance as the OEB may reasonably require to determine a matter in issue.⁴⁴

92. Thunder Bay Hydro submits that the OEB should reject entirely SEC's contention that the ACA or Mr. Tsimberg have any bias in favour of increased spending, that the ACA represents something other than an independent assessment of the health of the distribution system, or that the System Renewal portion of the Application is driven by something other than the ACA. None of these allegations have been substantiated by any credible or reliable evidence.

Project specific submissions

93. Several Parties, and AMPCO in particular, have made more detailed submissions on particular capital projects that are planned for the test year. Thunder Bay Hydro will address all of those more detailed submissions project-by-project here.

4kV Voltage Conversion Projects:

94. It is worth noting at the outset that while many Parties identified data limitations in the ACA, wood poles, substation transformers and distribution transformers all have a DAI of between 85-100%. None of these asset classes were flagged as having a High data gap. In addition, removal data for distribution transformers and substation transformers was available and provided to Kinectrics.⁴⁵
95. For these reasons, Thunder Bay Hydro has increased confidence in the ACA results for these asset classes. And this is relevant because renewal of aged and poor condition 4kV poles and transformers in the project areas is a primary driver for certain voltage conversion projects.⁴⁶
96. OEB Staff express some confusion over the 4kV voltage conversion projects planned for the test year.⁴⁷ It appears that OEB Staff has misunderstood the evidence as it relates to the need for each 4kV voltage conversion project.

⁴⁴ Appendix D of the May 11, 2017 Tsimberg Expert Report.

⁴⁵ ER-AMPCO-28.

⁴⁶ Transcript Vol. 2 pg. 44, line 1 to pg. 45, line 7.

⁴⁷ OEB Staff submissions at pgs. 7-10.

97. The misunderstanding likely arises, in part, because the rationale provided for each 4kV voltage conversion project must address two different, but equally important questions. First, why does the project need to occur in the test year? And second, why is Thunder Bay Hydro proposing something other than a like-for-like replacement?
98. OEB Staff in their submissions repeatedly confuse Thunder Bay Hydro's evidence which is being provided in response to the second question, as evidence intended to respond to the first question.
99. This confusion about the rationale about the different voltage conversion projects arose during the oral hearing as well. Ultimately this confusion resulted in Undertaking J3.1. In response to Undertaking J3.1, Thunder Bay Hydro attempted to consolidate the relevant evidence to provide a clearer and consolidated response to the question "why does the project need to occur in the test year?" for each voltage conversion project. At a minimum, the OEB panel should have a good understanding of why each of these projects should proceed in the test year. In summary:
- a. **Black Bay – Dewie Voltage Conversion (Project number B12111) and Dewe-Rita Voltage Conversion (B12112):** These two projects are works in-progress that were started in 2016, with poles being set and anchors installed (WIP of \$572,901 and \$620,355, respectively, as of the end of 2016). Thunder Bay Hydro intends to complete the balance of the work in 2017, including the stringing of conductors, installation of bushings and removal of the old 4kV assets. The status-quo is a "work-in-progress" situation that creates difficult operating conditions and lower system redundancy. This situation cannot be delayed.
 - b. **Finlayson – Brodie Voltage Conversion (Project number B12135):** This project was selected as part of removal of the Hardisty substation transformers which were identified as poor and fair condition and the 9 circuit breakers which are all identified as poor condition and pose a high risk of failure. As of June 15, 2017, this project has had partial poles and anchors installed with YTD expenditures of \$212,612 (24% of total budget spent).

- c. **Cumming-Brodie Voltage Conversion (Project number B1270):** This project was selected in the test year as part of the removal of the Hardisty substation transformers which were identified as poor and fair condition, in addition to the 9 circuit breakers which are all identified as poor condition and pose a high risk of failure. As of June 15, 2017, this project has had engineering staking finalized with YTD expenditures of \$16,655 (3% of total budget spent).
 - d. **Donald-Mountdale Voltage Conversion (B1277):** This project was selected due to it being the final project area which is now serviced from the Mountdale substation. This substation has only one transformer and there is no longer a tie between it and the other stations. If this project is not completed, it poses a risk to restoration and isolation for customers in this area. As of June 15, 2017, permitting for work in proximity to the airport have been received with YTD expenditures of \$20,135 (6% of total budget spent).
 - e. **MacDougal Court Voltage Conversion (B1298):** This project was selected based on the asset condition of poles and distribution transformers in the area where risk of failure would impact service to critical loads such as the district jail, a seniors' centre, a high school and 41 commercial services. As of June 15, 2017, materials have been ordered with YTD expenditures of \$101,023 (12% of total budget spent).
100. Thunder Bay Hydro does understand that its proposed 4kV replacements in the test year is currently in excess of what was recommended by Kinectrics in the ACA. Thunder Bay Hydro has committed to shifting the focus of its capital spending to achieve better alignment with the ACA results over a gradual 3-year period.
101. However, as the foregoing evidence demonstrates, you cannot stop, or turn, the titanic on a dime. Once you review the specific rational for each 4kV conversion project, this rationale illustrates the multi-year and interconnected nature of Thunder Bay Hydro's different system renewal projects. These projects cannot simply be cancelled or delayed because work was started in previous years, and not finishing these projects off as proposed would create operational risks that would result in decreased service levels for all affected customers that are not prudent or responsible.

102. The only exception to this is the McDougal Court Voltage Conversion. For this project, as described above, Thunder Bay Hydro has identified an opportunity to reduce the scope of to reduce test year spending by \$400,000. None of the other projects can simply be halted in the test year without increased risk of material adverse consequences for directly affected customers.

Underground Replacements (Project number B14129):

103. AMPCO argues that the budget for underground replacements should be reduced to \$200,000 in the test year. APMCO indicates that this will allow for about 1km of replacements, consistent with the kilometers replaced in 2016.⁴⁸
104. Thunder Bay Hydro does not agree.
105. Thunder Bay Hydro's system is made up of 256km of underground primary cable (Table 5.3.2-1 of the DSP) and 485 cct-km of underground secondary cable (Table 5.3.2-3). At a renewal rate of 1km per year, it would take hundreds of years to renew the Thunder Bay Hydro underground system.
106. In addition:

*"Of all the asset groups, 4kV underground cables were found, on average, to be in the worst condition. A total of 48% were found to be in poor or very poor condition."*⁴⁹

107. Luckily, there is only 44km of 4kV underground cables in the system.⁵⁰ However, the Kinectrics ACA identified a large backlog of all underground cables in the "very poor" (3%, or 11km of the sample), "poor" (3% or 10km of the sample) and "fair" (31%, or 115km of the sample) conditions (sample size was 374km).⁵¹
108. Because of this, the Kinectrics levelized flagged for action plan recommends a total of 7km of cable replacements in the test year, and that this renewal level be steadily increased to 63km in year ten.⁵²

⁴⁸ AMPCO submissions at pg. 9-10.

⁴⁹ Kinectrics ACA, Conclusions at pg. 23.

⁵⁰ Kinectrics ACA, Table III-1.

⁵¹ See pages 82-84 of the DSP, and Table III-1 of the Kinectrics ACA.

⁵² Kinectrics ACA at pg. 16, Table III-2.

109. Clearly, the renewal rate in underground must increase.
110. In its AIC, Thunder Bay Hydro readily acknowledged the data limitations associated with underground cable replacements. Thunder Bay Hydro is committed to completing the additional diagnostic testing recommended by Kinectrics. And Thunder Bay Hydro has limited its proposal to a modest 2.4km of underground cable replacement in the test year, for these same reasons.
111. Thunder Bay Hydro submits that its proposal reflects a measured approach to this increase that is reflective of the need for additional data while still moving the overall capital program in the right direction.

Transformer and Switch Replacements (Project number A18):

112. AMPCO argues that the budget for transformer and switch replacements should be reduced to \$500,000, which in AMPCO's view is in line with historical spending prior to 2015.⁵³
113. Thunder Bay Hydro does not agree.
114. Thunder Bay Hydro has forecasted \$756,484 in Transformer and Switch Replacements to occur in 2017. This amount is less than what was actually spent in 2015 (\$932,264) and 2016 (\$816,936).
115. Transformer and Switch Replacements refer to emergency reactive replacements required after a transformer or switch fail. The costs include the cost to replace the equipment, as well as any remediation costs required due to the equipment failure.
116. The amount of spending in the test year is reflective of an unexpected increase in failures of 4kV pad-mount transformers that began in 2015. The leaks from these failed transformers are costly to remediate. Because of this spike in failures, Thunder Bay Hydro did an analysis of the issue and identified a problem with 4kV leaking transformers which first surfaced in 2015 and which Thunder Bay Hydro anticipates will continue into 2017.⁵⁴ For this reason, Thunder Bay Hydro submits that its proposed budget in 2017 is appropriate.

⁵³ AMPCO submissions at page 10.

⁵⁴ Transcript Vol. 2, pg. 37-38.

117. Finally, it is worth noting that the faulty and problematic 4kV pad-mount transformers are exactly the type of transformers which Thunder Bay Hydro is proposing to systematically replace as part of its 4kV voltage conversion program. This is illustrative of the complicated and interconnected nature of system renewal projects. If a transformer that suffered a failure had been converted to 25kV earlier – the pad mount transformer would have been removed before it failed, it would never need to be replaced, and the environmental remediation costs would also be avoided.

25 kV Pole Replacements (Project number B11140):

118. AMPCO argues that the budget for 25kV wood pole replacements should be reduced by 50%, a reduction of \$292,192. AMPCO argues that this is due to the data gap associated with wood poles.⁵⁵
119. Thunder Bay Hydro does not agree.
120. Table III-4 of the Kinectircs ACA shows that wood poles have a DAI of 100% and only a medium-high data gap. Visual inspection data was available for all wood poles tested, and hammer testing is done when needed. The confidence in the ACA results for wood poles is consequently fairly high.
121. Thunder Bay Hydro witnesses indicated during cross-examination that they do not have access to the equipment necessary to perform additional, non-destructive testing of wood poles.⁵⁶ This is what is required to close the data gap. Thunder Bay Hydro remains committed to improving its pole data over time.
122. In this context, Thunder Bay Hydro has proposed an increase in its 25kV wood pole replacement in 2017 in direct response to the ACA results to \$584,384. The project rationale is clearly explained in Appendix J of the DSP. Specifically:

“This project category is comprised of the replacement of wood poles in the McDougall Court, Hodder Ave and Montreal Street areas. These poles are in poor condition and past their typical useful life (TUL). The selected poles are all at end of useful life or have prematurely degraded beyond what could be expected of poles

⁵⁵ AMPCO submissions at pages 13-14.

⁵⁶ Transcript Vol. 2 pages. 137-138.

of similar age. Selection of poles as part of this project category is a multi- step process consisting of an internal GIS model which selects poles of the oldest vintage with the highest criticality and worst risk assessment. Following this selection, field inspections are completed to verify the condition assumptions. This process results in selecting only the replacement of assets which have a high risk and probability of failure. Each project scope includes design, construction and installation of new poles framed to conform to O. Reg. 22/04 compliant standards. In certain cases where overhead conductor or porcelain insulators are identified as end of life, within these projects, replacement will also occur. (See the reference material) Through this project, Thunder Bay Hydro plans to improve the level of safety and reliability associated with newer standards and materials. It is expected that Thunder Bay Hydro will replace 60 poles in the 25kV Planned Pole Replacement program on 25kV / 12kV voltages.”

123. Given this, Thunder Bay Hydro submits that its planned spending on 25kV pole replacements in the test year is appropriate.

Line Safety Reports (Project number A1717):

124. APMCO recommends that planned spending on line safety reports be reduced by \$221,834 so that is more consistent with historical spending from 2012-2015.
125. Thunder Bay Hydro does not agree.
126. This project category is comprised of replacement of wood poles, overhead conductor, porcelain insulators wood cross arms, or wood pins that are identified to be in poor condition and that pose a potential risk to public safety and/or customer reliability. The assets do not get replaced in this project unless they are identified in a field inspection and line safety reports are submitted from customers and staff. These assets are, by definition, at end of life. The driver for replacement is immediate customer or worker safety risk, which explains the very high priority rankings ascribed to this project.
127. AMPCO excludes 2016 historical from its averaging due to data issues. This data discrepancy is easily explainable. Thunder Bay Hydro was asked in the discovery process to update Appendix 2-AA to reflect 2016 actuals of \$732,775. Appendix J was not similarly updated.

128. The forecasted 2017 spending on this project is \$761,834 is consistent with the bridge year spending. The forecasted spending is also consistent with the increasing trend in this work explained by Ms. Bailey during cross-examination:

“MS. BAILEY: So the line safety reports -- and I could probably refer you in the DSP. There is a capital project summary that talks about that specific projects, its drivers.

So it is -- the work that comes out of that is, as it's name implies, safety reports, so reports that come from our staff or our customers and are typically a result of our risk assessments that happen.

And so we have seen a trending upward of concerns that have occurred.”⁵⁷

Small Pole Replacements:

129. AMPCO noted a discrepancy between 2016 values shown for this project in Appendix 2-AA and Appendix J. During the course of the application process, Thunder Bay Hydro was asked to update Appendix 2-AA with 2016 actuals. A similar update was not requested, and was not done for Appendix J.

D.4 System Access (the highest priority projects)

130. Thunder Bay Hydro prioritized its System Access projects with the highest priority. System Access spending represents projects that Thunder Bay Hydro must do in the test year to comply with its mandatory obligation to connect, to respond to third party asset relocate requests, to comply with PCB replacement obligations, and to meet ongoing metering requirements. For these reasons, the projects have the highest priority (short of emergency/safety issues) which makes it highly unlikely that Thunder Bay Hydro will need to make cuts to any of its spending in these projects.
131. None of the Parties opposed Thunder Bay Hydro’s proposed System Access expenditures in the test year. As noted by OEB Staff, the test year forecast is “reasonably consistent with historic levels in the 2012 to 2015 period” and “OEB Staff accepts Thunder Bay Hydro’s forecasts in this category.”⁵⁸
132. Thunder Bay Hydro submits that its proposed System Access spending in the test year is appropriate.

⁵⁷ Transcript Vol. 2 at pg. 101, line 20 to pg. 102, line 1.

⁵⁸ OEB Staff submissions at pg. 5

E. OM&A PROGRAM (ISSUES 1.2 AND 2.1)

*“OEB staff accept that the OM&A programs Thunder Bay Hydro is undertaking are appropriate ones and does not recommend that any of these programs be discontinued or that any specific cuts in a particular program be made.”*⁵⁹

133. Despite the admitted prudence of Thunder Bay Hydro’s proposed OM&A programs, each of the Parties argue that Thunder Bay Hydro’s proposed test year OM&A budget is too high. They each cite different reasons to support their respective positions. In general, the Parties’ submissions reasons rely heavily on theoretical models and assumptions. Each of the Parties argue the OEB should ignore the underlying evidence of actual cost pressures that are being faced by the management of Thunder Bay Hydro.

134. Specifically:

- a. OEB staff argue that the OEB should arbitrarily reduce the OM&A budget for the test year by an arbitrary five percent (5%) to \$15 million. OEB Staff argue that the OEB should do this to incent Thunder Bay Hydro to achieve greater efficiencies.⁶⁰
- b. VECC similarly argues that the test year OM&A budget should be reduced by an envelope amount to \$14.9 million.⁶¹ VECC also does not recommend any specific cut to any particular OM&A program be made.
- c. Finally, SEC argues that the test year OM&A budget should be reduced to \$14.5 million, on the basis of the Aiken model which in SEC’s contention “provides a strong empirical basis for establishing a reasonable OM&A level for the Applicant in 2017 on a top-down basis”.⁶² AMPCO supports SEC’s top-down analysis and proposed OM&A budget on this basis as well.⁶³

135. In making this submission, the Parties purposefully ignore:

⁵⁹ OEB Staff submissions at pg. 19

⁶⁰ OEB Staff submissions at pg. 20.

⁶¹ VECC submissions at para. 4.8 and 4.9.

⁶² SEC Submissions at para 3.4.1 to 3.4.3.

⁶³ AMPCO submissions at pg. 18.

- a. The detailed evidence in support of the proposed OM&A expenditures in the test year, the prudence of which is readily acknowledged by OEB Staff in their submissions at pg. 19.
 - b. The clear and credible evidence of cost savings totalling \$687,484 in annual savings that have already been achieved (see E5 below).
 - c. The fact that the OEB's 4GIRM already includes an embedded efficiency incentive (stretch factor) that will incent Thunder Bay Hydro to achieve even more efficiencies during the entire 4GIRM term.
 - d. And each of the Parties deliberately ignore Thunder Bay Hydro's historical ROE performance, which falls well below the OEB's 300 basis point deadband. This is clear, bottom line, outcomes based evidence that for Thunder Bay Hydro there is currently a fundamental mismatch between existing rates and the actual cost pressures being faced by this utility.
136. Since the OEB has adopted a price-cap form of rate regulation with its 4GIRM rate setting methodology, it is important during rebasing applications for the OEB to carefully consider the evidence of the real and underlying cost drivers being faced by utilities. One of the OEB's roles is to ensure that rates are rebased to appropriately reflect fundamental cost drivers faced by the utility in the test year. The OEB must do this to ensure the 4GIRM formula works appropriately in subsequent years without putting the financial viability of the utility at risk.
137. Each of the Parties recommend that the OEB ignore the detailed evidence of actual cost drivers, in favour of different formulas and models to calculate an envelope OM&A budget. The challenge with these different theoretical models and assumptions is that they are not rooted in evidence of real cost pressures being faced by Thunder Bay Hydro. As described in Part B above, these cost pressures have partly caused a significant reduction in Thunder Bay Hydro's actual ROE performance over the historical period.
138. The evidence on actual ROE performance is symptomatic of an underlying concern that has been raised by Thunder Bay Hydro throughout this application process:

- a. “In practice, [the IRM] adjustment does not keep up with various costs such as rising salaries and wages, new initiatives and regulatory compliance requirements.”⁶⁴
 - b. When asked to provide evidence to support this concern, Thunder Bay Hydro demonstrated that the formulaic IRM adjustment was significantly lower than the actual cost drivers in at least two key categories: its negotiated wage rate increases, and changes in the OEB's annual assessment costs.⁶⁵
 - c. And when pressed during the oral hearing, Mr. Mace further explained “It's my view that the IRM formula does not compensate for additional added cost pressures, for example monthly billing, customer engagement, ESA surveys.”⁶⁶
139. To be clear, Thunder Bay Hydro does not object to the OEB's IRM formula. It has and will continue to operate its business within the confines of the OEB's rate setting policies and regulations. Thunder Bay Hydro should not be prejudiced or punished for pointing out evidence of a fairly a simple, and factual truth for its business at this time.
140. In this context, Thunder Bay Hydro submits that the OEB should not dismiss its extensive and detailed evidence of actual underlying cost drivers in favour of a formulaic approach.
141. While a formula may have an appeal because it is simple, what happens if the results of the formulas are wrong? What if management's evidence on cost drivers is accurate? What if new responsibilities (monthly billing, customer engagement, ESA surveys, etc.), negotiated wage increases, and other cost drivers have actually caused costs to increase beyond what the formula predicts?
142. A formulaic approach will serve to perpetuate the existing mismatch between rates, on the one hand, and real costs, on the other. If the costs are truly unavoidable, this will start eventually to erode actual ROE performance.
143. This is why the OEB's 4GIRM formulaic approach includes an off-ramp if actual ROE performance falls outside a (+/-) 300 basis point dead band.

⁶⁴ Exhibit 1 at page 36

⁶⁵ 1-SEC-11

⁶⁶ Transcript Vol. 2, page 157, lines 25-27.

144. What would this mean in this case?

145. Thunder Bay Hydro's actual ROE performance is shown in its OEB scorecard, is summarized at Table 1 of its AIC, and is reproduced again below for ease of reference:

Table 1: Thunder Bay Hydro's Historical Return on Equity ("ROE") Performance

	2012	2013	2014	2015	2016
Max. ROE Allowed by OEB	9.12%	8.98%	9.36%	9.30%	9.19%
ROE included in Rates	3.75%	7.00%	7.00%	7.00%	7.00%
ROE Achieved	7.74%	6.34%	5.99%	5.69%	1.4%
Difference	(1.38%)	(2.64%)	(3.37%)	(3.61%)	(7.79%)

146. The evidence shows that Thunder Bay Hydro's achieved return on equity in 2016 was a mere **1.4%**, more than 700 basis points less than the OEB's maximum permitted ROE and more than 500 basis points less than the ROE that is currently included in rates. In fact, Thunder Bay Hydro's achieved ROE was more than 300 basis points less than the OEB's maximum permitted ROE in each of 2014, 2015 and 2016.

147. Thunder Bay Hydro submits that in cases where the historical evidence demonstrates that actual ROE performance of a utility is less than the OEB's 300 basis point dead band, the OEB should depart from formulas and allow for evidence of cost drivers that are prudently incurred even if they otherwise might exceed the formulaic amounts.

E.1 OM&A increases in the bridge and test year are supported by detailed explanations of exceptional cost drivers and incremental costs being proposed to address key business risks. All forecasted costs are both prudent and reasonable, and are fully supported on the evidentiary record.

148. When assessing the comparative bridge year or test year OM&A increases, as OEB Staff does at page 14 of their submissions and VECC at paragraph 4.3, the OEB must also consider Thunder Bay Hydro's explanations of the exceptional cost drivers experienced in

2016,⁶⁷ and how those and other new cost drivers apply in the 2016 bridge year and 2017 test year forecast.⁶⁸

149. These exceptional cost drivers include numerous increases driven by mandatory changes:
- a. In 2016 and 2017, the transition to monthly billing (representing a \$221,300 unanticipated and unavoidable increase in OM&A costs that will recur into future years).⁶⁹ Thunder Bay Hydro did not have a choice in this matter. The change, and consequential cost increase, was mandatory. Ratepayers also benefit from this change, with a reduction in working capital allowance. However, this trade-off is ignored with a simple formulaic approach to OM&A increases.
 - b. In 2016 and 2017, new cost of service and customer engagement costs (representing \$168,000 actual unanticipated increase in OM&A costs in 2016, and a total forecasted total of \$269,000 in OM&A costs over the 2016-2017 period).⁷⁰ These costs were incurred in direct response to the OEB's RRFE requirements and the OEB's Chapter 5 DSP requirements (neither of which existed when 2013 rates were set). These new regulatory requirements mandate, among other things, the preparation of a formal Distribution System Plan and the completion of enhanced customer engagement including evidence on customer needs and preferences.
 - VECC appears to have misunderstood this evidence at paragraph 4.8 of their submissions. The total unavoidable costs of \$269,000 (of which \$168,000 was incurred in 2016) associated with cost of service and customer engagement are amortized properly for rate setting purposes.⁷¹ However, because the bulk of these costs were actually incurred in 2016, with the balance to be incurred in 2017, this does also impact a comparative year-over-year analysis of costs.

⁶⁷ 1-Staff-11.

⁶⁸ Transcript Vol. 2, page 19, line 4 - page 23, line 14.

⁶⁹ 4-SEC-24.

⁷⁰ Transcript Vol. 2 pg. 19 at line 22. This is the actually incurred 2016 portion of the \$269,000 costs estimated in Exhibit 4, page 50, lines 15-20.

⁷¹ Exhibit 4, page 50, lines 15-20.

- c. In 2016, the introduction of smart meter sampling for reverification (representing a \$60,000 unavoidable increase in OM&A costs that will recur into future years).⁷² These are mandatory and unavoidable costs being incurred to ensure compliance with Measurement Canada's Statistical Method Specification (S-S-06).⁷³ The costs arise at this time because of the age of the smart meters, which were installed due to government mandate.
- VECC appears to have misunderstood this evidence at paragraph 4.8 of their submissions. The meter sampling costs are not "one-time costs". They are costs that first arose in 2016 due to the age of the smart meters, but the costs relate to annual sampling that Thunder Bay Hydro must perform to avoid the premature mandatory retirement of smart meters older than 10 years.
- d. In 2016, the introduction of an ESA public safety survey (representing a \$20,000 unavoidable increase in OM&A costs that will recur into future years).⁷⁴ This is mandatory cost which is a requirement of Section (d) of 2.1.19 of the OEB's Annual RRR Scorecard Filing.
- e. In 2017, a mandatory increase in the OEB cost assessment (representing a \$118,000 unanticipated and unavoidable one-time increase in OM&A costs that will recur into future years).⁷⁵ Thunder Bay Hydro did not have a choice in this matter. The change, and consequential cost increase, was mandatory.
150. These exceptional cost drivers are coupled with other reasonable explanations for the variances. For example, 2016 included costs for the acquisition of fire retardant clothing for staff which is done once every two years (representing a \$116,000 cost that was incurred in 2016 but that would not have been incurred in 2015).⁷⁶ Because of the two-year cycle for this program, it artificially impacts any year-over-year variance analysis.

⁷² Exhibit 4, page 7, lines 15-17.

⁷³ Exhibit 4, page 11, line 28 – page 12, line 5.

⁷⁴ Transcript Vol. 2, pg. 20 at lines 1-2.

⁷⁵ 4-VECC-27.

⁷⁶ Transcript Vol. 2, pg. 19, line 27 – pg. 20, line 1.

151. Finally, during evidence-in-chief Mr. Mace identified four additional incremental cost drivers that arise in direct response to a formalized business planning and risk management process. These costs are a combination of “mandatory” costs that are required by law (such as the increase in tree trimming budget to address the new “no topping” requirement imposed by the City), and “necessary” costs that are required to address fundamental risks to the business that have been identified by management and are unique to Thunder Bay Hydro and this application. These four cost drivers are:

a. First, succession planning in Thunder Bay Hydro’s system control room (resulting in an incremental OM&A cost of \$80,000). Thunder Bay Hydro explained the risks associated with the known planned retirements of two (2) of Thunder Bay Hydro’s seven (7) system control room operators in the next two years.⁷⁷ This represents a 28.57% loss in skilled workers in a department that is critical to 24x7 utility operations. Because skilled system control room operators are difficult to hire, particularly in northern communities like Thunder Bay, management has determined that this risk is best addressed through the hiring of an apprentice in 2016 (at an incremental OM&A cost of \$80,000).⁷⁸ Because the apprentice will be trained over the next 3-4 years before they are able to take over responsibilities as a system control room operator, Thunder Bay Hydro will be over compliment in this department over this period of time.

- Thunder Bay Hydro acknowledges that this will increase compensation costs in the near term. However, the new hire is an unavoidable consequence of known planned retirements in this department. There is no other way to address this succession planning issue.

b. Second, managing workload in the finance and regulatory departments (resulting in an incremental OM&A cost of \$106,000). An increasing number of regulatory requirements have coupled with new IFRS requirements to cause the regulatory and accounting workload at Thunder Bay Hydro to increase substantially since the 2013 rate application. Mr. Mace expressed genuine concern about the health and well

⁷⁷ Transcript Vol. 2, pg. 20, lines 17-25.

⁷⁸ Ibid. line 26 to pg. 21, line 3.

being of the staff in this department, who are working very long hours beyond all reasonable expectations to meet these new demands and requirements. This has, not surprisingly, resulted in significant turn-over in management staff in this department. Between 2013 and 2017, fully 114% of the management positions have turned-over in that department. This is not sustainable. Nor is it reasonable. In Q4 2016, Thunder Bay Hydro hired a new corporate financial analyst (at \$106,000 incremental OM&A cost in the test year) to reduce workload and burn-out.⁷⁹

- Thunder Bay Hydro acknowledges that this will increase total compensation costs in this department. However, it is unreasonable to expect staffing levels to remain flat when workload increases dramatically as a response to externally imposed regulatory and financial reporting requirements. Thunder Bay Hydro has tried its best to manage the existing workload with existing staffing levels, and the cost has been employee burn-out and very high levels of turn-over. There is no other way to address this workload issue.
- c. Third, the introduction of a proactive maintenance program to address porcelain insulators, glass cutouts and arrestors that have known defects that can cause catastrophic failures and power outages (a prudent \$100,000 one-time increase in OM&A costs that will recur into future years to begin gradually phasing-out this known faulty equipment over time).⁸⁰ This program makes particularly good sense in light of the now known defects in this type of equipment and the expert evidence of Mr. Tsimberg that planned replacements represent a much more efficient use of funds *“since planned replacement unit cost is always lower than forced replacement unit cost.”*⁸¹ Ratepayers get better value for money by addressing these known defects now with a modest proactive maintenance program, rather than waiting for this defective equipment to fail, cause outages, and having to dispatch a crew in emergency situation to replace the defective equipment, remediate

⁷⁹ Transcript Vol. 2, pg. 21 lines 4-23.

⁸⁰ Transcript Vol. 2, pg. 22, lines 3-18. See also Transcript Vol. 3, page 137, line 21 to page 139, line 7. See also 4-AMPCO-19.

⁸¹ Tsimberg Report at pg. 14 and ER-VECC-5.

collateral damage caused by the failure, and restore power - all at potentially overtime rates.

- d. Fourth, an increase in costs associated with tree trimming due in large part to a new City of Thunder Bay bylaw interpretation⁸² that prohibits the topping of trees on City property, causing unanticipated incremental costs, as well as to facilitate achieving an industry standard 7-year tree-trimming cycle.⁸³ The business case for the transition to the 7-year tree trimming cycle is provided in 4-VECC-38. These costs were initially estimated to be a \$150,000 increase in 2017 OM&A costs over 2016 budget, but due in part to increases costs associated with the City bylaw interpretation as well as unexpected real lot work, in reality this represents a modest increase of less than \$28,000 over 2016 actuals.⁸⁴ These expenditures are prudent in light of the importance of vegetation management in overall system reliability. This was confirmed by Mr. Tsimberg during questioning by OEB Staff *“In many utilities I work with, one of the major contributors to O&M program is actually vegetation management. It's very important to, as accurately as possible, identify what the appropriate cycle is. It's not only impact on reliability. It's also impact on the financial situation, because if you have one-off clearings, it's more expensive than when you have a specific program. So you don't want to come back for just one situation. But at the same time, vegetation management and outages due to vegetation management is also linked with condition of assets. [...]”*⁸⁵ Finally, if this increased expenditure is approved by the OEB, Thunder Bay Hydro is also willing to begin revising its data collections practices in a manner consistent with the monitoring measures proposed by Mr. Tsimberg.
152. In Thunder Bay Hydro’s submission, the evidentiary record provides a detailed and compelling rationale for the various cost drivers being faced by Thunder Bay Hydro and prudence of Thunder Bay Hydro’s response to those cost drivers in the test year.

⁸² 4-SEC-26.

⁸³ Transcript Vol. 2, pg. 22, line 24 – pg. 23, line 8.

⁸⁴ 4-AMPCO-20.

⁸⁵ Transcript Vol. 2, pg. 66, lines 4-15.

E.2 The OEB's total cost benchmarking tool fails in its calculation of predicted costs to account for various exceptional cost drivers that are explained on the evidence and are entirely outside of management's control. In addition, this is just one benchmark that must be considered together with other relevant benchmarks, and evidence of quantified cost control measures totalling \$687,484 in annual cost savings.

153. When assessing OEB's total cost benchmarking tool, as OEB Staff did for 2016 at page 14 of their submissions, the OEB must also consider the underlying evidence associated with Thunder Bay Hydro's cost increases which were described in detail in Section E.1 above.

154. This was further explained in direct connection with the total cost benchmarking model in 1-Staff-11, which explains that the transition to monthly billing, the increase in the OEB fee assessment, the unexpected faults in porcelain insulators necessitating a new proactive maintenance program, or the unexpected change in City requirements banning the topping of trees are all not factored into the OEB's total cost benchmarking model of predicted costs. If the model is adjusted to account for these exceptional costs – the benchmarking results improve to 8.1% or Group 3 performance.

155. In addition, this total cost benchmarking should also be considered in light of other relevant benchmarks, including the fact that in 2016 Thunder Bay Hydro still had the 4th lowest monthly bill of any distributor in the Province of Ontario as calculated using the OEB's web based bill calculator for a typical residential customer (AIC at para. 13 and Figure 1).

156. Finally, this total cost benchmarking should be considered in view of the clear and credible quantified evidence of cost control initiatives undertaken by Thunder Bay Hydro totaling \$687,484 in annual savings (AIC paras. 45-46, as corrected in E.5 below).

E.3 The "Aiken Model" was never introduced as evidence, the Applicant has had no opportunity to conduct meaningful discovery on it, and consequently it must be disregarded by the OEB. In addition, the Aiken model is premised on assumptions that have not been fully tested. Finally, the Aiken model does not account for any of the exceptional cost drivers that are outlined in evidence and explained more fully in E.1 above.

157. The "Aiken model" was presented by counsel to SEC as an aid to cross-examination. For this reason, it was not objected to by counsel to Thunder Bay Hydro. It would be reasonable for Parties to cite evidence elicited from Thunder Bay Hydro's witnesses from

questioning that referred to this aid-to-cross. Thunder Bay Hydro would have no objection to this approach to the evidentiary record.

158. However, rather than doing this, the “Aiken Model” itself has subsequently been improperly treated as evidence itself by certain Parties (notably SEC, AMPCO and OEB Staff) in their submissions. Thunder Bay Hydro has been given no opportunity to conduct any meaningful discovery on the “Aiken model”. We do not know who the author actually was. We do not know where the numbers in it came from. We do not understand all of the assumptions embedded in the model. And, most importantly, we do not know upon what evidence those assumptions are based. Consequently, we are unable to meaningfully challenge those assumptions or the model. This is a fundamental violation of the rules of natural justice, which severely impedes the ability of Thunder Bay Hydro to discharge the evidentiary burden that it holds with this application.
159. For these reasons, Thunder Bay Hydro submits that the OEB should give little to no weight to the “Aiken model” in its decision. This would be both fair and consistent with the OEB’s determination with respect to the original Tsimberg letter – which was filed a full two weeks (rather than a few days) in advance of the oral hearing. To address the Tsimberg letter, the OEB adjourned the hearing to give the parties additional time to consider and conduct discovery on the Tsimberg evidence. However, Thunder Bay Hydro has been given no opportunity to conduct any meaningful discovery on the “Aiken model.”
160. Should be OEB choose to refer to the “Aiken model”, which Thunder Bay Hydro submits the OEB should not, what is immediately obvious is that the Aiken model assumes OM&A costs increases that are significantly lower than industry average wage increases for unionized employees at LDCs across Ontario. We know this because all collective agreements in the Province of Ontario are entered into the public domain once ratified.⁸⁶ Using this information source, any person can readily compile and compare wage increase information. Thunder Bay Hydro previously compared all available wage increase information to determine that:

⁸⁶ http://www.sdc.gov.on.ca/sites/mol/drs/ca/Pages/default_en.aspx

- a. across 58 Ontario LDCs in 2013, the industry average wage increase was 2.74% (data was unavailable for 3 of the 61 LDCs considered).
 - b. across 60 Ontario LDCs in 2014, the industry average wage increase was 2.54% (data was unavailable for 1 of the 61 LDCs considered). By contrast, the Aiken Model predicts an escalator of 1.65% (0.89% less than the average).
 - c. across 57 Ontario LDCs in 2015, the industry average wage increase was 2.35% (data was unavailable for 4 of the 61 LDCs considered). By contrast, the Aiken Model predicts an escalator of 1.47% (0.88% less).
 - d. across 45 Ontario LDCs in 2016, the industry average wage increase was 2.27% (data was unavailable for 16 of the 61 LDCs considered).⁸⁷ By contrast, the Aiken Model predicts an escalator of 1.92% (0.35% less).
 - e. Across 24 Ontario LDCs in 2017, the industry average wage increase was 2.30% (data was unavailable for 37 of the 61 LDCs considered).⁸⁸ By contrast, the Aiken Model predicts an escalator of 1.95% (0.35% less).
161. Thunder Bay Hydro never had the opportunity to put this disparity to a witness on cross-examination because the “Aiken model” was never properly introduced as evidence, and Thunder Bay Hydro was given no right to conduct discovery or cross examination.
162. For Thunder Bay Hydro, total wages and salaries are equal to 47.58% of the test year OM&A expenditures. While Thunder Bay Hydro’s negotiated wage increases (2.0% in 2013, 2.25% in 2014, 1.5% in 2015, 2.0% in 2016 and 2.0% in 2017)⁸⁹ were in each year below industry average, Thunder Bay Hydro has never once been successful in negotiating wage increases that match the impossibly low escalator assumed in the Aiken model for OM&A expenses.
163. Finally, the Aiken model does not account for any of the exceptional cost drivers outlined in Section E.1 above, including the transition to monthly billing, the increase in the OEB

⁸⁷ Data availability diminishes in 2016 and further in 2017 as collective agreements covering these years have not yet been negotiated or have not yet been filed.

⁸⁸ Data availability diminishes in 2016 and further in 2017 as collective agreements covering these years have not yet been negotiated or have not yet been filed.

⁸⁹ Exhibit 4, page 37 and 4-Staff-51.

fee assessment, the unexpected faults in porcelain insulators necessitating a new proactive maintenance program, or the unexpected change in City requirements banning the topping of trees, the introduction of customer engagement and new distribution system planning costs, new smart meter sampling costs, among others.

E.4 The difference between 2013 actual OM&A vs. 2013 OEB approved is fully explained on the evidence, and is a consequence of a combination of changes in accounting practices, two unforeseeable cost reductions, and prudent utility management reducing costs to remain within reduced revenues.

164. Several Parties raised concerns with the difference between Thunder Bay Hydro's actual 2013 OM&A budget, when compared against the forecasted OM&A budget for 2013 that was used by the OEB to set rates in EB-2012-0167.⁹⁰
165. Some of these Parties go on to argue that the OEB should infer from this that Thunder Bay Hydro has over the historical period recovered in rates OM&A amounts that were greatly in excess of its previous board approved OM&A budget. For example, SEC argues "*the current OM&A may also be a high-balled figure [...] and ratepayers could once again be paying for phantom OM&A costs.*"⁹¹
166. Nothing could be further from the truth. If Thunder Bay Hydro actually over collected OM&A expenses in rates, as is being suggested by some of the Parties, then this over earning would show up in the actual ROE performance on the OEB's scorecard. However, as was shown in paragraph 15 and Table 1 of AIC, Thunder Bay Hydro has historically earned less (not more) than the ROE that was included in rates. Thunder Bay Hydro has never once earned more than the ROE that was included in rates. The evidence is the opposite. Each of the Parties ignored this outcomes based evidence and the logical implication of it on their arguments.
167. It is a fundamental tenant of a price cap rate setting methodology that once the OEB establishes just and reasonable rates, then regardless of how those rates are set (whether by custom IR, cost of service, or by IRM formula) it becomes the responsibility of the utility to manage its business within the confines of those established rates. If the OEB approved

⁹⁰ OEB Staff submissions at pg. 15, VECC submissions at para 4.4, SEC submissions at para 3.2.1.

⁹¹ SEC submissions at para 3.2.5.

rates do not result in the expected revenues, management must have the discretion to curtail spending below what was previously forecast.

168. So what happened in 2013?
169. First, revenue from rates came in much less than was forecasted in 2013 in the OEB decision. The total revenue shortfall is between 2013 actuals and 2013 OEB approved is shown in Exhibit 3 at Table 3-28. In 2013, Thunder Bay Hydro recovered \$981,979 less revenue than anticipated in 2013 OEB approved.⁹²
170. You can't spend what you don't have. It is unreasonable to expect management to spend to a forecasted 2013 OM&A budget when management knows that they will never actually recover that level of spending in rates. The rationale implied by many of the Parties, that 2013 spending should match Board approved budget at all costs, is a ready way to bankrupt a utility that is otherwise prudently managing its business in the face of declining revenues.
171. Why did revenues come in short? This occurred in part because the load and demand were less than forecast and were less than Board approved. This reduction was entirely outside of management's control.
172. Revenues also came in short because of an anomaly that happens with every cost of service year that has a May 1st effective date for new rates. Specifically, pursuant to the Chapter 2 filing requirements a utility is required to forecast a OM&A budget over the entire test year, and based on that to derive a rate that will recover those costs over the entire test year. But in reality, new rates are generally not implemented until May 1st – after 1/3 of the year has already passed. Because of this, revenues will automatically be short of what is assumed in the OEB decision by an amount equal to 1/3 of the approved revenue deficiency. This is exactly what occurred in EB-2012-0167. Again, this revenue shortfall is entirely outside of management's control. All management can do is reduce costs to deal with this shortfall.

⁹² Exhibit 3, Page 24, Line 8 to page 25, line 15.

173. Second, the evidence identifies two specific accounting changes that must be accounted for when comparing 2013 OEB approved to 2013 actuals to ensure an “apples to apples” comparison is completed. These include:

a. The 2013 OM&A cost forecast that was used in the EB-2012-0167 application included \$174,930 (\$104,930 + \$70,000)⁹³ in *gross* costs incurred in relation to Thunder Bay Hydro’s affiliates. Those costs were later offset by a revenue offset, and ratepayers were held harmless. Following the OEB decision in EB-2012-0167, Thunder Bay Hydro changed its accounting practices associated with affiliate costs. This new accounting practice has been used consistently for the entire period of 2013-2017. Thunder Bay Hydro now records only the *net* affiliate costs in OEB account 4220. As a result, to accurately compare the OEB approved 2013 OM&A costs against 2013 actuals, it is necessary to reduce the OEB approved costs by \$174,930 to reflect this change in accounting practices. Once this change in valuations is accounted for, the true difference between 2013 OEB approved and 2013 actuals is \$892,186.⁹⁴

- Specifically, and in direct response to OEB Staff’s request,⁹⁵ the \$1,067,116 difference cited by OEB Staff less \$174,930 results in an actual difference of \$892,186.

b. The 2013 OM&A cost forecast used in the EB-2012-0167 application included an over-allocation of maintenance and supervisory costs to OM&A of \$182,000. These costs should have properly been allocated to capital, not OM&A. When Thunder Bay Hydro discovered the error, it corrected its allocation methodology in 2013 and into the future. As a result, to accurately compare the OEB approved 2013 OM&A costs against 2013 actuals, it is necessary to reduce the OEB approved costs by \$182,000 to reflect this change in allocation of maintenance and supervisory costs from OM&A to capital practices.⁹⁶ Once this change in the

⁹³ Exhibit 4, page 15, line 9. 4.0-SEC-25. Transcript V3, page 87, line 24.

⁹⁴ Transcript Vol. 3 pg. 87 lines 21 to pg. 88, line 3. See also Exhibit 4, page 15, line 9.

⁹⁵ OEB Staff submissions at pg. 15.

⁹⁶ Transcript Vol 3. at pg. 92, line 22 to pg. 93, line 11.

allocation of costs between OM&A and capital is accounted for the actual difference is \$710,186 (that is \$892,186 less \$182,000).

174. Third, the evidence identifies two specific cost reductions that were entirely unforeseeable and entirely outside of management's control which also must be accounted for when comparing 2013 OEB approved to 2013 actuals.

- a. The 2013 OM&A budget included a forecast for future employee benefits that was completed based on the best available information at the time the budgets were prepared. Subsequent to the OEB decision in EB-2012-0167, on January 1, 2014, Thunder Bay Hydro obtained a new actuarial valuation that indicated a substantial actuarial gain and, consequently, a substantial reduction in actual 2013 future employee benefit costs.⁹⁷ The aggregate value of the reduction in future employee benefit costs in 2013 was approximately \$270,000 – however only \$190,000 of that reduction is attributable to OM&A (the balance is attributable to capital). It is unreasonable to expect that management could have somehow foreseen a change that arose due to a third party actuarial valuation that was not completed until January 1, 2014. This change accounts for \$190,000 of the difference between 2013 OEB approved and 2013 actuals.⁹⁸ Accounting for this unforeseeable change results in a now unexplained differential of \$520,186 (\$710,186 less \$190,000).
- b. The 2013 OM&A budget forecast included an amount for operations and maintenance costs associated with unexpected trouble calls, including those arising due to bad weather. This forecast was prepared based on the best information available at the time, which included information on historical trends in these costs. The evidence is, however, that Thunder Bay Hydro experienced an unusually good weather year in 2013. As a result, the budget forecast for trouble calls (which were prepared based on historical average spending) which impact three specific line items in Exhibit 4, page 21, Table 4-9 (Maintenance Supervisory, Overhead/Underground Maintenance; and Administrative and Human Resources) were collectively \$350,000 higher than 2013 actuals due in part to the exceptionally

⁹⁷ Exhibit 4, page 14, line 14 to page 15, line 2.

⁹⁸ Transcript Vol. 3 pg. 87 lines 21 to pg. 89, line 22 to page 90, line 6. See also 9-SEC-34.

good weather experienced by Thunder Bay Hydro in 2013 and to significantly fewer than expected trouble calls. This cost shortfall was entirely outside of managements' control. Exceptionally good weather led to significantly fewer trouble calls in 2013, which in-turn meant that supervisory, contractor, and overtime costs that were reasonably forecast had it been a normal weather year never actually materialized.⁹⁹ Accounting for this unforeseeable change results in a now unexplained differential of \$170,186 (\$520,186 less \$350,000).

- Evidence of this exceptionally good weather can be seen in Thunder Bay Hydro's SAIDI (1.03) and SAIFI (2.02) statistics for 2013.¹⁰⁰ As Thunder Bay Hydro's 2015 OEB scorecard demonstrates, Thunder Bay Hydro has never before, nor has it ever after, achieved these low SAIDI and SAIFI outcomes. 2013 was truly an exceptionally good weather year for Thunder Bay Hydro.¹⁰¹

175. The balance of the difference between the 2013 OEB approved OM&A budget and 2013 OM&A actuals of \$170,186 arises in large part because management of Thunder Bay Hydro had to actively manage and reduce actual costs to ensure that they remained within the confines of actual revenues derived from rates, which (as discussed above) came in lower than forecasted. This is exactly what prudent utility management is expected to do under a price-cap method of regulation.
176. Thunder Bay Hydro submits that the OEB should not now penalize Thunder Bay Hydro for reducing its OM&A spending to match revenues. Doing so would create an unusual and perverse incentive for management to spend OM&A beyond their means in the future. This is certainly not in the public interest.
177. Finally, it is worth comparing the differential of \$170,186 with Thunder Bay Hydro's materiality threshold of \$119,980 (Exhibit 1, page 66, Table 1-31). A variance of up-to \$119,980 would be considered non-material for a utility the size of Thunder Bay Hydro. The differential we are considering here exceeds that threshold by a mere \$50,000.

⁹⁹ Transcript Vol. 3 pg. 91, line 1 to pg. 92, line 21. See also Exhibit 4, pg. 15, lines 4-8. .

¹⁰⁰ Exhibit 1, page 27, Table 1-5.

¹⁰¹ See also 2-Staff-23, 2-Staff-34.

E.5 *Thunder Bay Hydro's rate minimization philosophy has driven a culture of prudent cost management, resulting in quantifiable annual OM&A savings of \$687,484 in the test year alone. These quantifiable savings are a representative sample only. Numerous other cost savings exist but were too difficult to quantify in a meaningful way on the evidentiary record.*

178. Thunder Bay Hydro has demonstrated its focus on cost controls and rate minimization in the evidence, with a representative sample of quantifiable cost control initiatives totalling \$1,079,484 savings for ratepayers (AIC paras 45-46).
179. The AIC breaks down every component of these cost savings with detailed pinpoint citations to the evidentiary record where the evidence supporting the savings can be found.
180. **Correction:** Thunder Bay Hydro has identified one error in the calculation of its savings projection in its AIC. Specifically, and as discussed in further detail below, it has come to the attention of Thunder Bay Hydro that the approximately \$570,000 in OM&A cost savings arising due negotiated wage increases less than industry average was a cumulative savings which occurred between 2013-2017. The actual OM&A savings which occur in the 2017 test year, and which will recur annually into the future is \$172,400. Adjusting the \$1,079,484 by reducing it by the value of this cumulative savings of \$570,000, and then increasing it by \$178,000 in annual savings, results in actual annual OM&A savings of \$687,484.
181. The \$687,484 savings are annual savings. Ratepayers benefit from these savings in the test year, and in every subsequent year in perpetuity. In addition, these savings are only a representative sample. They are in addition to numerous other cost savings efforts that occurred, but were too difficult to quantify in a meaningful way on the evidentiary record.
182. OEB Staff identify in their submissions the "absence of supporting calculations and explanations" to support the evidence of approximately \$570,000 in OM&A cost savings identified by Mr. Wilson in evidence associated with negotiating collective agreement wage increases that were lower than the industry average.¹⁰² For this reason, OEB Staff argue that the OEB should place little weight on this number.

¹⁰² OEB Staff submissions at pg. 17.

183. Thunder Bay Hydro submits that the OEB Staff's proposal in this regard is unreasonable for three reasons.
184. First, the approximately \$570,000 in cost savings arises because of Thunder Bay Hydro management taking active steps to control its single largest cost driver: wages and salaries, which collectively are equal to 47.58% of OM&A costs in the test year. It is impossible for Thunder Bay Hydro to evidence its cost savings initiatives without reference to what it is doing to control its single largest cost driver. This is what OEB Staff recommends the OEB panel should do. This is not in the public interest.
185. Second, if OEB Staff believed that additional evidence on this topic would have been helpful, OEB Staff had every opportunity to conduct discovery on this point. The evidence is not new. The original Application states that "*Awarded wage increases that were below industry average for the years 2013 (2.0%), 2014 (2.25%), 2015 (1.5%).*"¹⁰³ Any party could have asked questions about this benchmark during the discovery process. They did not. Mr. Wilson then quantified this benchmark at approximately \$570,000¹⁰⁴ in savings during examination in-chief on June 29th. All of the Parties had two full days to ask questions on this topic. At no time during the next two days did OEB Staff or any other Party ask a question about this number.
186. Third, had any Party bothered to ask, Thunder Bay Hydro could have easily explained its calculation methodology. This is because Thunder Bay Hydro's negotiated wage increases are already on the evidentiary record (2.0% in 2013, 2.25% in 2014, 1.5% in 2015, 2.0% in 2016, and 2.0% in 2017).¹⁰⁵ In addition, all collective agreements in the Province of Ontario are entered into the public domain once ratified.¹⁰⁶ There is no need to file this material on the evidentiary record in this case – it is readily available to any Party who chooses to look it up. On this basis, Thunder Bay Hydro conducted internal benchmarking and determined that:

¹⁰³ Exhibit 4, page 37.

¹⁰⁴ Transcript Vol. 2 pg. 14, lines 1-15.

¹⁰⁵ Exhibit 4, page 37 and 4-Staff-51.

¹⁰⁶ http://www.sdc.gov.on.ca/sites/mol/drs/ca/Pages/default_en.aspx

- a. across 58 Ontario LDCs in 2013, the industry average wage increase was 2.74% (data was unavailable for 3 of the 61 LDCs considered). Thunder Bay Hydro's negotiated wage increase was 2.0% by comparison.
 - b. across 60 Ontario LDCs in 2014, the industry average wage increase was 2.54% (data was unavailable for 1 of the 61 LDCs considered). Thunder Bay Hydro's negotiated wage increase was 2.25% by comparison.
 - c. across 57 Ontario LDCs in 2015, the industry average wage increase was 2.35% (data was unavailable for 4 of the 61 LDCs considered). Thunder Bay Hydro's negotiated wage increase was 1.5% by comparison.
 - d. across 45 Ontario LDCs in 2016, the industry average wage increase was 2.27% (data was unavailable for 16 of the 61 LDCs considered).¹⁰⁷ Thunder Bay Hydro's negotiated wage increase was 2.0% by comparison.
 - e. across 24 Ontario LDCs in 2017, the industry average wage increase was 2.30% (data was unavailable for 37 of the 61 LDCs considered).¹⁰⁸ Thunder Bay Hydro's negotiated wage increase was 2.0% by comparison.
187. This information formed the basis of the evidence found at Exhibit 4, page 37 that *"Awarded wage increases that were below industry average for the years 2013 (2.0%), 2014 (2.25%), 2015 (1.5%)."* This trend continued once Thunder Bay Hydro knew its final collective agreement increases for 2016 (2.0%) and 2017 (2.0%).¹⁰⁹
188. All Mr. Wilson did to calculate the approximately \$570,000 in savings is take Thunder Bay Hydro's 2012 actual labour expenses attributable to OM&A (\$6,750,000.00) and inflate this number by (1) the industry average wage increase for each year, and (2) Thunder Bay Hydro's negotiated wage increase for that same year; and then (3) compare the difference between (1) and (2). This is shown in the Table below as \$581,000. Mr. Wilson was

¹⁰⁷ Data availability diminishes in 2016 and further in 2017 as collective agreements covering these years have not yet been negotiated or have not yet been filed.

¹⁰⁸ Data availability diminishes in 2016 and further in 2017 as collective agreements covering these years have not yet been negotiated or have not yet been filed.

¹⁰⁹ 4-Staff-51.

conservative in his evidence-in-chief and rounded this down to an approximate savings of \$570,000 over the 2013-2017 period, and savings of \$178,000 in 2017.

Table: Comparison of industry average wage increases to TBH wage increases

Starting Point (2012 OM&A - labour only)	\$6,750,000	2013	2014	2015	2016	2017
Industry Average Wage Increase (%)		2.74	2.54	2.35	2.27	2.30
Adjusted Labour costs (Industry Average)	\$6,750,000	\$6,934,000	\$7,110,000	\$7,277,000	\$7,442,000	\$7,613,000
TBH Wage Increase (%)		2.00	2.25	1.50	2.00	2.00
Adjusted Labour Costs (TBH)	\$6,750,000	\$6,885,000	\$7,040,000	\$7,146,000	\$7,289,000	\$7,435,000
Differential		\$49,000	\$70,000	\$131,000	\$153,000	\$178,000
Cumulative Differential (2013-2017)						\$581,000

189. With this additional information, which was readily available had it been asked during the discovery phase of this proceeding, the OEB now has a complete understanding of the derivation of this cost saving number.

F. CONCLUSIONS

190. For all of the foregoing reasons, Thunder Bay Hydro submits that the Board should make an order for just and reasonable rates in the test year approving the Applicant's proposed cost of capital, OM&A and capital budgets as proposed.

All of which is respectfully submitted this 28th day of July, 2017.

Original signed by Shane Freitag per John A.D. Vellone

John A.D. Vellone

Counsel to the Applicant

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