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BY E-MAIL

September 27, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: OEB Staff Submission

Application by Thunder Bay Hydro Electricity Distribution Inc. and Kenora Hydro Electric Corporation Ltd. under sections 18, 60, 77(5) and 86(1) of the Ontario Energy Board Act, 1998, and other related relief

Ontario Energy Board File Number: EB-2018-0124 and EB-2018-0233

In accordance with the OEB's directions, please find attached OEB staff's submission with respect to the above referenced application.

Yours truly,

Original Signed by

Andrew Bishop

Project Advisor
Applications Division

ONTARIO ENERGY BOARD

OEB Staff Submission

EB-2018-0124/EB-2018-0233

September 27, 2018

1 INTRODUCTION & SUMMARY

Thunder Bay Hydro Electricity Distribution Inc. (Thunder Bay) and Kenora Hydro Electric Corporation Ltd. (Kenora) (collectively, the Applicants) filed an application on April 12, 2018 under Sections 18, 60, 77, and 86 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the Act), for approval to amalgamate and continue operations as a single electricity distribution company. To enable the proposed amalgamation, Thunder Bay and Kenora requested the following Ontario Energy Board (OEB) approvals[1]:

- Leave for Thunder Bay and Kenora to amalgamate and continue as one corporation under a name to be determined by the Applicants (referred to herein as LDC Mergeco) pursuant to Section 86(1)(c) of the Act.
- Leave for Thunder Bay and Kenora to transfer their distribution licences and rate orders to LDC Mergeco pursuant to Section 18 of the Act.
- The issuance of a new electricity distribution licence for LDC Mergeco that will come into existence on the completion of the transfer of the distribution-related assets of the Applicants to LDC Mergeco pursuant to Section 60 of the Act.
- The cancellation of the distribution licences of the Applicants immediately following the issuance of LDC Mergeco's new Electricity Distribution Licence pursuant to Section 77(5) of the Act.

The April 12, 2018 application indicated that LDC Mergeco's distribution licence application was being filed separately from the amalgamation application.[2] On July 20, 2018, the Applicants filed their licence application (EB-2018-0233).

Through Procedural Order No. 2, the OEB ordered that the amalgamation application (EB-2018-0124) and distribution licence application (EB-2018-0233) be combined and adjudicated concurrently.

To enable the amalgamation, on March 9, 2018, the Applicants signed a Merger Participation Agreement consistent with Section 174 of the Business Corporations Act.[3] Among other matters, the agreement provides that each party will receive the following interest in the newly formed LDC Mergeco:

1. The City of Kenora, sole owner of Kenora Hydro, will receive 9,100 common shares; and

[1] Application, pp 25, 26
[2] Application, p. 26
[3] Application, p. 24

2. Thunder Bay Hydro Corporation, sole owner of Thunder Bay Hydro, will receive 90,900 common shares.

The above share distribution is based on utility valuations completed by KPMG LLP. These valuations, demonstrated in a report dated January 24, 2018, are referred to in the Merger Participation Agreement as “Initial Valuations”. The ultimate share distribution will be determined following KPMG LLP’s determination of each utility’s “Final Valuation”. As defined in the Merger Participation Agreement, the “Final Valuation” is to be based on each utility’s audited financial statements prepared as at the end of business on the day immediately prior to the transaction’s closing date.[4]

[4] Application, pp 39-44

2 RELEVANT REGULATORY PRINCIPLES

2.1 The "No Harm" Test

The OEB applies the "no harm" test when assessing applications that seek approval for regulated entities to consolidate. The "no harm" test was first established by the OEB in 2005 through its decision in an adjudicative proceeding (the Combined Proceeding),[5] and has been used to guide OEB decision making on MAADs applications since then.

The *Handbook to Electricity Distributor and Transmitter Consolidations* (the Handbook), issued by the OEB on January 19, 2016, confirmed that the OEB will continue its practice of applying the "no harm" test when adjudicating utility consolidation requests. The OEB considers whether the "no harm" test is satisfied based on an assessment of the cumulative effect of the transaction on the attainment of its statutory objectives. Those objectives include[6]:

> **Board objectives, electricity**
> 1 (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
>
> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
>
>   1.1 To promote the education of consumers.
>
> 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
>
> 3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
>
> 4. To facilitate the implementation of a smart grid in Ontario.
>
> 5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission

[5] RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257
[6] *Ontario Energy Board Act, 1998,* Section 1

> systems and distribution systems to accommodate the connection of renewable energy generation facilities. 2004, c. 23, Sched. B, s. 1; 2009, c. 12, Sched. D, s. 1; 2015, c. 29, s. 7.

If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the consolidation.[7]

2.2 OEB Policy on Rate-Making Associated with Consolidations

To encourage electricity distributor consolidations, the OEB introduced policies that provide consolidating distributors with an opportunity to offset merger-related transaction costs with any achieved savings through deferral of the rebasing of the consolidated entity.

The OEB's policies on rate-making associated with consolidations are set out in the *Report of the Board – Rate-making Associated with Distributor Consolidation*, issued July 23, 2007 (the 2007 Report) and a further report issued under the same name on March 26, 2015 (the 2015 Report). The 2007 Report permits a deferred rebasing period of five years. The 2015 Report extended the deferred rebasing period, permitting consolidating distributors to defer rebasing for up to ten years from the closing of the transaction.

Consolidating distributors are required to select a definitive timeframe for the deferred rebasing period. The OEB's expectation is that when consolidating distributors select a deferred rebasing period, they have committed to a plan based on the circumstances of the consolidation and that if an amendment to the selected deferred rebasing period is requested, the OEB will need to understand whether any change to the proposed rebasing timeframe is in the best interests of customers.

The OEB requires consolidating entities that propose to defer rebasing beyond five years to implement an earnings sharing mechanism (ESM) for the period beyond five years to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period. In this case, the Applicants have proposed a five-year rebasing deferral period and will therefore not be required to establish an ESM.[8]

[7] Handbook, pp. 3-4
[8] Application, p. 46

3 OEB STAFF SUBMISSIONS

In its review of the application, OEB staff has considered the requirements described in the Handbook and other applicable OEB policy as described herein.

3.1 Application Performance against the "No Harm" Test

The Handbook provides guidance to applicants and stakeholders on how the OEB reviews consolidation transactions proposed under Section 86 of the Act. As noted above in Section 2.1, the Handbook confirms that the OEB applies the "no harm" test in its assessment of Section 86 applications. If the proposed transaction has a positive or neutral effect on the attainment of the OEB's statutory objectives, the OEB will approve the application. While the OEB has broad statutory objectives, in applying the "no harm" test the OEB has primarily focused its review on the impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and the financial viability of the consolidating utilities.

Submission
OEB staff submits that the amalgamation proposed by the Applicants meets the "no harm" test as described in the Handbook.

3.2 Impact on Price, Economic Efficiency and Cost Effectiveness

The Applicants state that "LDC Mergeco expects to provide distribution rates upon the next rebasing (subsequent to the proposed five year deferral) that will be lower than they would have been, had the Parties remained as status quo independent LDC's."[9] Further, the Applicants state that these financial benefits will occur in both the near- and longer-term. As identified by the Applicants, the primary drivers of these benefits are the administrative and operational synergies resulting from the proposed amalgamation.

The Applicants selected a five-year rate rebasing deferral period from the closing of the proposed transactions, consistent with the 2015 Report and the Handbook. During this time, the Applicants indicate that the pre-existing rate plans for Thunder Bay[10] and Kenora[11], both effective May 1, 2018, will remain in effect until their expiry. The Applicants also state that Thunder Bay and Kenora will continue to have rates adjusted using the Price Cap Incentive Rate Mechanism (Price Cap IR) and Annual Incentive Rate Index, respectively, until the end of the five-year rebasing deferral period.

[9] Application, p. 27
[10] Thunder Bay's May 1, 2018 rates, set in accordance with the Annual Incentive Rate Index (IR) option, were approved by the OEB through EB-2017-0075.
[11] Kenora's May 1, 2018 rates, set in accordance with the Annual Incentive Rate Index (IR) option, were approved by the OEB through EB-2017-0054.

The Applicants submit that in absence of the amalgamation, Thunder Bay would file a cost-of-service application in 2022. The Applicant's state that historically, the adjustment of rates following a rebasing period is greater than under Price Cap IR.[12] Thus, the Applicants contend that Thunder Bay customers will benefit from the two-year extension using a Price Cap IR methodology to set rates resulting from the five-year rebasing deferral period. Consistent with current practice, Kenora customers will have rates set in accordance with the Annual Incentive Rate Index during the rebasing deferral period.[13] Therefore, Kenora customers will not experience merger-related rate impacts during the first five years following amalgamation.

The Applicants' evidence states that the amalgamation will financially benefit ratepayers by reducing, among other items, $3.8 million in operating, maintenance and administrative (OM&A) costs during the five-year rebasing period.[14] The Applicants also state that these savings will result in a lower cost structure for the amalgamated entity at the time of the first rebasing relative to the status quo and that these savings – approximately $900,000 per year – will continue in perpetuity following amalgamation.[15] The application specifies that these cost savings would not be possible without the proposed amalgamation.[16]

Table 1, extracted from page 30 of the application, illustrates the financial impact of the amalgamation on the combined cost structures of each utility. The Applicants show that the 2023 OM&A of the merged entity is forecast to be approximately $18.6 million. Absent the merger, the combined OM&A of both utilities is forecast to total approximately $19.5 million in 2023. The Applicants state that the savings, approximately $1 million, or 5% of the projected 2023 combined OM&A, represents the economic efficiencies enabled by the amalgamation from the status quo.

[12] Application, p. 27
[13] Kenora's last cost-of-service was filed in 2010 for 2011 rates.
[14] Application, p. 37
[15] Applicant IR Response. OEB Staff IR #12
[16] Application, p. 27

Table 1: Year-over-Year Comparative Cost Structure Analysis

	2018	2019	2020	2021	2022	2023
OM&A	**Year 0 ($)**	**Year 1 ($)**	**Year 2 ($)**	**Year 3 ($)**	**Year 4 ($)**	**Year 5 ($)**
Thunder Bay Hydro	15,989,680	16,245,515	16,505,443	16,769,530	17,037,843	17,310,448
Kenora Hydro	2,099,360	2,126,652	2,154,298	2,182,304	2,210,674	2,239,413
Consolidated OM&A Status Quo	18,089,040	18,372,167	18,659,741	18,951,834	19,248,517	19,549,861
OM&A Synergies	(800,000)	(260,220)	864,551	877,816	889,227	900,787
Post Consolidation	18,889,040	18,632,387	17,795,191	18,074,019	18,359,289	18,649,074

Given the geographic separation between Thunder Bay and Kenora, the Applicants anticipate negligible capital savings to result from the merger. Capital savings were therefore not a driver in the Applicants' decision to amalgamate.[17]

Submission

As part of its review of consolidation proposals, the OEB examines the underlying cost structures of the consolidating utilities. As distribution rates are based on a distributor's current and projected costs, the OEB has stated that it is important for the OEB to consider the impact of a transaction on the cost structure of consolidating entities both now and in the future, particularly if there appear to be significant differences in the size or demographics of consolidating distributors.[18]

The Applicants' evidence states that the synergies brought on by the amalgamation are expected to result in lower cost structures over the long term:

> "In total LDC Mergeco anticipates delivering approximately $3.8 M in synergies over the proposed five years following the amalgamation. ***This will result in a lower cost structure of the amalgamated utility at the time of the next rebasing relative to the status quo*** [emphasis added].[19]"

Further, in response to OEB staff interrogatory No. 12, which requested that the Applicants identify how long post-amalgamation cost savings would endure, the Applicants' stated "Anticipated synergistic cost savings are recognized permanently following amalgamation. Cost savings will continue in perpetuity." As demonstrated in Table 10 of the application, post-amalgamation, the Applicants project an annual cost savings of approximately

[17] Applicant IR Response. OEB Staff IR #16
[18] Handbook, p. 6
[19] Application, p. 38

$900,000. Based on this information as well as the Applicants' response to OEB staff interrogatory No. 12, it is understood that this level of savings will continue in perpetuity following the deferred rebasing period.

OEB staff accept the Applicants' claim that the amalgamation will offset the need for sizable OM&A expenditures that will, in turn, benefit customers through reduced cost structures. The value of these savings, approximately $3.8 million during the five-year deferral period, is expected to more than offset the Applicants' amalgamation transaction and transition cost forecast of $1.4 million. Based on the evidence on the record, OEB staff is satisfied that the amalgamation will not result in the customers of Thunder Bay or Kenora experiencing negative price implications in the near-term.

OEB staff anticipates that in their first cost-of-service application following the selected five-year rebasing deferral period, the Applicants will demonstrate the savings and efficiencies that have resulted from the amalgamation.

This anticipated area of inquiry is consistent with the provisions of the OEB's October 13, 2016 *Handbook for Utility Rate Applications* (the Rate Handbook), which states, in part:

> "***In the first cost of service or Custom IR application following the consolidation the OEB will scrutinize specific rate-setting aspects of the MAADs transaction*** [emphasis added], including a rate harmonization plan and/or customer rate classifications post consolidation.
>
> This will include consideration of:
>
> - The treatment of any premium above book value paid as part of a consolidation (no premium is to be recovered from customers).
> - ***The savings that have been generated through the consolidation*** [*emphasis added*].
> - Whether there were any inducements or incentives beyond the purchase price to encourage a shareholder to agree to the consolidation and if so whether there is any intent to recover the costs of those inducements or incentives from customers. Any costs incurred will be reviewed to ensure that the costs incurred are delivering the best value to customers.
> - Whether the rate harmonization plan includes a detailed explanation and justification for the implementation plan, and an impact analysis. For acquisitions, distributors can propose plans that place acquired customers into an existing rate class or into a new rate class. ***Regardless of the option adopted, the OEB will assess whether the proposed harmonized rates will reflect the cost to serve the acquired customers, including the***

anticipated productivity gains resulting from consolidation [emphasis added].[20]"

The Applicants have indicated their intent to provide this information in the future through their response to OEB staff interrogatory No. 12 where the Applicants stated "LDC Mergeco will document actual realized cost savings as the efficiencies forecast come to fruition."

3.3 Impact on Service Quality and Reliability

The Handbook requires consolidating utilities to indicate the impact that the proposed transaction will have on consumers with respect to reliability and quality of electricity service. The Handbook also provides that in considering the impact of a proposed transaction on the quality and reliability of electricity service, and whether the "no harm" test has been met, the OEB will be informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.[21]

Following review of the Applicants' 2016 Electricity Utility Scorecards, OEB staff identified that although the Applicants' System Reliability Metrics did meet OEB targets, both utilities appeared to have an increasing trend in the System Average Interruption Frequency Index (SAIFI) metric. Given the observed trend, through OEB staff interrogatory No. 11, the Applicants were requested to provide both SAIFI and System Average Interruption Duration Index (SAIDI) statistics for 2017. In addition, the Applicants were asked to update average SAIFI and SAIDI scores for the 2012 to 2017 period, given that 2017 statistics were now available. The Applicants' response, which excludes incidents related to loss of supply and major outages, is provided in Table 2 below.

Table 2: Historical SAIDI and SAIFI Performance

Description	2012	2013	2014	2015	2016	2017	Average
SAIDI							
Thunder Bay	1.28	1.03	1.92	2.02	1.69	1.63	**1.60**
Kenora	0.43	0.36	0.53	0.61	0.59	3.84	**1.06**
SAIFI							
Thunder Bay	3.12	2.02	2.69	2.39	2.70	3.05	**2.66**
Kenora	0.46	0.11	0.29	0.35	0.43	1.88	**0.59**

The Applicants' response to OEB staff interrogatory No. 11 revealed that the SAIDI and SAIFI metrics for Kenora meaningfully increased in 2017. On September 11, 2018, the

[20] Handbook for Utility Rate Application, p. 21
[21] Handbook, p. 7

Applicants provided the following additional evidence in order to clarify why the significant increases had occurred:

"It can be observed by reviewing the tabular SAIDI and SAIFI statistics in the tables below that Scheduled Outage (Code 1) and Adverse Environment (Code 7) have peaked in Kenora Hydro's reliability contribution during the 2017 year. The two events which contributed highly to these statistics are further described below.

Cause Code	SAIDI Description	2014	2015	2016	2017	Average
	Kenora Hydro	0.53	0.61	0.59	3.84	1.39
1	Scheduled Outage	0.11	0.05	0.07	0.78	0.25
3	Tree Contacts	0.03	0.17	0.19	0.46	0.21
5	Defective Equipment	0.04	0.10	0.06	0.10	0.08
6	Adverse Weather	0.00	0.00	0.00	0.00	0.00
7	Adverse Environment	0.00	0.00	0.00	2.48	0.62
	Total	0.18	0.32	0.32	3.82	1.16
	Percentage Contribution	34.0%	52.5%	54.2%	99.5%	109.4%

Cause Code	SAIFI Description	2014	2015	2016	2017	Average
	Kenora Hydro	0.29	0.35	0.43	1.88	0.74
1	Scheduled Outage	0.07	0.02	0.05	1.06	0.30
3	Tree Contacts	0.02	0.02	0.07	0.28	0.10
5	Defective Equipment	0.07	0.04	0.05	0.07	0.06
6	Adverse Weather	0.00	0.00	0.00	0.00	0.00
7	Adverse Environment	0.00	0.00	0.00	0.45	0.11
	Total	0.16	0.08	0.17	1.86	0.57
	Percentage Contribution	55.2%	22.9%	39.5%	98.9%	96.7%

Outage Event #1*: In 2017 Kenora Hydro experienced a larger than average Scheduled Outage* ***(Code 1)*** *to its substation. Through regular patrols Kenora Hydro discovered there was a cracked insulator on the 115 kV side of the substation. Unfortunately due to safety concern Hydro One could not isolate the particular feed to allow quick repair without customer interruption, as a result Kenora Hydro determined that it was necessary to repair and scheduled a city-wide outage. In this particular instance Kenora Hydro hired a company out of Thunder Bay to remove the cracked insulator from service. The full city outage lasted approximately 45 minutes and contributed to SAIDI by approximately 0.7 and SAIFI by approximately 1.0.*

Outage Event #2*: The second event contributing to the 2017 increase in Kenora Hydro's reliability statistics occurred in April as a result of very wet weather and a tracking cutout, Kenora Hydro experienced a pole fire. The location was in an*

> *isolated area in the bush and the outage occurred very late at night categorizing this particular outage as Adverse Environment* ***(Code 7)****. Due to the challenges Kenora Hydro employees took longer than regularly required to discover the location and problem of the outage. This outage was a complicated double circuit structure that was very badly damaged and required a large amount of reconstruction. This outage occurrence contributed approximately 2.48 to SAIDI and SAIFI by approximately 0.45."*

In OEB staff interrogatory No. 5, the Applicants were asked about the types of challenges that LDC Mergeco will face in terms of best servicing customers due to the geographic separation between Kenora and Thunder Bay. The Applicants response stated that LDC Mergeco does not predict the manner and level of service to customers to change as service centres will remain in both Kenora and Thunder Bay. The Applicants also stated that Kenora and Thunder Bay operations will be reviewed with regard to control of the distribution system assets and a best practice approach in the design of the amalgamated utility will be exercised. The Applicants did, however, state that post amalgamation, it is anticipated that, through attrition, the number of staff that are assigned to distribution-system related tasks in the Kenora service centre will decline by up to two from the previous eight employees. Further, the Applicants outlined that any reductions in staff associated with distribution-system related tasks will be subject to successfully providing support for the Kenora service territory from existing Thunder Bay staff.

Submission

Based on the evidence provided by the applicants, OEB staff submits that LDC Mergeco can reasonably be expected to maintain the service quality and reliability standards currently provided by each of the amalgamating utilities subject to one clarification that the Applicants should make in their reply submission. This will be discussed further below. As described by the Applicants, the events which drove the increased SAIFI and SAIDI metrics within Kenora's service territory appear anomalous; they appear to be the result of one-time events.

OEB staff also submits that the OEB is able to monitor the performance of LDC Mergeco on an ongoing basis through performance scorecards as well as the OEB's Electricity Reporting and Record Keeping Requirements (RRRs).

In response to OEB staff interrogatory No. 5, the Applicants stated:

> "It is anticipated that through attrition the number of staff that are assigned to distribution-system related tasks in the Kenora service-centre will decline by up to two from the previous eight employees. ***This reduction of two employees will be***

> ***subject to providing support for the Kenora service territory from existing Thunder Bay resources*** [emphasis added] in functions such as (but not limited to) emergency crew dispatch, remote distribution system operation, capital expenditure planning/design/project management, forestry operations, distribution maintenance management, materials procurement, metering installations, underground locate coordination, fleet management and new customer connection support."

Further, in response to OEB staff interrogatory No. 9, the Applicants also stated that "***any reductions in staff associated with distribution-system related tasks will be subject to successfully providing support for the Kenora service territory from existing Thunder Bay staff*** [emphasis added]."

OEB staff understands from the application that it is the Applicants' proposal that the staffing resources of LDC Mergeco are sufficient to sustain current service level standards.[22] However, the statements above appear to contradict this position. OEB staff recommends that the Applicants clarify what is meant by the two emphasized statements above by referring to evidence already on the record, in their reply submission.

3.4 Impact on Financial Viability

The OEB sets out in the Handbook that the impact of a proposed transaction on the acquiring utility's financial viability for an acquisition, or on the financial viability of the consolidated entity in the case of a merger will be assessed. The OEB's primary considerations in this regard are:

- The effect of the purchase price, including any premium paid above the historic (book) value of the assets involved
- The financing of incremental costs (transaction and integration costs) to implement the consolidation transaction[23]

Submission

The transaction between the parties is non-cash in nature. To effect the amalgamation, Thunder Bay and Kenora will carry out the share exchange as described in the Merger Participation Agreement and outlined in Section 1 of this submission. Review of the Applicants' *pro forma* financial statements also indicates the financial viability of the amalgamated entity will not be adversely affected by the transaction. Consequently, in OEB staff's opinion, there is no impact to the financially viability of the Applicants.

[22] Application, p. 28
[23] Handbook, p. 8

3.5 LDC Mergeco Distribution Licence Application

As part of the consolidation application, the Applicants requested that the OEB approve an Electricity Distribution Licence that would allow LDC Mergeco to own and operate the distribution systems currently serving Thunder Bay and Kenora service areas, as established through ED-2002-0529 and ED-2003-0030, respectively.

On July 20, 2018, the Applicants filed a distribution licence application under OEB file number EB-2018-0233. The application confirmed that, if approved, LDC Mergeo would continue to provide the same distribution services to the customers of Thunder Bay and Kenora as currently offered. The Applicants also stated that the establishment of LDC Mergeco would not adversely affect competition, access to transmission/distribution services, or the level of service currently provided to the customers of Thunder Bay and Kenora.

Submission

OEB staff has reviewed the distribution licence application and considers it complete. OEB staff notes that the application does not contain any requests for licence conditions that would depart from those found in the typical form of electricity distributor licence.

OEB Staff supports the Applicants' request for approval of a new distribution licence for LDC Mergeco.

3.6 Other Matters

The Applicants have indicated that a complete and thorough review of each utility's accounting policies has not been undertaken to date but it is anticipated that Thunder Bay's accounting policies will be adopted by the newly formed LDC Mergeco.[24]

The Applicants suggest that there are aspects of Kenora's current accounting policies that may differ from Thunder Bay's and that will need to be aligned upon amalgamation, however, nothing material has been noted to date.[25]

Submission

The revenue requirement over the deferred rebasing period is underpinned by the pre-amalgamation accounting policies of each utility. The Applicants have stated that changes in accounting policies as a result of the amalgamation will not have an impact on the approved rates during the deferred rebasing period, however, have further stated that to-

[24] Applicant IR Response. OEB Staff IR #25
[25] Ibid

date they have not completed a full analysis of their accounting policies.[26]

OEB staff notes that accounting policy changes in areas such as capitalization and depreciation can have a material impact on the revenue requirement approved over the deferred rebasing period. Given that the Applicants have yet to complete a fulsome review of their amalgamated accounting policies, and the fact that they have not adequately justified why they believe that there will be no impact to the rates approved over the deferred rebasing period; OEB staff submits that the Applicants should be ordered to establish a deferral account that captures the annual difference over the deferred rebasing period between the revenue requirement calculated using the pre-amalgamation accounting policies and the revenue requirement calculated using the new accounting policies.

This proposed account should be brought forward for disposition at a later date and will be subject to an OEB prudence review at that time. OEB staff further submits that this account should be approved as part of this current application and, therefore, the Applicants must prepare and submit to the OEB a draft accounting order for this proposed account.

3.7 Conclusion

The Applicants have requested the OEB's approval for:

- The issuance of a new Electricity Distribution Licence for LDC Mergeco that will come into existence on the completion of the transfer of the distribution-related assets of the Applicants to LDC Mergeco pursuant to Section 60 of the Act.
- Leave for Thunder Bay and Kenora to amalgamate and continue as one corporation under a name to be determined by the Applicants pursuant to Section 86(1)(c) of the Act.
- Leave for Thunder Bay and Kenora to transfer their distribution licences and rate orders to LDC Mergeco pursuant to Section 18 of the Act.
- The cancellation of the distribution licences of the Applicants immediately following the issuance of LDC Mergeco's new Electricity Distribution Licence pursuant to Section 77(5) of the Act.

[26] Ibid

Submission

OEB staff submits that the amalgamation proposed by the Applicants reasonably meets the “no harm” test as described in the Handbook. Therefore, OEB staff does not have any concerns with the approval of these requests.

As described in Section 3.6, OEB staff recommend that the OEB Panel require the Applicants to establish a deferral account in order to capture the annual difference over the deferred rebasing period between the revenue requirement calculated using the pre-amalgamation accounting policies and the revenue requirement calculated using the new accounting policies. OEB staff further submits that this account should be considered and approved by the OEB as part of this current application, and that the Applicants should be required to prepare and submit to the OEB a draft accounting order for this proposed account.

All of which is respectfully submitted