Upper Canada Transmission Inc. (NextBridge Infrastructure LP)

OEB Staff Compendium

EB-2020-0150

March 26, 2021

(Revised March 29, 2021)

OEB Staff Compendium for EB-2020-0150 Oral Hearing

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TAB 1

Ontario Energy Board
Commission de l'énergie de l'Ontario

Ontario Energy Board

Filing Requirements For
Electricity Transmission Applications

Chapter 2

Revenue Requirement Applications

February 11, 2016

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Chapter 2 Filing Requirements for Revenue Requirement Applications

2.0 Introduction

The filing requirements contained in this chapter outline the minimum information necessary for a transmission revenue requirement application. Applicants should review Chapter 1 of this document, which provides an overview of the OEB's expectations on certain generic matters, such as the completeness and accuracy of an application, the exploration of non-material items, and confidential filings.

On October 18, 2012, the OEB released its *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Report). While the RRFE Report related specifically to electricity distributors, the OEB stated that "[i]n due course, the OEB will provide further guidance regarding how the policies in this Report may be applied to transmitters." The changes to the filing requirements in this document provide the initial steps toward the integration of core RRFE concepts into the rate application process for transmitters.

In the RRFE Report the OEB provided electricity distributors with three rate-setting methods: 4th Generation Incentive Rate-setting (now called Price Cap IR), Custom Incentive Rate-setting and Annual Incentive Rate-setting Index. As a move toward greater adoption of an incentive- and performance-based rate setting framework for transmitters, the OEB has created two new transmission revenue plan options:

- A custom incentive-rate setting plan, which will consist of a transmitter-specific revenue trend for the plan term, which shall be not less than five years (Custom IR)
- An incentive-based revenue index plan of five years, comprising an initial application to establish a revenue requirement based on a single test year cost of service application, followed by incentive-based and indexed adjustments to revenue requirement for the balance of the term. Analogous to a Price Cap for distributors, this "Revenue Cap index" approach includes expectations for the development of an index, as well as productivity and stretch commitments. The OEB invites transmitters to propose and substantiate the appropriate method and commitments for these elements.

The OEB will not require all existing electricity transmitters to apply under Custom IR or a Revenue Cap index immediately. Transmitters continue to have the option, for their first application after these filing requirements are issued, to apply to have their revenue requirement set for one or two years through a cost of service application for those applicants where significant adjustments to business processes and planning activities would be required prior to embarking on a new five year rate plan. New entrants will be expected to select either a Custom IR or Revenue Cap index plan.

The OEB will nevertheless expect two elements of the RRFE policy to begin to be incorporated into all applications for transmission revenue requirements: enhanced reporting on customer engagement, and a proposed scorecard to measure performance. Performance monitoring and reporting are key elements in moving towards an outcomes-based regulatory framework.

In addition, the OEB will require evidence on asset condition, planning and prioritization of capital expenditures to be presented in a Transmission System Plan, consolidated into a dedicated exhibit in the application. The OEB will assess the fit between the applicant's plan and its stated objectives, and consider how the plan contributes to positive outcomes for electricity customers, in particular those outcomes that arise from the asset management decisions reflected in the applicant's Transmission System Plan. The OEB will also consider the planning and pacing proposals of the applicant and whether the test year requests are appropriately aligned with the Transmission System Plan, while at the same time recognizing and taking into consideration the division of network planning responsibilities in Ontario, the OEB's statutory objectives and relevant provincial policies.

Benchmarking is a key component of rate-setting for electricity distributors under the RRFE. Benchmarking evidence is required to support cost forecasts and system planning proposals, given the assistance it can provide in establishing the reasonableness of costs. However, the OEB recognizes that a transition period may better accommodate the gradual entrenchment of RRFE objectives and principles in transmission rate-setting over time. Therefore, where a transmitter is filing based on cost of service or the Revenue Cap index, if benchmarking evidence is not currently available, the transmitter must file in its application a strategy to acquire such evidence for its subsequent application.

The amount and quality of the evidence filed to support an application should be sufficient to demonstrate to the OEB that the revenue requirement(s) sought are reasonable and provide value for customers. A transmitter seeking approval of revenue requirements under Custom IR or Revenue Cap will be expected to demonstrate that its planning has been sufficiently robust that the utility will be able to manage within the revenue set, given that actual costs and revenues will vary from forecast.

In recognition of the forecasting uncertainty involved in longer terms, the OEB has included in section 2.8.12 a provision for a “Z-factor” claim, similar to that for electricity distributors operating under multi-year rate plans.

In addition, the OEB will consider requests for a mechanism to fund significant incremental capital during the rate term from applicants proposing a Revenue Cap index. This will enable review during the cost of service application of the need and prudence of any significant, discrete projects coming into service over the plan term that are part of a transmitter’s Transmission System Plan and which transmitters cannot manage through the revenue established through the index. Applicants must propose all criteria and parameters for approval of any capital module.

The OEB will require from transmitters applying for approval of revenue requirements under a Custom IR or Revenue Cap application a proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income supported by the approved return on equity, such as a capital variance account or an earnings sharing mechanism.

The use of the phrase “OEB-approved” in these filing requirements typically refers to the set of data used by the OEB as the basis for approving the most recent revenue requirements. It does not mean that the OEB, in fact, “approved” any of the data, but only that the final approved revenue requirement and uniform transmission rates were based on those data.

2.1 General Requirements

The basic format of an application for a revenue requirement must include the following exhibits:

Exhibit 1	Administrative Documents
Exhibit 2	Transmission System Plan
Exhibit 3	Rate Base
Exhibit 4	Service Quality and Reliability Performance and Reporting
Exhibit 5	Operating Revenue
Exhibit 6	Operating Costs
Exhibit 7	Cost of Capital and Capital Structure
Exhibit 8	Deferral and Variance Accounts
Exhibit 9	Cost Allocation to Uniform Transmission Rate Pools: Charge Determinants
Exhibit 10	Rate Design for Uniform Transmission Rates

Other exhibits may also be included in an application in support of, or to document, other proposals for which the applicant is seeking OEB review and approval.

The OEB has provided numerous appendices (Excel-based data spreadsheets) for electricity distributors, as part of the Filing Requirements for Electricity Distributors. These appendices allow a consistent review of application information from the various distributors. Appendices have not been provided as part of these filing requirements. However, transmitters may wish to review the appendices to Chapter 2 of the Filing Requirements for Electricity Distributors to further support their evidence by providing appendices that are applicable to their transmission applications.

The items outlined below are general requirements that are applicable throughout the application:

- Written direct evidence is to be included before data schedules.
- Average of the opening and closing fiscal year balances must be used for items in rate base.
- Total capitalization (debt and equity) must equate to total rate base.
- Data for the following years, at a minimum, must be provided:
  - Test year = prospective rate year
  - Bridge year = current year
  - Four most recent historical years (or number of years necessary to provide actuals back to and including the most recent OEB-approved test year, but not less than four years)
  - Most recent OEB-approved test year
- Custom IR applicants must include in their evidence forecasts for revenue, costs and inflation for each year of the proposed rate term, and benchmarking evidence supporting the cost forecasts.
- Documents are to be provided in bookmarked and text-searchable Adobe PDF format.
- Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical.

If a transmitter updates its evidence throughout the proceeding, the transmitter must ensure that any models submitted in the original application are updated appropriately.

To assist applicants in applying using Revenue Cap or Custom IR proposals, the following chart outlines the basic components of the new revenue requirement-setting options:

Category	Revenue Cap index	Custom IR
Going-in rates	Determined in single forward test-year cost of service review	Determined in multi-year application review
Form	Index: Revenue Cap option	Custom Index
Coverage	Comprehensive	Comprehensive
Annual adjustment – inflation	To be proposed; any deviation from OEB inputs to be justified	Transmitter-specific revenue requirement trend for the plan term to be determined by the OEB, informed by: (1) the transmitter’s forecasts (revenue and costs, inflation, productivity); (2) the OEB’s inflation analysis; and (3) internal and external benchmarking to assess the reasonableness of the transmitter’s forecasts
Annual adjustment – productivity	Productivity and stretch factor expected	
Benchmarking	Both internal (against own cost performance over time to demonstrate continuous improvement) and external (against other transmitters), including rationale for selected comparators	
Sharing of benefits	Stretch and/or productivity factor to be proposed	Case-by-case
Term	5 years (rebasing plus 4 years)	Minimum term of 5 years
Capital module	Option for capital factor proposals	N/A
Unforeseen events	Z-factor available	Z-factor available
Deferral and Variance Accounts	Status quo	Status quo + case-by-case
Performance Reporting and Monitoring	Draft scorecard, RRR filings & case-by-case	Draft scorecard, RRR filings & case-by-case

As indicated in the introduction, transmitters have the option, for their first application after these filing requirements are issued, to apply to have revenue requirement set for one or two years through a cost of service application.

2.1.1 Materiality Thresholds

The applicant must provide justification for changes from year to year to its rate base, capital expenditures, operations, maintenance and administration costs and other items above a materiality threshold. The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement.

Unless a different threshold applies to a specific section of these filing requirements, the default materiality thresholds are as follows:

- $50,000 for a transmitter with a transmission revenue requirement less than or equal to $10 million
- 0.5% of transmission revenue requirement for a transmitter with a transmission revenue requirement greater than $10 million and less than or equal to $200 million
- $3 million for a transmitter with a transmission revenue requirement of more than $200 million

An applicant may provide additional details of items below the threshold if it determines that this would assist the OEB with its review of the application. Applicants are reminded that the onus is on the applicant to make its case and ensure that the OEB has the information it needs to properly assess and deliberate on the application.

2.2 Accounting Standards

This section provides information on the following accounting standards relevant to the filing of revenue requirement applications. The Canadian Accounting Standards Board has established a mandatory transition to International Financial Reporting Standards by January 1, 2015. On this basis, the following accounting standards may be applicable to transmitters for 2015 and beyond:

- International Financial Reporting Standards (IFRS)
- United States Generally Accepted Accounting Principles (USGAAP)
- Accounting Standards for Not-for-Profit Organizations
- Accounting Standards for Private Enterprise (ASPE)

The accounting standard that is used as the basis of the application must be clearly stated. Regardless of the accounting standard used in the application, the applicant must provide a summary of changes to its accounting policies made since the applicant's last revenue requirement application (e.g. capitalization of overhead, capitalization of interest, depreciation, etc.). Revenue requirement impacts of any changes in accounting policies must be separately quantified.

2.2.1 Modified IFRS Application

Transmitters should refer to the following documents for guidance relating to the use of IFRS in application filings:

- *Report of the Board: Transition to IFRS;* dated July 28, 2009;
- *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment*, dated June 13, 2011; and
- *Asset Depreciation Study for the Ontario Energy Board*, Kinectrics Inc. for distributors sponsored by the Board dated July 8, 2010.

For those applicants that have adopted IFRS for financial reporting purposes or will adopt IFRS for financial reporting purposes effective January 1, 2015 or earlier, revenue requirement applications must be filed on the basis of modified IFRS ("MIFRS").

2.2.2 Application under Accounting Standards for Not-for-Profit Organizations

For those transmitters that adopted Accounting Standards for Not-for-Profit Organizations for purposes of financial reporting, revenue requirement applications must be filed on the basis of this accounting standard.

2.2.3 USGAAP or ASPE Application

The OEB requires a utility that adopts USGAAP or ASPE, in its first revenue requirement application following the adoption of the new accounting standard, to provide the following:

- Evidence of the eligibility of the utility under the governing securities legislation to report financial information using that standard (if applicable)
- A copy of the authorization to use the standard from the corresponding Canadian securities regulator (if applicable)
- Evidence demonstrating the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation

2.3 Exhibit 1 - Administrative Documents

The items identified in this Exhibit provide the background and summary to the application as filed and are grouped into four sections:

1) Executive Summary
2) Customer Engagement
3) Financial Information
4) Administration

2.3.1 Executive Summary

This section is the opportunity for the applicant to provide an overview of key elements of its application and its overall business strategy. A transmitter should provide the OEB with a broad overview of the utility, past and expected performance, and its plans for the future. The overview should include information about the transmitter's objectives and business plan, how these relate to what is being sought in the application and, where applicable, how they align with the objectives of the RRFE. The application should also describe whether and how the transmitter's objectives reflect customer feedback.

The Executive Summary must contain a brief summary of the following items in the application. Applicants must separately identify all proposed changes to revenue requirement that will have a material impact on customers, including any changes that may affect particular customer groups.

A. Revenue Requirement

- Revenue requirement requested for the test year(s)
- Increase/decrease ($ and %) from previously approved revenue requirement
- Schedule of main drivers of revenue requirement changes from the last OEB approved year

B. Budgeting Assumptions

- Economic overview (such as growth and inflation)

C. Load Forecast Summary

- Load growth (percentage change from last OEB approved)
- Brief description of forecasting method(s) used

D. Transmission System Plan

- Summary of the major drivers and elements of the transmitter's capital plan
- Details of the investment planning process, including asset condition assessment, identification and prioritization of capital investments, trade-offs with the operations, maintenance and administration expenditures
- Capital expenditures requested for the test year(s)
- Change in capital expenditures from last OEB approved ($ and %)

E. Rate Base

- Rate base requested for the test year(s)
- Change in rate base from last OEB approved ($ and %)

F. Performance and Reporting

- A proposed scorecard that could be used to measure and monitor the transmitter's performance including measures for all of the key RRFE objectives of public policy responsiveness, financial performance, operational effectiveness and customer focus.
- Demonstration of how the applicant has addressed the performance standards for transmitters as set out in Chapter 4 of the Transmission System Code.
- Discussion of any outstanding areas of non-compliance and the effect they have had on the application, including any relief sought.

G. Operations, Maintenance and Administration (OM&A) Expense

- OM&A for the test year(s) and the change from last OEB approved ($ and %)
- Summary of overall drivers and cost trends
- Inflation rates used for OM&A forecasts
- Total compensation for the test year(s) and the change from last OEB approved ($ and %)

H. Cost of Capital

- A statement as to whether or not the applicant is using the OEB's cost of capital parameters
- Summary and rationale of any deviations from the OEB's cost of capital methodology

I. Cost Allocation and Rate Design

- Summary of how costs are allocated to each of the three transmission rate pools

J. Deferral and Variance Accounts
- Accounts requested for disposition
- Total disposition and disposition period
- New deferral and variance accounts requested

K. Bill Impacts
- Summary of total bill impacts ($ and %) at the wholesale level (ie, change in the three uniform transmission rates, including an illustration of the impact on a typical customer connected directly to the transmission system that is not a distributor) and for typical retail customers (Residential at 800 kWh per month and General Service <50 kWh at 2000 kWh per month)

2.3.2 Customer Engagement

The RRFE contemplates an active role by distributors in customer engagement. The OEB expects that transmitters will initiate or continue customer engagement activities and provide a summary of those activities as part of the application.

The Transmission System Code (TSC) defines customer as a generator, consumer, distributor or unlicensed transmitter whose facilities are connected to or are intended to be connected to the transmission system. The TSC requires some communications and discussions with customers related to matters such as regional planning, connection procedures, testing and inspections, system performance and outages. The applicant's report should describe these and any other activities designed to engage all customers connected to the transmission system, including discussions related to investment planning and transmission rates and charges.

Transmitters should specifically discuss how their customers were engaged in order to determine their needs, what their needs are, and how the application has responded to any identified needs. Applicants must separately report on the needs of end-use load customers (as distinct from regulated distributors) served directly from the transmission system, and explain how the transmitter's application responds to the needs of these customers. Similarly, any discussion of the needs of generator customers should be presented separately.

A report of customer satisfaction surveys undertaken and results of these surveys should be provided. Information on planned future customer engagement activities should also be detailed in this section. Transmitters may find Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence.

Transmitters are expected to file with the OEB their response to the matters raised in any letters of comment sent to the OEB related to the transmitter's application.

2.3.3 Financial Information

This section must include the following:

- Non-consolidated audited financial statements of the utility (excluding operations of affiliated companies that are not rate regulated) for which the application has been made, for the most recent three historical years (i.e. two years' statements must be filed).
  - Where the regulated entity conducts more than one activity regulated by the OEB, the transmitter shall disclose information separately about each of its operating segments in accordance with the Segment Disclosure provisions which corporate entities are encouraged to adopt by the Canadian Institute of Chartered Accountants Handbook.
  - If the most recent final audited financial statements are not available at the time of filing the application, the draft financial statements must be filed and the final audited financial statements must be provided as soon as they are available.
- Detailed reconciliation of the financial results shown in the Annual Reports/ Audited Financial Statements with the regulatory financial results filed in the application. The reconciliation must include:
  - The separation of non-utility businesses, for example the fixed assets
  - The identification of any deviations that are being proposed between the Annual Reports/Audited Financial Statements and the regulatory financial statements including the identification of any prior OEB approvals for such deviations that may exist
- Annual Report and management's discussion and analysis for the most recent year of the parent company, if applicable
- Rating agency report(s), if available
- Prospectuses, information circulars, etc. for recent and planned public debt or equity offerings

2.3.4 Administration

This section must include the following:

- Table of Contents
- Statement as to who will be affected by the application, including identification of

any specific customer or customer groups that may be significantly affected by a particular request or proposal
- Confirmation of the applicant's internet address for purposes of viewing the application and related documents
- Contact information. The primary contact for the application may be a person within the applicant's organization other than the primary licence contact (the primary contact's name, address, phone number, fax and email address must all be provided). The OEB will communicate with this person during the course of the application. After completion of the application, the OEB will revert to communication with the primary licence contact.
- Identification of any legal or other representation for the application
- The requested effective date(s)
- Bill impacts for each year of the term for a typical Ontario residential customer using 800 kWh per month and for an Ontario General Service <50kW customer using 2000 kWh per month, or as applicable
- Statement as to the form of hearing requested (i.e. written or oral) and an explanation as to the reasons for the applicant's preference
- List of specific approvals requested and relevant section of legislation. All approvals, including accounting orders (deferral or variance accounts) which the applicant is seeking, must be separately identified in this exhibit and clearly documented in the appropriate section of the application.
- A statement of the proposed length of the term, and brief description of the proposed method for establishing revenue requirement for each year of the term
- Changes in tax status (e.g. a change from a corporation to a limited partnership) must be disclosed
- Existing Accounting Orders
- A map of the applicant's assets and operations, showing where the utility operates within the province, and the communities serviced by the utility. A utility may provide more detailed geographic and/or engineering maps where these may be useful to understand parts of the application, such as a capital expansion or replacement program.
- Corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include any planned changes in corporate or operational structure (including any changes in legal organization and control) and rationale for organizational change and the estimated cost impact, including the following:
  - Corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company board
  - The reporting relationships between utility management and parent company officials

- The Accounting Standard used and when it was adopted
- A statement identifying all deviations from the filing requirements, if any
- A statement identifying any changes to the methodologies used in previous applications and a description and rationale for the changes
- If an applicant is conducting non-utility businesses, it must confirm that the accounting treatment it has used has segregated all of these activities from its rate-regulated activities
- A clear indication of the way the applicant has satisfied any prior OEB Decisions or Orders and the impact on the current application (e.g. filing of a study as directed in a previous decision)
- All responses to matters raised in letters of comment filed with the OEB during the course of the proceeding

2.4 Exhibit 2 - Transmission System Plan

Exhibit 2 consists of a consolidated transmission system plan, including an asset management plan and regional planning considerations.

Transmitters may wish to refer to Chapter 5 of the Distribution Filing Requirements for further guidance on the content and structure of a Transmission System Plan.

The Transmission System Plan must include a summary of the investment planning process which includes:

- The strategic plan for the utility
- The overall strategy for investments
- The longer term economic and planning assumptions
- The asset management plan
- A description of how investments are prioritized and selected
- A discussion of transmission investments identified in a regional planning process
- Highlights of recent and proposed investments and their fit with the strategic plan
- A description of how the needs of customers and overall system planning policy objectives are being reflected, including any commitments stemming from the Long Term Energy Plan or the Conservation First policy, and consideration for the OEB's statutory objectives, including facilitating a smart grid and the connection of renewables
- The linkages and trade-offs between certain capital projects and ongoing OM&A

spending

2.4.1 Asset Management Plan

The transmitter must file a detailed asset management plan for its transmission assets. The plan should include the utility's asset management policy, strategy and objectives; an inventory and assessment of the condition of all capital assets whose net book value is material to the transmitter; and how this inventory informs the transmitter's plan for capital expenditures and plan for maintenance expenditures. The inventory should identify in which pool each class of asset belongs, and identify which of these are part of the bulk electricity system as defined by applicable North American Electric Reliability Corporation (NERC) standards. The transmitter shall identify any exemptions received from NERC, including any such requests that are planned or in progress, and a discussion of any associated costs in the event that the exemption is denied.

The asset management plan should demonstrate how these elements produce an integrated capital investment, asset maintenance and asset retirement plan that will drive the development of investment and maintenance for the test year(s) and beyond.

2.4.2 Regional Considerations

Planning transmission infrastructure in a regional context helps promote the cost effective development of electricity infrastructure in Ontario. Accordingly, these filing requirements provide that, where applicable, a transmitter shall file information on the regional planning process(es) in which it is a participant and information demonstrating that regional considerations have been appropriately considered and addressed in the development of the transmitter's plans.

For all applicable regions, the applicant shall therefore submit lead transmitter documentation in support of the application as contemplated in the TSC and the Distribution System Code.

1) Where a regional infrastructure planning process has been completed, the applicant shall submit a copy of the final Regional Infrastructure Plan that describes the investments in transmission and/or distribution facilities set out in the Plan. The applicant shall specifically identify any such investment(s), for which the applicant will be seeking approval.
2) Where regional planning is underway, but a Regional Infrastructure Plan has

not yet been completed for the applicable region, the applicant shall submit a letter from the Independent Electricity System Operator (IESO), identifying the status of the regional planning process, and the potential impacts on the applicant's investment plans.

3) Where the applicant's participation in a regional planning process is not required at this time, the applicant shall submit its needs assessment report documenting that regional planning is not required.

A transmitter may have infrastructure investments that span more than one region. The applicant should identify in the application where that occurs and the relationship between the applicable regional planning processes (including where the investment involves another lead transmitter).

2.4.2.1 Coordinated planning with third parties

For each region, to demonstrate that a transmitter has met the OEB's expectations in relation to coordinating infrastructure planning with customers, the lead transmitter, other transmitters or distributors, and the IESO (or other third parties where appropriate), a transmitter must provide a description of the consultation(s), including:

- The purpose of the consultation (e.g. regional planning process)
- Whether the transmitter initiated the consultation or was invited to participate in it
- The other participants in the consultation process (e.g. customers; distributors; other transmitters; IESO; municipalities)
- The nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan)
- An indication of whether and how the consultation(s) have or are expected to affect the transmitter's plans as filed

Where a final deliverable of the regional planning process is expected but not available at the time of filing, the transmitter must provide information indicating:

- The role of the transmitter in the consultation
- The status of the consultation process
- Where applicable, the expected date(s) on which final deliverables are expected to be issued

2.4.3 Capital Expenditures

The transmission applicant must provide an overall summary of capital expenditures over the past five historical years, which would include the bridge year, and five future years including the test year(s), showing capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress (“CWIP”).

The following capital expenditure information should be provided by the applicant on a project specific basis, grouped appropriately. Where a program or initiative includes numerous similar projects across a portfolio of similar assets, the evidence can be presented on a program or portfolio basis.

- For projects or programs with a value greater than the materiality threshold and not subject to a leave to construct application:
  - Need, scope, and purpose of project or program, related customer attachments, load and capital costs, as well as any applicable cost-benefit analysis
  - A discussion of other capital and non-capital alternatives which were considered and rejected in favour of the proposed project or program
  - Detailed information on the priority of the project or program relative to other investments and risks of not proceeding with the project or program
  - For any sustainment or renewal investment, details on the condition or life expectancy of the asset(s) being improved through reinvestment
  - Detailed breakdown of starting dates and in-service dates for each project or program
- Drivers of capital expenditure increases for the test year(s)
- The basis for the estimated budget for the project or program (e.g. historical cost, preliminary engineering estimates, request for proposals)
- A summary of the evidence for any project that requires leave to construct approval under the OEB Act, where construction is to commence in a test year
- Identification of any project that has been undertaken in compliance with a condition included in the transmitter’s licence as a result of a directive issued by the Minister of Energy to the OEB or has been declared a priority project by the Lieutenant Governor in Council

The following information about other capital expenditures should also be provided:

- Components of all other capital expenditures (those not already addressed above), including a reconciliation of all capital components to the transmitter’s total capital budget

- Written explanation of variances, including that of actuals versus the OEB-approved amounts for the applicant's last OEB-approved revenue requirement application
- The proposed accounting treatment, including the treatment of the cost of funds, for investments spanning more than one year

The applicant must also include in the Transmission System Plan:

- Any cost benchmarking studies (internal and external) or utility cost comparisons conducted by or for the applicant to support the applicant's proposed expenditures. This requirement is mandatory for Custom IR applications. For other applicants, as a transitional measure, where no benchmarking studies are available, transmitters must detail their strategy to prepare or acquire benchmarking studies or cost comparisons for their subsequent rebasing application.
- For applicants filing a Custom IR or Revenue Cap application:
  - A description of quantifiable continuous improvement or efficiency gains that will be achieved over the term
  - The means by which those gains and savings will be achieved and the benefits assured for customers
  - A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income supported by the approved return on equity, using such tools as a capital variance account or an earnings sharing mechanism

2.5 Exhibit 3 - Rate Base

This section must include the following:

1) Overview
2) Gross Assets – Property, Plant and Equipment and Accumulated Depreciation
3) Allowance for Working Capital
4) Capitalization Policy

2.5.1 Overview

For rate base, the applicant must include the opening and closing balances, and the average of the opening and closing balances for gross assets and accumulated depreciation. Alternatively, if an applicant uses a similar method such as calculating the average in-service balance based on the average of monthly values, it must document the methodology used. Rate base shall also include an allowance for working capital.

At a minimum, the filed material in support of the requested rate base must include data for the historical actuals, bridge year (actuals to date and balance of year as budgeted), and test year(s).

Continuity statements and year-over-year variance analyses must be provided. Continuity statements must provide year-end balances and include interest during construction, and all overheads. Variance analyses must provide a written explanation for rate base-related material when there is a variance greater than the applicable materiality threshold.

If continuity statements have been re-stated for the purposes of the application, the utility must provide a thorough explanation for the restatement and also provide reconciliation to the original statements.

The following comparisons must be provided:

- Historical OEB-approved vs. historical actual (for most recent OEB- approved years)
- Historical actual vs. preceding historical actual (for the relevant number of years)
- Historical actual vs. bridge
- Bridge vs. test year(s)

The opening and closing balances of gross assets and accumulated depreciation that are used to calculate the fixed asset component of rate base must correspond to the respective balances in the fixed asset continuity statements. In the event that the balances do not correspond, the applicant must provide an explanation and reconciliation.

This reconciliation must be between or among the last actual year, bridge year and any test year(s) net book value balances reported on a fixed asset continuity schedule and the balances included in the rate base calculation. Examples of adjustments that would be made to the fixed asset continuity schedule balances for rate base calculation purposes are the removal of the amounts for work in progress and asset retirement obligations.

The information outlined in the fixed asset continuity schedule must be provided for each year, in both the application material and in working Microsoft Excel format.

2.5.2 Gross Assets – Property, Plant and Equipment and Accumulated Depreciation

The applicant must provide the following information:

- Breakdown by function (transmission plant, general plant, other plant) for required statements and analyses
- Detailed breakdown by major plant account for each functionalized plant item
    - For the test year(s), each plant item must be accompanied by a description.
- Detailed breakdown of the in-service capital additions for the test year(s)
- Continuity statements reconcilable to the calculated depreciation expenses (under Exhibit 4 – Operating Costs) and presented by asset account

2.5.3 Allowance for Working Capital

If a transmitter is proposing to include an allowance for working capital in its rate base, it must support this with a lead/lag analysis. A lead/lag study analysis for two time periods is required; namely:

- The time between the date customers receive service and the date that the customers' payments are available to the transmitter (the lag)
- The time between the date when the transmitter receives goods and services from its suppliers and vendors and the date that it pays for them (the lead)
    - Leads and lags are measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e. lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. This amount is included in the applicant's rate base determination.
    - For transmitters in Ontario, the lead/lag study should reflect the fact that the IESO provides the bulk of the revenue to the transmitter, with minimal contributions from other sources.

2.5.4 Customer Connection and Cost Recovery Agreements

When proposed capital expenditures are related to projects which require a contribution from a customer, the transmitter should show these amounts separately as an offset to rate base.

For any Customer Connection and Cost Recovery Agreements executed by transmitters with Ontario rate-regulated distributors that are due to be reviewed during the term as a result of reaching a fifth anniversary (or a 10th or 15th etc.) the applicant shall provide the number of agreements being reviewed and provide an aggregated estimate of the total expected true-up contributions, as well as any proceeds from a bypass agreement. Applicants shall also provide detail on the financial and regulatory accounting treatment of these proceeds.

2.5.5 Capitalization Policy

The transmitter must provide its capitalization policy, including changes to that policy since the last revenue requirement application filed with the OEB.

Regardless of the accounting standard used, if the transmitter has changed its capitalization policy since the last revenue requirement application, the transmitter must explain the reason for these changes and whether they are a result of adhering to an accounting requirement. The changes must be identified, (e.g. capitalization of indirect costs, etc.) and the causes of the changes must also be identified.

2.5.5.1 Capitalization of Overhead

Regardless of whether the applicant has filed the application under MIFRS, USGAAP, ASPE, or CGAAP, the applicant must provide information, depending on the accounting basis on which the application has been filed, regarding overhead costs on self-constructed assets.

2.5.5.2 Burden Rates

The transmitter must identify the burden rates related to the capitalization of costs of self-constructed assets. If the burden rates were changed since the last rebasing application, the applicant must identify the burden rates prior to and after the change.

2.5.6 Capital Module

Applicants proposing a Revenue Cap index may request a capital increment for discrete projects being placed in service after the rebasing year that:

- Are part of the Transmission System Plan
- Are intended to come into service during the index period
- Involve costs that the transmitter cannot manage through the revenue established through the index

The request must address proposed approval criteria (materiality, need, prudence) and the process for implementation of the recovery of the capital increment.

2.6 Exhibit 4 - Service Quality and Reliability Performance and Reporting

2.6.1 Proposed Scorecard

The OEB initiated the use of scorecards to facilitate performance monitoring and benchmarking of electricity distributors in 2013. Each transmitter must, in its first revenue requirement application following the issuance of these revised filing requirements, propose a scorecard that could be used to measure and monitor the performance of the electricity transmitter and, where appropriate, enable comparison between transmitters. The format should be similar to the scorecard developed for distributors (available on the OEB's website) and include measures for public policy responsiveness, operational effectiveness, customer focus and financial performance, but the applicant may propose other performance categories and measures that it believes would be meaningful for their operations as an Ontario transmitter. The proposed scorecard should provide for the inclusion of data for at least a five year period. Transmitters may propose measures for which five years of data are not yet available conditional on a plan and commitment to collect such data through the course of the plan.

In creating the scorecard, applicants may wish to consider the data they are already required to file under the TSC and the Reporting and Record Keeping Requirements (RRR).

Applicants may also choose to propose in their applications other performance measures to be reported annually that are applicable to their individual business. The OEB will expect transmitters to report on performance metrics, such as cost control and project completion, if a multi-year term is approved.

2.6.2 Reliability Performance

All applicants, whether proposing a single or multi-year term, must document in their applications achieved reliability performance, using measures developed by the Canadian Electricity Association including, transmission frequency of delivery point interruptions and transmission duration of delivery point interruptions, unsupplied energy in minutes and transmission system unavailability (percentage of system unavailable). The applicant must also document how it has addressed the performance standards for transmitters as set out in Chapter 4 of the TSC.

The applicant should compare the results for its system performance to those of other systems both nationally and internationally, where available.

2.6.3 Compliance Matters

While most compliance matters are normally resolved outside of the revenue requirement application process, transmitters must discuss any outstanding areas of non-compliance which have had an effect on the application, including any relief sought through this application to resolve the non-compliance.

2.7 Exhibit 5 - Operating Revenue

This exhibit includes evidence on the applicant’s forecast of customers, energy and load, service revenue and other revenue, and variance analyses related to these items.

The applicant must provide its customer, volume and revenue forecast, weather normalization methodology, and other sources of revenue in this exhibit. The applicant must include a detailed description of the methodologies and the assumptions used. Estimates must be presented excluding commodity revenues.

The information presented must include:

1) Load and revenue forecasts

2) Accuracy of load forecast and variance analyses
3) Other revenue

2.7.1 Load and Revenue Forecasts

The transmission load forecast is used to support the charge determinant load forecast for the three transmission rate pools: Network, Line Connection and Transformation Connection. The applicant must provide an explanation of the causes, assumptions and adjustments for the volume forecast. All economic assumptions and data sources used in the preparation of the load and customer count forecast, including the impact of conservation, must be included in this section, including when the forecast was prepared.

The applicant must also provide an explanation of the weather normalization methodology used. All economic models, econometric models, end-use models customer forecast surveys and load shape analyses must also be described and documented.

The applicant must provide a detailed CDM forecast, with impact of CDM shown on the load forecast for each of the three rate pools. The applicant must also indicate how the forecast reflects IESO CDM forecasts and targets in the load forecast.

The applicant's load forecast must also take into account the impact of forecast embedded generation on the transmission system load. The applicant must explain its assumptions and methodology.

2.7.2 Accuracy of Load Forecast and Variance Analyses

The applicant must demonstrate the historical accuracy of the load forecast for at least the past 5 years by providing the following, as applicable:

- Schedule of volumes (in kW for those rate pools that use this charge determinant), revenues, customer/connections count by rate pool and total system load in kWh) for:
  - Historical OEB-approved
  - Historical actual for the past 5 years
  - Historical actual for the past 5 years – weather normalized
  - Bridge year
  - Bridge year – weather normalized

- o Test year(s)

The applicant must provide the following variance analyses and relevant discussion for volumes, revenues, customer/connections count and total system load:

- Comparison with the latest applicable provincial forecast(s) from the IESO, including a discussion of significant differences
- Historical OEB-approved vs. historical actual
- Historical OEB-approved vs. historical actual – weather normalized
- Historical actual – weather-normalized vs. preceding year's historical actual – weather-normalized (for the necessary number of years)
- Historical actual – weather normalized vs. bridge year – weather-normalized
- Bridge year – weather-normalized vs. test year(s)

All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format.

2.7.3 Other Revenue

The applicant must provide the following information:

- Comparison of actual revenues for historical years to forecast revenue for bridge and test year(s), including explanations for significant variances in year-over-year comparisons
- How costing and pricing for other revenues is determined, any new proposed service charges, and/or changes to rates or new rules for applying existing charges
- Any revenue from affiliate transactions, shared services or corporate cost allocations. For each affiliate transaction the applicant must provide identification of the service, the nature of the service provided to affiliated entities, accounts used to record the revenue and the associated costs to provide the service

Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue.

2.8 Exhibit 6 - Operating Costs

Exhibit 6 includes information that summarizes the OM&A costs, depreciation expense and taxes.

OM&A costs should be presented on an output/program-focused basis. This exhibit must include the following sections:

1) Overview
2) Summary and cost driver tables
3) Program delivery costs with variance analysis
4) Employee Compensation
5) Shared Services and Corporate Cost Allocation
6) Purchases of Non-Affiliate Services
4) Depreciation/amortization/depletion
5) Taxes, if applicable

2.8.1 Overview

The overview should provide a brief explanation (quantitative and qualitative) of the following:

- OM&A levels for the test year(s)
- Associated cost drivers and significant changes that have occurred relative to historical and bridge years
- Overall trends in costs
- Business environment changes
- Any cost benchmarking studies (internal and external) or utility cost comparisons conducted by or for the applicant. This requirement is mandatory for Custom IR applications.
- For applicants filing a Custom IR or Revenue Cap application, a description of the continuous improvement or efficiency gains that will be achieved over the term, and the means by which those gains and savings will be achieved and the benefits assured for customers.
- Inflation rate assumed: Each year the OEB will determine an inflation factor that applies to electricity distributors for Incentive Rate Setting (IRM) applications. If the transmitter has used an inflation factor different than this in forecasting its costs, it should provide a full explanation as to why the proposed inflation factor is more appropriate.

2.8.2 Summary and Cost Driver Tables

The applicant must include the following tables as part of its evidence:

- Summary of recoverable OM&A expenses
- OM&A cost drivers

Regardless of whether the applicant has filed the application under MIFRS, USGAAP, Accounting Standards for Not-for-Profit Organizations, or ASPE, the applicant must identify the overall change in OM&A expense in the test year(s) that is attributable to a change in capitalized overhead. The applicant must provide a variance analysis for the change in OM&A expense for the test year(s) in respect to each of the bridge year and historical years.

2.8.3 Program Delivery Costs with Variance Analysis

The applicant should provide details of costs in the following categories.

1. Employee compensation
2. Shared services and corporate cost allocation
3. Purchase of non-affiliate services
4. One-time costs
5. OEB costs
6. Charitable and political donations

2.8.4 Employee Compensation

The applicant must provide information on employee complement, compensation, and benefits for both management and union/non-union employees. Information on labour and compensation must include the total amount, whether expensed or capitalized. Applicants may wish to review Appendix 2K to the Filing Requirements for Distributors as a guide as to how this information should be presented.

Applicants must provide a description of their compensation strategy, and clearly explain the reasons for all material changes to head count and compensation and the outcomes expected from these changes. A complete explanation includes:

- Year over year variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees

- Basis for performance pay, goals, measures, and review processes for any pay-for-performance plans, including evidence of rational linkages between individual performance goals, company objectives and intended regulatory outcomes for the sector
- Any relevant studies conducted by or for the applicant (e.g., compensation benchmarking)

Applicants who are virtual utilities (i.e. utilities that have outsourced the majority of functions, including employees to affiliates) must also provide these details in relation to the employees who are doing the work of the regulated utility. The status of pension funding and all assumptions used in the analysis must be provided.

Where there are three or fewer employees in any category, the applicant must aggregate this category with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees.

The applicant must provide details of employee benefit programs, including pensions and other costs charged to OM&A for the last OEB-approved rebasing application, historical, bridge and test years. The most recent actuary report(s) must be included in the pre-filed evidence. What is disclosed in the tax section of the pre-filed evidence must agree with this analysis.

2.8.5 Shared Services and Corporate Cost Allocation

Shared services is defined as the concentration of a company's resources performing activities (typically spread across the organization) in order to service affiliates (including a parent company) with the intention of achieving lower costs and higher service levels.

The applicant must identify all shared services among the affiliated entities, including the extent to which the applicant is a "virtual" utility.

Corporate cost allocation is an allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa).

The applicant must provide the allocation methodology, a list of costs and allocators, and any third party review of the corporate cost allocation methodology used.

The applicant must provide details about each service provided or received for the historical (actuals), bridge and test years. Applicants must provide a reconciliation of the revenue arising from these transactions with the amounts included in other revenue in section 2.7.3.

Variance analyses, with explanations, are required for the following:

- Test year(s) vs. last OEB-approved
- Test year(s) vs. most current actuals

The applicant must identify any Board of Director-related costs for affiliates that are included in its own costs.

2.8.6 Purchase of Non-Affiliate Services

Utility expenses incurred through the purchase of services from non-affiliated firms must be documented and justified. An applicant must provide a copy of its procurement policy including information on such areas as the level of signing authority, a description of its competitive tendering process and confirmation that its non-affiliate services purchases are in compliance with it.

For any such transactions above the materiality threshold that were procured without a competitive tender, or are not in compliance with the procurement policy, the applicant must provide an explanation as to why this was the case, as well as the following information for historical (actuals):

- Summary of the nature of the product or service that is the subject of the transaction
- A description of the specific methodology used in determining the vendor (including a summary of the tendering process/cost approach, etc.)

2.8.7 One-time Costs

The applicant must identify one-time costs in the historical, bridge and test years and provide an explanation as to how the costs included in the test year(s) will not result in an over recovery of costs in future years.

2.8.8 Regulatory Costs

The applicant must provide a breakdown of the actual and anticipated regulatory costs, including OEB cost assessments and expenses for the current application such as legal fees, consultant fees, costs awards, etc. The applicant must provide information supporting the level of the costs associated with the preparation and review of the current application.

2.8.9 Charitable and Political Donations

The applicant must file the amounts paid in charitable donations (per year) from the last OEB-approved rebasing application up to and including the test year(s). The recovery of charitable donations will generally not be allowed for the purpose of setting revenue requirement. If the applicant wishes to recover such contributions, it must provide detailed information for such claims.

The applicant must review the amounts filed to ensure that all other non-recoverable contributions are identified, disclosed and removed from the revenue requirement calculation. The applicant must also confirm that no political contributions have been included for recovery.

2.8.10 Depreciation, Amortization and Depletion

The applicant must provide details for depreciation, amortization and depletion by asset group for the historical, bridge and test years, including asset amount and rate of depreciation or amortization. This must tie back to the accumulated depreciation balances in the continuity schedule under rate base.

The applicant must identify any asset retirement obligations (AROs) and any associated depreciation or accretion expenses in relation to the AROs, including the basis and calculation of how these amounts were derived.

The OEB's general policy for rate setting is that capital additions would normally attract six months of depreciation expense when they enter service in the test year. This is commonly referred to as the "half-year" rule. The applicant must identify its historical practice and its proposal for the test year. Variances from this "half-year" rule, such as calculating depreciation based on the month that an asset enters service, must be documented with explanation.

The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant must provide a written description of the depreciation practices followed and used in preparing the application. Regardless of the accounting standard used in the application, the applicant must provide a summary of changes to its depreciation/amortization policy made since the applicant's last cost of service filing.

The applicant must ensure that the significant parts or components of each item of Property, Plant and Equipment are being depreciated separately. The applicant must explain if it departs from this practice.

2.8.11 Taxes or Payments In Lieu of Taxes (PILs) and Property Taxes

The applicant must provide the information outlined below:

- Detailed calculations of income tax or PILs, as applicable, including derivation of adjustments (e.g., tax credits, CCA adjustments) for the historical, bridge and test years. Note: regulatory assets (and regulatory liabilities) must generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts.
- Supporting schedules and calculations identifying reconciling items
- Copies of most recent federal and provincial tax returns (non-utility tax items, if material, must be separated)
- Financial statements included with tax returns, if different from the financial statements filed in support of the application
- A calculation of tax credits (e.g., apprenticeship training tax credits, education tax credits). A Scientific Research and Experimental Development return, if filed, may contain confidential personal information of apprentices such as social insurance number, address, hourly rate, etc. which must be excluded from the filing.
- Supporting schedules, calculations and explanations for “other additions” and “other deductions” in the applicant’s PILs/tax model

Taxes other than PILs (e.g. property taxes) should be clearly identified where included.

2.8.11.1 Non-recoverable and Disallowed Expenses

There may be some expenses incurred by a transmitter that are deductible for general tax purposes, but for which recovery is partially or fully disallowed.

Where an expense incurred by a transmitter is non-recoverable in the revenue requirement (e.g. certain charitable donations) or disallowed for regulatory purposes, such amounts are generally excluded from the regulatory tax calculation.

2.8.11.2 Integrity Checks

The applicant must ensure the following integrity checks have been completed in its application and provide a statement to this effect, or an explanation if this is not the case:

- The depreciation and amortization added back in the application's PILs/tax model agree with the numbers disclosed in the rate base section of the application.
- The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for historic, bridge and test years.
- Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st. If the amounts do not agree, then the applicant must provide a reconciliation with explanations for the reasons.
- The CCA deductions in the application's PILs/tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application.
- Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application.
- CCA is maximized even if there are tax loss carry-forwards.
- A statement is included in the application as to when the losses, if any, will be fully utilized.
- Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, Financial Services Commission Ontario reports, and the actuarial valuations
- The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.

2.8.12 Z-Factor Claims

Transmitters who are operating under a Revenue Cap index or Custom IR may apply to recover material costs associated with unforeseen events that are outside the control of a transmitter's ability to manage, such as damage that is the result of a storm.

As with the policy applicable to distributors, transmitters must submit evidence that the costs incurred meet certain eligibility criteria:

- Causation: amounts must be clearly related to the Z-factor event, and outside of the base upon which revenue requirements were set. The application must demonstrate that the management of the transmitter could not have been able

to plan and budget for the event and that the harm caused by the extraordinary event is genuinely incremental to their experience or reasonable expectations.
- Materiality: the event must have a significant influence on the operations of the transmitter.
- Prudence: the amounts must have been prudently incurred. The transmitter's decisions to incur the amounts must represent the most cost-effective option for ratepayers.

To enable this process, a transmitter must also propose in its revenue requirement application a materiality threshold and explain the basis for it. At minimum, the threshold should exceed the OEB-defined materiality threshold set out in section 2.1.1 on a revenue requirement basis. Transmitters must also make the case that failure to recover the proposed threshold amount would have a significant influence on the operations of the transmitter.

As with the Z-factor policy applicable to distributors, a transmitter must also:

- Notify the OEB promptly of all Z-factor events. Failure to notify the OEB within six months of the event may result in disallowance of the claim.
- Record costs for which recovery will be sought
- Apply to the OEB for any cost recovery of amounts recorded in the deferral account. This will allow the OEB and any affected transmitter the flexibility to address extraordinary events in a timely manner. Subsequently, the OEB may review and prospectively adjust the amounts for which Z-factor treatment is claimed.
- Outline the manner in which it intends to allocate the incremental revenue requirement to the various rate pools, the proposed disposition period, the rationale for the selected approach and a discussion of the merits of alternative allocation methods
- Provide a detailed calculation of the incremental revenue requirement

Costs are to be recorded in Account 1572.

2.9 Exhibit 7 - Cost of Capital and Capital Structure

The OEB's general guidelines for cost of capital in rate regulation are currently provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009 (2009 Report).

As per the 2009 Report, the OEB issues the cost of capital parameter updates for cost of service applications. Transmitters should use the most recent parameters as a placeholder, subject to an update if new parameters are available prior to the issuance of the OEB's decision for a specific transmitter's application.

If the applicant wishes to adopt the OEB's guidelines for the cost of capital, the application must clearly state this and confirm that the cost of capital parameters will be updated in accordance with the OEB's guidelines at the time of the OEB's decision.

Alternatively, the applicant may apply for a utility-specific cost of capital and/or capital structure. If the applicant wishes to take such an approach, it must provide appropriate justification and supporting evidence for its proposal.

Applicants requesting multi-year revenue requirement approvals must indicate whether they are proposing that the cost of capital be updated annually or fixed for all test years, and the reasons for that proposal.

2.9.1 Capital Structure

The elements of the deemed capital structure are shown below and must be presented with the appropriate schedules for current OEB-approved, historical actuals, bridge and test years:

- Long-term debt
- Short-term debt
- Preference shares
- Common equity

Any explanations of changes in actual capital structure are required including:

- Retirements of debt or preference shares and buy-back of common shares
- Short-term debt, long-term debt, preference shares and common share offerings

2.9.2 Cost of Capital (Return on Equity and Cost of Debt)

These requirements are outlined in the 2009 Report. The applicant must provide the following information for each year:

- Calculation of the cost for each capital component
- Profit or loss on redemption of debt and/or preference shares, if applicable
- Copies of any current promissory notes or other debt arrangements with affiliates
- Explanation of the applicable debt rate for each existing debt instrument, including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report
- Forecasts of new debt anticipated in the bridge and test years, including estimates of the applicable rate and any pertinent information on each new debt instrument (e.g. whether the debt is affiliated or with a third party, expected term/maturity, any capital project(s) that the debt funding is for, etc.)
- If the applicant is proposing any rate that is different from the OEB guidelines, a justification of forecast costs by item, including key assumptions

2.9.3 Not-for-Profit Corporations

In prior decisions, the OEB has determined that applicants which are not-for-profit corporations may apply using the OEB's deemed capital structure and cost of capital to the extent that the excess revenue is to be used for the purpose of meeting the applicant's need to build up or accumulate appropriate operating and capital reserves. The OEB has further stated that once the appropriate limits for these reserves have been achieved, it would expect such applicants to submit an application seeking an adjustment to revenue requirement.

2.10 Exhibit 8 - Deferral and Variance Accounts

The information outlined below is required whether or not the applicant is seeking disposition of any deferral and variance accounts:

- List of all outstanding deferral and variance accounts and sub-accounts. The applicant must provide a brief description of any account.
- A continuity schedule in Excel format for the period following the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances.
- Interest rates applied to calculate the carrying charges for each regulatory deferral and variance account. The applicant must provide the rates by month or by quarter for each year.

- Explanation if the account balances in the continuity schedule differ from the account balances reported through the RRR and the audited financial statements.
- A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule
- A statement as to any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account. This must correspond with information provided in Exhibit 1.
- A statement as to whether or not the applicant has made any adjustments to deferral and variance account balances that were previously approved by the OEB on a final basis. If this is the case, the applicant must provide explanations for the nature and amounts of the adjustments and include supporting documentation; under a section titled "Adjustments to Deferral and Variance Accounts".

In the event an applicant seeks an accounting order to establish a new deferral or variance account, the following eligibility criteria must be met:

- Causation - The forecasted expense must be clearly outside of the base upon which revenue requirement(s) were derived.
- Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the transmitter. Otherwise they must be expensed in the normal course and addressed through organizational productivity improvements.
- Prudence - The nature of the costs and forecasted quantum must be reasonably incurred, although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating why the option selected represents the cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, applicants must include a draft accounting order with a description of the mechanics of the account, including examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

2.10.1 Disposition of Deferral and Variance Accounts

The applicant must:

- Identify all accounts for which it is seeking disposition
- Identify any accounts for which the applicant is not proposing disposition and the reasons why
- Propose the method to be used for recovery or refund of balances that are proposed for disposition
- Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements and provide explanations for any variances
- Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's quarterly and annual RRR filings for each account
- Provide explanations even if such variances are below the 5% threshold if the variances in question relate to: (1) matters of principle (i.e. prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in applicable filings
- Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period

2.11 Exhibit 9 - Cost Allocation to Uniform Transmission Rate Pools: Charge Determinants

The applicant should identify the cost allocation methodology that is proposed to allocate costs to the three transmission rate pools: Network, Line Connection and Transformation Connection.

The applicant must outline the key steps taken to functionalize the assets in the functional categories including the criteria used to define each asset category and, how costs are apportioned to the functional categories and rate pools. Allocation factors for dual function assets must be explained.

The applicant must describe how the revenue requirement is allocated to the rate pools including allocation factors applied to each asset or groups of assets. The applicant must show how depreciation, return on capital, taxes and OM&A costs are assigned to the rate pools.

In some cases, another rate pool may be created (such as the Wholesale Meter

Pool, established by Hydro One Networks Inc.). Similar information must be provided for any assigning of costs to non-standard rate pools.

2.12 Exhibit 10 - Rate Design for Uniform Transmission Rates

2.12.1 Bill Impact Information

Each applicant must provide bill impact information including information on the dollar and percentage impact of the application on the average customer's total bill as well as the percentage impact on transmission rates.

The bill comparisons must be provided for typical customers and consumption levels. At a minimum, bill impacts must be provided for typical Ontario residential customers consuming 800 kWh per month and typical Ontario General Service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Transmitters must also include bill impacts for a typical directly connected non-LDC customer.

2.12.2 Setting the Uniform Transmission Rates

Hydro One Networks Inc., or another transmitter designated by the OEB, shall, at the request of the OEB, provide information to allow the OEB to establish uniform transmission rates (UTR) for the province. The information filed must include the following:

- An overview of how the UTR are established in Ontario and how these rates are determined
- The revenue requirement and load forecast data (from each transmitter) that is used to compile the transmission charge determinants for each rate pool
- If applicable, the determination of the Export Transmission Service rates and the treatment of revenues generated through these rates

A table explaining and documenting the determination of the UTR, including:

- The previously approved revenue requirements and load forecast charge determinants for all other transmitters in the pool
- The OEB file number of each decision approving each revenue requirement and charge determinant
- The proposed revenue requirements and charge determinants as proposed in

the application

- The calculation of the UTR for each pool
- The transmission revenue allocator for each of the Ontario transmitters in the pool
- An explanation of any changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates

-End-

TAB 2

Table 1. Summary of Cost of Capital for Test Year 2022 ($ Millions)

NextBridge
Summary of Cost of Capital
Utility Capital Structure
Calculation of Revenue Requirement
Test Year (April 1, 2022 to March 31, 2023)
($ Millions)

Line No.	Particulars	($ M)	%	Cost Rate (%)	Return ($ M)
		(a)	(b)	(c)	(d)
I	Long-term debt	431.4	56.0%	3.2%	13.8
2	Short-term debt	30.8	4.0%	2.8%	0.8
3	Deemed long-term debt	0.0	0.0%	0.0%	0.0
4	Total debt	462.3	60.0%	3.2%	14.7
5	Common equity	308.2	40.0%	8.5%	26.3
6	Total rate base	770.4	100.0%	5.3%	41.0

TAB 3

STAFF INTERROGATORY #65

INTERROGATORY

Reference: (1) Exhibit G / Tab 1 / Schedule 1 / pp. 1-3

Preamble:
The total Cost of Capital Rate proposed by NextBridge is 5.32% with $41.0 million revenue requirement from April 1, 2022 to December 31, 2022.

The 2021 Cost of Capital Parameters released by the OEB on November 9, 2020 for rates effective January 1, 2021 is 2.85 % for long-term debt, 1.75 % for short term debt and 8.34% for return on equity.

Staff Table – 2021 Cost of Capital Parameters

Test Year 12 Months				
Amount of Deemed			Cost Rate	Return
Return	($ Millions)	%	(%)	($ Millions)
Long-term debt	431.4	56	2.85	12.29
Short-term debt	30.8	4	1.75	0.54
Common Equity	308.2	40	8.34	25.20
Total	770.4		5.00%	38.5

Question(s):

a) Based on the 2021 OEB Cost of Capital Parameters OEB Staff calculates a total cost of capital rate of 5.00% and revenue requirement of $38.5 million for the test year for NextBridge. Please confirm if NextBridge agrees with this calculation.

RESPONSE

NextBridge agrees with the calculation shown in the Staff table. Please refer to Staff #70 part b.

TAB 4

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY E-MAIL AND WEB POSTING

October 31, 2019

To: All Rate-regulated Electricity Distributors and Transmitters
All Rate-regulated Natural Gas Utilities
Ontario Power Generation Inc.
All Registered Intervenors in 2020 Cost-based Applications
All Other Interested Parties

Re: 2020 Cost of Capital Parameters

The Ontario Energy Board (OEB) has determined the values for the Return on Equity (ROE) and the deemed Long-Term (LT) and Short-Term (ST) debt rates for use in the 2020 cost-based applications (i.e. cost of service and custom incentive rate-setting (custom IR) applications, including any applicable custom IR updates). The ROE and the LT and ST debt rates are collectively referred to as the cost of capital parameters. The updated cost of capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

Cost of Capital Parameters for 2020 Rates

For cost of service and custom IR applications with effective dates in 2020, the OEB has updated the cost of capital parameters based on: (i) the September 2019 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low or A (A-stable) commercial customers, for the ST debt rate; and (ii) data three months prior to January 1, 2020 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LP, for all other cost of capital parameters.

The OEB has determined that the updated cost of capital parameters for rate applications for rates effective in 2020 are:

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
2300, rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4
T 416-481-1967 1-888-632-6273
F 416-440-7656 **OEB.ca**

Cost of Capital Parameter	Value for Applications for rate changes in 2020
ROE	8.52%
Deemed LT Debt rate	3.21%
Deemed ST Debt rate	2.75%

Detailed calculations of the cost of capital parameters are attached.

The OEB considers the cost of capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

The OEB updates cost of capital parameters for setting rates once per year. For this reason, the cost of capital parameters above will be applicable for all cost of service and custom incentive rate-setting applications (as applicable) with rates effective in the 2020 calendar year.

The OEB monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in individual rate hearings in support of different cost of capital parameters due to the specific circumstances, but must provide strong rationale and supporting evidence for deviating from the OEB's policy.

All queries on the cost of capital parameters should be directed to the OEB's Industry Relations hotline, at 416-440-7604 or industryrelations@oeb.ca

Yours truly,

Original Signed By

Christine E. Long
Registrar and Board Secretary

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For rate changes effective in 2020)

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2019

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
Day		10-yr	30-yr	30-yr		
1	1-Sep-19					
2	2-Sep-19					
3	3-Sep-19	1.13	1.40	2.94	0.27	1.54
4	4-Sep-19	1.13	1.40	2.96	0.27	1.56
5	5-Sep-19	1.26	1.53	3.06	0.27	1.53
6	6-Sep-19	1.28	1.50	3.04	0.22	1.54
7	7-Sep-19					
8	8-Sep-19					
9	9-Sep-19	1.34	1.55	3.09	0.21	1.54
10	10-Sep-19	1.43	1.62	3.15	0.19	1.53
11	11-Sep-19	1.42	1.63	3.17	0.21	1.54
12	12-Sep-19	1.45	1.67	3.20	0.22	1.53
13	13-Sep-19	1.51	1.71	3.24	0.20	1.53
14	14-Sep-19					
15	15-Sep-19					
16	16-Sep-19	1.48	1.67	3.20	0.19	1.53
17	17-Sep-19	1.45	1.63	3.15	0.18	1.52
18	18-Sep-19	1.43	1.59	3.12	0.16	1.53
19	19-Sep-19	1.43	1.58	3.09	0.15	1.51
20	20-Sep-19	1.39	1.54	3.04	0.15	1.50
21	21-Sep-19					
22	22-Sep-19					
23	23-Sep-19	1.37	1.52	3.01	0.15	1.49
24	24-Sep-19	1.30	1.48	2.96	0.18	1.48
25	25-Sep-19	1.39	1.57	3.05	0.18	1.48
26	26-Sep-19	1.36	1.54	3.02	0.18	1.48
27	27-Sep-19	1.36	1.54	3.02	0.18	1.48
28	28-Sep-19					
29	29-Sep-19					
30	30-Sep-19	1.37	1.53	3.01	0.16	1.48
31						
		1.36	1.56	3.08	**0.196**	**1.516**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts* Survey Date: September 9, 2019

	3-month	12-month		Average	
September 2019	1.400	1.600	❸	**1.500**	%

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	1.500	%
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.196	%
Long Canada Bond Forecast (LCBF)	❹	**1.696**	%

Step 4: Return on Equity (ROE) forecast

Initial ROE				9.75	%
Change in Long Canada Bond Yield Forecast from September 2009					
LCBF (September 2019) (from Step 3)	④	1.696	%		
Base LCBF		4.250	%		
Difference		-2.554	%		
0.5 X Difference				-1.277	%
Change in A-rated Utility Bond Yield Spread from September 2009					
A-rated Utility Bond Yield Spread (September 2015) (from Step 1)	②	1.516	%		
Base A-rated Utility Bond Yield Spread		1.415	%		
Difference		0.101	%		
0.5 X Difference				0.050	%
Return on Equity based on September 2019 data				**8.52**	%

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2019 (from Step 3)	④	1.696	%
A-rated Utility Bond Yield Spread September 2019 (from Step 1)	②	1.516	%
Deemed Long-term Debt Rate based on September 2019 data		**3.21**	%

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations
(For rate changes effective in 2020)

Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in September, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	Average Spread over 90-day Bankers Acceptance		Date of input
Bank 1	100.0	bps	Sept. 2019
Bank 2	80.0	bps	Sept. 2019
Bank 3	100.0	bps	Sept. 2019
Bank 4	82.5	bps	Sept. 2019
Bank 5			
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	4	
High estimate	100.0	bps
Low estimate	80.0	bps

C. Average annual Spread	91.250	bps	❶

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2019

Month: **September 2019**

	Day	**Bankers' Acceptance Rate (%) 3-month**
1	1-Sep-19	
2	2-Sep-19	
3	3-Sep-19	1.79 %
4	4-Sep-19	1.83 %
5	5-Sep-19	1.81 %
6	6-Sep-19	1.82 %
7	7-Sep-19	
8	8-Sep-19	
9	9-Sep-19	1.82 %
10	10-Sep-19	1.83 %
11	11-Sep-19	1.83 %
12	12-Sep-19	1.83 %
13	13-Sep-19	1.85 %
14	14-Sep-19	
15	15-Sep-19	
16	16-Sep-19	1.85 %
17	17-Sep-19	1.83 %
18	18-Sep-19	1.82 %
19	19-Sep-19	1.84 %
20	20-Sep-19	1.84 %
21	21-Sep-19	
22	22-Sep-19	
23	23-Sep-19	1.85 %
24	24-Sep-19	1.85 %
25	25-Sep-19	1.85 %
26	26-Sep-19	1.84 %
27	27-Sep-19	1.84 %
28	28-Sep-19	
29	29-Sep-19	
30	30-Sep-19	1.83 %
31		
		1.833 % ❷

Source: Bank of Canada / Statistics Canada Series V39071

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.913	%	①
Average Bankers' Acceptance Rate	1.833	%	②
Deemed Short Term Debt Rate	**2.75**	%	

Reference on Calculation Method:
- Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

TAB 5

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL and WEB POSTING

November 9, 2020

To: All Rate-regulated Electricity Distributors and Transmitters
All Rate-regulated Natural Gas Utilities
Ontario Power Generation Inc.
All Registered Intervenors in 2021 Cost-based Applications
All Other Interested Parties

Re: 2021 Cost of Capital Parameters

The Ontario Energy Board (OEB) has determined the values for the Return on Equity (ROE) and the deemed Long-Term (LT) and Short-Term (ST) debt rates for use in the 2021 cost-based applications (i.e. cost of service and custom incentive rate-setting (custom IR) applications, including any applicable custom IR updates). The ROE and the LT and ST debt rates are collectively referred to as the cost of capital parameters. The updated cost of capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

Cost of Capital Parameters for 2021 Rates

For cost of service and custom IR applications with effective dates in 2021, the OEB has updated the cost of capital parameters based on: (i) the July 2020 survey from Canadian banks for the spread over the Bankers' Acceptance rate of short-term loans for R1-low or A (A-stable) commercial utility customers, for the ST debt rate; and (ii) data three months prior to January 1, 2021 from the Bank of Canada, Investment Industry Regulatory Organization of Canada, *Consensus Forecasts*, and Bloomberg LP, for all cost of capital parameters.

The OEB has determined that the updated cost of capital parameters for rate applications for rates effective in 2021 are:

Cost of Capital Parameter	Value for Applications for rate changes in 2021
ROE	8.34%
Deemed LT Debt rate	2.85%
Deemed ST Debt rate	1.75%

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
2300, rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4
T 416-481-1967 1-888-632-6273
F 416-440-7656 **OEB.ca**

Detailed calculations of the cost of capital parameters are attached.

The OEB notes that, since the beginning of the current COVID-19 pandemic, it has been closely monitoring socioeconomic conditions and the financial and operational implications for the sector now and as the recovery proceeds into 2021. Based on currently available data and forecasts to at least the end of 2021, the OEB believes that the COVID-19 pandemic and its implications on the economy, generally, and on the energy sector, do not result in any distortion of the formulaic calculation of the cost of capital parameters set out above and current market conditions and data. The OEB considers the cost of capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

The OEB updates cost of capital parameters for setting rates once per year. For this reason, the cost of capital parameters above will be applicable for all cost of service and custom incentive rate-setting applications (as applicable) with rates effective in the 2021 calendar year.

The OEB monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in individual rate hearings in support of different cost of capital parameters due to the specific circumstances, but must provide strong rationale and supporting evidence for deviating from the OEB's policy.

All queries on the cost of capital parameters should be directed to the OEB's Industry Relations hotline, at 416-440-7604 or industryrelations@oeb.ca.

Yours truly,

Original Signed By

Christine E. Long
Registrar

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For rate changes effective in 2021)

Step 1: Analysis of Business Day Information in the Month

Month: September 2020

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
Day		10-yr	30-yr	30-yr		
1	1-Sep-20	0.58	1.10	2.55	0.52	1.45
2	2-Sep-20	0.55	1.06	2.50	0.51	1.44
3	3-Sep-20	0.54	1.04	2.49	0.50	1.45
4	4-Sep-20	0.59	1.10	2.55	0.51	1.45
5	5-Sep-20					
6	6-Sep-20					
7	7-Sep-20					
8	8-Sep-20	0.57	1.08	2.55	0.51	1.47
9	9-Sep-20	0.59	1.10	2.56	0.51	1.46
10	10-Sep-20	0.56	1.08	2.54	0.52	1.46
11	11-Sep-20	0.55	1.06	2.52	0.51	1.46
12	12-Sep-20					
13	13-Sep-20					
14	14-Sep-20	0.55	1.06	2.52	0.51	1.46
15	15-Sep-20	0.55	1.08	2.53	0.53	1.45
16	16-Sep-20	0.57	1.11	2.56	0.54	1.45
17	17-Sep-20	0.57	1.09	2.55	0.52	1.46
18	18-Sep-20	0.58	1.10	2.56	0.52	1.46
19	19-Sep-20					
20	20-Sep-20					
21	21-Sep-20	0.55	1.08	2.55	0.53	1.47
22	22-Sep-20	0.55	1.08	2.57	0.53	1.49
23	23-Sep-20	0.55	1.08	2.57	0.53	1.49
24	24-Sep-20	0.55	1.08	2.59	0.53	1.51
25	25-Sep-20	0.54	1.07	2.59	0.53	1.52
26	26-Sep-20					
27	27-Sep-20					
28	28-Sep-20	0.55	1.10	2.62	0.55	1.52
29	29-Sep-20	0.54	1.08	2.61	0.54	1.53
30	30-Sep-20	0.57	1.11	2.66	0.54	1.55
31						
		0.56	1.08	2.56	**0.523**	**1.477**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts*	Survey Date:	September 14, 2020		
	3-month	12-month		Average
September 2020	0.700	1.000	❸	**0.850** %

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	0.850 %
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.523 %
Long Canada Bond Forecast (LCBF)	❹	**1.373** %

Step 4: Return on Equity (ROE) forecast

Initial ROE			9.75 %
Change in Long Canada Bond Yield Forecast from September 2009			
LCBF (September 2020) (from Step 3)	④	1.373 %	
Base LCBF		4.250 %	
Difference		-2.877 %	
0.5 X Difference			-1.438 %
Change in A-rated Utility Bond Yield Spread from September 2009			
A-rated Utility Bond Yield Spread (September 2020) (from Step 1)	②	1.477 %	
Base A-rated Utility Bond Yield Spread		1.415 %	
Difference		0.062 %	
0.5 X Difference			0.031 %
Return on Equity based on September 2020 data			**8.34** %

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2020 (from Step 3)	④	1.373 %
A-rated Utility Bond Yield Spread September 2020 (from Step 1)	②	1.477 %
Deemed Long-term Debt Rate based on September 2020 data		**2.85** %

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For rate changes effective in 2021)

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, typically in September, OEB staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	Average Spread over 90-day Bankers' Acceptance Rate (basis points)		Date of input
Bank 1	150.0	bps	Aug. 2020
Bank 2	178.75	bps	Aug. 2020
Bank 3	150.0	bps	Aug. 2020
Bank 4	130.0	bps	Aug. 2020
Bank 5			
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	4	
High estimate	178.75	bps
Low estimate	130.0	bps

C. Average annual Spread	150.000	bps	❶

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2020

Month: **September 2020**

Day		**Bankers' Acceptance Rate (%) 3-month**
1	1-Sep-20	0.25 %
2	2-Sep-20	0.25 %
3	3-Sep-20	0.25 %
4	4-Sep-20	0.24 %
5	5-Sep-20	
6	6-Sep-20	
7	7-Sep-20	
8	8-Sep-20	0.25 %
9	9-Sep-20	0.25 %
10	10-Sep-20	0.26 %
11	11-Sep-20	0.25 %
12	12-Sep-20	
13	13-Sep-20	
14	14-Sep-20	0.25 %
15	15-Sep-20	0.25 %
16	16-Sep-20	0.25 %
17	17-Sep-20	0.25 %
18	18-Sep-20	0.25 %
19	19-Sep-20	
20	20-Sep-20	
21	21-Sep-20	0.25 %
22	22-Sep-20	0.25 %
23	23-Sep-20	0.25 %
24	24-Sep-20	0.25 %
25	25-Sep-20	0.25 %
26	26-Sep-20	
27	27-Sep-20	
28	28-Sep-20	0.26 %
29	29-Sep-20	0.25 %
30	30-Sep-20	0.26 %
31		
		0.251 % ❷

Source: Investment Industry Regulatory Organization of Canada (IIROC)

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	1.500	%	①
Average Bankers' Acceptance Rate	0.251	%	②
Deemed Short Term Debt Rate	**1.75**	%	

TAB 6

(Revised from Version Contained in Original Compendium)

OEB Staff Table 1 – Revenue Requirement[1]

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	TOTAL
NextBridge's Proposed Revenue Requirement($M)[2]	41.8	56.8	58.0	59.1	60.3	61.5	62.8	64.0	65.3	66.6	596.2
OM&A (includes 2% Inflation factor)[3]($M)	3.7	5.0	5.1	5.2	5.3	5.5	5.6	5.7	5.8	5.9	52.9
Depreciation($M)[4]	6.9	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	90.3
Taxes($M)[5]	0.4	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	5.2
Deemed Return on Capital using 2020 Parameters($M)[6]	30.7	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	399.7
Deemed Return on Capital using 2021 Parameters($M)	28.9	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	375.4
Adjusted Revenue Requirement (2020 parameters $M)	41.8	55.9	56.0	56.1	56.1	56.2	56.4	56.5	56.6	56.7	548.1
Adjusted Revenue Requirement (2021 parameters $M)	40.0	53.4	53.5	53.6	53.6	53.7	53.9	54.0	54.1	54.2	523.8

[1] Exhibit A / Tab 3 / Schedule 1 / p. 21
[2] Exhibit E / Tab 1 / Schedule 1 / Table 3 / p. 2
[3] Exhibit F / Tab 1 / Schedule 1
[4] Exhibit F / Tab 11 / Schedule 1
[5] Exhibit F / Tab 13 / Schedule 1
[6] Exhibit G / Tab 1 / Schedule 1

TAB 7

(Revised from Version Contained in Original Compendium)

OEB Staff Table 2 – Transmission Rate Base - Return on Equity

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Opening Rate Base ($M)	775.11[1]	770.4	761.1	752.1	742.8	733.5	724.3	715.0	705.8	696.5	
Depreciation ($M)	4.6	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	
Closing Rate Base ($M)	770.4	761.1	752.1	742.8	733.5	724.3	715.0	705.8	696.5	687.2	
Average Rate Base ($M)	770.4	765.8	756.6	747.4	738.2	728.9	719.6	710.4	701.1	691.9	733.0
Return on Equity on $770.4M using 2020 Deemed ROE of 8.52% ($M)	19.7	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	256.0
Return on Equity on Average Rate Base for Each Year using 2020 Deemed ROE of 8.52% ($M)	19.7	26.1	25.8	25.5	25.2	24.8	24.5	24.2	23.9	23.6	243.2
Return on Equity on $770.4M using 2021 Deemed ROE of 8.34% ($M)	19.3	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	250.6
Return on Equity on Average Rate Base for Each Year using 2021 Deemed ROE of 8.34% ($M)	19.3	25.5	25.2	24.9	24.6	24.3	24.0	23.7	23.4	23.1	238.1

[1] Exhibit A / Tab 3 / Schedule 1 / p. 13

TAB 8

(Revised from Version Contained in Original Compendium)

OEB Staff Table 3 – Transmission Rate Base - Return on Debt

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Opening Rate Base ($M)	775.11[1]	770.4	761.1	752.1	742.8	733.5	724.3	715.0	705.8	696.5	
Depreciation ($M)	4.6	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	
Closing Rate Base ($M)	765.9	761.1	752.1	742.8	733.5	724.3	715.0	705.8	696.5	687.2	
Average Rate Base ($M)	770.4	765.8	756.6	747.4	738.2	728.9	719.6	710.4	701.1	691.9	
Return on Long-term Debt on $770.4 M Rate Base using 2020 Deemed LTD of 3.21% ($M)	10.4	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	134.3
Return on Long-term Debt on Average Rate Base for Each Year using 2020 Deemed LTD of 3.21%($M)	10.4	13.8	13.6	13.4	13.3	13.1	12.9	12.8	12.6	12.4	128.3
Return on Long-term Debt on $770.4 M Rate Base using 2021 Deemed LTD of 2.85% ($M)	9.2	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	119.9
Return on Long-term Debt on Average Rate Base for Each Year using 2021 Deemed LTD of 2.85%($M)	9.2	12.2	12.1	11.9	11.8	11.6	11.5	11.3	11.2	11.0	113.9
Return on Short term Debt on $770.4 M using 2020 Deemed STD of 2.75%($M)	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	8.2
Return on Short term Debt on Average Rate Base for Each Year using 2020 Deemed STD of 2.75% ($M)	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	7.9
Return on Short term Debt on $770.4 M using 2021 Deemed STD of 1.75% ($M)	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	5.3
Return on Short term Debt on Average Rate Base for Each Year using 2021 Deemed STD of 1.75% ($M)	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	5.0

[1] Exhibit A / Tab 3 / Schedule 1 / p. 13

TAB 9

(Revised from Version Contained in Original Compendium)

OEB Staff Table 4 – Revenue Requirement

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	TOTAL
NextBridge's Proposed Revenue Requirement($M)[1]	41.8	56.8	58.0	59.1	60.3	61.5	62.8	64.0	65.3	66.6	596.2
OM&A (includes 2% Inflation factor)[2]	3.7	5.0	5.1	5.2	5.3	5.5	5.6	5.7	5.8	5.9	52.9
Depreciation[3]	7.0	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	90.7
Taxes[4]	0.4	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	5.2
Deemed Return on Debt on Average Rate Base using 2020 Parameters[5]	11.0	14.6	14.4	14.3	14.1	13.9	13.7	13.6	13.4	13.2	136.2
Deemed Return on Equity on Average Rate Base using 2020 Parameters	19.7	26.1	25.8	25.5	25.2	24.8	24.5	24.2	23.9	23.6	243.2
Return on Equity Based on NextBridge's Proposed Revenue Requirement($M)	19.7	27.4	28.6	29.8	31.1	32.4	33.7	35.0	36.3	37.7	311.6
Calculated Return on Equity (%)	8.52	8.93	9.44	9.97	10.53	11.10	11.70	12.32	12.96	13.63	10.91[6]

[1] Exhibit E / Tab 1 / Schedule 1 / Table 3 / p. 2
[2] Exhibit F / Tab 1 / Schedule 1
[3] Exhibit F / Tab 11 / Schedule 1
[4] Exhibit F / Tab 13 / Schedule 1
[5] Exhibit G / Tab 1 / Schedule 1
[6] IR Term Average

TAB 10

(Revised from Version Contained in Original Compendium)

OEB Staff Table 5 – Revenue Requirement - 0% Inflation Factor and 0.5 % Stretch Factor

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	TOTAL
Staff Proposed Revenue Requirement($M)[1]	40.0	53.0	52.8	52.5	52.2	52.0	51.7	51.5	51.2	51.0	507.9
OM&A ($M)[2]	3.7	5.0	5.1	5.2	5.3	5.5	5.6	5.7	5.8	5.9	52.9
Depreciation($M)[3]	6.9	9.3	9.3	9.3	9.3	9.3	9.3	9.4	9.4	9.4	91.1
Taxes($M)[4]	0.4	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	5.2
Deemed Return on Debt on Average Rate Base ($M)[5]	9.6	12.8	12.6	12.5	12.3	12.2	12.0	11.9	11.7	11.6	119.2
Calculated Return on Equity on Average Rate Base ($M)[6]	19.3	25.4	25.1	24.9	24.7	24.5	24.3	24.0	23.8	23.6	239.5
Average Rate Base($M)	770.4	765.8	757.2	749.0	740.1	731.0	721.9	713.2	704.4	695.2	734.8[7]
Actual Return on Equity (%)	8.35	8.28	8.30	8.31	8.34	8.37	8.40	8.42	8.45	8.48	8.37[8]

[1] Based on 2021 OEB cost of capital parameters
[2] Exhibit F / Tab 1 / Schedule 1 with annual 2% increase in OM&A
[3] Exhibit F / Tab 11 / Schedule 1
[4] Exhibit F / Tab 13 / Schedule 1
[5] Exhibit G / Tab 1 / Schedule 1
[6] Staff Proposed Revenue Requirement – OM&A - Depreciation – Taxes – Deemed Return on Debt
[7] IR Term Average Includes IRM Capital Plan
[8] IR Term Average

TAB 11

(Revised from Version Contained in Original Compendium)

OEB Staff Table 6 – Revenue Requirement - Capital - 0% Inflation Factor and 0.75 % Stretch Factor and OM&A 2% Inflation Factor and 0.3% Stretch Factor

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	TOTAL
Staff Proposed Revenue Requirement($M)[1]	40.0	53.0	52.7	52.5	52.2	51.9	51.7	51.4	51.1	50.8	507.3
OM&A ($M)[2]	3.7	5.0	5.1	5.2	5.3	5.5	5.6	5.7	5.8	5.9	52.9
Depreciation($M)[3]	6.9	9.3	9.3	9.3	9.3	9.3	9.3	9.4	9.4	9.4	91.1
Taxes($M)[4]	0.4	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	5.2
Deemed Return on Debt on Average Rate Base ($M)[5]	9.6	12.8	12.6	12.5	12.3	12.2	12.0	11.9	11.7	11.6	119.2
Calculated Return on Equity on Average Rate Base ($M)[6]	19.3	25.3	25.1	24.9	24.6	24.4	24.2	23.9	23.7	23.5	239.0
Average Rate Base($M)	770.4	765.8	757.2	749.0	740.1	731.0	721.9	713.2	704.4	695.2	734.8[7]
Actual Return on Equity (%)	8.35	8.27	8.29	8.30	8.32	8.35	8.37	8.39	8.42	8.45	8.35[8]

[1] Based on 2021 OEB cost of capital parameters
[2] Exhibit F / Tab 1 / Schedule 1 with annual 2% increase in OM&A
[3] Exhibit F / Tab 11 / Schedule 1
[4] Exhibit F / Tab 13 / Schedule 1
[5] Exhibit G / Tab 1 / Schedule 1
[6] Staff Proposed Revenue Requirement – OM&A - Depreciation – Taxes – Deemed Return on Debt
[7] IR Term Average Includes IRM Capital Plan
[8] IR Term Average

TAB 12

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2017-0182

UPPER CANADA TRANSMISSION INC.
(ON BEHALF OF NEXTBRIDGE INFRASTRUCTURE)

Application for leave to construct an electricity transmission line between Thunder Bay and Wawa, Ontario

EB-2017-0194

HYDRO ONE NETWORKS INC.

Application to upgrade existing transmission station facilities in the Districts of Thunder Bay and Algoma, Ontario

EB-2017-0364

HYDRO ONE NETWORKS INC.

Application for leave to construct an electricity transmission line between Thunder Bay and Wawa, Ontario

BEFORE: Christine Long
Presiding Member

Allison Duff
Member

Michael Janigan
Member

February 11, 2019

3 DECISION ON THE TRANSMISSION LINE APPLICATIONS

Under section 96(1) of the Act, leave to construct is granted if the OEB is of the opinion that the project is in the public interest. In the circumstances of this case, pursuant to section 96(2) of the Act only the interests of consumers with respect to prices and the reliability and quality of electricity service shall be considered by the OEB in assessing whether a project is in the public interest.[13] As noted earlier, given the Priority Project OIC, the OEB must accept that the transmission line between Wawa and Thunder Bay is needed.

As noted above, in the December Decision, the OEB found that the NextBridge-EWT Project is acceptable from a reliability and quality of electricity service perspective. As a result, the outstanding issue is the interests of consumers with respect to prices. The OEB's concerns in this regard prompted it to allow for the submission of a NTE price by each of the proponents, in order to mitigate ratepayer risk.

Given the Directive, mitigation of ratepayer risk through a comparative analysis of two competing applications based on costs is no longer an option.

The OEB remains concerned with the construction costs put forward by NextBridge. At designation, NextBridge's cost estimate for the construction of the transmission line was $409 million. By the time it filed its leave to construct application, NextBridge's construction estimate had increased to $737 million. NextBridge did not provide an updated construction cost estimate since filing its application nor did NextBridge submit a construction cost estimate associated with a 2021 in-service date. During the oral hearing, NextBridge stated that if it did not have to accelerate to ensure a December 2020 in-service date, it could actually bring the construction costs in lower.[14] This Decision and Order should not be taken as accepting the level of costs of the NextBridge-EWT Project for the purposes of recovery from ratepayers. NextBridge will have to demonstrate the prudence of its costs when seeking to recover those costs in the future.

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[13] Section 96(2) of the Act also includes the promotion of the use of renewable energy sources as an issue to be considered, where applicable. As noted in the December Decision, the promotion of the use of renewable energy sources is not relevant in this case.
[14] EB-2017-0182/EB-2017-0194/EB-2017-0364 Oral Hearing Transcript, Volume 7, October 12, 2018, p. 50, lines 4-9.

TAB 13

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0182** **EB-2017-0194** **EB-2017-0364**	**Upper Canada Transmission Inc. (on behalf of NextBridge Infrastructure) and Hydro One Networks Inc.**

VOLUME:	**7**	
DATE:	**October 12, 2018**	
BEFORE:	**Christine Long**	**Presiding Member**
	Allison Duff	**Member**
	Michael Janigan	**Member**

MS. TIDMARSH: I will just confer with my panel. Thank you.

[Witness panel confers.]

MS. TIDMARSH: So if NextBridge did not have to accelerate to ensure that it was going to meet a December 2020 date, and a decision was made and communicated to NextBridge by the Board that the 2021 date was more appropriate, we believe that we could actually bring the costs in lower than what we have.

So we have some costs in there that are -- you can see in IR 49 there's four caveats about doubling up on management crews and that type of thing.

So we think that we will still be within the plus or minus 10 percent band, but we could be tighter on that.

MS. DUFF: Does that change your -- what is it called? -- the AACE Class 2? I mean, does that change you being in that class?

MS. TIDMARSH: No. So the AACE Class 2 is about the scope and how much design and work that's done on the project. So the scope is still the same; the scope has always been same. And so it doesn't change that kind of estimate, but it does with the work that we would be able to do -- and then -- but I will say it depends on what timing. So if it is just four months in, so if it is April 2021, it would be different than December 2021.

So we would actually have to have those conversations, but there would be less cost for compression in our schedule.

TAB 14

Prepared for:

NextBridge Infrastructure

Transmission Cost Benchmarking Study

Prepared by:

Charles River Associates

401 Bay Street, Suite 600

PO Box 46

Toronto, Ontario, M5H 2Y4

Date: October 13, 2020

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1. Overview

1.1. Mandate

Charles River Associates ("CRA") was engaged by NextBridge Infrastructure ("NextBridge") to prepare a benchmarking study of transmission projects comparable to that of its East-West Tie Line ("New EWT Line") as described in detail in Ontario Energy Board ("OEB") matter EB-2017-0182.

To complete this study, CRA reviewed publicly available data from transmission solicitations, public documents, regulatory filings, and benchmarking reports in an effort to present benchmarks against which to assess the reasonableness of the proposed costs of the New EWT Line. Wherever possible when choosing benchmarks, CRA considered specifics related to the New EWT Line's construction including project requirements, terrain, and technology.

Transmission projects are unique and there are a variety of factors that can contribute to differences in cost estimates across projects. Therefore, the ultimate goal of this benchmarking study is to employ objective research and analysis in order to provide the OEB with a basis for assessing the relative reasonableness of the projected costs of the New EWT Line. CRA has applied a sensitivity analysis its benchmark results in order to account for variations that can exist across cost escalation approaches.

1.2. Approach

In order to develop a robust set of comparable benchmarks, CRA reviewed a number of publicly available sources and included the following in this study:

- Hydro One's 2007 Bruce to Milton application and relevant transmission rate filings thereafter;
- BC Hydro's information on the Northwest Transmission Line project;
- Black & Veatch's 2014 transmission expansion planning report for the Western Electricity Coordinating Council ("WECC"); and,
- Alberta Electric System Operator's ("AESO") transmission cost benchmarking database.
- Hydro One's Niagara Reinforcement Limited Partnership's 2020-2024 Transmission Revenue Cap IR Application and Evidence Filing

CRA analyzed each of these and gathered information on reported costs of comparable transmission benchmarks. We have noted some particular challenges in benchmarking the New EWT Line against existing projects. In general, the overall challenge is the number of factors that make the New EWT Line unique from an engineering standpoint. This includes the challenging terrain and weather of Northwestern Ontario and use of double circuit guyed-Y tower type structures. It was challenging to find projects that were an exact technical match so in order to incorporate the uniqueness of the New EWT Line in this benchmarking study as effectively as possible, CRA endeavored to include only those benchmarks that were as technically similar to the New EWT Line as reasonably possible. The fundamental requirement was that benchmarks be as close to 240 kilovolt ("kV") as possible (only 230 kV, 240 kV and 287 kV projects were included), double circuit (if possible), and have relatively long line lengths (greater than 100 km was preferred, with the understanding that due to lack of available public cost information, lengths as low as 80 km were accepted). The difference between 230 kV, 240 kV and 287 kV was considered immaterial to overall cost. Bruce to Milton is an exception as it is 500 kV. In order to scale the Bruce to Milton project from 500 kV to 230 kV, CRA used the WECC 2014 study by Black and Veatch which provided the base capital cost per mile for projects of both voltages. On average, this study found that the base capital cost of a 500 kV double circuit project was 1.99 times more expensive than a 230 kV double circuit project. Therefore, CRA applied the factor of 1.99 to scale the 2012 reported cost of Bruce to Milton to approximate what a 230 kV would cost and then escalated this to 2022 dollars. Again, the difference between 240 kV and 230 kV was considered immaterial. While CRA considers this factor derived from WECC is the best available, its application in Ontario adds a degree of uncertainty to the results. CRA has accordingly applied a wider, +/- 5%, sensitivity band to this project to produce a wider range of potential benchmark cost results.

In general, all historical costs have been escalated to 2022 Canadian dollars ("CAD") using the extrapolated 2017 Handy-Whitman Index for utility construction costs in the United States ("US") Plateau region[1] and the Canadian Price Index ("CPI"). The CAD to US Dollar ("USD") annual average exchange rate was taken as published by the Board of Governors of the Federal Reserve System.[2]

For the sensitivity analysis, CRA applied +2% to -2% on the base 2017 CAD millions per km ("M/km") benchmark results to account for potential variations and subjectivity that can exist in cost escalation approaches. Once again, for Bruce to Milton this was extended to +/-5% to

1 The Handy-Whitman Index is prepared by Whitman, Requardt and Associates and is representative of cost trends for different types of utility construction. Separate Indices are published for the electric, gas and water industries. These are used by regulatory bodies, operating bodies, operating utilities, service companies, valuation engineers as well as insurance companies. For example, PJM uses this index to complete its annual update of Maintenance Adder Escalation Index Numbers. Handy-Whitman Index values are widely used to trend earlier valuations and original cost records to estimate reproduction cost at prices prevailing at a certain date. (Source: https://wrallp.com/about-us/handy-whitman-index)

2 Board of Governors of the Federal Reserve System (US), Canada / U.S. Foreign Exchange Rate [AEXCAUS], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/AEXCAUS, November 30, 2017.

capture potential uncertainties inherent in using the WECC 2014 model to scale the project from 500 kV to get a cost representative of a 230 kV.

2. Assumptions and Calculations

2.1. Foreign Exchange and Cost Escalation

Two primary data sources are expressed in USD: The WECC 2014 study and the Handy-Whitman index. The exchange rates used for this purpose and for adaptation of the Handy-Whitman index were the annual average of the USD to CAD daily exchange rates for the applicable year as published by the Board of Governors of the Federal Reserve System.

In order to estimate benchmark escalation, where granular costs were available CRA grouped them into three categories: (i) Materials; (ii) Construction; and (iii) Other. CRA calculated the cost share of each of these categories as a percentage of the project's total cost.

To escalate Materials costs, CRA used a blend of Handy-Whitman's Towers & Fixtures and Overhead Conductors and Devices indices. Materials involved in transmission project costs have large commodity components, even within Canada, these material elements would be expected to track the CAD equivalent of the USD index. The index escalation was therefore compounded with the exchange rate changes to arrive at an effective CAD Handy-Whitman index.

Material costs are driven largely by the economy at the time the project's materials were tendered. Changes in the price of commodities such as steel, aluminum and to a lesser extent, copper, drive changes to the price of materials. The volatility exhibited by these commodities makes it difficult to determine an constant annual growth rate for the purposes of cost escalation. Therefore, it is prudent in this case, to use with industry-standard best practice and use the Handy-Whitman Indices for transmission material costs. The Handy-Whitman index has been used by expert economic consulting firms in total factor productivity studies presented as evidence in matters before the OEB. There is no Canadian equivalent of the Handy-Whitman index suitable for escalating transmission project costs.

For Construction costs and Other costs, CRA has used the Canadian CPI to escalate benchmark costs. The labour element (at least) of Construction and Other costs is not freely traded between Canada and the US, so is much less impacted by exchange rate changes. CRA analyzed the 10-year compound annual growth rates ("CAGR") for Transmission Project Construction related costs reported by Statistics Canada's Electric Utility Consumer Price Index ("EUCPI") and found that these costs escalated ~2.3% per year on average from 2004 to 2014.

Since the EUCPI is currently being reviewed by Statistics Canada, it was not used in this study.[3] CRA decided that CPI at a 10-year CAGR of 1.6% ("CAD CPI") and 1.7% in the case of US CPI were appropriate and conservative escalators for Construction and Other costs.

The relative share of construction costs to total project cost varied widely across projects studied. Construction costs depend on the supply, demand and price of labour, but to a greater extent on the location of a project, its terrain, structures, geography, land use, and environmental considerations. Each of these factors influences the degree of construction and engineering complexity and ultimately, this impacts cost. Going from flat to mountainous terrain increases the cost of a transmission line, as the terrain influences where structures are located, how many structures will be required and which type (strength) of structures will be required. As terrain becomes more rugged, access to the site and construction also becomes more complex and costly. Construction costs for utility specific applications such as transmission or distribution are extremely dependent on the aforementioned factors.

Other costs include all other costs not classified as Materials or Construction. These can include but are not limited to, regulatory, engineering, development, and project management costs. For Other costs, CRA applied the CPI to escalate costs to 2022 dollars.

Handy-Whitman indices used for escalating Materials cost were taken from its Plateau Region, which includes Montana, Idaho, Wyoming, Nevada, Utah, Colorado, New Mexico, and Arizona. The Plateau region was chosen for a number of reasons. First, the population density and terrain of Montana, Wyoming, Idaho, and Colorado are generally similar to that of Northwestern Ontario with densely forested regions and mountainous terrain. Second, as depicted by Figure 1 and Figure 2, the Plateau indices for each of Towers and Fixtures and Conductors and Devices exhibit escalation generally at the lower end of the range, so that escalated cost results will be at the conservative end of the range of Handy-Whitman regions.

3 In 2014 Statistics Canada suspended the Electric Utility Construction Price Index ("EUCPI") series which measured the price change for constructing distribution systems and transmission lines systems. The EUCPI provided users with information that could be employed in contract escalation, cost-benefit analysis, benchmarking studies and time series analysis. The EUCPI is currently under review to ensure that the models used in its future computation will take into account current practices in construction. Source: Statistics Canada. Table 327-0011 - Electric utility construction price index (EUCPI), annual (Index, 1992=100) and CRA Analysis.

Figure 1. Handy-Whitman Towers and Fixtures (All Regions, CAD)

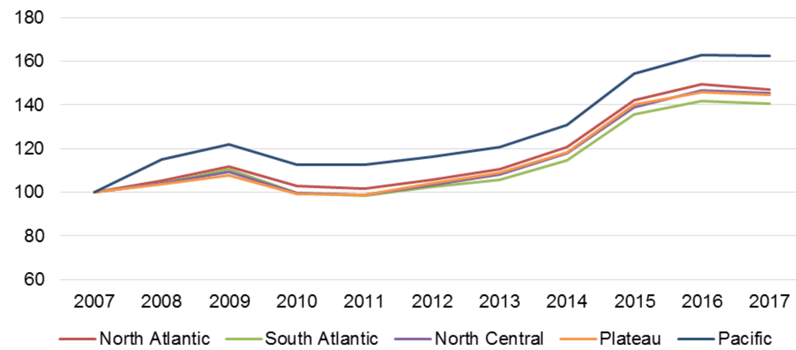
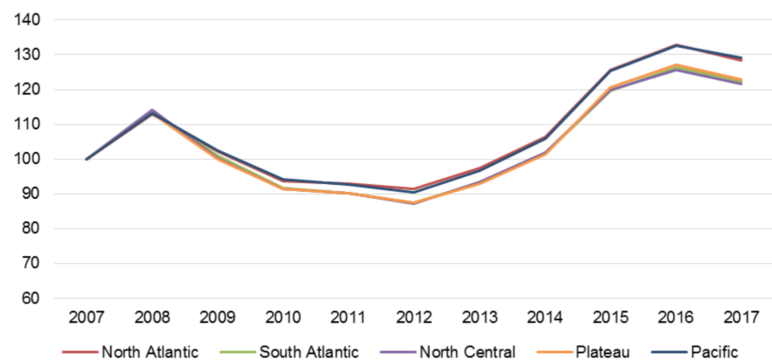


Figure 2. Handy-Whitman Overhead Conductors and Devices (All Regions, CAD)



2.2. Benchmark Calculations

2.2.1. New EWT Line

Development costs from August 2013 through July 2017, and construction costs starting in August 2017 were included to conduct the New EWT Line benchmarking. Construction costs are projected to end in 2022, with the commercial operation date anticipated by the end of March 2022.

For comparative purposes, CRA has analyzed the present value of the annual project costs for the New EWT Line so that all benchmark results could be compared in 2022 dollars. Costs as provided by NextBridge are included in Figure 3 while the costs adjusted to 2022 CAD are shown in Figure 4.

Figure 3. New EWT Line Annual Project Costs

Costs	Total	*Pre 8/1/2017*	2017	2018	2019	*2020 to COD*
Development	36,572	36,572	-	-	-	-
Construction	578,948	-	2,135	22,973	73,503	480,337
Materials*	66,870	-	-	-	11,242	55,628
Other	60,320	-	2,539	8,709	16,914	32,158
Subtotal	**742,710**	**36,572**	**4,674**	**31,682**	**101,659**	**568,123**
IDC	31,003	-	249	835	4,597	25,322
Total	**773,713**	**36,572**	**4,923**	**32,517**	**106,256**	**593,445**

*Materials outside of EPC contract; the Construction category has Materials sourced by EPC contractor

Figure 4. New EWT Costs in 2022 CAD

Discounted Costs	Disc.	*Pre 8/1/2017*	2017	2018	2019	*2020 to COD*
Development	1.6%	32,410	-	-	-	-
Construction	1.6%		1,970	21,538	70,031	465,089
Materials*	3.4%		-	-	10,134	51,910
Other	1.6%		2,342	8,165	16,115	31,137
Subtotal		**32,410**	**4,312**	**29,702**	**96,280**	**548,136**
IDC	1.6%	-	783	4,380	24,518	-
Total		**32,410**	**5,095**	**34,082**	**120,798**	**548,136**

Total Cost	**740,521**
Cost M/km	**1.65**

2.2.2. Bruce to Milton

In their initial 2007 application, Hydro One estimated that the total cost of the 500 kV Bruce to Milton project would be $635 million with $68 million, or 11%, estimated for station work.[4] However, in 2012 Hydro One submitted their 2013 - 2014 transmission rate application and cited in it that the cost of the Bruce to Milton project had increased to $732 million.[5] CRA has therefore assumed a total line cost of $651 million which is based on the updated total project cost estimate of $732 million (nominal $) included in Hydro One's rate application less 11% ($80.5 million) estimated for station work. Figure 5 provides CRA's assumptions for the Bruce to Milton project.

Figure 5. Bruce to Milton Calculations

Reported Costs	
2012 Reported Costs ($)	732,000,000
Less Station Cost ($)	(80,520,000)
2012 Line Cost ($)	651,480,000
Scaling Factor	1.99
2012 Line Cost Scaled to 230 kV ($)	327,376,884

Reporting Year	2012
Length (km)	180
Voltage	500 kV

Indices Used	2012	2022	CAGR	Growth
HW - Towers & Fixtures	494	780	4.7%	**4.7%**
HW - Overhead Conductors & Devices	536	853	4.8%	
Construction Costs - CPI	104	120	1.4%	**1.4%**
Other Costs - CPI	104	120	1.4%	**1.4%**

Cost Breakdown	% of total cost
Materials	**38.4%**
Construction	**13.4%**
Other	**48.1%**

Cost Escalation	2012 Costs	Assumed Growth	Escalation Factor	2022 Costs
Materials	$ 125,869,772	4.7%	1.59	$ 199,671,021
Construction	$ 43,881,205	1.4%	1.14	$ 50,216,640
Other	$ 157,625,907	1.4%	1.14	$ 180,383,458
Total Assumed Scaled Cost	**$ 327,376,884**		**Total Cost**	**$ 430,271,120**
			Cost M/km	**$ 2.39**

CRA then scaled the 500 kV project to a 230 kV project using the ratio between the baseline capital costs for each type of system as reported in the Black & Veatch's 2014 transmission expansion planning report for the WECC. According to this report a 500 kV system would be

4 Hydro One. *Project Cost, Economics and other Public Interest Considerations.* EB-2007-0050. Exhibit B. Tab 4. Schedule 1. March 29, 2007. pp. 1-2. This figure for Bruce-Milton does not appear to include development costs.

5 Hydro One. *In-Service Capital Additions.* EB-2012-0031. Exhibit D1, Tab 1, Schedule 2. August 15, 2012. p2.

1.99 times more costly per mile, than a 230 kV system.[6] After scaling, the 2012 total line cost is approximately $327 million.

2.2.3. BC Hydro's Northwest Transmission Line

The Northwest Transmission Line is a 344 km, 287 kV single circuit guyed lattice tower transmission line[7] between Skeena BC and Bob Quinn Lake. It was completed in 2014 at a total reported cost of $746 million.[8] This includes costs for substations but because the project was exempt from the Utilities Commission Act and a regulatory review was not undertaken, detailed cost estimates, annual project cash flows, and substation costs are not publicly available. CRA has therefore assumed 11% (or $82 million) of the total cost of the project was attributable to substations work consistent with the Bruce to Milton project. CRA also recognizes that some of the project costs would have been incurred in years prior to 2014. CRA has taken the conservative approach by escalating the total project cost from 2014 to 2022 by assuming that all costs were incurred in 2014. Figure 6 provides the calculations for the Northwest Transmission Line benchmark results under these assumptions.

Figure 6. Northwest Transmission Line Calculations

Statement of Average Rate Base ($CAD)		
2014 Reported Costs	$	746,000,000
Less Substation Cost Estimate	$	(82,060,000)
2014 Total Costs	$	663,940,000

Reporting Year	2014
Length km	344
Voltage	287kV

Indices Used	2014	2022	CAGR	Growth
HW - Towers & Fixtures	560	780	4.2%	4.1%
HW - Overhead Conductors & Devices	624	853	4.0%	
Construction Costs - CPI	107	120	1.3%	1.3%
Other Costs - CPI	107	120	1.3%	1.3%

NRLP Rate Base	2014 Amount ($ Mil per km)	Annual Growth	Escalation Factor	2022
	$ 663,940,000	2%	1.31	$ 870,506,162

2022 Total Cost (76 km	$ 870,506,161.65
2022 Total Cost M/km	$ 2.53

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6 WECC 2014 includes new line cost 2014 (USD/mile) of $3,071,750 for a 500 kV double circuit system and $1,536,400 for a 230 kV double circuit system.

7 Burns and McDonnell. *Northwest Transmission Line.* https://www.burnsmcd.com/projects/northwest-transmission-line.

8 Correspondence with BC Hydro Stakeholder Engagement. January 2, 2018.

2.2.4. Alberta Projects

All transmission facility capital cost estimates and final costs for projects built in Alberta since 2005 are entered into the AESO cost benchmark database.[9] CRA filtered through the AESO database to display the actual costs for two 100+ km double circuit, 240 kV projects. Both projects used in this analysis as benchmarks are actual projects constructed in Alberta in 2010[10] with costs reported by the AESO in 2013 CAD. Costs included and reported by AESO were grouped into categories by CRA as follows and escalated from 2013 to 2022:

- **Materials:** Conductor, Hardware, Lattice Structures
- **Labor:** Construction, ROW Preparation Brush, Engineering, Survey
- **Others:** Contingency and Escalation, Owner Costs, Project and Construction Management, Salvage, AFUDC, and E&S

This data provided granular-enough cost categories such that CRA was able to take proportionate shares of materials, construction and other costs into consideration when escalating costs. These assumptions and calculations are shown in Figure 7.

9 AESO. Transmission Costs. <https://www.aeso.ca/grid/transmission-costs>

10 Project 1 is representative of the AESO's Line Facility ID: L10611336112 and Project 2 is representative of the AESO's Line Facility ID: L_10607745763.

Figure 7. Alberta Benchmark Calculations

Reported Costs Project 1 Line ID: L_10311336112		
2013 Reported Costs	$	3,261,617
2013 Line Cost (per km)	$	3,261,617
2013 Line Cost (450 km)	$	1,467,727,650

Reporting Year	2013
Length km	450
Voltage	240 kV

Reported Costs Project 2 Line ID: L_10607745763		
2013 Reported Cost	$	2,962,952
2013 Line Cost (per km)	$	2,962,952
Line Cost (per 450 km)	$	1,333,328,400

Reporting Year	2013
Length km	450
Voltage	240 kV

Indices Used	2013	2022	CAGR	Growth
HW - Towers & Fixtures	529	780	4.4%	4.5%
HW - Overhead Conductors & Devices	569	853	4.6%	
Construction Costs - CPI	105	120	1.4%	1.4%
Other Costs - CPI	105	120	1.4%	1.4%

Project 1: Cost Breakdown	% of total cost
Materials	16.3%
Construction	33.0%
Other	50.7%

Project 2: Cost Breakdown	% of total cost
Materials	16.6%
Construction	33.6%
Other	49.8%

Project 1 Cost Escalation		2013 Amount (per km)	Annual Growth	Escalation Factor		2022 Amounts
Materials	$	530,346	4.5%	1.49	$	788,661
Construction	$	1,076,247	1.4%	1.13	$	1,220,183
Other	$	1,655,024	1.4%	1.13	$	1,876,366
				Total Cost	$	3,885,210
				Cost M/km	$	3.89
				Cost (450 km)	$	1,748,344,517

Project 2 Cost Escalation		2013 Amount (per km)	Annual Growth	Escalation Factor		2022 Amounts
Materials	$	491,421	4.5%	1.49	$	730,777
Construction	$	996,451	1.4%	1.13	$	1,129,716
Other	$	1,475,080	1.4%	1.13	$	1,672,356
				Total Cost	$	3,532,848
				Cost M/km	$	3.53
				Cost (450 km)	$	1,589,781,807

Project 1 Cost Escalation		2013 Amount (per km)	Annual Growth	Escalation Factor		2017 Amounts
Materials	$	530,346	7.5%	1.33	$	707,166
Construction	$	1,076,247	1.5%	1.06	$	1,140,619
Other	$	1,655,024	1.5%	1.06	$	1,754,013
				Total Cost	$	3,601,798
				Cost M/km	$	3.60
				Cost (450 km)	$	1,620,809,051

Project 2 Cost Escalation		2013 Amount (per km)	Annual Growth	Escalation Factor		2017 Amounts
Materials	$	491,421	7.5%	1.33	$	655,263
Construction	$	996,451	1.5%	1.06	$	1,056,050
Other	$	1,475,080	1.5%	1.06	$	1,563,307
				Total Cost	$	3,274,620
				Cost M/km	$	3.27
				Cost (450 km)	$	1,473,578,867

2.2.5. Western Electricity Coordinating Council 2014 Study

CRA took the base capital cost for a 230 kV double circuit project from the Black & Veatch 2014 transmission expansion planning report done for the WECC in 2014 and applied cost escalation of approximately 1.4% per year to determine the 2022 base capital cost in USD per mile. CRA then applied the following multipliers and adders to this base 2022 USD capital cost:

- **Conductor Type:** ACSR, cost multiplier of 1.00
- **Transmission Structure:** Lattice, cost multiplier of 0.90
- **Transmission Length:** > 10 miles, cost multiplier of 1.00
- **Terrain:** Forested, PG&E, cost multiplier of 1.50[11]
- **Right of Way Widths:** 64m, equating to 25.44 ROW/acres per mile[12]
- **Land Cost/Acre:** BLM zone 6, equating to a land cost of $1,024 USD per acre

CRA then applied a forecasted 2022 CAN/USD exchange rate of 1.33 and converted miles to km to arrive at the total cost per km in 2022 CAD. Figure 8 provides the calculation breakdown for the WECC benchmark.

Figure 8. WECC Benchmark Calculations

11 CRA utilized the terrain cost multiplier provided by NextBridge.

12 CRA relied on a 65m ROW width provided by NextBridge. Acres/mile values were calculated in accordance with the WECC study, by multiplying the right of way width by 5,280 feet per mile and dividing by 43,560 sq. ft. per acre.

Reported Capital Costs		
Total Capital Cost (2014 USD per Mile)	$	1,536,400

Reporting Year	2014
Length km	450
Length (mile)	280
ROW Width for New EWT (miles)	64
Voltage	230 kV
miles to km	1.60934

Multipliers and Adders	Capital Cost Multiplier
Conductor: ACSR	1.0
Transmission Structure: Lattice	0.9
Length: >10 miles	1.0
Terrain: Forested	1.5
ROW/acres per mile	25.44
Land Cost/acre: BLM Zone 6	1,024

Indices Used (USD)	2014	2022	CAGR	Growth
HW - Towers & Fixtures	507	588	1.9%	1.7%
HW - Overhead Conductors & Devices	565	643	1.6%	
Construction Costs - CPI	109	120	1.2%	1.2%
Other Costs - CPI	109	120	1.2%	1.2%
CAN/USD FX	1.10	1.33	2.3%	2.3%

Average Annual Growth Rate		1.4%
Total Capital Cost (2022 USD per Mile)	$	1,707,155
Total Cost Per Mile (incl. Multipliers & Adders)	$	2,330,715
Total Cost Per Mile (2022 CAD)	$	3,092,626
Total Cost Per Km (2022 CAD)	$	1,921,673
Total Cost (M/km)	**$**	**1.92**

2.2.6. Niagara Reinforcement

- For the 2020 update, CRA reviewed the settlement agreement filed with the Ontario Energy Board in connection with the application by the Niagara Reinforcement Limited Partnership (NRLP). The 76 km double circuit 230 kV transmission line connects the Allanburg Transformer Station and the Middleport Transformer Station. The settlement agreement included the NRLP Statement of Average Rate Base for 2019. CRA used the Handy-Whitman Index and the USD/CAD exchange rate in order to calculate material and index cost growth from 2017 to 2022 (Demonstrated in Figure 14. Indices Used in Analysis)[13]. The calculations for the 2022 Total Cost of $1.66 million per kilometer are demonstrated below in Figure 9. NRLP Benchmark Calculations
- **Materials:** Conductor, Towers & Fixtures
- **Construction:** Transmission Corridor Land and Rights

Figure 9. NRLP Benchmark Calculations

[13] The Niagara region has different, and more difficult, terrain than that of Northwestern Ontario, which may lead lower construction costs compared to Northwestern Ontario.

Statement of Average Rate Base ($CAD)		
2019 Report Costs (per km)	$	1,571,447
2019 Reported Costs (76 km)	$	119,430,000
2022 Line Cost (per km)	$	1,657,500
2022 Line Cost (76 km)	$	125,970,027

Reporting Year	2019
Length km	76
Voltage	230 kV

Indices Used	2019	2022	CAGR	Growth
HW - Towers & Fixtures	741	780	1.8%	1.8%
HW - Overhead Conductors & Devices	808	853	1.8%	
Construction Costs - CPI	115	120	1.4%	1.4%
Other Costs - CPI	115	120	1.4%	1.4%

NRLP Rate Base	2019 % of total cost
Materials	99.2%
Construction	0.8%
Other	0.0%

NRLP Rate Base	2019 Amount ($ Mil per km)		Annual Growth	Escalation Factor	2022	
Materials	$	1.56	1.8%	1.05	$	1.64
Construction	$	0.01	1.4%	1.04	$	0.01
Other	$	-	1.4%	1.04	$	-

2022 Total Cost per Kn	$	1,657,500
2022 Total Cost (76 km	$125,970,026.97	
2022 Total Cost M/km	$	1.66

2.3. Operation, Maintenance & Administration Expenses

As part of the 2020 update, CRA was asked to review the Operation, Maintenance, & Administration (OM&A) benchmarking for Bruce to Milton and Niagara Reinforcement rate case filings. On page 233 of Hydro One's Niagara Reinforcement Revenue Cap IR Application they included Summary costs of OM&A for forecast year 2020 added to Figure 10. Bruce to Milton, Niagara & New EWT OM&A Benchmarking. In Hydro One's Bruce to Milton Cost of Service Application, OM&A costs were included for 2014 to 2019. The Bruce to Milton OM&A costs for 2019 can be found in Figure 10. Additionally, the final line in Figure 10 assumes a 1/1.30 exchange rate for USD/CAD.

Figure 10. Bruce to Milton, Niagara & New EWT OM&A Benchmarking

$k (CAD)	Niagara 2020	Bruce-Milton 2019	New EWT
O&M Expenses	320	600	1,275
Admin. & Corporate[14]	510	200	1,665
Regulatory			65
Total OM&A	**830**	**1,600**[15]	**3,005**[16]

14 The figure for the Niagara project includes costs associated with the Managing Director's office

15 Includes "Incremental expenses" of $800k (CAD)

16 The new EWT also includes expenses for Indigenous Participation and Compliance costs. As these are not directly comparable to the other projects, and unique to the EWT, they have been excluded from this total.

Total kilometers	76	180	450
OM&A / km (CAD)	**10.92**	**8.89**	**6.68**
OM&A / km (USD)	8.40	6.84	5.14

3. Results

CRA benchmarked the current estimated New EWT Line capital cost[17] against other projects using the approach and assumptions described above. CRA has included the indices used in cost escalation in Appendix A. Figure 11 provides an overview of the benchmarking results, which shows that the current estimated costs for the New EWT Line at $1.65 M/km are reasonable and cost-effective when compared to other similar transmission projects.

To ensure robustness of the analysis CRA has also provided results when base M/km results are scaled up and down by 2%. The results for this sensitivity analysis are shown in Figure 12. The resulting range around the base results and how they compare to the New EWT cost are shown graphically in Figure 13 where the vertical lines represent the variation around the base case, with the base case represented by the small blue diamonds. This graphic illustrates that even under the widest ranges of sensitivity on the cost escalation indices used, the New EWT Line remains reasonable compared to other similar projects.

Figure 11. Benchmarking Base Results[18]

	NextBridge EWT (Designation Proceeding)	New EWT	Bruce to Milton	BC NTL	2014 WECC	AESO Project 1	AESO Project 2	Niagara
Voltage (kV)	230 kV	230 kV	500 kV	287 kV	230 kV	240 kV	240 kV	230 kV
Length (km)	400	450	180	344	450	450	450	76
Costs reported in $	2012	2017	2012	2014	2014	2013	2013	2019
Total Cost Line Only ($M)	**419**	**711**	**327**	**664**	**653**	**1468**	**1333**	**119**
Line Cost (adjusted to 2022 $M)	**489**	**741**	**430**	**871**	**866**	**1748**	**1590**	**126**
2022 Cost M/km	**1.22**	**1.65**	**2.39**	**2.53**	**1.92**	**3.89**	**3.53**	**1.66**

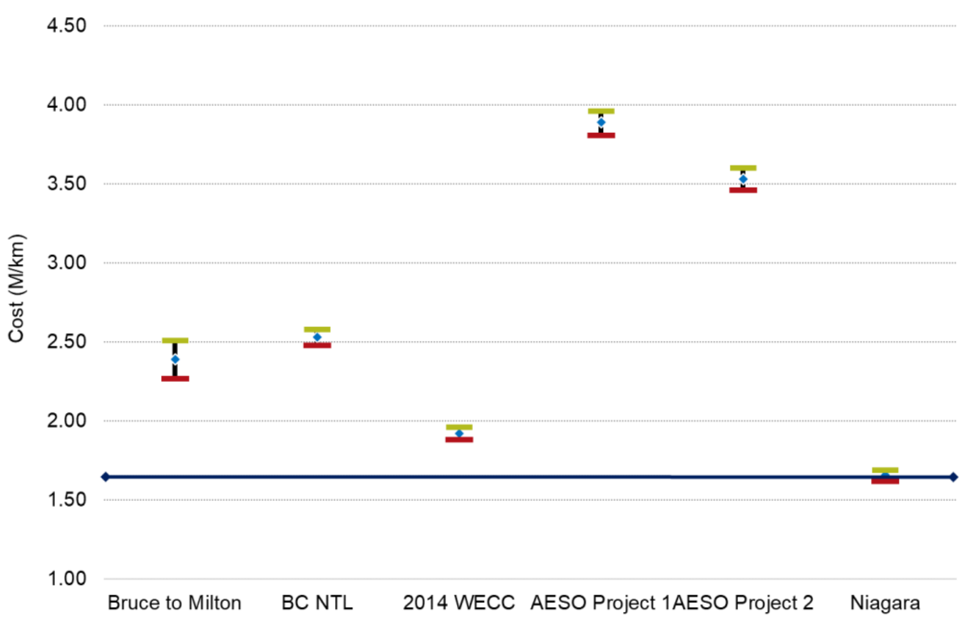
17 Capital cost is an all-in amount, including development and constructions costs.

18 Note: Bruce to Milton has been scaled to 230 kV by a factor of 1.99, consistent with the differences in base capital cost in the WECC 2014 study.

Figure 12. Sensitivity Analysis Results

Sensitivity Analysis	Bruce to Milton	BC NTL	2014 WECC	AESO Project 1	AESO Project 2	Niagara
5%	2.51					
4%	2.49					
3%	2.46					
2%	2.44	2.58	1.96	3.96	3.60	1.69
1%	2.41	2.56	1.94	3.92	3.57	1.67
-1%	2.37	2.51	1.90	3.85	3.50	1.64
-2%	2.34	2.48	1.88	3.81	3.46	1.62
-3%	2.32					
-4%	2.29					
-5%	2.27					

Figure 13. Range of Benchmark Results



The estimated average project capital cost per km for the New EWT Line in 2022 CAD is approximately $1.65 M/km which is calculated by discounting annual Construction project costs by the 10-year CAGR for CPI, annual Materials costs by the 10-year CAGR of the Handy-Whitman Plateau Indices, and by discounting Other costs again, by CPI. Construction costs, however, can be very weather-dependent, and harsher weather in Northwestern Ontario compared to the Plateau region may lead our estimates to be conservative.

This calculation results in New EWT Line total 2022 project costs of $741M, and at $1.65 M/km, it is a lower-cost project compared to the benchmarks presented in Figure 11. Costs per km for the New EWT Line remain lower than the benchmarks even under forecasting sensitivity tests.

The Bruce to Milton benchmark ranges from $2.27 M/km to $2.51 M/km. This project has been scaled down to a 230 kV using the WECC study but even under the widest sensitivity bands, the New EWT Line is still less expensive.

BC's Northern Transmission Line is estimated at $2.53 M/km in the benchmarking base case. Compared to this project in BC, the estimated New EWT cost per km is significantly lower.

The Niagara Reinforcement is estimated at $1.66 M/km. The cost for the 76 kilometer, 230kV line is relatively low compared to other projects, and similar to the new EWT Line.

A WECC study from 2014 estimated that a 230 kV transmission line located in a forested area that uses the same conductor type (ACSR) as the New EWT Line would be $1.92 M/km.

Finally, the AESO's cost benchmark database offers two technically similar project costs, one project at a cost of $3.89 M/km and another at $3.53 M/km. Both of these projects are 240 kV double circuit transmission lines larger than 100 km constructed in Alberta.

Appendix A: Benchmarking Analysis Inputs

Figure 14. Indices Used in Analysis

Handy Whitman Plateau (USD)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	*2018*	*2019*	*2020*	*2021*	*2022*		10-Year CAGR	5-Year CAGR
HW - Towers & Fixtures	424	463	471	458	474	494	514	507	523	526	539	*548*	*558*	*568*	*578*	*588*		2.4%	1.8%
HW - Poles & Fixtures	473	498	521	540	518	529	533	526	540	541	546	*549*	*553*	*556*	*560*	*564*		1.4%	0.6%
HW - Structural Steel Erected	444	509	510	469	488	497	513	511	519	495	514	*517*	*521*	*524*	*528*	*532*		1.5%	0.7%
HW - Overhead Conductors & De	559	613	678	551	543	536	552	565	582	601	587	*598*	*609*	*620*	*631*	*643*		0.5%	1.8%
																	Average	**1.5%**	**1.4%**
US CPI (2010 = 100)	94.9	98.7	98.4	100.0	103.2	105.3	106.8	108.6	108.7	110.1	112.2	*113.6*	*115.1*	*116.5*	*118.0*	*119.5*		**1.7%**	**1.3%**
CAN CPI (2010=100)	95.6	98.0	98.3	100.0	102.9	104.5	105.5	107.5	108.7	110.2	111.8	*113.3*	*114.8*	*116.4*	*118.0*	*119.6*		**1.6%**	**1.4%**
FX USD/CAD	1.07	1.07	1.14	1.03	0.99	1.00	1.03	1.10	1.28	1.32	1.30	*1.30*	*1.33*	*1.33*	*1.33*	*1.33*			

Handy Whitman Plateau (CAD)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	*2018*	*2019*	*2020*	*2021*	*2022*		10-Year CAGR	5-Year CAGR
HW - Towers & Fixtures	455	494	537	472	469	494	529	560	669	697	700	*711*	*741*	*754*	*767*	*780*		4.4%	7.2%
HW - Poles & Fixtures	508	531	595	556	512	529	549	581	691	716	709	*712*	*734*	*738*	*743*	*748*		3.4%	6.0%
HW - Structural Steel Erected	477	543	582	483	482	497	528	564	664	656	667	*670*	*691*	*696*	*701*	*705*		3.4%	6.1%
HW - Overhead Conductors & De	600	653	774	567	537	536	569	624	744	796	762	*775*	*808*	*823*	*838*	*853*		2.4%	7.3%
																	Average	**3.4%**	**6.9%**
US CPI (2010 = 100)	94.9	98.7	98.4	100.0	103.2	105.3	106.8	108.6	108.7	110.1	112.2	*113.6*	*115.1*	*116.5*	*118.0*	*119.5*		**1.7%**	**1.3%**
CAN CPI (2010=100)	95.6	98.0	98.3	100.0	102.9	104.5	105.5	107.5	108.7	110.2	111.8	*113.3*	*114.8*	*116.4*	*118.0*	*119.6*		**1.6%**	**1.4%**

CRA Notes
1. HW Plateau (USD) for 2018-2022 is calculated based on 2012 to 2017 CAGR
2. CPI for 2018-2019 is calculated based on 2012 to 2017 CAGR
3. FX USD/CAD is added for 2018 and 2019 using Bank of Canada Annual Exchange Rates
4. HW Plateau (CAD) for 2018-2019 is calculated using the USD/CAD and HW Plateau (USD) figures

Figure 15. Electric Utility Construction Price Index (Indicative Only)[19]

Transmission Construction Price Index Components	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	10-Year CAGR	5-Year CAGR
Initial grading and clearing	136.6	149.7	160.4	176.7	194.5	191.4	191.2	195.6	198.3	186.6	189.2	3.3%	-0.2%
Installation labour	127.2	125.3	127.5	130.3	127.7	127.2	132.8	143.4	147.1	142.1	138.8	0.9%	1.8%
Installation equipment	139	142.9	144.6	144.7	154	156.1	149.3	150	153	156.7	164.4	1.7%	1.0%
Construction indirects	122.3	121.3	123.5	128.9	131	140.5	143.4	147.8	146.9	146.3	152.8	2.3%	1.7%
Engineering	130.4	130.8	133	138.9	142	154.2	158.1	164.5	166.4	164.2	172.4	2.8%	2.3%
Head office administration	129.5	130	132.2	137.8	140.9	152	155.8	161.7	163.5	161.7	169.5	2.7%	2.2%
											Average	**2.3%**	**1.5%**

19 Statistics Canada. Table 327-0011 - Electric utility construction price index, annual (index, 1992=100) which was discontinued in 2014.

TAB 15

Prepared for:

NextBridge Infrastructure

Transmission Cost Benchmarking Study

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Date: January 18, 2018

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1. Overview

1.1. Mandate

Charles River Associates ("CRA") was engaged by NextBridge Infrastructure ("NextBridge") to prepare a benchmarking study of transmission projects comparable to that of its East-West Tie Line ("New EWT Line") as described in detail in Ontario Energy Board ("OEB") matter EB-2017-0182.

To complete this study, CRA reviewed publicly available data from transmission solicitations, public documents, regulatory filings, and benchmarking reports in an effort to present benchmarks against which to assess the reasonableness of the proposed costs of the New EWT Line. Wherever possible when choosing benchmarks, CRA considered the specifics related to the New EWT Line's construction including project requirements, terrain, and technology.

Transmission projects are highly unique and there are a variety of factors that can contribute to differences in cost estimates across projects. Therefore, the ultimate goal of this benchmarking study is to employ objective research and analysis in order to provide the OEB with a basis for assessing the relative reasonableness of the projected costs of the New EWT Line. CRA has applied a sensitivity analysis on its benchmark results in order to account for variation that can exist across cost escalation approaches.

1.2. Approach

In order to develop a robust set of comparable benchmarks, CRA reviewed a number of publicly available sources and ultimately included the following in this study:

- Hydro One's 2007 Bruce to Milton application and relevant transmission rate filings thereafter;
- BC Hydro's information on the Northwest Transmission Line project;
- Black & Veatch's 2014 transmission expansion planning report for the Western Electricity Coordinating Council ("WECC"); and,
- Alberta Electric System Operator's ("AESO") transmission cost benchmarking database.

CRA analyzed each of these and gathered information on reported costs of comparable transmission benchmarks. We have noted some particular challenges in benchmarking the New EWT Line against existing projects. In general, the overarching challenge is the many factors that make the New EWT Line unique from an engineering standpoint. This includes the challenging terrain of Northern Ontario and use of double circuit guyed-Y tower type structures. It was challenging to find projects that were an exact technical match so in order to incorporate the uniqueness of the New EWT Line in this benchmarking study as effectively as possible, CRA endeavored to include only those benchmarks that were as technically similar to the New EWT Line as reasonably possible. The fundamental requirement was that benchmarks be as close to 240 kilovolt ("kV") as possible (only 230 kV, 240 kV and 287 kV projects were included), double circuit (if possible), and have relatively longer line lengths (greater than 100 km was preferred, with the understanding that due to lack of available public cost information, lengths as low as 80 km were accepted). The difference between 230 kV, 240 kV and 287 kV was considered immaterial to overall cost. Bruce to Milton is an exception as it is 500 kV. In order to scale the Bruce to Milton project from 500 kV to 230 kV, CRA used the WECC 2014 study by Black and Veatch which provided the base capital cost per mile for projects of both voltages. On average, this study found that the base capital cost of a 500 kV double circuit project was 1.99 times more expensive than a 230 kV double circuit project. Therefore, CRA applied the factor of 1.99 to scale the 2012 reported cost of Bruce to Milton to approximate what a 230 kV would cost and then escalated this to 2017 dollars. Again, the difference between 240 kV and 230 kV was considered immaterial. While CRA considers this factor derived from WECC is the best available, its application in Ontario adds a degree of uncertainty to the results. CRA has accordingly applied a wider, +/- 5%, sensitivity band to this project to produce a wider range of potential benchmark cost results.

In general, all historical costs have been escalated to 2017 Canadian dollars ("CAD") using the 2017 Handy-Whitman Index for utility construction costs in the United States ("US") Plateau region[1] and the Canadian Price Index ("CPI"). The CAD to US Dollar ("USD") annual average exchange rate was taken as published by the Board of Governors of the Federal Reserve System.[2]

For the sensitivity analysis, CRA applied +2% to -2% on the base 2017 CAD millions per km ("M/km") benchmark results to account for potential variations and subjectivity that can exist in cost escalation approaches. Once again, for Bruce to Milton this was extended to +/-5% to

1 The Handy-Whitman Index is prepared by Whitman, Requardt and Associates and is representative of cost trends for different types of utility construction. Separate Indices are published for the electric, gas and water industries. These are used by regulatory bodies, operating bodies, operating utilities, service companies, valuation engineers as well as insurance companies. For example, PJM uses this index to complete its annual update of Maintenance Adder Escalation Index Numbers. Handy-Whitman Index values are widely used to trend earlier valuations and original cost records to estimate reproduction cost at prices prevailing at a certain date. (Source: https://wrallp.com/about-us/handy-whitman-index)

2 Board of Governors of the Federal Reserve System (US), Canada / U.S. Foreign Exchange Rate [AEXCAUS], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/AEXCAUS, November 30, 2017.

capture potential uncertainties inherent in using the WECC 2014 model to scale the project from 500 kV to get a cost representative of a 230 kV.

2. Assumptions and Calculations

2.1. Foreign Exchange and Cost Escalation

Two primary data sources are expressed in USD: The WECC 2014 study and the Handy-Whitman index. The exchange rates used for this purpose and for adaptation of the Handy-Whitman index was the annual average of the USD to CAD daily exchange rates for the applicable year as published by the Board of Governors of the Federal Reserve System.

In order to estimate benchmark escalation, where granular costs were available CRA grouped them into three categories: (i) Materials; (ii) Construction; and (iii) Other. CRA calculated the cost share of each of these categories as a percentage of the project's total cost.

To escalate Materials costs, CRA used a blend of Handy-Whitman's Towers & Fixtures and Overhead Conductors and Devices indices. Materials involved in transmission project costs have large commodity components, even within Canada, these material elements would be expected to track the CAD equivalent of the USD index. The index escalation is therefore compounded with the exchange rate changes to arrive at an effective CAD Handy-Whitman index. Furthermore, Material costs are driven largely by the economy at the time the project's materials were tendered and changes in the price of the raw materials used for the physical infrastructure elements of the project (i.e., towers, conductors, and wires). Changes in the price of commodities such as steel, aluminum and to a lesser extent, copper drive changes to the price of materials. The volatility exhibited by these commodities makes it difficult to determine an accurate annual growth rate for the purposes of cost escalation. Therefore, it is prudent in this case, to go with industry standard best practice and use the Handy-Whitman Indices for transmission material costs. The Handy-Whitman index has been used by expert economic consulting firms in total factor productivity studies presented as evidence in matters before the OEB. There is no Canadian equivalent of the Handy-Whitman index suitable for escalating transmission project costs.

For Construction costs and Other costs, CRA has used the Canadian CPI to escalate benchmark costs. The labour element (at least) of Construction and Other costs is not freely traded between Canada and the US, so is much less impacted by exchange rate changes. CRA analyzed the 10-year compound annual growth rates ("CAGR") for Transmission Project Construction related costs reported by Statistics Canada's Electric Utility Consumer Price Index ("EUCPI") and found that these costs escalated ~2.3% per year on average from 2004 to 2014.

Since the EUCPI is currently being reviewed by Statistics Canada, it was not used in this study.[3] However, comparatively, CRA decided that CPI at a 10-year CAGR of 1.6% (CAD CPI) and 1.7% in the case of US CPI were appropriate and conservative escalators for Construction and Other costs.

The relative shares of construction costs to total project cost varied widely across projects studied. Construction costs depend on the supply, demand and price of labour, but to a greater extent on the location of a project, its terrain, structures, geography, land use, and environmental considerations. Each of these factors influences the degree of construction and engineering complexity and ultimately, this impacts cost. Going from flat to mountainous terrain increases the cost of a transmission line as terrain influences where structures are located, how many structures will be required and which type (strength) of structures will be required. As terrain becomes more rugged, access to the site and construction also gets more complex and costly. Construction costs for utility specific applications such as transmission or distribution are extremely dependent on the aforementioned factors.

Other costs include all other costs not classified as Materials or Construction. These can include but are not limited to, regulatory, engineering, development, and project management costs. For Other costs, CRA applied the CPI to escalate costs to 2017.

Handy-Whitman indices used for escalating Materials cost were taken from its Plateau Region, which includes Montana, Idaho, Wyoming, Nevada, Utah, Colorado, New Mexico, and Arizona. The Plateau region was chosen for a number of reasons. First, the population density and terrain of Montana, Wyoming, Idaho, and Colorado are generally similar to that of Northern Ontario with densely forested regions and mountainous terrain. Second, as depicted by Figure 1 and Figure 2, the Plateau indices for each of Towers and Fixtures and Conductors and Devices exhibit escalation generally at the lower end of the range, so that escalated cost results will be at the conservative end of the range of HW regions.

3 In 2014 Statistics Canada suspended the Electric Utility Construction Price Index ("EUCPI") series which measured the price change for constructing distribution systems and transmission lines systems. The EUCPI provided users with information that could be employed in contract escalation, cost-benefit analysis, benchmarking studies and time series analysis. The EUCPI is currently under review to ensure that the models used in its future computation will take into account current practices in construction. Source: Statistics Canada. Table 327-0011 - Electric utility construction price index (EUCPI), annual (Index, 1992=100) and CRA Analysis.

Figure 1. Handy-Whitman Towers and Fixtures (All Regions, CAD)

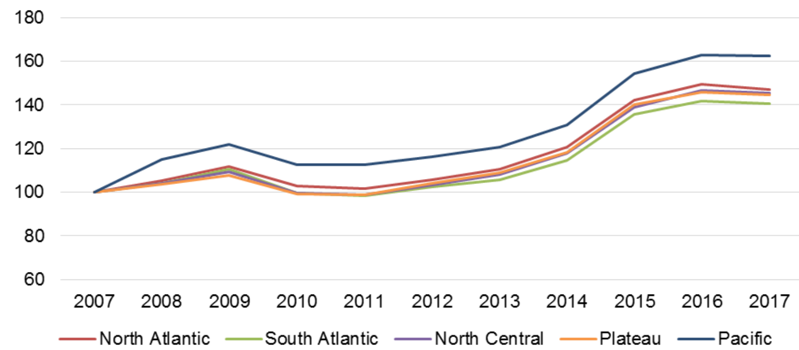
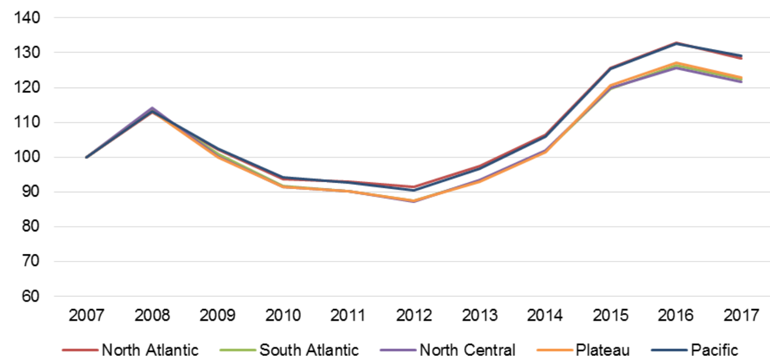


Figure 2. Handy-Whitman Overhead Conductors and Devices (All Regions, CAD)



2.2. Benchmark Calculations

2.2.1. New EWT Line

Costs for the New EWT Line will occur starting in 2017 and will culminate in 2020 when the project is anticipated to reach commercial operation. For comparative purposes, CRA has taken the present value of the annual project costs for the New EWT Line so that all benchmark results could be compared in 2017 dollars. Costs as provided by NextBridge are included in Figure 3 while the costs de-escalated to 2017 CAD are shown in Figure 4.

Figure 3. New EWT Line Annual Project Costs

	Total	2017	2018	2019	2020
Construction	$ 447,677	$ -	$ 30,591	$ 233,538	$ 183,548
Materials	$ 89,408	$ -	$ 17,882	$ 44,704	$ 26,822
Other	$ 209,093	$ 42,055	$ 41,158	$ 54,322	$ 71,558
subtotal	$ 746,178	$ 42,055	$ 89,631	$ 332,564	$ 281,928
AFUDC	$ 31,003	$ 326	$ 2,269	$ 9,136	$ 19,272
Total	**$ 777,181**	**$ 42,381**	**$ 91,900**	**$ 341,700**	**$ 301,200**

Figure 4. New EWT Costs in 2017 CAD

Costs	Index & Discount Factors		2017	2018	2019	2020
Construction	CPI	1.6%	$ -	$ 30,116	$ 226,336	$ 175,123
Material	Handy Whitman	3.4%	$ -	$ 17,290	$ 41,792	$ 24,244
Other	CPI	1.6%	$ 42,055	$ 40,518	$ 52,647	$ 68,273
AFUDC	CPI	1.6%	$ 326	$ 2,234	$ 8,854	$ 18,387
Total			**$ 42,381**	**$ 90,157**	**$ 329,629**	**$ 286,028**

Total Cost	**$ 748,195**
Cost M/km	**$ 1.66**

2.2.2. Bruce to Milton

In their initial 2007 application, Hydro One estimated that the total cost of the 500 kV Bruce to Milton project would be $635 million with $68 million, or 11%, estimated for station work.[4] However, in 2012 Hydro One submitted their 2013 - 2014 transmission rate application and cited in it that the cost of the Bruce to Milton project had increased to $732 million.[5] CRA has therefore assumed a total line cost of $651 million which is based on the updated total project cost estimate of $732 million (nominal $) included in Hydro One's rate application less 11% ($80.5 million) estimated for station work. Figure 5 provides CRA's assumptions for the Bruce to Milton project.

Figure 5. Bruce to Milton Calculations

Reported Costs		
2012 Reported Costs ($)	$	732,000,000
Less Station Cost ($)	$	(80,520,000)
2012 Line Cost ($)	$	651,480,000
Scaling Factor		1.99
2012 Line Cost Scaled to 230 kV ($)	$	327,376,884

Reporting Year	**2012**
Length (km)	180
Voltage	500 kV

Indices Used	**2012**	**2017**	**CAGR**	**Growth**
HW - Towers & Fixtures	494	701	7.3%	**7.3%**
HW - Overhead Conductors & Devices	536	763	7.3%	
Construction Costs - CPI	104	112	1.4%	**1.4%**
Other Costs - CPI	104	112	1.4%	**1.4%**

Cost Breakdown	**% of total cost**
Materials	**38.4%**
Construction	**13.4%**
Other	**48.1%**

Cost Escalation		**2012 Costs**	**Assumed Growth**	**Escalation Factor**		**2017 Cost**
Materials	$	125,869,772	7.3%	1.42	$	179,037,855
Construction	$	43,881,205	1.4%	1.07	$	46,942,163
Other	$	157,625,907	1.4%	1.07	$	168,621,192
Total Assumed Scaled Cost	**$**	**327,376,884**		**Total Cost**	**$**	**394,601,210**
				Cost M/km	**$**	**2.19**

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4 Hydro One. *Project Cost, Economics and other Public Interest Considerations.* EB-2007-0050. Exhibit B. Tab 4. Schedule 1. March 29, 2007. pp. 1-2.

5 Hydro One. *In-Service Capital Additions.* EB-2012-0031. Exhibit D1, Tab 1, Schedule 2. August 15, 2012. p2.

From there, CRA scaled the 500 kV project to a 230 kV project using the ratio between the baseline capital costs for each type of system as reported in the Black & Veatch's 2014 transmission expansion planning report for the WECC. According to this report a 500 kV system would be 1.99 times more costly per mile, than a 230 kV system.[6] After scaling, the 2012 total line cost is approximately $327 million.

2.2.3. BC Hydro's Northwest Transmission Line

The Northwest Transmission Line is a 344 km, 287 kV single circuit guyed lattice tower transmission line[7] between Skeena BC and Bob Quinn Lake. It was completed in 2014 at a total reported cost of $746 million.[8] This includes costs for substations but because the project was exempt from the Utilities Commission Act and a regulatory review was not undertaken, detailed cost estimates, annual project cash flows, and substation costs are not publically available. CRA has therefore assumed 11% (or $82 million) of the total cost of the project was attributable to substations work consistent with the Bruce to Milton project. CRA also recognizes that some of the project costs would have been incurred in years prior to 2014. CRA has taken the conservative approach by escalating the total project cost from 2014 to 2017 by assuming that all costs were incurred in 2014. Figure 6 provides the calculations for the Northwest Transmission Line benchmark results under these assumptions.

Figure 6. Northwest Transmission Line Calculations

Reported Costs		
2014 Reported Costs	$	746,000,000
Less Substation Cost Estimate	$	(82,060,000)
2014 Total Cost	$	663,940,000

Reporting Year	2014
Length (km)	344
Voltage	287 kV

Indices Used	2014	2017	CAGR	Growth
HW - Towers & Fixtures	494	701	12.4%	12.5%
HW - Overhead Conductors & Devices	536	763	12.5%	
Construction Costs - CPI	107	112	1.3%	1.3%
Other Costs - CPI	107	112	1.3%	1.3%

Average Annual Growth Rate		5.0%
2017 Estimated Project Cost	$	840,445,552
Cost M/km	$	2.44

6 WECC 2014 includes new line cost 2014 (USD/mile) of $3,071,750 for a 500 kV double circuit system and $1,536,400 for a 230 kV double circuit system.

7 Burns and McDonnell. *Northwest Transmission Line.* <https://www.burnsmcd.com/projects/northwest-transmission-line>.

8 Correspondence with BC Hydro Stakeholder Engagement. January 2, 2018.

2.2.4. Alberta Projects

All transmission facility capital cost estimates and final costs for projects built in Alberta since 2005 are entered into the AESO cost benchmark database.[9] CRA filtered through the AESO database to display the actual costs for two 100+ km double circuit, 240 kV projects. Both projects used in this analysis as benchmarks are actual projects constructed in Alberta in 2010[10] with costs reported by the AESO in 2013 nominal CAD. Costs included and reported by AESO were grouped into categories by CRA as follows and escalated from 2013 to 2017:

- **Materials:** Conductor, Hardware, Lattice Structures
- **Labor:** Construction, ROW Preparation Brush, Engineering, Survey
- **Others:** Contingency and Escalation, Owner Costs, Project and Construction Management, Salvage, AFUDC, and E&S

This data provided granular enough cost categories such that CRA was able to take proportionate shares of materials, construction and other costs into consideration when escalating costs. These assumptions and calculations are shown in Figure 7.

Figure 7. Alberta Benchmark Calculations

Reported Costs Project 1 Line ID: L_10311336112		
2013 Reported Costs	$	3,261,617
2013 Line Cost (per km)	$	3,261,617
2013 Line Cost (450 km)	$	1,467,727,650

Reporting Year	2013
Length km	450
Voltage	240 kV

Reported Costs Project 2 Line ID: L_10607745763		
2013 Reported Cost	$	2,962,952
2013 Line Cost (per km)	$	2,962,952
Line Cost (per 450 km)	$	1,333,328,400

Reporting Year	2013
Length km	450
Voltage	240 kV

Indices Used	2013	2017	CAGR	Growth
HW - Towers & Fixtures	529	701	7.3%	7.5%
HW - Overhead Conductors & Devices	569	763	7.6%	
Construction Costs - CPI	105	112	1.5%	1.5%
Other Costs - CPI	105	112	1.5%	1.5%

Project 1: Cost Breakdown	% of total cost
Materials	16.3%
Construction	33.0%
Other	50.7%

Project 2: Cost Breakdown	% of total cost
Materials	16.6%
Construction	33.6%
Other	49.8%

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9 AESO. Transmission Costs. <https://www.aeso.ca/grid/transmission-costs>

10 Project 1 is representative of the AESO's Line Facility ID: L10611336112 and Project 2 is representative of the AESO's Line Facility ID: L_10607745763.

Project 1 Cost Escalation	2013 Amount (per km)	Annual Growth	Escalation Factor	2017 Amounts
Materials	$ 530,346	7.5%	1.33	$ 707,166
Construction	$ 1,076,247	1.5%	1.06	$ 1,140,619
Other	$ 1,655,024	1.5%	1.06	$ 1,754,013
			Total Cost	**$ 3,601,798**
			Cost M/km	**$ 3.60**
			Cost (450 km)	**$ 1,620,809,051**

Project 2 Cost Escalation	2013 Amount (per km)	Annual Growth	Escalation Factor	2017 Amounts
Materials	$ 491,421	7.5%	1.33	$ 655,263
Construction	$ 996,451	1.5%	1.06	$ 1,056,050
Other	$ 1,475,080	1.5%	1.06	$ 1,563,307
			Total Cost	**$ 3,274,620**
			Cost M/km	**$ 3.27**
			Cost (450 km)	**$ 1,473,578,867**

2.2.5. Western Electricity Coordinating Council 2014 Study

CRA took the base capital cost for a 230 kV double circuit project from the Black & Veatch 2014 transmission expansion planning report done for the WECC in 2014 and applied cost escalation of 1.3% per year to determine the 2017 base capital cost in USD per mile. CRA then applied the following multipliers and adders to this base 2017 USD capital cost:

- **Conductor Type:** ACSR, cost multiplier of 1.00
- **Transmission Structure:** Lattice, cost multiplier of 0.90
- **Transmission Length:** > 10 miles, cost multiplier of 1.00
- **Terrain:** Forested, PG&E, cost multiplier of 1.50[11]
- **Right of Way Widths:** 64m, equating to 25.44 ROW/acres per mile[12]
- **Land Cost/Acre:** BLM zone 6, equating to a land cost of $1,024 USD per acre[13]

CRA then applied the 2017 CAN/USD exchange rate of 1.30 and converted miles to km to arrive at the total cost per km in 2017 CAD. Figure 8 provides the calculation breakdown for the WECC benchmark.

11 CRA utilized the terrain cost multiplier selected by NextBridge.

12 CRA relied on a 65m ROW width provided by NextBridge. Acres/mile values were calculated in accordance with the WECC study, by multiplying the right of way width by 5,280 feet per mile and dividing by 43,560 sq. ft. per acre.

13 CRA relied on the selection of BLM 6 by NextBridge.

Figure 8. WECC Benchmark Calculations

Reported Capital Costs		
Total Capital Cost (2014 USD per Mile)	$	1,536,400

Multipliers and Adders	Capital Cost Multiplier
Conductor: ACSR	1.0
Transmission Structure: Lattice	0.9
Length: >10 miles	1.0
Terrain: Forested	1.5
ROW/acres per mile	25.44
Land Cost/acre: BLM Zone 6	1,024

Reporting Year	2014
Length km	450
Length (mile)	280
ROW Width for New EWT (miles)	64
Voltage	230 kV
miles to km	1.60934

Indices Used (USD)	2014	2017	CAGR	Growth
HW - Towers & Fixtures	507	539	2.1%	1.7%
HW - Overhead Conductors & Devices	565	587	1.3%	
Construction Costs - CPI	109	112	1.1%	1.1%
Other Costs - CPI	109	112	1.1%	1.1%
CAN/USD FX	1.10	1.30	5.6%	

Average Annual Growth Rate		1.3%
Total Capital Cost (2017 USD per Mile)	$	1,595,816
Total Cost Per Mile (incl. Multipliers & Adders)	$	2,180,407
Total Cost Per Mile (2017 CAD)	$	2,835,785
Total Cost Per Km (2017 CAD)	$	1,762,079
Total Cost (M/km)	$	**1.76**

3. Results

CRA has benchmarked the current estimated New EWT Line capital cost[14] against other projects using the approach and assumptions described above. CRA has included the indices used in cost escalation in Appendix A. Figure 9 provides an overview of the benchmarking results, which shows that the current estimated costs for the New EWT Line at $1.66 M/km are competitive and quite reasonable when compared to other similar transmission projects.

To ensure robustness of analysis CRA has also provided results when base M/km results are scaled up and down by 2%. The results for this sensitivity analysis are shown in Figure 10. The resulting range around the base results and how they compare to the New EWT cost are shown graphically in Figure 11 where the vertical lines represent the variation around the base case with the base case represented by the small blue diamonds. This graphic illustrates that even under the most extreme ranges of sensitivity on the cost escalation indices used it is clear that the cost of the New EWT Line remains comparatively reasonable.

14 Capital cost is an all-in amount, including development and constructions costs.

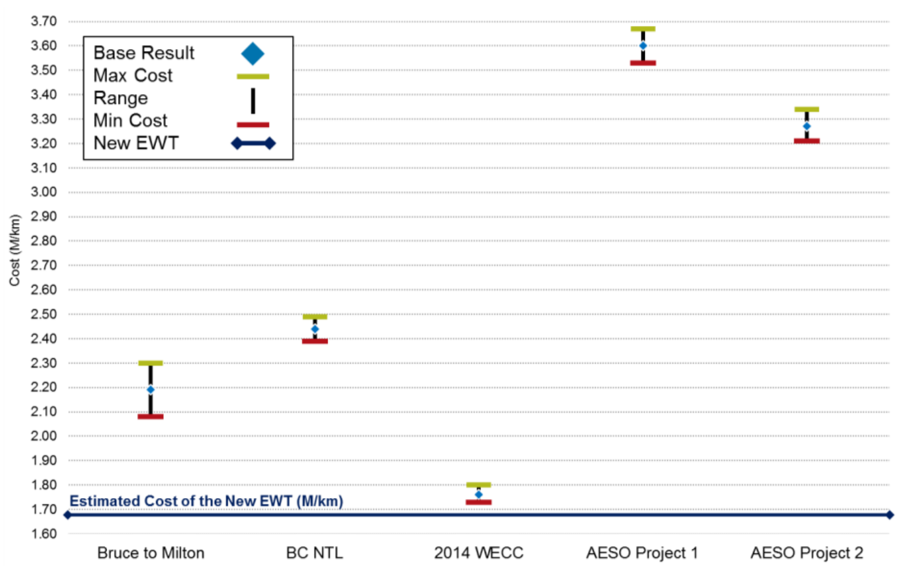
Figure 9. Benchmarking Base Results[15]

	New EWT	Bruce to Milton	BC NTL	2014 WECC	AESO Project 1	AESO Project 2
Voltage (kV)	240 kV	500 kV	287 kV	230 kV	240 kV	240 kV
Length (km)	450	180	344	450	450	450
Costs reported in $	2017	2012	2014	2014	2013	2013
Total Cost Line Only ($M)	777	651	716	611	1468	1333
Line Cost (adjusted to 2017 $M)	748	395	824	794	1621	1474
2017 Cost M/km	1.66	2.19	2.40	1.76	3.60	3.27

Figure 10. Sensitivity Analysis Results

Escalation Sensitivity	Bruce to Milton	BC NTL	2014 WECC	AESO Project 1	AESO Project 2
Base Result	2.19	2.40	1.76	3.60	3.27
5%	2.30				
4%	2.28				
3%	2.26				
2%	2.24	2.44	1.80	3.67	3.34
1%	2.21	2.42	1.78	3.64	3.31
-1%	2.17	2.37	1.74	3.57	3.24
-2%	2.15	2.35	1.73	3.53	3.21
-3%	2.13				
-4%	2.10				
-5%	2.08				

Figure 11. Range of Benchmark Results



The estimated average project capital cost per km for the New EWT Line in 2017 CAD is approximately $1.66 M/km which is calculated by discounting annual Construction project costs

15 Note: Bruce to Milton has been scaled to 230 kV by a factor of 1.99, consistent with the differences in base capital cost in the WECC 2014 study.

by 10-year CAGR for CPI, annual Materials costs by the 10-year CAGR of the Handy-Whitman Plateau Indices, and by discounting Other costs again, by CPI. This brings the New EWT Line total 2017 project cost to $748M and at $1.66 M/km makes it a lower cost project compared to the benchmarks presented in Figure 9. Costs per km for the New EWT Line remain lower than the benchmarks even under forecasting sensitivity tests.

The Bruce to Milton benchmark ranges from $2.08 M/km to $2.19 M/km. This project has been scaled down to a 240 kV using the WECC study but even under the widest bands of sensitivity, the New EWT Line is still relatively inexpensive.

BC's Northern Transmission Line is estimated at $2.44 M/km in the benchmarking base case. Compared to this project in BC, the estimated New EWT cost per km is far less.

A WECC study from 2014 estimated that a 230 kV transmission line located in a forested area that uses the same conductor type (ACSR) as the New EWT Line would be $1.76 M/km.

Finally, the AESO's cost benchmark database offers two technically similar project costs, one project at a cost of $3.60 M/km and another at $3.27 M/km. Both of these projects are 240 kV double circuit transmission lines larger than 100 km in Alberta constructed in 2010.

Appendix A: Benchmarking Analysis Inputs

Figure 12. Indices Used in Analysis

Handy Whitman Plateau (USD)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	10-Year CAGR	5-Year CAGR
HW - Towers & Fixtures	424	463	471	458	474	494	514	507	523	526	539	2.4%	1.8%
HW - Overhead Conductors & Devices	559	613	678	551	543	536	552	565	582	601	587	0.5%	1.8%
											Average	**1.5%**	**1.4%**
US CPI (2010 = 100)	94.9	98.7	98.4	100.0	103.2	105.3	106.8	108.6	108.7	110.1	112.2	**1.7%**	**1.3%**
CAN CPI (2010=100)	95.6	98.0	98.3	100.0	102.9	104.5	105.5	107.5	108.7	110.2	111.8	**1.6%**	**1.4%**
FX USD/CAD	1.07	1.07	1.14	1.03	0.99	1.00	1.03	1.10	1.28	1.32	1.30		

Handy Whitman Plateau (CAD)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	10-Year CAGR	5-Year CAGR
HW - Towers & Fixtures	455	494	537	472	469	494	529	560	669	697	701	4.4%	7.3%
HW - Overhead Conductors & Devices	600	653	774	567	537	536	569	624	744	796	763	2.4%	7.3%
											Average	**3.4%**	**6.9%**
US CPI (2010 = 100)	94.9	98.7	98.4	100.0	103.2	105.3	106.8	108.6	108.7	110.1	112.2	**1.7%**	**1.3%**
CAN CPI (2010=100)	95.6	98.0	98.3	100.0	102.9	104.5	105.5	107.5	108.7	110.2	111.8	**1.6%**	**1.4%**

Figure 13. Electric Utility Construction Price Index (Indicative Only)[16]

Transmission Construction Price Index Components	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	10-Year CAGR	5-Year CAGR
Initial grading and clearing	136.6	149.7	160.4	176.7	194.5	191.4	191.2	195.6	198.3	186.6	189.2	3.3%	-0.2%
Installation labour	127.2	125.3	127.5	130.3	127.7	127.2	132.8	143.4	147.1	142.1	138.8	0.9%	1.8%
Installation equipment	139	142.9	144.6	144.7	154	156.1	149.3	150	153	156.7	164.4	1.7%	1.0%
Construction indirects	122.3	121.3	123.5	128.9	131	140.5	143.4	147.8	146.9	146.3	152.8	2.3%	1.7%
Engineering	130.4	130.8	133	138.9	142	154.2	158.1	164.5	166.4	164.2	172.4	2.8%	2.3%
Head office administration	129.5	130	132.2	137.8	140.9	152	155.8	161.7	163.5	161.7	169.5	2.7%	2.2%
											Average	**2.3%**	**1.5%**

16 Statistics Canada. Table 327-0011 - Electric utility construction price index, annual (index, 1992=100) which was discontinued in 2014.

TAB 16

Analysis of EWT costs in 2020 Charles River Associates Report

Chart 1: Copy of Figure 3 from 2020 Benchmarking Report "New EWT Line Annual Project Costs"

Costs	Total	Pre-8/1/2017	2017	2018	2019	2020 to COD
Development	36,572	36,572				
Construction	578,948		2,135	22,973	73,503	480,337
Materials	66,870				11,242	55,628
Other	60,320		2,539	8,709	16,914	32,158
Sub-Total	**742,710**	**36,572**	**4,674**	**31,682**	**101,659**	**568,123**
IDC	31,003		249	835	4,597	25,322
Total	**773,713**	**36,572**	**4,923**	**32,517**	**106,256**	**593,445**

Chart 2: Copy of Figure 4 from 2020 Benchmarking Report "New EWT Costs in 2022 CAD"

Discounted Costs	Disc.	Pre-8/1/2017	2017	2018	2019	2020 to COD
Development	1.6%	32,410				
Construction	1.6%		1,970	21,538	70,031	465,089
Materials	3.4%				10,134	51,910
Other	1.6%		2,342	8,165	16,115	31,137
Sub-Total		**32,410**	**4,312**	**29,702**	**96,280**	**548,136**
IDC	1.6%		783	4,380	24,518	
Total		**32,410**	**5,095**	**34,082**	**120,798**	**548,136**
Total Cost		**740,521**				
Line Kilometres		**450**				
$M/km		**1.65**				

Chart 3: Reproduction of Figure 4 from 2020 Benchmarking Report, Discounting Values

Costs	Discount Factor	Pre-8/1/2017	2017	2018	2019	2020 to COD
Notes on Reproduction		Pre-8/1/2017 values discounted 7.5 years	2017 values discounted 5 years	2018 values discounted 4 years	2017 values discounted 3 years	2020 to COD values discounted 2 years
		n.b. In the 2020 report, discounted IDC values were shifted left by one cell, and the value for 2017 was omitted. This was a subject of Staff IR #49 k.				
Development	1.6%	32,467				
Construction	1.6%		1,972	21,560	70,085	465,327
Materials	3.4%				10,169	52,030
Other	1.6%		2,345	8,173	16,127	31,153
Sub-Total		**32,467**	**4,317**	**29,733**	**96,381**	**548,510**
IDC	1.6%		784	4,383	24,531	
Total		**32,467**	**5,101**	**34,116**	**120,912**	**548,510**
Total Cost		**741,107**				
Line Kilometres		**450**				
$M/km		**1.65**				

Chart 4: Version of Figure 4 from 2020 Benchmarking Report, Inflating Values

Costs	Inflation Factor	Pre-8/1/2017	2017	2018	2019	2020 to COD
Notes on Calculations		Pre-8/1/2017 values inflated 7.5 years	2017 values inflated 5 years	2018 values inflated 4 years	2019 values inflated 3 years	2020 to COD values inflated 2 years
Development	1.6%	41,196				
Construction	1.6%		2,311	24,479	77,088	495,831
Materials	3.4%				12,428	59,475
Other	1.6%		2,749	9,280	17,739	33,195
Sub-Total		**41,196**	**5,060**	**33,759**	**107,255**	**588,501**
IDC	1.6%		270	890	4,821	26,139
Total		**41,196**	**5,330**	**34,649**	**112,076**	**614,640**
Total Cost		**807,890**				
Line Kilometres		**450**				
$M/km		**1.80**				

TAB 17

STAFF INTERROGATORY #71

INTERROGATORY

Reference: (1) Filing Requirements for Electricity Transmission Applications / Chapter 2 / p.35
(2) Exhibit H / Tab 1 / Schedule 1 / p.1

Preamble:
Reference 1 states that:

> In the event an applicant seeks an accounting order to establish a new deferral or variance account, the following eligibility criteria must be met:
> - Causation - The forecasted expense must be clearly outside of the base upon which revenue requirement(s) were derived.
> - Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the transmitter. Otherwise they must be expensed in the normal course and addressed through organizational productivity improvements.
> - Prudence - The nature of the costs and forecasted quantum must be reasonably incurred, although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating why the option selected represents the cost-effective option (not necessarily least initial cost) for ratepayers.

In Reference 2, NextBridge states that it seeks the Board's approval to establish five new deferral/variance accounts:
- Taxes or Payments in Lieu of Taxes Variance Account, existing USofA account 1592
- Revenue Differential Variance Account
- Construction Cost Variance Account
- Debt Rate Variance Account
- Z Factor Treatment (Account 1572)

Question(s):
a) Except for the existing accounts 1592 and 1572, please explain how the eligibility criteria (i.e. causation, materiality and prudence) for the three new variance accounts requested is expected to be satisfied.

RESPONSE

a. Materiality (explanation for all three accounts):

Several variance accounts were needed due to the unique, start-up circumstances of NextBridge including: 1) as a new transmitter, 2) applying a Revenue Cap framework in its first application, 3) not having existing operations or revenues by which to balance the potential financial exposure, and 4) building a large new infrastructure project. The combination of the minimum materiality applied to each account could materially impact the operations of the company. If all three accounts discussed below held the minimum materiality amount, NextBridge would be expensing approximately $835,000 which would materially affect its operations. As reference, NextBridge calculated its materiality consistent with the Filing Requirements for Electricity Transmission Applications, Section 2.1.1. This equates to $55,700,000 x 0.5%, or $278,500.

As NextBridge's Application includes forecasted construction costs, all accounts are symmetrical which means the materiality is applied equally to customers as it is to NextBridge. NextBridge's Application request for recovery of $737.1 is based on substantial evidence of the prudency of those costs, including that approximately 90 percent are known and fixed through executed contracts. NextBridge is also proposing a one-time update to its long-term debt costs such that it allows for a credit to customers if the costs of actual long-term debt decreases or increasing the cost of debt if actual long-term debt is higher than that proposed in the Application.

In the context of a recently settlement, in EB-2019-0261, Decision and Order (Nov. 19, 2020), the OEB accepted deferral accounts prior to knowing the expected balance including OEB's approval of Hydro Ottawa Limited's (Hydro Ottawa) sub-account "1508 – Subset of system access capital additions (net of contributions) revenue requirement differential variance account". Consistent with the Hydro Ottawa, NextBridge is proposing:

- Revenue Differential Variance Account (RDVA)
    - Causation: The RDVA will only be utilized if the in-service date is not March 31, 2022. Amounts included in this deferral account will be distinguished as outside of the base revenue as the application calculated the revenue requirement based on a March 31, 2022 in-service date.

    - Prudence: As determined by the IESO, the NextBridge project is developed to provide the least-cost solution to supply power to Northwestern Ontario and delivering the project in-service is cost effective for customers. While NextBridge currently projects the March 31, 2022 in-service date as achievable, unknown events, such as the ongoing COVID-

19 pandemic, may impact the in-service date. The costs associated with addressing unknown events, such as COVID-19, will be prudently incurred as required to bring the East-West Tie line in-service. Therefore, it is reasonable to establish a revenue tracking account for the potential that either the East-West Tie line is brought into service prior to or after the March 31, 2022 in-service date.

- Construction Cost Variance Account (CCVA)
  - Causation: The rate application is based on forecasted construction costs as the East-West Tie line is not yet in-service. Any amounts included in this variance account will be easily distinguishable as the revenue requirement included in the variance account will be calculated a new rate base than is different from the rate base in the Application. The costs included in this account will include costs necessary to complete the construction of the East-West Tie line.

  - Prudence: While NextBridge's forecasted costs for the East-West Tie line project are $737.1 million, the project is not due to be in-service until March 31, 2022. This account would capture any currently unknown and prudently incurred costs beyond the $737.1 for review and disposition at a later date. As any new and prudently incurred costs will be beyond the $737.1 million. As the NextBridge Application sets forth forecasted construction cost, the final prudently incurred construction costs can be different than what was projected in the Application. This account will contain the revenue requirement difference between the forecasted East-West Tie line construction costs and actual prudently incurred construction costs. NextBridge will identify and track any new costs in a manner that shows they are not included in the $737.1 million forecast.

- Debt Rate Variance Account (DRVA)
  - Causation: The Application is based on the OEB Cost of Capital Parameters and the long-term debt rate used in the application was 3.21%. NextBridge expects the long-term debt rate to be secured on financing closer to the in-service date and the debt rate used to ultimately finance the utility is not yet available. The revenue requirement difference due to the long-term debt rate will be easily distinguishable as the calculations will clearly outline the difference due to the actual cost of long-term debt rate as compared to 3.21% included in the application.

  - Prudence: Securing private debt placement for the project is prudent because it will ensure long-term financial viability of the company. Not securing long-term debt for the project would leave the project exposed to short term interest rate volatility and weaken NextBridge's financial viability.

TAB 18

Revenue Differential Variance Account

7. This account will track the revenue impact should there be a difference from the currently planned in-service date. Specifically, the account will record the difference between revenue earned by NextBridge as part of its share of the 2022 UTR revenue based on the forecasted in-service date and the revenue requirement that would have been calculated had rates been established based on the actual achieved in-service date (earlier or later).

8. To facilitate the OEB's review of costs and prudence on a timely basis and to allow time to ensure all project construction cost accounting is finalized and an audit has taken place, NextBridge proposes to seek initial disposition of the balance in this account in the second annual update following in-service. This update is expected to be the filed in 2023 for inclusion in 2024 UTR rates.

9. See draft accounting order in Attachment 2 in this Exhibit.

10. Construction Cost Variance Account

- This account will track any difference in revenue requirement resulting from: difference between forecasted construction costs in this Application and the actual final project construction costs, including IDC;
- COVID-19 related capital costs incurred during construction in excess of forecasted construction costs in this Application. NextBridge has explained its preference for the treatment of these costs to the OEB as part of the current stakeholder process to inform accounting guidance for COVID-19 impacts being included in deferral accounts. This submission can be found at Exhibit H, Tab 1, Schedule 1, Attachment 5. As explained in the submission, it is appropriate to continue to track the incremental construction work in progress and interest costs related to the COVID-19 emergency in a new subaccount of Account 2055;

- Directly related costs associated with construction that extend past the in-service date such as environmental costs that are a result of commitments in the OBP and/or Amended EA for construction monitoring and mitigation programs that are not already accounted for in the construction costs (i.e. environmental mitigation costs of $1 million that were included in construction costs but occur post in-service date because they were known and quantifiable amounts). NextBridge expects these costs to begin after the March 31, 2022 in-service date and continue for up to the end of the IR Term, as discussed in Exhibit C. The amount of environmental mitigation to be performed during this time period is highly dependent on monitoring activities and in some cases is weather or nature dependent. As an example, the transfer strategy and timing of caribou is dependent upon the results of pre-transfer monitoring. Monitoring will indicate where the caribou will originate from and the gender ratio available to relocate (See OBP Permit and Conditions at Exhibit C. Tab 2, Schedule 4, Attachment 3). As these costs are expected to decline each year after in service and are non-recurring, NextBridge proposes that the variance account method is best for customers instead of including in O&MA costs and potentially overstating O&MA costs for the following nine years of the revenue cap index. To demonstrate this savings, NextBridge provides the following example in Table 1 below as a comparison of including the first year's cost comparing the treatment in the revenue requirement now as an O&MA cost versus including these environmental costs in the construction cost variance account. As shown below in the totals over the five-year period, O&MA could be overstated by $2.4 million if these costs were included in O&MA as part of this Application. Since the costs reduce over time and are not quantifiable at this time, the appropriate way to account for the costs is in the CCVA.

Table 1. Example of Cost Treatment Alternatives for Post Construction Environmental Costs

	Dollars					
	ISD[14] + 1 Year	ISD + 2 Years	ISD + 3 Years	ISD + 4 Years	ISD + 5 Years	Total
O&MA if in Revenue Requirement	Estimate included in construction costs	$972,000	$972,000	$972,000	$972,000	**$3,888,000**
Variance Account (as incurred)	Estimate included in construction costs	$972,000	$198,000	$106,000	$143,000	**$1,419,000**

- After five years post in-service date, the costs are expected to be less than $10,000 annually and are not included in this example, which is for illustrative purposes.

- To facilitate the OEB's review of costs and prudence on a timely basis and to allow time to ensure all project construction cost accounting is finalized and an audit has taken place, NextBridge proposes to seek initial disposition of the balance in this account in the second annual update following in-service. This update is expected to be the filed in 2023 for inclusion in 2024 UTR rates. NextBridge seeks to leave the CCVA open for the remainder of the IR Term to account for activities that are a direct result of construction, such as environmental costs associated with the Overall Benefits Permit and Amended EA. The final disposition will take place at the end of the IR Term and in the next rebasing application for NextBridge.

- See draft accounting order in Attachment 3 in this Exhibit.

[14] In-Service date ("**ISD**")

TAB 19

STAFF INTERROGATORY #74

INTERROGATORY

Reference: (1) Exhibit H / Tab 1 / Schedule 1 / pp.2-4
(2) Exhibit H / Tab 1 / Schedule 1 / Attachment 3

Preamble:
In Reference 1, NextBridge requests a Construction Cost Variance Account (CCVA) to track any difference in revenue requirement resulting from: difference between forecasted construction costs in this Application and the actual final project construction costs, including interest during construction.

In Reference 1, NextBridge states that “it is appropriate to continue to track the incremental construction work in progress and interest costs related to the COVID-19 emergency in a new subaccount of Account 2055” which it has proposed to the OEB in its letter dated June 11, 2020.

Per the draft accounting order in Reference 2, Next Bridge proposes that the CCVA is to be recorded in a sub account under Account 1508 and will include three components as below:
- The difference between the forecasted and actual construction costs
- COVID-19 related capital costs incurred during construction in excess of forecasted construction costs in this Application
- directly related costs associated with construction that extend past the in-service date such as environmental costs that are a result of commitments in the OBP and/or Amended EA for construction monitoring and mitigation programs that are not already accounted for in the construction costs (*i.e.*, environmental mitigation costs of $1 million that were included but occur post in-service date because they were known and quantifiable amounts).

In Reference 1, NextBridge explains why the third component of post-dated environmental costs should be included in the CCVA:

> As these costs are expected to decline each year after in service and are non-recurring, NextBridge proposes that the variance account method is best for customers instead of including in O&MA costs and potentially overstating O&MA costs for the following nine years of the revenue cap index.

NextBridge also provides an example in the table below to show the differences:

Table 1. Example of Cost Treatment Alternatives for Post Construction Environmental Costs

	Dollars					
	ISD[14] + 1 Year	ISD + 2 Years	ISD + 3 Years	ISD + 4 Years	ISD + 5 Years	Total
O&MA if in Revenue Requirement	Estimate included in construction costs	$972,000	$972,000	$972,000	$972,000	**$3,888,000**
Variance Account (as incurred)	Estimate included in construction costs	$972,000	$198,000	$106,000	$143,000	**$1,419,000**

- After five years post in-service date, the costs are expected to be less than $10,000 annually and are not included in this example, which is for illustrative purposes.

With respect to the disposition of the CCVA, NextBridge states that:

> NextBridge proposes to seek initial disposition of the balance in this account in the second annual update following in-service. This update is expected to be the filed in 2023 for inclusion in 2024 UTR rates. NextBridge seeks to leave the CCVA open for the remainder of the IR Term to account for activities that are a direct result of construction, such as environmental costs associated with the Overall Benefits Permit and Amended EA. The final disposition will take place at the end of the IR Term and in the next rebasing application for NextBridge.

Question(s):

a) Please clarify the relationship between the COVID-related construction costs that are recorded in the sub-account under Account 2055 and the costs to be recorded in the CCVA (a sub-account under Account 1508).
b) Please confirm that the $1,419,000 estimated environmental costs post in-service date is accurate as of this date. If not, please provide a revised number.
c) Please confirm that the nature of the environmental cost after the in-service date is OM&A, and not capital related.
d) If c) is confirmed, would it be more appropriate to amortize the total $1,419,000 over the IR term and include the amortized annual amount of $141,900 into the

OM&A cost of the test year which is the approach used in the regulatory costs in a typical transmission/distribution rebasing application? Please provide NextBridge's position on this approach.

e) Please confirm whether the primary reason for NextBridge's proposal to leave the CCVA open and dispose of the account on a final basis at the end of the IR term is to allow for recoveries of environmental costs in excess of the $1,419,000 forecasted.
f) In the event that the CCVA does not include environmental costs (instead these costs are included in the revenue requirement), please confirm whether NextBridge would agree to close the CCVA at the second annual update following the in-service date of operation.
g) If e) is not confirmed, please specify any other costs that could be included in the CCVA post the in-service date of operation.
h) With respect to the difference between the forecasted and actual project costs that is to be recorded in the CCVA, please confirm that this component could result in a debit balance to be collected from the ratepayers or a credit balance to be refunded to the ratepayers.

RESPONSE

a) COVID-related construction costs that are recorded in the CWIP sub-account under Account 2055 are capital costs incurred during construction; while the associated revenue requirement for those costs are to be recorded in the CCVA.
b) This estimate of $1,419,000 is accurate as of this date.
c) The environmental costs are a direct result of the capital construction of the line and were necessary requirements to secure permitting and construction of the line. Due to this, the costs are part of the capital project and the appropriate accounting treatment is as capital.
d) In addition to the costs being capital costs, it is not appropriate to amortize the costs over the IR period because the $1,419,000 is the expected spend of the first year post in-service. To collect that amount over 9 years and 9 months, while it was spent it in the first year of IR period, would leave NextBridge in a position of under collection for the entire IR term. Additionally, there would a loss due to the carrying cost associated with the $1,419,000.
e) Yes, the primary reason for leaving the CCVA open through the IR term is to capture environmental costs associated with remediating construction impacts.
f) Yes, NextBridge would agree to close the CCVA with the approval of a Z-factor account if a material unplanned remediation cost occurred.
g) N/A, (e) is confirmed
h) Yes, the account could result in a debit or credit balance.

TAB 20

SEC INTERROGATORY #17

INTERROGATORY

Question:

[H-1-1, Attach 3] Please explain why the Applicant proposes to record COVID-19 related construction costs in the proposed Construction Cost Variance Account and not in the OEB's Account 1509, COVID-19 Emergency, Sub-account Other Costs.

RESPONSE

NextBridge will track and record COVID-19 costs through the in-service date in Account 2055 (CWIP) as these costs are part of construction of the line. Once in-service and the COVID-19 costs for the duration of construction are known, NextBridge will record the revenue requirement associated with these capital COVID-19 costs in the proposed Construction Cost Variance Account as these capital costs were not part of the revenue requirement proposed in this application. NextBridge is not using Account 1509 as all costs incurred at this time, through the in-service date, are capital construction costs; it is understood that the deferral Account 1509 is for differences in earnings for transmitters with rates in place.

TAB 21

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL AND WEB POSTING

April 29, 2020

To: Ontario Power Generation Inc.
All Rate-regulated Electricity Transmitters
All Other Interested Parties

Re: Accounting Order for the Establishment of Deferral Accounts to Record Impacts Arising from the COVID-19 Emergency for Ontario Power Generation Inc. and Electricity Transmitters

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In the Ontario Energy Board's (OEB) March 25, 2020 accounting order,[1] the OEB acknowledged that electricity and natural gas distributors may incur incremental costs as a result of the ongoing COVID-19 pandemic. The OEB therefore ordered the establishment of a deferral account with sub-accounts for electricity and natural gas distributors to use to track any incremental costs and lost revenues related to the COVID-19 pandemic effective March 24, 2020. The OEB understands that Ontario Power Generation Inc. (OPG) and electricity transmitters (transmitters) may also be impacted by the COVID-19 pandemic. This accounting order confirms the applicability of the account to OPG and transmitters.

In light of the uncertainty surrounding the COVID-19 emergency, the OEB is of the view that the account established in the March 25, 2020 accounting order should also apply to OPG so that it can track lost revenues and incremental costs arising from the COVID-19 pandemic.

[1] Accounting Order for the Establishment of Deferral Accounts to Record Impacts Arising from the COVID-19 Emergency, dated March 25, 2020

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
2300, rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4
T 416-481-1967 1-888-632-6273
F 416-440-7656 **OEB.ca**

Transmitters' licences require that transmitters follow the Accounting Procedures Handbook that is approved by the OEB. Therefore, Account 1509 - Impacts Arising from the COVID-19 Emergency, which was established in the March 25, 2020 accounting order is applicable to transmitters as well.

The two sub-accounts that may be applicable to OPG and transmitters are:

i. Sub-account, Lost Revenues which is to record lost revenues.
ii. Sub-account, Other Costs which is to record incremental identifiable costs related to the COVID-19 emergency, including costs relating to bad debt expenses

Carrying charges at the OEB's prescribed rate apply to these sub-accounts.

The OEB has not yet made a determination on the nature of revenue or costs that will be recoverable. In the event that OPG and any transmitter chooses to use the sub-accounts, they must maintain detailed tracking and records to support amounts that have been recorded, for the OEB's consideration. The OEB will assess any claimed costs and/or lost revenues associated with any of the sub-accounts in this letter, at the time these sub-accounts are requested for disposition, subject to established materiality thresholds.

Yours truly,

Original signed by

Christine E. Long
Registrar and Board Secretary

TAB 22

3. Construction Cost Update

A. Project Cost Update Summary

Construction costs for the EWT Project are forecasted to be on budget when compared to the LTC application budget. While increases have been identified in certain budget areas, the use of the previously-budgeted value for contingency allows for sufficient allocation of funds to address areas where budget increases were identified. However, at this point in time the total costs related to the COVID-19 Global Pandemic are unknown.

B. Project Cost Update Table

Cost Categories for NextBridge's Construction Costs Reporting		Actuals Spent: A Spent This Reporting Period $	Actuals Spent: B Total Spent To Date $	Budget: C Budget Per LTC Application $	Budget: D=C-B Budget Remaining	Budget: E=D/C*100 Budget Remaining %	Forecast Budget Variance: F Forecast Budget Change $	Forecast Budget Variance: G Forecast Budget Change %	Forecast Budget Variance: H Revised Total Budget	Reasons For Change
Engineering & Construction		**89,396,704**	**395,393,413**	**572,761,388**	**177,367,975**	**31%**	**41,505,901**	**7%**	**614,267,289**	**Revised based on in-service date**
1	Engineering, Design and Procurement	566,597	7,284,755	19,342,245	12,057,490	62%	(10,808,892)	-56%	8,533,353	
2	Materials and Equipment	15,610,865	57,972,799	89,408,231	31,435,432	35%	(22,538,717)	-25%	66,869,514	
8	Site Clearing, Access	32,542,786	116,207,404	107,463,339	(8,744,065)	-8%	33,169,524	31%	140,632,863	
9	Construction	40,676,455	213,928,455	356,547,573	142,619,118	40%	41,683,986	12%	398,231,559	
Environmental & Remediation Activities		**887,757**	**17,206,744**	**26,929,260**	**9,722,516**	**36%**	**4,620,902**	**17%**	**31,550,162**	**Revised based on in-service date**
3	Environmental and Regulatory Approvals	849,566	16,552,092	13,030,561	(3,521,531)	-27%	6,066,463	47%	19,097,024	
10	Site Remediation	38,191	654,652	13,898,699	13,244,047	95%	(1,445,561)	-10%	12,453,138	
Indigenous Activities		**1,942,368**	**17,549,321**	**20,211,000**	**2,661,679**	**13%**	**3,442,555**	**17%**	**23,653,555**	**Revised based on in-service date**
5	Indigenous Economic Participation	961,902	7,629,102	7,000,000	(629,102)	-9%	2,730,452	39%	9,730,452	
6	Indigenous Consultation	980,466	9,920,218	13,211,000	3,290,782	25%	712,103	5%	13,923,103	
4	**Land Rights (excludes Aboriginal)**	**1,153,176**	**17,931,382**	**23,830,512**	**5,899,130**	**25%**	**0**	**0%**	**23,830,512**	
7	**Other Consultation**	**75,403**	**1,212,080**	**2,530,194**	**1,318,114**	**52%**	**0**	**0%**	**2,530,194**	
11	**Contingency**	**-**	**-**	**49,399,445**	**49,399,445**	**100%**	**(49,399,445)**	**-100%**	**-**	**Allocation of Contingency**
12	**Regulatory**	**229,820**	**4,105,487**	**5,405,078**	**1,299,591**	**24%**	**(0)**	**0%**	**5,405,078**	
13	**EWT Management**	**156,602**	**4,238,388**	**4,900,644**	**662,256**	**14%**	**(0)**	**0%**	**4,900,644**	
Total Project Spend		**93,841,829**	**457,636,814**	**705,967,521**	**248,330,707**	**35%**	**169,913**	**0%**	**706,137,434**	
14	**Interest During Construction (IDC)[1]**	**2,218,412**	**13,050,442**	**31,003,000**	**17,952,558**	**58%**	**-**	**0%**	**31,003,000**	
Total Construction Costs [2,3,4]		**96,060,241**	**470,687,256**	**736,970,521**	**266,283,265**	**36%**	**169,913**	**0%**	**737,140,434**	

1 IDC has not been reforecasted as interest rates will vary based on the OEB prescribed rates
2 On the record (EB-2017-0182)
3 Development Costs eligible for consideration as construction costs of $5.3 MM not reflected in column B. (OEB Decision, December 20, 2018)
4 Construction related costs due to COVID-19 are not included in the table above; as of Q4 2020, $0.4M has been incurred

TAB 23

STAFF INTERROGATORY #26

INTERROGATORY

Reference: (1) Exhibit E / Tab 1 / Schedule 1 / pp. 1-4

Preamble:
Reference 1 states that "NextBridge is proposing an RCI term for a 10-year period. Under the proposed methodology, the revenue requirement for the Test Year t+1 is equal to the revenue requirement in the Test Year t, inflated by the RCI…."

Reference 1 also states that "NextBridge proposes to adopt the OEB's calculation of the RCI "I" parameter…."

Reference 1 also states:

> NextBridge proposes a productivity factor of 0%. NextBridge does not expect to recognize OM&A efficiencies over the IR Term as it is a single new asset and most of the OM&A is contractual and essentially fixed.… Notably, there are Indigenous reserve crossing permits, within OM&A that are expected to inflate annually at the City of Toronto's annual CPI....
>
> Additionally, NextBridge plans to continue capital investments over the IR Term beginning in the Test Year, that have not been included in the revenue requirement and will not be added to rate base during the IR Term....

Question(s):

a) Please explain why it is not possible to recognize OM&A efficiencies over the IR Term.
b) Which OM&A items are not contractual or essentially fixed? Of these items, can cost efficiencies be recognized in NextBridge's view? If so, how? If not, why not?
c) NextBridge notes that OM&A costs are contractual and essentially fixed; does this mean that some contracts can be revised? If so, which contracts?
d) Please explain why a proposed productivity factor of 0% is appropriate in NextBridge's view.
e) Please explain why a proposed inflation adjustment of 100% of the annual OEB approved Inflation factor is appropriate in NextBridge's view when other transmitters have received less than this amount.
f) Please explain why Indigenous reserve crossing permits are expected to inflate at the City of Toronto's annual CPI?

g) Please provide the historical 10 year and forecast 10-year difference for the City of Toronto CPI compared to the Ontario CPI.

<u>RESPONSE</u>

a) NextBridge does not expect to recognize OM&A efficiencies over the IR term as it is a single new asset. Most of the OM&A is scoped and budgeted minimally which will lead to increases as materials and labour costs increase.

b) All OM&A is contractual but not completely fixed. On the personnel side, NextBridge has already utilized partner employees to provide efficiencies in the budgeted costs. NextBridge does not expect to recognize efficiencies in this area as the East-West Tie line is already benefitting from the structure that allows for shared resources and minimally budgeted costs for this support. For example, NextBridge only bears a fraction of the cost of an accountant in the current structure versus having to employ/pay for a full-time accountant. On the O&M side, while there will be a HONI SLA contract, the contract is activity and time based, it is not a fixed price but can vary based on the amount of support needed. NextBridge has budgeted for the expected amount of services but incremental services will need to be funded with the funding envelope of the Revenue Cap rate structure. Additionally, the contract is for a 3 year term with a potential to extend for 2 years while the IR term is 9 years and 9 months, leaving NextBridge exposed to managing cost increases for the difference in terms. While the Federal Section 28.2 permits required for First Nation Reserve crossings are fixed, most have inflation factors which increase the cost through time.

c) To ensure certainty for the IR Term, NextBridge negotiated contracts with longer terms. For example, the Federal Section 28.2 permits required for First Nation Reserve crossings have durations of 20 years. However, some of the contracts will require renewal during the IR period and the most financially material one is the maintenance service contract with HONI. The maintenance service contract with HONI and Supercom is for three years, with an option to renew for an additional two years. While NextBridge does have an agreement with NEET to supply labour, increases associated increasing labour costs will impact NextBridge since charges are based on actual labour costs.

d) NextBridge's proposed productivity factor of 0% is appropriate because of the length of the IR term and NextBridge's challenge to manage costs over the extended term of 9 year and 9 month term within the funding allowed under the Revenue Cap framework.

e) Other transmitters have had no capital expenditures during the IR Term, whereas East-West Tie line has planned capital expenditures that will increase reliability and decrease long term maintenance of the project. Additionally, NextBridge has offered a longer IR Term which could expose NextBridge to higher inflation

f) Some of the Indigenous Reserve crossing permits will inflate at the City of Toronto's CPI. This is based on the executed contractual agreement with the First Nation and the Federal government. For clarity, NextBridge makes payments to the Federal government in Toronto which is held in trust for the First Nation.

g) Please see tables below for historical comparison. Forecast data was not available for comparison.

CPI Summary Table (Statistics Canada. Table 18-10-0005-01 Consumer Price Index, annual average, not seasonally adjusted)			
Year	**Ontario**	**Toronto**	**Difference**
2010	2.46%	2.55%	0.09%
2011	3.09%	3.00%	-0.09%
2012	1.42%	1.50%	0.08%
2013	0.99%	1.23%	0.25%
2014	2.36%	2.51%	0.16%
2015	1.19%	1.50%	0.31%
2016	1.81%	2.10%	0.30%
2017	1.70%	2.06%	0.36%
2018	2.35%	2.54%	0.19%
2019	1.85%	2.04%	0.19%

TAB 24

STAFF INTERROGATORY #29

INTERROGATORY

Reference: (1) Exhibit F / Tab 4 / Schedule 2 / p. 1

Preamble:
Of the $4.94 million of OM&A costs, $1.27 million are indicated as Operations and Maintenance expenses.

Reference 1 states:

> These OM&A expenses relate to ensuring the safety and reliability of the East-West Tie line. Approximately half of the annual OM&A expenses will be used for routine and cyclical maintenance services and remediation of findings as a result of cyclical maintenance. The maintenance services will be provided by two field personnel from NEET and HONI under the HONI SLA.

Questions:

a) Please provide, in table form, a breakdown of the $1.27 million operations and maintenance expenses including:
   a. Expense for NEET Agreement;
   b. Expense for HONI SLA;
   c. Expense for maintenance services not included in the HONI SLA, including services identified in response to Staff-15a, and Staff-23d.
   d. Expense for maintenance services contract described in response to Staff-35 if separate from contracts identified above;
   e. Other expenses (please describe).

RESPONSE

a)

Breakdown of Operations and Maintenance Expenses	$000's
a. Expense for NEET Agreement	268
b. Expense for HONI SLA	400
c. Expense for maintenance services not included in the HONI SLA, including services identified in response to Staff-15a, and Staff-23d	312
d. Expense for maintenance services contract described in response to Staff-35 if separate from contracts identified above	0

e. Other expenses including ICCP link, line monitoring and dispatch, vehicles and UTVs, office rent and expenses, equipment, tools and communications	295
Total	**1,275**

TAB 25

STAFF INTERROGATORY #30

INTERROGATORY

Reference: (1) Exhibit F / Tab 4 / Schedule 2 / p. 4

Preamble:
Of the $4.94 million of OM&A costs, $1.67 million are indicated as Compliance and Administration expenses.

Reference 1 states:

> NextBridge has a Project Director, who is employed by NEET…
> Included in these costs is only 75% of the expected cost for the Project Director's labour costs. NextBridge will not seek recovery of the remaining 25% as an efficiency mechanism, thus providing direct efficiency savings to ratepayers.

Question(s):

a) Please breakdown the $1.67 million Compliance and Administration expenses into:
   i) Project Director's Office
   ii) Property Owner Relations
   iii) Non-Indigenous Stakeholder Relations
   iv) Corporate Services
   v) Insurance expenses.
b) Could you please quantify the cost savings associated with not seeking recovery of 25% of the Project Director's labour costs?
c) Please explain the rationale that was used to determine the 75% recovery of the Project Director's labour costs.
d) Please confirm that this plan to recover 75% of the Project Director's labour costs meets the requirements of the Affiliate Relationship Code.

RESPONSE

a) Compliance and Administration of $1.67 million is broken down as follows:
   i) Project Director's Office: $627,000
   ii) Property Owner Relations: $169,000
   iii) Non-Indigenous Stakeholder Relations: $254,000
   iv) Corporate Services: $558,000
   v) Insurance expenses: $62,000

b) The cost savings of 25% of the Project Director's labour, which includes the Project Director and the Project Director's analyst, is $141,000 per year. This includes applicable labour overheads such as benefits, payroll tax, and employee incentive.

c) The rationale for only seeking recovery of 75% of the Project Director's labour is to account for non-productive time. Non-productive time will include vacation, holiday, sick, training or other non-productive time so NextBridge has proposed absorbing this expense.

d) Please refer to Staff #28 (b) on why the ARC is inapplicable.

TAB 26

SUMMARY OF OM&A EXPENDITURES

1. SUMMARY OF OM&A EXPENDITURES

The proposed Operation, Maintenance, and Administration ("OM&A") expenses represent the work required to meet public and employee safety objectives, maintain transmission reliability, and to comply with regulatory requirements, environmental requirements and Government direction. Key components in the build-up of OM&A requirements are:

- Service Level Agreement with Hydro One Networks ("HONI"), and
- Ongoing Incremental Expenses of the Partnership

Table 1 presents the required funding for OM&A in the 2020 Test Year, along with the actual and planned spending levels for the bridge and historical years, for each of these key components. Overall, B2M LP OM&A spending on a per asset basis is low in comparison to other transmitters in Ontario. This relates primarily to the characteristics of the assets that it owns. B2M LP owns a 500kV double-circuit transmission line that is parallel to an existing 500kV double-circuit line, so servicing of the line will be efficient given its proximity to the existing circuit. B2M LP owns no station assets. Additionally, this type of asset is extremely reliable and has a very low probability of fault or other incident requiring corrective maintenance or repair expenditures.

Table 1 - Summary of OM&A ($ Millions)

Description	Historical								Bridge		Test
	2015		2016		2017		2018		2019		2020
	Plan	Act	Plan	Act	Plan	Act	Plan	Act	Plan	Frcst	Frcst
Service Level Agreement Costs	0.9	0.7	0.8	0.8	0.8	1.0	2.0	1.1	0.8	0.7	0.7
Incremental Expenses	0.9	0.4	0.4	0.3	0.5	0.3	0.4	0.3	0.7	0.7	0.4
Total OM&A	**1.8**	**1.1**	**1.2**	**1.1**	**1.2**	**1.3**	**2.4**	**1.4**	**1.5**	**1.3**	**1.2**

Witness: Jeffrey Smith

Over the 2015 to 2019 period, the OM&A spending has generally been on plan. The two exceptions would be:

(i) 2015, which saw spending below plan by about $0.7 million, resulting from lower than anticipated Operating Services costs as discussed below and lower than anticipated Incremental expenses; and

(ii) 2018, which saw spending below plan by about $1.0 million due mainly to variances in the Operating Services costs and the Transmission Rights-of-Way Maintenance as discussed below in Section 2.1.

The proposed OM&A spending for the 2020 Test year is forecast to be $1.2 million, consistent with the average annual spend over the historical years. The 2020 Test Year forecast represents a decrease of $0.2 million over the 2019 Bridge year forecast. This decrease is related entirely to the forecast Regulatory expenses in 2019 in this Application. All other OM&A components are substantially unchanged in the Test Year, compared to the Bridge year. More details on the historical and future spending on each of these components are included below.

2. KEY COMPONENTS OF THE OM&A EXPENDITURES

2.1 SERVICE LEVEL AGREEMENT COSTS

The bulk of the OM&A expenses required to satisfy the obligation and objectives of the company arise as the result of a Service Level Agreement between HONI and B2M LP.

The costs for these services are estimated using the HONI fully-allocated costs incurred to perform the services outlined in the Service Level Agreement. Table 2 presents the required funding for these services in the 2020 Test Year, along with the actual and planned spending levels for the bridge and historical years. Further details on these services are provided in the following sections.

Table 2 - Total Service Level Agreement Costs ($ Millions)

Description	Historical								Bridge		Test
	2015		2016		2017		2018		2019		2020
	Plan	Act	Plan	Act	Plan	Act	Plan	Act	Plan	Frcst	Frcst
Operations and Maintenance Expenses	0.7	0.4	0.5	0.5	0.5	0.8	1.8	0.9	0.6	0.4	0.5
Administrative and Corporate Expenses	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total Service Level Agreement Costs	**0.9**	**0.7**	**0.8**	**0.8**	**0.8**	**1.0**	**2.0**	**1.1**	**0.8**	**0.7**	**0.7**

The actual to plan variances of the Service Level Agreement costs over the five-year period (2015 to 2019) noted in Table 2 are mainly a result of the Operations and Maintenance expenses due to:

(i) Lower than anticipated Operating Services costs. The actual Operating Services costs were consistently below the original expectation by about $0.2 million per year; and

(ii) Shifts in the timing of the execution of the Transmission Rights-of-Way Maintenance work program. The timing of the execution of the forestry services varied compared to plan but was substantially completed as expected with actual costs within $0.1 million of the original forecast over the five-year period.

Looking forward, the proposed 2020 forecast for these services takes into consideration the above trends by reducing the 2020 forecast for Operating Services expense by about 40% from previous period estimates to align with the actual level of expenditure over the previous five years and by addressing the timing and expected expenditure of Transmission Rights-of-Way Maintenance work program over the rate period.

2.1.1 OPERATION AND MAINTENANCE EXPENSES

The Operation and Maintenance expenses relate to the Operating Services and Maintenance Services performed by HONI, on behalf of B2M LP. Examples of the services received are listed below:

Operating Services:

- Monitoring/Control of the transmission system, including alarm monitoring, asset monitoring, and minor control;
- Asset Operation within HONI-prescribed limits including application of HONI equipment directives and switching on HONI transmission system to regulate B2M LP 's transmission system;
- Emergency Response to transmission system events, including response to IESO-directed emergency actions, and implementation of load shedding;
- Outage Processing including scheduling, planning, and submitting to IESO;
- Crew Dispatching, including 24/7 assessment, contacting, and dispatching;
- Record Maintenance including retention of logged items, retention of SCADA information, and trip reports; and
- Power System IT Support of the power system applications used by operators.

Maintenance Services:

- Overhead Transmission Lines maintenance including thermovision, helicopter and ground patrols; and
- Transmission Right-of-Way maintenance, including mandatory annual NERC vegetation patrols, line clearing, brush control, condition patrol and property owner notifications.

Further details on the maintenance services are presented in B2M LP’s Transmission System Plan in Attachment 1 to Exhibit B, Tab 3, Schedule 1.

2.1.2 ADMINISTRATIVE AND CORPORATE EXPENSES

The Administrative and Corporate Expenses include the costs arising from the support functions provided by HONI to B2M LP for administrative services and systems. The investment in those systems and the cost of their operation are incurred by HONI but are allocated to Hydro One Inc. and its affiliates through a cost allocation methodology.

This methodology lowers costs for all of the Hydro One Inc. subsidiaries by providing access to a sophisticated administration infrastructure at a lower cost than if each built its own unique and independent system. This sharing of the costs for a unified infrastructure benefits rate payers through lower rates and has been accepted by the Board in numerous previous proceedings, including B2M LP's 2015 to 2019 Transmission Rates Application (EB-2015-0026). Further details on the common corporate costs and cost allocation methodology are provided in Exhibit F, Tab 4, Schedule 1.

2.2 INCREMENTAL EXPENSES

There are certain functions that must be executed by B2M LP to meet its obligations and objectives that are not supported by the Service Level Agreement with HONI. Table 3 presents the required funding in the 2020 Test Year, along with the actual and planned spending levels for the bridge and historical years. Further details on these functions are provided in the following sections.

Table 3 - Total Incremental Expenses ($ Millions)

Description	Historical								Bridge		Test
	2015		2016		2017		2018		2019		2020
	Plan	Act	Plan	Act	Plan	Act	Plan	Act	Plan	Frcst	Frcst
Insurance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Regulatory	0.3	-	-	-	-	-	-	-	0.3	0.3	-
Administrative	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Managing Director's Office	0.4	0.3	0.2	0.2	0.2	0.1	0.2	0.1	0.2	0.2	0.2
Total Incremental Expense	**0.9**	**0.4**	**0.4**	**0.3**	**0.5**	**0.3**	**0.4**	**0.3**	**0.7**	**0.7**	**0.4**

2.2.1 INSURANCE

B2M is obligated, by agreement and by good utility practice, to maintain an appropriate level of insurance to protect its assets, its owners and its customers from catastrophic loss. B2M LP is fortunate to be able to leverage the existing Hydro One Inc. insurance policies, rather than procuring insurance protection unilaterally, resulting in cost savings for B2M LP. The annual premiums for this insurance are about $0.1 million.

2.2.2 REGULATORY

B2M LP incurs regulatory expenses related to its transmission rate application proceedings, which require rebasing on a five-year term based on the OEB Filing Requirements. The total amount anticipated in 2019 is $0.3 million to cover costs for notice, studies, intervenors, OEB hearing charges and other items incurred directly by B2M LP. The 2020 Test Year does not include funding for this item. However, B2M LP does expect a similar level of regulatory expenses in the preparation of its next five-year transmission rate application and will need to manage this expense within the approved envelope.

2.2.3 ADMINISTRATIVE

B2M LP incurs administrative expenses for other external fees and expenses not otherwise covered, such as auditor and professional fees, statutory remittances, and other items. The administrative expenses included in the 2020 Test Year are $0.1 million, in line with the actual spend in the historical years.

2.2.4 MANAGING DIRECTOR'S OFFICE

The partnership has one employee, the Managing Director, who is empowered to oversee and operate the partnership. The duties of this person include:

- Monitoring and ensuring that the terms and conditions of the partnership agreement are fulfilled;

- Working with employees from HONI and other entities to ensure that the Applicant and its assets are properly maintained and administered;
- Managing and Chairing Advisory Committee meetings with the partners on a regular basis, as spelled out in the partnership agreement;
- Ensuring that the partners are kept well informed and advised of the partnership's operations, and educated on what it means to be a transmission owner and operator in Ontario;
- Authorizing the disbursement of funds by the partnership to meets it obligations and expenses;
- Instituting communications with communities and the public at large, through meetings, websites and other media;
- Representing the partnership with various stakeholders at hearings, industry events and other situations; and
- Any and all other duties that may be required to represent the partnership and effectively support its operations.

To complete these tasks, the Managing Director's Office is provided an annual budget for things such as salary, office, communication, and other expenses that may be required. The total Managing Director's Office expense included in the 2020 Test year is $0.2 million in line with the average annual spend over the historical years.

TAB 27

SUMMARY OF OM&A EXPENDITURES

1. SUMMARY OF OM&A EXPENDITURES

The proposed Operation, Maintenance, and Administration ("OM&A") expenses represent the work required to meet public and employee safety objectives, maintain transmission reliability, and to comply with regulatory requirements, environmental requirements and Government direction. Key components in the build-up of OM&A requirements include:

- Service Level Agreement with Hydro One Networks ("HONI"), and
- Ongoing Incremental Expenses of the Partnership.

Table 1 presents the required funding for OM&A in the 2020 Test Year for each of these key components. Overall, NRLP's OM&A spending on a per asset basis is low in comparison to other transmitters in Ontario. This relates primarily to the characteristics of the assets that it owns. NRLP owns a 230kV double-circuit transmission line that requires periodic vegetation management expenses and operating services costs but otherwise very little given that the company owns no station assets. Additionally, this type of asset is extremely reliable and has a low probability of fault or other incident requiring corrective maintenance or repair expenditures.

Table 1 - Summary of OM&A ($ Millions)

Description	Test 2020 Forecast
Service Level Agreement Costs	0.52
Incremental Expenses	0.31
Total OM&A	**0.83**

The proposed OM&A spending for the 2020 Test year is forecast to be $0.83 million. More details on the future spending on each of these components are included below.

2. KEY COMPONENTS OF THE OM&A EXPENDITURES

2.1 SERVICE LEVEL AGREEMENT COSTS

The bulk of the OM&A expenses required to satisfy the obligation and objectives of the company arise as the result of a Service Level Agreement between HONI and NRLP.

The costs for these services are estimated using the HONI fully-allocated costs incurred to perform the services outlined in the Service Level Agreement. Table 2 presents the required funding for these services in the 2020 Test Year. Further details on these services are provided in the following sections.

Table 2 - Total Service Level Agreement Costs ($ Millions)

Description	Test 2020 Forecast
Operations and Maintenance Expenses	0.32
Administrative and Corporate Expenses	0.20
Total Service Level Agreement Costs	**0.52**

2.1.1 OPERATION AND MAINTENANCE EXPENSES

The Operation and Maintenance expenses relate to the Operating Services and Maintenance Services performed by HONI, on behalf of NRLP. Examples of the services received are listed below:

Operating Services:

- Monitoring/Control of the transmission system, including alarm monitoring, asset monitoring, and minor control;
- Asset Operation within HONI-prescribed limits including the application of HONI equipment directives and switching on HONI’s transmission system to regulate NRLP 's transmission system;

- Emergency Response to transmission system events, including response to IESO-directed emergency actions, and implementation of load shedding;
- Outage Processing including scheduling, planning, and submitting to IESO;
- Crew Dispatching, including 24/7 assessment, contacting, and dispatching;
- Record Maintenance including retention of logged items, retention of SCADA information, and trip reports; and
- Power System IT Support of the power system applications used by operators.

Maintenance Services:

- Overhead Transmission Lines maintenance including thermovision, helicopter and ground patrols; and
- Transmission Right-of-Way maintenance, including mandatory annual NERC vegetation patrols, line clearing, brush control, condition patrol and property owner notifications.

Further details on the maintenance services are presented in NRLP's Transmission System Plan in Attachment 1 to Exhibit B, Tab 1, Schedule 3.

2.1.2 ADMINISTRATIVE AND CORPORATE EXPENSES

The Administrative and Corporate Expenses include the costs arising from the support functions provided by HONI to NRLP for administrative services and systems. The investment in those systems and the cost of their operation are incurred by HONI but are allocated to Hydro One Inc. and its affiliates through a cost allocation methodology.

This methodology lowers costs for all of the Hydro One subsidiaries by providing access to a sophisticated administration infrastructure at a lower cost than if each built its own unique and independent system. This sharing of the costs for a unified infrastructure benefits ratepayers through lower rates and has been accepted by the Board in numerous previous proceedings, including B2M LP's 2015 to 2019 Transmission Rates Application (EB-2015-0026). Further details on the common corporate costs and cost allocation methodology are provided in Exhibit F, Tab 4, Schedule 1.

2.2 INCREMENTAL EXPENSES

There are certain functions that must be executed by NRLP to meet its obligations and objectives that are not supported by the Service Level Agreement with HONI. Table 3 presents the required funding in the 2020 Test Year. Further details on these functions are provided in the following sections.

Table 3 - Total Incremental Expenses ($ Millions)

Description	Test 2020 Forecast
Insurance	0.05
Managing Director's Office	0.26
Total Incremental Expense	**0.31**

2.2.1 INSURANCE

NRLP is obligated, by its partnership agreement and by good utility practice, to maintain an appropriate level of insurance to protect its assets, its owners and its customers from catastrophic loss. NRLP is fortunate to be able to leverage the existing Hydro One Inc. insurance policies, rather than procuring insurance protection unilaterally. This results in considerable savings for NRLP. The annual premiums for this insurance are about $0.05 million.

2.2.2 MANAGING DIRECTOR'S OFFICE

The partnership has a Managing Director, who is empowered to oversee and operate the partnership. The duties of this person include:

- Monitoring and ensuring that the terms and conditions of the partnership agreement are fulfilled;
- Working with employees from HONI and other entities to ensure that the Applicant and its assets are properly maintained and administered;
- Managing and Chairing Advisory Committee meetings with the partners on a regular basis, as spelled out in the partnership agreement;
- Ensuring that the partners are kept well informed and advised of the partnership's operations, and educated on what it means to be a transmission owner and operator in Ontario;
- Authorizing the disbursement of funds by the partnership to meets its obligations and expenses;
- Instituting communications with communities and the public at large, through meetings, websites and other media;
- Representing the partnership with various stakeholders at hearings, industry events and other situations; and
- Any and all other duties that may be required to represent the partnership and effectively support its operations.

To complete these tasks, the Managing Director's Office is provided with an annual budget for things such as salary, office, communication, and other expenses that may be required. The total Managing Director's Office expense included in the 2020 Test year is $0.26.

TAB 28

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

Reference: Exhibit A, Tab 3, Schedule 1, Page 10; Exhibit B, Tab 1, Schedule 4.

Preamble: "The majority of NextBridge's maintenance services were competitively bid and will be awarded to a partnership between HONI and Supercom, which will result in a service level agreement to plan and organize the operation and maintenance of the assets."

a) Please provide a list of the services bid, the number of bidders and the range of costs (omit names except HONI/Supercom).
b) Please provide more information on Supercom and its role in the HONI/Supercom services agreement.
c) Please file a copy of the Service Agreement with HONI/Supercom.

RESPONSE

a) Below is the list of services bid.

Maintenance services including a detailed visual aerial inspection of one third of the transmission line on an annual basis, with the remaining two thirds of the line being aerially (alternatives will be considered) inspected for obvious and critical issues only. For the visual inspection, high resolution photos of each structure will be taken and reviewed further by the bidder's transmission line subject matter experts. The detailed visual inspection will be submitted to NextBridge within 2 weeks and include the following transmission line, right-of-way and access inspection points;

- Steel structures
- Hardware
- Loose/damaged guys and missing/damaged guy guards
- Conductors, overhead shield wire and OPGW (broken strands, sag, clearance issues, etc.)
- Insulator assemblies
- Arrestors
- Vibration dampeners
- Backfill problems
- Erosion issues/Washouts
- Rock-fall
- Tree growth that may have encroached on limits of approach/hazard trees

- Public improvements/interference

The maintenance services agreement will also include responses to unplanned outages and emergencies. Response will be needed on a 24x7x365 basis and will require immediate action due to the serious effects of line outages and potential public safety impacts. Qualified personnel will need to be immediately dispatched to assess the event and develop a response plan. At a minimum the work plan will require the following items:

- Details outlining of all the required activities, timing and schedule/sequence
- Responsibility structure
- Material list
- Safe work plan
- Preliminary cost estimate based on time and material rates
- Applicable engineering resources and drawings
- Estimated restoration time
- Equipment list (i.e., cranes, trucking, helicopters, etc.)
- Access plan

The maintenance services provider will, upon notification of an emergency, in light of the circumstances of the emergency, endeavor to arrive in the area of the emergency within 24 hours to perform an initial assessment of the infrastructure, and prepare a work plan within 24 hours of the initial site visit for approval of NEET field personnel. Furthermore, in respect of such emergency, the maintenance services provider shall, in good faith, with reasonable and expeditious effort, deploy all labour, equipment and materials in accordance with the work plan approved by NEET field personnel, to perform the required restoration.

Maintenance services will include identification and storage of spare material. While NextBridge will have some spare material for the transmission line, a complete list of expected spare material will need to be developed, including costs and storage type and location(s).
Vegetation maintenance services during the operational phase of the transmission line will also be required.

Number of Bidders

NextBridge sent the RFP to 5 potential bidders, and three bid responses were received.

Range of Costs

The cost range was \$0.3M to \$0.4M annually.

b) Supercom Industries LP (Supercom) is a unique partnership of six First Nations who ensure maximum employment and economic benefits for Indigenous communities along the East-West Tie line area. Their focus includes facilitating training programs and the procurement of materials, services, and labour from Indigenous communities. HONI and Supercom will be a limited partnership that links the focus areas of Supercom mentioned above with the long-established capacities and resources of HONI.

c) The maintenance services agreement with HONI/Supercom has not yet been finalized but is expected to be complete Q1 2021. It will be filed at that time.

TAB 29

ENERGY PROBE INTERROGATORY #25

INTERROGATORY

Reference: Exhibit F, Tab 4, Schedule 2, Attachment 1, Page 35, TVMP

Preamble: "The Leader Vegetation Management - T/S will maintain the processes, standards and documentation to ensure that the vegetation in the transmission system is properly maintained. This TVMP shall be reviewed and updated as necessary based on adopted revisions to FAC-003-1 requirements or as changing field conditions and circumstances warrant."

a) Why is the NextEra Energy TVM Agreement filed? Please confirm that UCT/NextBridge will contract with Hydro One for vegetation management.
b) Please either confirm Hydro One will perform vegetation management under the same terms/conditions specified in the NextEra Energy Document, or file the appropriate Hydro One TVMP document(s).
c) Please summarize the Annual Targets for TVM (km line)
d) What is the forecast Hydro One annual TVM cost? Will this include escalation provisions?

RESPONSE

a) Confirmed. The NextEra Energy TVMP was filed as a placeholder until the Maintenance Services Agreement was completed. As part of the Maintenance Services Agreement, HONI/Supercom will be performing vegetation management for UCT/NextBridge and UCT/NextBridge will utilize the HONI TVMP.

b) Confirmed. As part of the Maintenance Services Agreement, HONI/Supercom will be performing vegetation management for UCT/NextBridge and will follow the appropriate HONI TVMP. Once the Maintenance Services Agreement is signed, the HONI TVMP will be adopted, and UCT/NextBridge will file the appropriate HONI TVMP documents.

c) One of NextBridge's targets requires that the entire 450km East-West Tie line will be inspected on annual basis, as required by North American Electric Reliability Corporation Reliability Standard FAC-003-4 and its successor versions. In addition, NextBridge is targeting 0 (zero) vegetation caused outages. NextBridge's annual inspection plan includes aerial inspections of the entire length of the right-of-way, followed by appropriate vegetation remediation measures resulting from the inspections. This approach will proactively manage vegetation and support

NextBridge's target of 0 (zero) vegetation caused outages.

d) There is no specific line item for TVM annual inspection cost. Rather the annual inspection costs are part of the overall $400,000 budget in the maintenance services contract with HONI/Supercom. The $400,000 budget is firm for 3 years, with an available extension for two additional years, and, therefore, there is no escalation included.

TAB 30

STAFF INTERROGATORY #15

INTERROGATORY

Reference: (1) Exhibit B / Tab 1 / Schedule 4 / p.10-11

Preamble:
Reference 1 states “Maintenance services (majority provided by HONI/Supercom)”.

Reference 1 also states:

> When contracted by NextBridge under the HONI SLA, HONI will routinely inspect the overhead transmission lines by ground and aerial-based patrols to identify safety and reliability deficiencies. At NextBridge’s direction, HONI will also undertake emergency repairs and responses to restore power or minor corrective work to resolve reliability and safety problems with transmission line assets when necessary.

Question(s):

a) Please describe what maintenance services are not expected to be provided by HONI/Supercom.
b) What is NextBridge’s plan to procure services described in response to a)?
c) Please confirm that costs for all services provide by HONI/Supercom will be included in the cost of the HONI SLA.
d) Please explain how NextBridge has satisfied itself that the arrangement with HONI/Supercom was the most cost-effective approach?
e) Which NextBridge representative(s) will be authorized to direct HONI to undertake emergency repairs and responses as described in Reference 1?

RESPONSE

a) The following maintenance activities are expected to be provided by NEET personnel;
    - Coordination and monitoring of the maintenance services provider to support the safety and reliability of the East-West Tie line.
    - Direction of planning, budgeting, and execution of work.
    - Follow-up review of service provider’s detailed inspection findings and recommendations by subject matter experts from NEET or NEET affiliates.
    - Storage for small maintenance spare parts (such as lighting components) will be provided at the Operations office.
    - Management of maintenance files, spot audits for adequacy of performed services and complaint investigations.

- Ensure the compliance of maintenance operating and reliability standards, specifications, and procedures.

b) NEET personnel will self-perform the services listed in part a. under the NEET service level agreement.

c) Confirmed.

d) A competitive procurement process was undertaken to award a maintenance services agreement to a qualified, cost-competitive service provider to supply maintenance, operations, and emergency services on the East-West Tie line. As the Application explains, a partnership between HONI and Supercom was selected to provide these services. While the selected HONI/Supercom partnership bid was not the lowest priced option of the three bids received, based on NEET's experience, it was still cost effective and prudent particularly because HONI has infrastructure that parallels the majority of the East-West Tie line, which provides HONI with a complete and historical understanding of the area and conditions under which maintenance activities will be conducted. HONI's proximity to the East-West Tie line also allows them to quickly respond to potential unplanned outages. In this regard, the maintenance agreement with HONI/Supercom also involves emergency response services, which again HONI/Supercom will be able to provide a superior response given HONI's familiarity with and proximity to the East-West Tie line. Finally, while the bidders were competitive through most selection criteria, HONI's Indigenous Economic Benefits program through their partnership with Supercom, was far superior

e) The field Operations Lead in conjunction with the NextBridge Project Director will be authorized to direct HONI/Supercom to undertake emergency repairs and responses.

TAB 31

SUMMARY OF OM&A EXPENDITURES

1. The proposed OM&A expenses represent the work required to meet public and personnel safety objectives, maintain transmission reliability, and to comply with regulatory and environmental requirements. Key components of OM&A requirements include:

- Operations & Maintenance Services;
- Regulatory (such as annual/periodic filings, OEB/IESO proceedings monitoring, general support);
- Compliance & Administration (such as land filings/matters, audit/tax filing fees, hourly personnel support charges, stakeholder relations, insurance);
- Indigenous Participation;
- Indigenous Compliance (such as compliance with conditions of Species at Risk permits); and
- Property Taxes & Land Rights Payments.

2. Table 1 below presents the required funding for OM&A in the Test Year (April 1, 2022 to March 31, 2023) for each of these key components. Overall, NextBridge's OM&A spending on a per asset basis is low in comparison to other transmitters in Ontario, as detailed in the CRA benchmarking study attached as Exhibit B, Tab 1, Schedule 7, Attachment 1. This relates primarily to the characteristics of the assets that it owns. NextBridge's East-West Tie line is a 230 kV double-circuit transmission line that requires periodic vegetation management expenses and operating services costs, but otherwise very little additional operation given that NextBridge owns no station assets. Additionally, this type of asset is extremely reliable and has a low probability of fault or other incident requiring corrective maintenance or repair expenditures. As explained in Exhibit 3 (Rate Base), NextBridge does not capitalize overheads and therefore there is zero OM&A expense for capitalized overheads.

Table 1. NextBridge OM&A Expense ($ Millions)

Cost Category	2022
Operations & Maintenance	1.27
Regulatory	0.07
Compliance & Administration	1.67
Indigenous Participation	0.89
Indigenous Compliance	0.44
Property Taxes & Rights Payments	0.60
Total OM&A	**4.94**

More details on the future spending on each of these components are included below.

TAB 32

(New Item not Contained in Original Compendium)

Overview of the Aboriginal Loan Guarantee Program (ALGP)

- The $650 million Aboriginal Loan Guarantee Program supports Aboriginal participation in renewable green energy infrastructure in Ontario including transmission projects and wind, solar and hydroelectric generation projects.
- The program was announced in the 2009 Ontario budget and provides a Provincial guarantee for a loan to an Aboriginal corporation to purchase up to 75 per cent of an Aboriginal corporation's equity in an eligible project, to a maximum of $50 million.
- The program is available to corporations that are wholly-owned by Aboriginal communities.
- By participating in eligible renewable energy projects, First Nation and Métis communities can benefit from jobs and training as projects are developed and from dividends once projects come into service.
- Loan guarantees are provided under the program no earlier than at the point of financial close for the project, after regulatory approvals are in place and at the same time, or after, all other financing is put in place.
- The Ontario Financing Authority (OFA) administers the program on behalf of the Province.
- The ALGP requires a sufficient level of due diligence in order to satisfy eligibility criteria and to draft the required underlying legal agreements. The applicant is required to obtain financial and legal advice, and may incur costs passed on from the lender. The OFA and the Province will not be responsible for any costs and/or expenses incurred by the applicant related to the ALGP application and review process, and the applicant will not be able to recover any such costs or expenses from the ALGP. As the scale of these costs is similar, regardless of the size of the application, a small application may not be cost-efficient. The ALGP is better suited for applications greater than $5 million.
- The Aboriginal Loan Guarantee Program is a discretionary, non-entitlement program. Any decision to provide a loan guarantee will be at the sole and absolute option of the Province. This means that even if an application meets the program objectives and criteria, the Province is under no obligation to provide a guarantee. Assistance in the form of loan guarantees is limited.