RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-237

Reference: Exhibit 2B, Section E7.4, Pages 30-32

Preamble:

OEB Staff have created the following table which summarizes actual and forecast costs for 2020-2024 from the variance explanation in the reference 1.

Reactive Hydro One Contribution and True-Up Costs	2020-2024 $ million
Copeland TS Phase 1 True-Up	9.9
Switchyard Expansion Bermondsey and Richview TS	8.5
New Cable Carlaw TS to Gerrard TS	2.4
Additional Unforeseen	1.9
Reactive Total	**22.7**

QUESTION (A):

a) Table 18 in reference 1 shows a 2020-2024 Actual/Forecast Costs of $24.9M for Reactive Hydro One Contribution and True-Up Costs. Please reconcile the difference between this value and the value compiled in the table above.

RESPONSE (A):

Table 1 below expands upon the table provided in the preamble, and shows the complete costs adding to $24.9 million for Reactive Hydro One Contribution and True-Up Costs.

Table 1: Complete Actual and Forecast Costs Reactive Hydro One Contribution and True-Up Costs over 2020-2024 ($ Millions)

Reactive Hydro One Contribution and True-Up Costs	2020-2024
Copeland TS Phase 1 True-Up	9.9
Switchyard Expansion Bermondsey and Richview TS	8.5

Reactive Hydro One Contribution and True-Up Costs	**2020-2024**
New Cable Carlaw TS to Gerrard TS	2.4
Additional Unforeseen	1.9
Renewal and Customer Connection Projects (To be reversed)	1.2
Long-Lead Item Procurement	1.0
Reactive Total	**24.9**

The difference between the $22.7 million shown in the preamble, versus the $24.9 million reported in Exhibit 2B, Section E7.4 at page 27[1] is due to an additional: $1.0 million advanced payment incurred in 2022 for long-lead item procurement, and an additional $1.2 million for renewal and customer connection projects for which costs will be recovered from the customer.

QUESTION (B):

b) For each of the projects in Table 19: Hydro One Contributions 2020-2024 Variances, and the projects that make up the Reactive Contributions and True-Ups:

i. Please categorize the costs as construction costs or load true-up.

ii. Please provide the agreements between Toronto Hydro and Hydro One.

iii. Please provide any invoices and calculations from Hydro One (i.e. output of the Hydro One DCF model).

iv. For those costs not yet invoiced by Hydro One, please provide the cost estimate and calculations from Hydro One (i.e. output of the Hydro One DCF model). In the absence of documentation from Hydro One, please provide Toronto Hydro's detailed DCF calculations for the true-up payment.

v. In cases where Toronto Hydro was, or may be, required to make a payment during 2020-2024 due to reduced or unrealized load, please explain why the load forecast at the time of the agreement with Hydro One was not realized. (For example, the $5.7M incurred on the Copeland TS Phase 1. Project).

[1] As of Toronto Hydro's Application update submitted on January 29

RESPONSE (B):

i.

Subsegment	Project	Cost Categorization
Horner Expansion	Horner Expansion	Construction Cost
Hydro One Transformer Upgrades	Bridgman TS T11/T12/T13/T14 Upgrade	Construction Cost
	Cecil TS T3/T4 Upgrade	Load True-Up
	Charles TS T3/T4 Upgrade	Construction Cost
	Dufferin TS T1/T3/T4 Upgrade	Construction Cost
	Main TS T3/T4 Upgrade	Construction Cost
	Strachan TS T12 Upgrade	Construction Cost
	Strachan TS T14 Upgrade (Partial Cost)	Construction Cost
Reactive Hydro One Contribution and True-Up Costs	Copeland TS Phase 1 True-Up	Load True-Up and Construction Cost
	Switchyard Expansion Bermondsey and Richview TS	Construction Cost
	New Cable Carlaw TS to Gerrard TS	Construction Cost
	Additional Unforeseen	Forecast – Expected: Construction Cost
	Incorrect Mapping of Renewal Work	Construction Cost
	Customer Connection Requiring HONI Contribution	Construction Cost
	Incorrect Mapping of Partial Cost of Strachan TS T12 Upgrade	Construction Cost

With regards to ii. and iii. please see the agreements and invoices attached as appendices.

iv. The only project without a CCRA and formal cost estimate is the Bermondsey TS switchyard expansion. Hydro One provided Toronto Hydro a planning estimate for this project which is reflected in the forecast.

v. There were two load true-up payments in the 2020-2024 period: the Copeland TS Phase 1 True-Up, and the Cecil TS T3/T4 Upgrade.

With respect to Copeland TS – Phase 1, the CCRA was based on Toronto Hydro's 2013 System Peak Demand (2012 actuals). In 2015, Toronto Hydro recalibrated its load forecasting methodology to reflect the latest growth trends observed in actuals and align with the 2016 Regional Infrastructure

Plan methodology.[2] These changes coupled with a drop in peak demand in the surrounding area resulted in the load true up. However, it is important to note that Copeland TS is needed both to enable switchgear renewal at Windsor TS, and to provide thermal capacity and feeder positions to its surrounding area. The value of switchgear renewal and additional feeder positions is not substantially diminished by partially unrealized load.

Similarly, Toronto Hydro made a load true-up payment for the historic project, Cecil TS T3/T4 Upgrade which was executed in 2005. The payment was the result of differences in Toronto Hydro's 2021 System Peak Demand Forecast relative to Toronto Hydro's 2015 System Peak Demand Forecast, submitted for each respective true-up evaluation. This difference is attributed to lack of load realization from customers relative to load requested over the 2013-2017 period, and the impact of COVID-19 in the Cecil area. Additionally, as the in-service date for Copeland Phase II had not been set at the time of the 2015 forecast, it did not reflect the impact of future load transfers from Cecil to Copeland TS (post-Phase 2). These transfers were reflected in the 2021 forecast which formed the basis of the true-up.

[2] Toronto Hydro notes that the 2016 Regional Infrastructure Plan was the first following the launch of the IRRP process (in May 2015).

CONNECTION AND COST RECOVERY AGREEMENT (CCRA) - LOAD

between

Toronto Hydro-Electric System Limited

and

Hydro One Networks Inc.

for

Copeland (formerly Bremner) MTS Line Connection

CONNECTION AND COST RECOVERY
<u>AGREEMENT (CCRA) – LOAD</u>

Toronto Hydro-Electric System Limited (the "**Customer**") has requested and Hydro One Networks Inc. ("**Hydro One**") has agreed to connect Copeland MTS (formerly called Bremner MTS) to Hydro One's transmission system (the "**Project**") on the terms and conditions set forth in this Agreement dated the 26th day of FEBRUARY, 2014 (the "**Agreement**") and the attached Standard Terms and Conditions for Load Customer Transmission Customer Connection Projects V4 3-2012 (the "**Standard Terms and Conditions**" or "**T&C**"). Schedules "A", "B", "C", "D", "E", "F" and "G" attached hereto and the Standard Terms and Conditions are to be read with and form part of this Agreement.

<u>Project Summary</u>

The Customer has requested that Hydro One connect their proposed transformer station ("**Copeland MTS**") which will be located at the intersection of Bremner Blvd and Rees Street, having a municipal address of 25 Rees Street, Toronto (the "**Customer's Site**") to Hydro One's transmission system via [redacted] The Project will also involve the construction of a high-voltage (HV) switching facility ("**Copeland SS**") to be owned and operated by Hydro One at the Customer's Site.

<u>Term:</u> The term of this Agreement commences on the date first written above and terminates on the 25th anniversary of the In Service Date.

<u>Special Circumstances</u>

A. Hydro One and the Customer agree to continue to explore opportunities to advance the Ready for Service Date.

B. **In addition to the circumstances described in Section 5 of the Standard Terms and Conditions, the Ready for Service Date is subject to:**

   (a) the Customer executing and delivering this Agreement to Hydro One by no later than March 1, 2014 (the "**Execution Date**"); and

   (b) the Hydro One High-Voltage (HV) gas insulated switchgear (GIS) room in the Customer's building with all required elements/components described in Schedule "C", Section 1(a) being ready on or before August 4, 2014 such that Hydro One can commence the Pre-GIS Equipment Installation Work (as that term is defined in Schedule "C") on or before August 5, 2014; and

   (c) the Hydro One HV GIS room in the Customer's building with all required elements/components described in Sections 1(a) and 1(b) of Schedule "C" being completed on or before September 8, 2014 such that Hydro One can commence the GIS Equipment Installation Work (as that term is defined in Schedule "C") on or before September 9, 2014; and

   (d) the Hydro One relay, DC switchgear and battery rooms in the Customer's building with all required elements/components described in Section 2(a) of Schedule "C" being complete on or before January 9, 2015, such that Hydro One can commence the Pre-equipment Installation Work (as that term is defined in Schedule "C") on or before January 12, 2015; and

(e) the Hydro One relay, DC switchgear and battery rooms in the Customer's building with all required elements/components described in Sections 2(a) and 2(b) of Schedule "C", being ready on or before January 30, 2015 so that Hydro One can commence the Equipment Installation Work (as that term is defined in Schedule "C") on or before February 2, 2015; and

(f) the Customer's New Tunnel with all required elements/components described in Section 3 of Schedule "C", being completed on or before August 15, 2014 such that Hydro One can commence the Cable Installation Work (as that term is defined in Schedule "C") on or before August 18, 2014.

C. The parties agree that Section 24 and "Appendix" B of the Standard Terms and Conditions are hereby deleted.

D. Land Rights

The Customer shall enter into the real estate rights/land agreements listed below with Hydro One at the Customer's expense in respect of the Customer's land described as PART OF BLOCKS C AND D, PLAN 536E; PART OF JOHN STREET, LAKE STREET, PLAN 536E, CLOSED BY ES4725, KNOWN AS REES STREET, DESIGNATED AS PARTS 2, 3, 4, 5, 6, 7, 8 AND 9, PLAN 64R13541; S/T CA212869 CITY OF TORONTO (the "**Customer's Land**"):

(i) a grant of easement in gross in perpetuity to Hydro One for nominal consideration substantially in the form of the grant of easement in gross attached to the Agreement as Schedule "D", but subject to reasonable negotiations by both parties, on or before May 1, 2015;

(ii) an Early Access Agreement with Hydro One for nominal consideration substantially in the form of the Early Access Agreement attached to the Agreement as Schedule "E", but subject to reasonable negotiations by both parties, on or before August 15, 2014; and

(iii) an agreement for a Construction Pad and Assembly Area with Hydro One for nominal consideration substantially in the form of Agreement for Construction Pad and Assembly Area attached to the Agreement as Schedule "F", but subject to reasonable negotiations by both parties, on or before August 4, 2014; and

(iv) a Tunnel Occupancy Agreement with Hydro One for nominal consideration substantially in the form of the Tunnel Occupancy Agreement attached to the Agreement as Schedule "G", but subject to reasonable negotiations by both parties, on or before December 31, 2014.

With respect to the acquisition of land rights, the cost of same includes, but is not limited to, easements/lease/licence costs along with any associated costs such as the cost of performing appraisals, surveys, submitting applications, licence and review fees, legal and land disbursement closing costs.

Subject to Section 31 of the Standard Terms and Conditions, this Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper authorized signatories, as of the day and year first written above.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Name: Anthony Haines
Title: President and CEO

Name: Dino Priore
Title: Executive Vice President, Engineering & Construction
We have the authority to bind the Corporation

HYDRO ONE NETWORKS INC.

for
Name: Brad Colden
Title: Manager – Manager, Key Accounts
Execution Date: FEB. 26, 2014
I have the authority to bind the Corporation

CONNECTION AND COST RECOVERY
AGREEMENT (CCRA) – LOAD

Schedule "A" Copeland MTS Line Connection – Project Scope

PROJECT SCOPE

New or Modified Connection Facilities: Hydro One will design, construct, own and operate a new high-voltage (HV) line connection, including HV switching facilities to be called Copeland SS, for the Customer's new Copeland MTS.

Connection Point: 115 kV underground transmission circuits, H9EJ and H10EJ [redacted]

Ready for Service Date: 29th day of August, 2015

HYDRO ONE CONNECTION WORK

Part 1: Transformation Connection Pool Work

- Not applicable.

Part 2: Line Connection Pool Work

Hydro One will perform the work described below:

A. General Requirements

1. Obtain approvals and permits as required for the Hydro One facilities, including but not limited to municipal consent for Hydro One underground cables to be on the City of Toronto's right-of-way.
2. Carry out acceptance checks, testing and commissioning of station equipment, associated systems and facilities.
3. Coordinate with the Customer and their consultants regarding technical requirements of the Customer's tunnel as well as space and service requirements for Hydro One equipment to be located at the Customer's site.
4. Arrange for outages required for providing the line connection.
5. Provide for Registration and Transfer of Control of facilities in coordination with the Customer and in compliance with the IESO and OGCC requirements.
6. Review the land rights and other agreements described in Section D under "Special Circumstances" in this Agreement to be granted/executed by the Customer in accordance with the terms thereof.

B. High-Voltage Cable Connection

1. Provide a HV, three-phase cable connection as described below via underground HV circuits currently designated as H9EJ and H10EJ through the tunnel which is being built by and will be owned by the Customer (the "**Customer's New Tunnel**") :
   a. [redacted]

b. [redacted]

c. [redacted]

d. The cables are to be rated for 250 kV, but initially operated at 115 kV.

2. Provide to the Customer the support brackets for the circuits that are to be mounted in open air.
3. Provide and install [redacted] the mounting brackets and the cable sheaths.
4. Provide and install an insulated ground conductor which will serve to carry return fault currents.
5. Provide and install an integrated fibre optic temperature and sensing system to monitor cable operating temperature.

C. High-Voltage GIS Switching Facilities

1. Provide and install 230 kV class HV gas insulated switching (GIS) facilities ("Copeland SS") which will be located at the Customer's Site consisting of the following:
   a. Four (4) circuit breakers, two per circuit, at the main line entrances
   b. Two (2) normally-open circuit breakers, one per circuit
   c. Twelve (12) motorized, remotely controlled breaker disconnect switches
   d. Four (4) motorized, remotely controlled disconnect switches for the transformer connections
   e. Four (4) motorized, remotely controlled disconnect switches at the main line entrances
2. Provide and install four (4) sets of HV surge arresters at the incoming cable terminations.
3. Provide and install twenty eight (28) 3-phase ground switches.
4. Provide and install Local Control Centres (LCC) associated with Hydro One's GIS facilities.
5. Provide and install mounting plates/anchor bolts for Hydro One HV GIS switchgear.
6. Provide and install cabling between the HV GIS switchgear and the LCC cabinets via cable trays located on the underside of the floor slab.
7. Provide and install grounding for the GIS to the ground wire on the perimeter of Hydro One's Copeland SS GIS room.
8. Provide and install cable trays and mounting hardware beneath the GIS room floor for cabling associated with the GIS equipment.
9. Install the Customer's HV cables into Hydro One's HV GIS switchgear.
10. Provide test equipment for the GIS.

D. AC and DC Station Service

1. Provide and install DC station service supply which includes the following
   a. In each of two DC station service rooms:
      i. An AC automatic transfer switch (ATS)
      ii. A manual transfer scheme (MTS)
      iii. A battery charger
      iv. An AC distribution panel
      v. All required connections
      vi. Appropriate grounding
   b. In each of two battery rooms:
      i. 125 Volt batteries

   ii. Connection to the MTS
   iii. Appropriate grounding
   iv. Self-contained eye wash station

2. Provide and install AC station service facilities to supply electrical loads for Copeland SS' GIS room, relay room and battery rooms, including 120/208 Volt distribution panels (AC station service sources for Copeland SS are to be provided by the Customer).

E. Protections, Control and Tele-Protection Systems

1. Provide and install required protections facilities at Copeland SS in two separate relay rooms, one for the "A" protection equipment and the other for the "B" protection equipment consisting of:
   a. New line protections from Copeland SS and John TS
   b. New line protections from Copeland SS and Esplanade TS
   c. HV bus/cable protections
   d. Six (6) HV breaker protections
2. Provide and install cable tray systems between the GIS room and the two relay rooms at Copeland SS as well as the cable tray entry openings in walls.
3. Provide to the Customer the design for the computer floor in the two relay rooms at Copeland SS.
4. Install fibre optics inter-site cables between Copeland SS, John TS and Esplanade TS through the Customer's New Tunnel and Hydro One's existing tunnel at Front Street and Lower Simcoe Street ("**Hydro One's Existing Tunnel**")
5. Provide SCADA communications to the OGCC, IESO and the Customer.
6. Test and commission all P&C devices associated with the Hydro One's new facilities.
7. Confirm the final protection settings.
8. Perform Zone Test Trip for the new line protections.

F. Services in Hydro One Areas

1. Provide the Customer with Hydro One's requirements for floor and wall penetrations.
2. For Lighting and Electrical Systems:
   a. Provide and install all electrical services in the Hydro One GIS room at Copeland SS, including services for the crane, lighting, and receptacles.
   b. Provide and install all electrical equipment and electrical services in the two Hydro One relay rooms.
   c. Provide and install all electrical equipment and electrical services in the Hydro One's DC station service and battery rooms.
   d. Provide support steel for cable trays as required for lighting fixtures.
   e. Provide and install GIS grounding to be connected to the station grounding grid that is to be provided by the Customer.
   f. Provide and install emergency and exit lights in Hydro One areas.
3. For the Crane in the Hydro One GIS room at Copeland SS:
   a. Provide a crane and associated bridge for the Customer to install in Hydro One's GIS room at Copeland SS. The delivery schedule is to be coordinated with the Customer.
   b. Provide to the Customer requirements for bridge crane rails and for installation of the rails, bridge and the crane.
   c. Provide and install wiring for the bridge crane.
   d. Provide and install the platform and stairs for the crane.
4. For the HVAC Systems:

   a. Provide and install local HVAC control panel in Relay Room "A" at Copeland SS to be interfaced with the Customer's remote master HVAC panel. Controls will send control output signals to and receive status input signals from the Customer's panel at Copeland MTS.

5. For Sensor and Alarm Systems:
   a. Provide and install all fire alarm equipment in the Hydro One rooms at Copeland SS, including a local panel in Relay Room "A", smoke detectors, sensors and annunciation.
   b. Provide and install all electrical wiring associated with the fire alarm system in the Hydro One areas and provide appropriate signals to the Customer's systems at Copeland MTS.
   c. Provide and install all SF6 sensing and annunciating equipment in all Hydro One rooms and in the basement below Hydro One's HV GIS room and a local panel in Relay Room "A" at Copeland SS.
   d. Provide and install all electrical wiring associated with SF6 gas sensing system in the Hydro One areas at, on or below Copeland SS, and provide appropriate signals to the Customer's systems.
   e. Provide and install cyber security systems required for Hydro One P&C areas at Copeland SS.
   f. Provide and install a warning system that is audible in all Hydro One areas at Copeland SS, in the event of an operation or SF6 gas leak.
6. Provide a Physical Security Perimeter in compliance with NERC requirements.

G. **Exclusions/Assumptions**

Cost estimates and the scope of the Hydro One Connection Work are based on the following assumptions:

1. The entire Copeland MTS building and the Customer's New Tunnel will be designed and built by the Customer at the Customer's sole expense.
2. The Customer is responsible for all environmental and municipal approvals associated with the construction of Copeland MTS and the Customer's New Tunnel.
3. The Customer will provide adequate space for the installation of Hydro One facilities, including, but not limited to Copeland SS.
4. The Customer will provide and install all equipment/facilities outside Hydro One areas unless otherwise indicated.
5. The Customer will be installing the bridge crane in Hydro One's GIS room at Copeland SS.
6. The crane will be installed prior to installation of the roof above the GIS room at Copeland SS so as to avoid the requirement for a large assembly area for the crane.
7. The Customer will provide and install all security-related items such as card readers, cameras and door locks throughout the building.
8. The Customer will provide a lay-down area for Hydro One's GIS equipment during its delivery and installation.
9. The Customer will provide and install the connectors on the Hydro One end of the Customer's HV cables according to the IEC 62271-209:2007 standard for high-voltage switchgear and control gear under the supervision of Hydro One's HV GIS switchgear contractor. Hydro One will install the Customer cables into the Hydro One HV GIS switchgear located at Copeland SS.

Part 3: Network Customer Allocated Work

Not Applicable

Part 4: Network Pool Work (Non-Recoverable from Customer)

Not Applicable

Part 5: Work Chargeable to Customer

Hydro One will:

- Review the Customer's protections/operations strategy to ensure compatibility with Hydro One's transmission system.
- Conduct a review of the Customer's Interface Documents and review compliance with the Transmission System Code and Hydro One's Functional Requirements for New Transmission Load Connections.
- Assist with commissioning of the Customer's HV GIS circuit breakers at Copeland MTS.
- Review and revise/upgrade, as necessary, protections at John TS, Terauley TS, Hearn SS and Esplanade TS, including:
    - Replacing existing distance protections at John TS for H9EJ and H10EJ with line differential protections
    - Installing new DC monitoring cabinets at John TS to feed the new differential protections
    - Revising protection settings for H9EJ and H10EJ at Esplanade TS
    - Revising protection settings for H9EJ and H10EJ at Hearn SS
- Provide new operating plates and revise operating diagrams at John TS, Terauley TS, Hearn SS and Esplanade TS, if necessary.

Part 6: Scope Change

For the purposes of this Part 6 of Schedule "A", the term "Non-Customer Initiated Scope Change(s)" means one or more changes that are required to be made to the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" such as a result of any one or more of the following:

- any environmental assessment(s);
- requirement for Hydro One to obtain approval under Section 92 (leave to construct) of the Ontario Energy Board Act if the transmission line route selected by Hydro One is greater than 2 km in length;
- Hydro One having to expropriate property under the Ontario Energy Board Act;
- conditions included by the OEB in any approval issued by the OEB under Section 92 of the Ontario Energy Board Act or any approval issued by the OEB to expropriate under the Ontario Energy Board Act; and
- any IESO requirements identified in the System Impact Assessment or any revisions thereto.

Any change in the Project Scope as detailed and documented in Parts 1 to 5 of this Schedule "A" whether they are initiated by the Customer or are Non-Customer Initiated Scope Changes, may result in a change to the Project costs estimated in Schedule "B" of this Agreement and the Project schedule, including the Ready for Service Date.

All Customer initiated scope changes to this Project must be in writing to Hydro One.

Hydro One will advise the Customer of any cost and schedule impacts of any Customer initiated scope changes. Hydro One will advise the Customer of any Material cost and/or Material schedule impacts of any Non-Customer Initiated Scope Changes.

Hydro One will not implement any Customer initiated scope changes until written approval has been received from the Customer accepting the new pricing and schedule impact.

Hydro One will implement all Non-Customer initiated scope changes until the estimate of the Engineering and Construction Cost of all of the Non-Customer initiated scope changes made by Hydro One reaches 10% of the total sum of the estimates of the Engineering and Construction Cost of:

(i) the Transformation Connection Pool Work,
(ii) the Line Connection Pool Work;
(iii) Network Pool Work;
(iv) Network Customer Allocated Work; and
(v) The Work Chargeable to Customer.

At that point, no further Non-Customer initiated scope changes may be made by Hydro One without the written consent of the Customer accepting new pricing and schedule impact. If the Customer does not accept the new pricing and schedule impact, Hydro One will not be responsible for any delay in the Ready for Service Date as a consequence thereof.

CUSTOMER CONNECTION WORK

The Customer will perform the work described below:

A. General Requirements

1. Provide Hydro One with the following:
    a. Site location map(s) with suitable details of the access road, transformer station, line routing and the proposed connection to Hydro One's facilities
    b. Survey plans, topographical maps, shop drawings, schematic control drawings and station layouts and property plans, if available
    c. Four (4) sets of single line diagrams of the transformer station, for which Hydro One will provide to the Customer the final single line diagram for their 230 kV class HV switching facilities.
    d. Four sets of technical descriptions of the operating philosophy of the electrical equipment and the protection and control philosophy of the Customer's Facilities that could affect Hydro One's transmission system
    e. AutoCAD 10 drawings as per Hydro One requirements.
    f. Details about the Customer's New Tunnel

- g. Permanent vehicular access to the station for equipment loading and unloading.
- h. Permanent access at no charge inside the station for Hydro One to maintain and operate and maintain Hydro One equipment
- i. Permanent access at no charge inside the Customer's New Tunnel from Hydro One's Existing Tunnel [redacted] to Copeland SS for Hydro One to install, maintain and operate Hydro One equipment

2. Acquire all necessary permits for construction of the Copeland MTS as well as the Customer's New Tunnel, including, but not limited to those related to noise, soil removal, drainage and landscaping.
3. Submit an Environmental Assessment Report to the Ministry of the Environment (MOE) and abide by any MOE requirements.
4. Submit an application to the IESO for a System Impact Assessment (SIA) and abide by any SIA requirements.
5. Meet the requirements outlined in the IESO's SIA Report and any addendums thereto and provide a copy of the SIA Report and any addendums thereto to Hydro One.
6. Meet the requirements as set out in "Hydro One's Functional Requirements for New Transmission Load Connections", including those requirements for providing adequate station grounding.
7. Provide station grounding study results performed by the Customer to Hydro One for review.

B. Tunnel

1. Build the Customer's New Tunnel from Hydro One's Existing Tunnel breakout at Front Street and Lower Simcoe Street to the Copeland SS on the Customer's Site as mutually agreed between the Customer and Hydro One, having features including, but not limited to, the following:
   - a. four sections comprised of the following:
     - i. A main tunnel (the "**Main Tunnel**")
     - ii. An adjoining staired section between the breakout of Hydro One's Existing Tunnel and the Main Tunnel (the "**Staired Section**")
     - iii. A hand-dug section joining the Main Tunnel to the Copeland MTS ("**Hand-dug Section**")
     - iv. Two vertical cable shafts between the Hand-dug Section and Copeland MTS below Copeland SS ("**Cable Shafts**")
   - b. Minimum tunnel inside diameter of 2.7 meters for the Main Tunnel
   - c. Two sets of four (4) cable ducts, having a diameter of eight (8) inches each, embedded in either side of the lower portion of the Main Tunnel for two of the HV cable circuits
   - d. Four telecom cable ducts in the floor of the Main Tunnel having a diameter of four (4) inches
   - e. Four telecom cable ducts in the Staired Section, continuous from Hydro One's Existing Tunnel to the Main Tunnel
   - f. Four telecom cable ducts in the Hand-dug Section, continuous from the Main Tunnel to the bottom of the Cable Shafts
   - g. Ensure that the Cable Shafts are adequately sized to install Hydro One's HV cables
   - h. Transitions from Hydro One's Existing Tunnel to the Customer's New Tunnel, from the Customer's Main Tunnel to the Hand-dug Section and from the Hand-

dug Section to the Cable Shafts having suitable corners which allow for the required cable bending radius for pulling as recommended by Hydro One's cable contractor

2. Provide and install forced ventilation with a minimum of 1200 feet per minute in the Main Tunnel as set out in the Kinectrics study dated October 6, 2012.
3. Provide and install forced ventilation with a minimum capacity of 1300 liters per second for each of the two Cable Shafts.
4. Provide status of ventilation system in the Customer's Main Tunnel and the Cable Shafts.
5. Provide and install a sealed door between Hydro One's Existing Tunnel and the Customer's New Tunnel.
6. Install cable brackets in all sections of the Customer's New Tunnel provided by Hydro One and consistent with Hydro One specifications
7. Provide and install pull ropes/cables in all cable ducts, for both power and telecom fiber cables, capable of withstanding the pulling forces required by Hydro One's cable installer.
8. Provide and install an emergency water evacuation system.
9. Integrate the HV cable temperature sensing system with the controls for the Customer's New Tunnel ventilation system.

C. Customer's High-Voltage Switching Facilities and Cables

1. Provide and install circuit breakers at the HV terminations of the Customer's step-down transformers.
2. Provide and install six (6) HV cable circuits between the Customer's HV circuit breakers at Copeland MTS and Hydro One's GIS equipment at Copeland SS.
3. Provide and install six (6) sets of connectors at the Hydro One end of the Customer's HV cables according to the IEC 62271-209:2007 standard for high-voltage switchgear and control gear under the supervision of Hydro One's HV GIS switchgear contractor.

D. AC Station Service Supply

1. Provide Hydro One with two (2) independent, reliable, 120-208 Volt, three-phase AC station service sources to the Hydro One relay rooms at Copeland SS as mutually agreed between the Customer and Hydro One.
2. Provide Hydro One with one (1) reliable, 600 Volt, 30 Amperes, three-phase AC source to the Hydro One GIS room at Copeland SS as mutually agreed between the Customer and Hydro One. This source is to be wired to the crane.

E. Protection, Control and Teleprotections

1. Provide information from Copeland MTS in accordance with Standard OD-11 and as will be as defined by the TCA – Schedule 1, Appendix IV Real Time Operating Information to be provided from the Customer to the Transmitter, including:
   a. HV/LV active power (MW) and reactive power (MVA) flows and directions
   b. HV/LV phase-to-phase or three-phase-to-neutral voltages
   c. Transformer ULTC position
   d. Status of HV breakers and switches
   e. Status of LV transformer and bus breakers
2. Transmit to Hydro One an alarm signal whenever there is an operation of a Customer-owned protection which is designated to trip Hydro One breakers. Alarms shall identify the name of the station and the designation of the HV interrupted circuit.

3. Provide a separate alarm for each circuit supplying the Customer.

F. Building Facilities and Services

1. Design and construct the building which will house Copeland MTS as well as Hydro One's Copeland SS.
2. Provide the following space in the building for Hydro One's Copeland SS as mutually agreed between the Customer and Hydro One which will include space for the following:
    a. One (1) GIS room
    b. Accommodation for unobstructed cable routing from Cable Shafts to Copeland SS
    c. Two (2) relay rooms
    d. Two (2) DC station service battery rooms
    e. Two (2) DC station service transfer scheme rooms
3. Provide a temporary staging area in the Customer's medium-voltage room during staging delivery and installation of Hydro One's HV switchgear.
4. Provide an opening in the roof and in the floor of Hydro One's GIS room for feeding the Hydro One's HV cables into the Cable Shafts as mutually agreed by the Customer and Hydro One and meeting the requirements of Hydro One's cable contractor.
5. Provide and install entry and egress doors as per requirements of the Ontario Building Code.
6. Provide lighting and electrical receptacles in the basement below Hydro One's GIS room.
7. Provide for SF6 gas removal to Hydro One's requirement to achieve a level of less than 20 PPMV SF6.
8. Provide station grounding grid and connections to the Hydro One areas at the Customer's Site.
9. Provide and install grounding bus around the perimeter of Hydro One's GIS room, relay rooms, DC station service rooms and battery rooms, and connect to the Copeland MTS grounding grid.
10. Provide and install all security-related items such as card readers, cameras and door locks throughout the building.
11. Provide and install an emergency water evacuation system consisting of sumps and redundant sump pumps.
12. Provide adequate space in the cable basement below the Copeland SS GIS room for clamping twelve (12) incoming Hydro One HV cables coming through the Cable Shafts.
13. For HVAC Systems:
    a. Provide and install heating, ventilation and air conditioning (HVAC) units in a remote mechanical room.
    b. Provide and install HVAC facilities in the Hydro One areas at the Customer's Site as mutually agreed between the Customer and Hydro One.
    c. Provide and install separately controlled smoke dampers in ductwork into Hydro One relay rooms so as to isolate the areas from smoke. Dampers are to be activated by the smoke detectors.
14. For Sensing and Alarm Systems:
    a. Provide overall building security, SF6 gas sensing system, fire alarms system which will be integrated with sensors in the Hydro One areas and provide to Hydro One dry contact alarm requirements.
    b. Provide and install connection to the Hydro One fire alarm, HVAC and SF6 detection control panels.

15. For Hydro One's GIS room:
    a. Provide the floor cut out below cable terminal compartment of Hydro One's GIS, adequate for all the terminals to pass through and make connection to GIS.
    b. Allow provisions for pulling Hydro One's HV cables through Hydro One's GIS room into the Cable Shafts.
    c. Provide temporary 100 Amperes, 120/208 Volt AC supply and install temporary lighting for use during construction.
    d. Provide grounding provisions along walls in accordance with Hydro One's drawings and specifications.
    e. Provide and install the rails for the bridge crane and structural components for supporting the rails in Hydro One's GIS room.
    f. Install the crane and associated bridge on to the rails in Hydro One's GIS room.
    g. Provide openings in walls and floor for P&C, AC and DC station service cables in accordance with Hydro One's layout drawings.
16. For Hydro One's relay, DC switchgear and battery rooms:
    a. Provide and install computer floor in Hydro One's relay rooms in accordance with Hydro One's requirements.
    b. Provide temporary electrical 120 Volt AC supply for use during construction.
    c. Provide and install temporary lighting for use during construction.
    d. Provide and install 6" PVC conduits in Hydro One's Relay Room "A" to facilitate routing of Relay Room "B" cables.
    e. Provide a phone jack in Hydro One Relay Room "A".

[redacted]

Notes:

1. Existing Load means the Customer's Assigned Capacity at the Existing Load Facility as of the date of this Agreement (Section 3.0.3 of the Transmission System Code).

2. Any station load above the Normal Capacity of the Existing Load Facility (Overload) will be determined in accordance with Section 6.7.9 of the Transmission System Code and Hydro One's Connection Procedures. If the Overload is transferred to the New or Modified Connection Facilities, the Overload will be credited to the Line Connection Revenue, Transformation Connection Revenue or Network Revenue requirement, whichever is applicable.

3. A power factor of 90% has been assumed.

OTHER RELEVANT CONSIDERATIONS:

There is an existing Connection and Cost Recovery Agreement for Cecil TS Capacity Increase, dated April 26, 2002.

EXCEPTIONAL CIRCUMSTANCES RE. NETWORK CONSTRUCTION OR MODIFICATIONS:

Not applicable.

MISCELLANEOUS

Customer Connection Risk Classification: Low Risk

True-Up Points:

(a) following the fifth and tenth anniversaries of the In Service Date; and

(b) following the fifteenth anniversary of the In Service Date if the Actual Load is 20% higher or lower than the Load Forecast at the end of the tenth anniversary of the In Service Date.

Customer's HST Registration Number: 896718327RT0001

Documentation Required (after In Service Date):

- Documentation describing the as-built electrical characteristics of the Copeland MTS. This documentation shall include, but is not necessarily limited to the system and dc station service single line diagrams, teleprotection ac and dc elementary wiring diagram (EWD), line protection ac and dc EWD, transformer protection ac and dc EWD, HV breaker and disconnect switch ac and dc EWD, LV transformer and bus tie breakers ac and dc EWD, and breaker failure ac and dc EWD of the Copeland MTS. Documentation will be in the form of four (4) sets of full size drawings, folded and collated, and electronic files in CD-RON format that are compatible with AutoCAD 2009.
- Step-down transformer data including impedances and ratings
- The as-built position of the underground cable will be delivered in an ESRI compatible digital file format with accompanying projection and datum information. The digital file shall include coordinates in linear or point format, at minimum every two meters along the length of the underground cables. Placement discrepancies must be no greater than 0.5 meters, however higher accuracy is encouraged.

Ownership: Hydro One will own all equipment provided by Hydro One as part of the Hydro One Connection Work.

The following equipment to be installed by the Customer will be owned by Hydro One:

- Bridge crane in the Hydro One GIS room at Copeland SS
- Tunnel cable brackets

Approval Date (if Section 92 required to be obtained by Hydro One): Not applicable

Security Requirements: Nil

Security Date: Not applicable

Easement Term: In perpetuity

Approval Date (for OEB leave to construct): Not applicable.

Revenue Metering: IESO compliant revenue metering is to be provided by the Customer.

Customer Notice Info:

Toronto Hydro-Electric System Limited
14 Carlton Street,
Toronto, Ontario
M5B 1K5

Fax: (416) 542-2833

Schedule "B" Copeland MTS Line Connection – Cost and Payment

TRANSFORMATION CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Transformation Connection Pool Work: Not applicable

Estimate of Transformation Connection Pool Work Capital Contribution: Not applicable

Actual Engineering and Construction Cost of the Transformation Connection Pool Work: Not Applicable

Actual Transformation Connection Pool Work Capital Contribution:

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: Not Applicable

LINE CONNECTION POOL WORK

Estimate of the Engineering and Construction Cost of the Line Connection Pool Work: $41,378,288 plus HST in the amount of $ $5,379,177.44

Estimate of Line Connection Pool Work Capital Contribution: $38,247,400.00 plus HST in the amount of $4,972,162.00

Actual Engineering and Construction Cost of the Line Connection Pool Work: To be provided 180 days after the Ready for Service Date.

Actual Line Connection Pool Work Capital Contribution: To be provided 180 days after the Ready for Service Date.

Capital Contribution Includes the Cost of Capacity Not Needed by the Customer: Not applicable

NETWORK CUSTOMER ALLOCATED WORK

Estimate of the Engineering and Construction Cost of the Network Customer Allocated Work: Not Applicable

Actual Engineering and Construction Cost of the Network Customer Allocated Work: Not Applicable

NETWORK POOL WORK (NON-RECOVERABLE FROM CUSTOMER):

Not applicable

WORK CHARGEABLE TO CUSTOMER

Estimate of the Engineering and Construction Cost of the Work Chargeable To Customer: $1,634,752 plus HST in the amount of $ $212,517.76

Actual Engineering and Construction Cost of the Work Chargeable To Customer: To be provided 180 days after the Ready for Service Date.

MANNER OF PAYMENT OF THE ESTIMATE OF CAPITAL CONTRIBUTIONS AND WORK CHARGEABLE TO CUSTOMER

The Customer shall pay Hydro One the estimate of the Transformation Connection Pool Work Capital Contribution, the Estimate of Line Connection Pool Work Capital Contribution, the estimate of the Network Customer Allocated Work Capital Contribution and the estimate of the Engineering and Construction Cost of the Work Chargeable to Customer by making the progress payments specified below on or before the Payment Milestone Date specified below. Hydro One will invoice the Customer for each progress payment 30 days prior to the Payment Milestone Date.

Payment Milestone Date	Transformation Pool Work Capital Contribution	Line Pool Work Capital Contribution	Network Customer Allocated Work Capital Contribution	Work Chargeable To Customer	Total Payment Required
Prior to Execution	$ 0	$ 18,638,000	$0	$0	$18,638,000 plus HST in the amount of $2,422,940
Execution	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
April 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
May 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
June 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
July 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98

August 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
Septembe r 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
October 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
November 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
December 1, 2014	$0	$1,960,940	$0	$163,475.20	$2,124,415.20 plus HST in the amount of $276,173.98
Total	$0	$38,247,400	$0	$1,634,752	$39,882,152.00 plus HST in the amount of $5,184,679.76

TRANSFORMATION CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Not Applicable.

LINE CONNECTION REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Annual Period Ending On:	New Load** - (MW)	Part of New Load Exceeding Normal Capacity of Existing Load Facilities [C]	Adjusted Load Forecast (MW) [D]	Line Connection Revenue (k$) for True-Up, Based on [C] or [D], whichever is applicable
1st Anniversary of In Service Date	0	0	0	0
2nd Anniversary of In Service Date	4.2	4.2	4.2	41.4
3rd Anniversary of In Service Date	16.1	16.1	16.1	158.0
4th Anniversary of In Service Date	30.1	30.1	30.1	296.6
5th Anniversary of In Service Date	42.4	42.4	42.4	417.6
6th Anniversary of In Service Date	52.7	52.7	52.7	518.5
7th Anniversary of In Service Date	63.6	63.6	63.6	625.7
8th Anniversary of In Service Date	70.5	70.5	70.5	693.7
9th Anniversary of In Service Date	73.6	73.6	73.6	724.0
10th Anniversary of In Service Date	76.4	76.4	76.4	751.7
11th Anniversary of In Service Date	80.0	80.0	80.0	787.0
12th Anniversary of In Service Date	82.8	82.8	82.8	814.7
13th Anniversary of In Service Date	85.6	85.6	85.6	842.5
14th Anniversary of In Service Date	88.7	88.7	88.7	872.7
15th Anniversary of In Service Date	91.8	91.8	91.8	903.0
16th Anniversary of In Service Date	94.8	94.8	94.8	933.2
17th Anniversary of In Service Date	97.9	97.9	97.9	963.5
18th Anniversary of In Service Date	101.0	101.0	101.0	993.7
19th Anniversary of In Service Date	104.6	104.6	104.6	1029.0
20th Anniversary of In Service Date	107.9	107.9	107.9	1061.8
21st Anniversary of In Service Date	110.6	110.6	110.6	1088.4
22nd Anniversary of In Service Date	112.0	112.0	112.0	1101.7
23rd Anniversary of In Service Date	113.2	113.2	113.2	1114.3
24th Anniversary of In Service Date	114.3	114.3	114.3	1124.4
25th Anniversary of In Service Date	115.2	115.2	115.2	1133.7

Average monthly peak load for the anniversary year is based on an average loading factor of 0.854.

** New Load based on Customer's Load Forecast which includes Part of New Load Exceeding Normal Capacity of Existing Load Facilities. "Overload" derived in accordance with Section 6.7.9 of the Transmission System Code and the OEB-Approved Connection Procedures. Any Customer load below the Normal Capacity of the Existing Load Facilities transferred to the New or Modified Facilities will not be credited towards the Transformation Connection Revenue Requirements, Line Connection Revenue Requirements or the Network Connection Revenue Requirements. The discounted cash flow calculation for Network Revenue requirements will be based on Incremental Network Load which is New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

NETWORK REVENUE REQUIREMENTS AND LOAD FORECAST AT THE NEW OR MODIFIED CONNECTION FACILITIES

Not Applicable.

Schedule "C" Copeland MTS Line Connection – Detailed Requirements

For the purposes of this Schedule "C" and the "Special Circumstances", the following terms shall have the following meanings:

"Pre-Equipment Installation Work" means the Hydro One Connection Work described in Part 2 of Schedule A in Item 2 of Section D, Item 2 of Section E and Items 2b, 2c, 2d, 2f, 4a, 5a, 5b, 5c, 5d, 5e and 5f of Section F; and

"**Pre-GIS Equipment Installation Work**" means the Hydro One Connection Work described in Part 2 of Schedule "A" in Item 8 of Section C, Items 2a, 2d, 2f, 3c, 3d, 5a, 5b, 5c, 5d and 5f of Section F.

"Cable Installation Work" means the Hydro One Connection Work described in Part 2 of Schedule "A" in Section B;

"Equipment Installation Work" means the Hydro One Connection Work described in Part 2 of Schedule "A" in remaining items in Section D, Section E and Section F pertaining to Hydro One's P&C, Station Service and Battery Rooms;

"GIS Equipment Installation Work" means the Hydro One Connection Work described in described in Part 2 of Schedule "A" in remaining items in Section C and Section F pertaining to Hydro One's GIS Room;

The major elements/components as part of the Customer's building and tunnel to be ready on or before the commitment dates noted in this Agreement under "Special Circumstances" in order for Hydro One to commence the work identified below includes but is not limited to the following:

1. CUSTOMER'S BUILDING – HYDRO ONE HV GIS ROOM:

(a) Requirements for Hydro One to commence the Pre-GIS Equipment Installation Work:

1. Cable entry openings in concrete slab for 230kV HV XLPE cables as well as the LCC cables shall be formed per Hydro One layout drawings
2. Temporary lighting for use during construction
3. Temporary 120 Volt AC supply for use during construction
4. Grounding provisions along walls to meet Hydro One requirements
5. 600 Volt AC, 30 Ampere supply to crane panel available per Hydro One layout drawings and specifications
6. Crane installed on overhead rails per Hydro One layout drawings and specifications, before the roof installation above the GIS room
7. Ventilation required to sustain conditions suitable for working (habitable conditions)
8. Ramp and/roof access into building capable of handling shipping traffic and available during installation period (estimated to be April 30, 2014 to February 28, 2015), subject to coordination with General Contractor
9. Clear and unobstructed pathway from ramp and/or roof access into building to Hydro One HV GIS & relay rooms during installation period (estimated to be April 30, 2014 to February 28, 2015), subject to coordination with General Contractor

10. Openings in floor for Protection, Control, AC and DC Station Service Cables as per Hydro One layout drawings
11. Provisions for station service supply of 100 Ampere, 120/208 Volts AC for both A and B systems
12. Openings in walls of Stairwell #1 for Protection, Control, AC and DC Station Service Cables as per Hydro One layout drawings
13. FAS "fire signal" to be provided in the Customer's portion of the building

(b) Additional Requirements for Hydro One to commence the GIS Equipment Installation Work:
1. Finished floor (smooth and treated so as to be dust free)
2. The Customer's medium-voltage (MV) room (across the hall from Hydro One HV GIS room) available for staging Hydro One HV GIS switchgear for duration of delivery and installation (estimated to be April 30, 2014 to February 28, 2015), subject to coordination with General Contractor
3. Sufficient ventilation to meet requirements for installing equipment

2. **CUSTOMER'S BUILDING – HYDRO ONE RELAY ROOMS, DC SWITCHGEAR ROOMS AND BATTERY ROOMS:**

(a) Requirements for Hydro One to commence the Pre-Equipment Installation Work:
1. Temporary lighting for use during construction
2. Temporary 120 Volt AC for use during construction
3. Access floor openings in Hydro One relay rooms as per Hydro One layout drawings
4. Entry and egress doors have been located and provided as per the requirements of the Ontario Building Code.
5. Ground bar
6. Ventilation required to sustain habitable conditions

(b) Additional Requirements for Hydro One to commence Equipment Installation Work
1. Finished floor (smooth and treated so as to be dust free)
2. Computer floor
3. Provisions for permanent station service supply of 100 Ampere 120/208 Volts AC for both A and B systems.
4. Sufficient ventilation to meet requirements for installing equipment
5. All interior walls installed

3. **CUSTOMER'S NEW TUNNEL:**

Requirements for Hydro One to commence the Cable Installation Work:
1. The Customer's New Tunnel, including the Main Tunnel, the Staired Section and the Hand-dug Section, complete, poured and cured
2. The Cable Shafts complete
3. The cable brackets installed in all sections of the Customer's New Tunnel and cast-ins in the Cable Shafts
4. All tunnel access shafts on Simcoe Street complete
5. Ventilation required to sustain habitable conditions
6. Drainage system in place and working

7. Cable concrete ducts in Main Tunnel, complete for being able to pull cables (power and telecom fiber) through
8. Guide ropes/wires present in all concrete ducts, both for power cables and telecom fiber cables, as required by the cable installer
9. Cable trench in Hand-dug Section, complete ready to accept cables
10. Completed raceway for the fiber optic cable for the entire run in the Main Tunnel.
11. Ducts for telecom cables installed in Hand-dug Section and the Staired Section of the Customer's New Tunnel
12. Openings in the roof of the Customer's building and floor of Hydro One's GIS room as required for feeding Hydro One's HV cables
13. Provisions for temporary power
14. Provisions for temporary lighting

Schedule "D": Copeland MTS Line Connection

GRANT OF EASEMENT IN GROSS

A. [NOTE – INSERT FULL LEGAL NAME OF TRANSFEROR] (the "**Transferor**") is the owner in fee simple and in possession of ● (the "**Lands**").

B. Hydro One Networks Inc. (the "**Transferee**") has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) in, through, under, over, across, and along and upon the Lands.

IN CONSIDERATION of the payment of ● DOLLARS ($●.) paid by the Transferee to the Transferor, mutual covenants hereinafter set forth and other good and valuable consideration, the Transferor and Transferee hereto agree as follows:

1 The Transferor hereby grants and conveys to the Transferee, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the **"Rights")** in, through, under, over across, along and upon that portion of the Lands of the Transferor being Part of Lot ●, Concession ●, shown as Parts ● & ●, on Reference Plan ●R-●●●● (the "Strip") for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip and electrical transmission system and telecommunications system consisting in both instances of pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **("Works")** as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"** whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any person or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(f) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement subject to compensation afterwards for any crop or other physical damage only to the Lands or permitted structures sustained by the Transferor caused by the exercise of this right of entry and passageway.

(g) To remove, relocate and reconstruct the line on or under the Strip.

2 The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing erect or cause to be erected or permit in, under or upon the strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes walks, drains, sewers water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction , Installation or contravention complained of from the Strip, without being liable for any damages cause thereby.

(b) Notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) No other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) The Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) The Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip; and

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interest to the transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

8. The Transferee declares, pursuant to Section 50(3)(d) of the *Planning Act*, R.S.O. 1990 c. P.13 that the Rights are being acquired, for the purpose of an electricity distribution line or an electricity transmission line within the meaning of Part VI of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B.

[NOTE – IF TRANSFEROR ARE INDIVIDUALS ADD THE FOLLOWING CLAUSE AS #9

9. The Transferor represents that, except to the extent such consent has been obtained, spousal consent to this transaction is not necessary and upon registration of this Grant of Easement will not be necessary under the provisions of the *Family Law Act*, R.S.O. 1990 c.F.3

IN WITNESS WHEREOF the parties hereto have executed this Grant of Easement.

Signed by the Transferee this day of , 2012.

HYDRO ONE NETWORKS INC.

Per:____________________________________
Name:
Position:

I have authority to bind the Corporation.

Signed by the Transferor this day of , 2012.

[NOTE – INSERT FULL LEGAL NAME OF TRANSFEROR]

Per:____________________________________
Name:
Position:

Per:____________________________________
Name:
Position:

We/I have authority to bind the Corporation

[OR IF TRANSFEROR IS INDIVIDUAL]

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
)
______________________________) ________________________ (seal)
Signature of Witness) Transferor's Signature

)
)
______________________________) ______________________ (seal)
Signature of Witness) Transferor's Signature
)

SIGNED, SEALED AND DELIVERED) Consent Signature & Release of
In the presence of) Transferor's Spouse, if non-owner.
)
)
)
______________________________) ______________________(seal)
Signature of Witness

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated ____________________

Between ______________________________ and _______________________________________

and registered as Instrument Number _______________ on ____________________________ does hereby consent to this Easement and releases and discharges the rights and easement herein from the said Charge/Mortgage of Land.

Name:	Signature(s)	Date of Signatures Y M D

Per: _______________________________

Per: _______________________________

I/We have authority to bind the Corporation

Schedule "E": Copeland MTS Line Connection

FORM OF EARLY ACCESS AGREEMENT - USED EASEMENT LANDS

THIS AGREEMENT made in duplicate the day of 20XX

BETWEEN:

HYDRO ONE NETWORKS INC (hereinafter called the "HONI") OF THE FIRST PART

and

INSERT NAME (hereinafter called the "Owner") OF THE SECOND PART

WHEREAS:

1. The Owner is the registered owner of lands legally described as

(the "Lands").

2. HONI will be constructing new Electrical Transmission Facilities on a portion of the Lands shown highlighted in red on Schedule "A" attached hereto.

3. The Owner is agreeable in allowing HONI to enter onto the Lands to construct its facilities in accordance with the Drawing subject to the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the lump sum of FIVE Dollars ($5.00) now paid by each party to the other and the respective covenants and agreements of the parties hereinafter contained (the receipt and sufficiency of which are hereby acknowledged by the parties hereto), the parties hereto agree as follows:

1. HONI agrees that it will enter into, with the Owner, (i) an easement agreement, on HONI's standard form, with respect to the Works located on the portion of the Lands as shown hatched and highlighted in red on the attached Schedule "A" (the "Easement") within a reasonable period of time following execution by the parties of this Agreement.

2. The Owner hereby grants to HONI the right to enter upon the Lands for the purpose of commencing construction of the works, as of the date this Agreement is executed by both parties.

3. HONI agrees that it shall take all reasonable care in its construction practices.

4. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Lands shall be at the sole risk of HONI and the Owner shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the

extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Owner.

5. HONI agrees that it shall indemnify and save harmless the Owner from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Lands or of its activities on or in connection with the Lands arising out of the permission granted herein except to the extent any of such Costs arise out of the negligence or willful misconduct of the Owner.

6. This Agreement and the permission granted herein shall automatically terminate upon the registration of the Easement.

7. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

8. Any amendments, modification or supplement to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with same degree of formality as the execution of this Agreement.

IN WITNESS WHEREOF the parties hereto have executed this Agreement by the hands of their duly authorized signing officers in that regard.

Dated this Day of , 20XX

WITNESS:

Signature: ______________________ Per: ______________________

Name: Name:

I have authority to bind the Company

WITNESS:

Signature: ______________________ Per: ______________________

Name: Name:

I have authority to bind the Company

HYDRO ONE NETWORKS INC.

Per: ______________________

Name:

Title:

I have authority to bind the Company

Schedule "A"

INSERT SKETCH

Schedule "F": Copeland MTS Line Connection

Agreement for Construction Pad and Assembly Area

THIS AGREEMENT made in duplicate the day of 20xx

Between:

INSERT NAME
(hereinafter referred to as the "Grantor")

OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to "HONI")

OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as **(INSERT LEGAL DESCRIPTION)**

WHEREAS HONI in connection with its___________ (the "Project") desires the right to enter onto and use a portion of the Lands for the purpose of constructing temporary construction pads and assembly areas in order to access the construction site associated with the Project together with parking trailers to be used for the purposes of a construction field office on, over and upon portions of the Lands.

WHEREAS the Grantor is agreeable in allowing HONI to enter onto a portion of the Lands for the purpose of constructing temporary construction pads and assembly areas and parking trailers on, over and upon a portion of the Lands, subject to the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the sum of **(BLANK)** to be paid by HONI to the Grantor, and the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. The Grantor hereby grants, conveys and transfers to HONI in, over, along and upon that part of the Lands highlighted and hatched in yellow as shown in Schedule "A" attached hereto (the "Construction Pad and Assembly Area"), the rights privileges, and easements as follows:

(a) for the servants, agents, contractors and workmen of HONI at all times with all necessary vehicles and equipment to pass and repass over the Construction Pad and Assembly Area for the purpose of access to the construction site associated with the Project and for access to the Trailers (as defined below);

(b) to construct, use and maintain upon the Construction Pad and Assembly Area, a temporary pad and assembly area as may be necessary for HONI's purposes (collectively, the "Works"), all of which Works shall be removed by HONI upon completion of the construction associated with the Project;

(c) to place upon the Construction Pad and Assembly Area, temporary trailers maximum tow (2)) for HONI's purposes of a construction field office for the purposes of the Project (the "Trailers"); and

(d) to cut and remove all trees, brush and other obstructions made necessary by the exercise of the rights granted hereunder

2. The term of this Agreement and the permission granted herein shall be a term of **(INSERT)** months commencing on **(INSERT DATE),** (the "Commencement Date") and ending **(INSERT DATE)**. HONI may, in its sole discretion, and upon 5 days' notice to the Grantor, extend the Term for an additional length of time, which shall be negotiated and agreed to between the parties for an additional fee.

3. Upon the expiry of the Term or any extension thereof, HONI shall remove the Trailers and repair any physical damage to the Construction Pad and Assembly Area and/or Lands resulting from HONI's use of the Construction Pad and Assembly Area and the permission granted herein; and, shall restore the Construction Pad and Assembly Area to its original condition so far as possible and practicable to the satisfaction of the Grantor.

4. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Construction Pad and Assembly Area shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

5. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the "Costs") whatsoever arising out of HONI's presence on the Construction Pad and Assembly Area or of its activities on or in connection with the Construction Pad and Assembly Area arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

6. Notices to be given to either party shall be in writing, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile or other similar means of prepaid recorded communication to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

TO HONI:

Hydro One Networks Inc.
Real Estate Services
1800 Main Street East
Milton, Ontario L9T 753

Attention:
Tel:
Fax:

TO GRANTOR:

7. Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or other similar means of prepaid recorded communication shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. "Business Day" shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

8. Any amendments, modifications or supplements to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

9. The burden and benefit of this Agreement shall run with the Lands and everything herein contained shall operate to the benefit of, and be binding upon, the respective heirs, successors, permitted assigns and other legal representatives, as the case may be, or each of the Parties hereto.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

SIGNED, SEALED & DELIVERED In the presence of: ________________________ Witness	**INSERT GRANTOR** ________________________ Name:Title: ________________________ Name: Title: I/We have authority to bind the Corporation

HYDRO ONE NETWORKS INC.

____

Name:

Title:

I have authority to bind the Corporation

INSERT SCHEDULE A SHOWING AREA

Schedule "G": Copeland MTS Line Connection

Tunnel Occupancy Agreement

THIS LICENCE AGREEMENT made in duplicate this _____ day of _____________, 2014.

BETWEEN:

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

(hereinafter called "THESL")
OF THE FIRST PART

AND

HYDRO ONE NETWORKS INC.

(hereinafter called "HONI")
OF THE SECOND PART

WHEREAS THESL is the owner of an underground concrete tunnel located under road allowance in the City of Toronto and lands owned by THESL into THESL's Copeland Municipal Transformer Station ("Copeland MTS"), formerly known as Bremner MTS, which route is more particularly shown on Schedule "A" attached hereto (the "Bremner Tunnel").

AND WHEREAS HONI desires to place high voltage underground cable circuits and associated material and equipment in the Bremner Tunnel to supply Copeland MTS and THESL is agreeable to such on the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the sum of FIVE DOLLARS ($5.00), the mutual agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, THESL and HONI hereby agree as follows:

1. GRANT OF LICENCE

THESL hereby grants to HONI an exclusive right to:

(a) Occupy and install, lay, construct, use, operate, inspect, maintain, repair, replace, relocate, reconstruct, alter, renew and remove underground cable circuits consisting of wires, cables, telecommunication cables, grounding electrodes, conductors, apparatus, works accessories, and associated material and equipment and appurtenances, in the Bremner Tunnel ("HONI's Works").

(b) Enter and exit, and to pass and repass at any and all times in, along, upon, across, through the Bremner Tunnel, as required, for HONI and its respective officers, employees, workers, permittees, servants, agents, contractors and subcontractors, with or without vehicles, supplies, machinery, plant, material and equipment for all purposes necessary or convenient to the exercise and enjoyment of the said rights granted herein.

2. TERM AND FEES

(a) For the permission granted herein, HONI shall pay to THESL the sum of FIVE Canadian Dollars ($5.00) as good and valuable consideration, which amount, THESL acknowledges it has received.

(b) The permission granted herein shall commence as of the date first written above and shall continue until such time that HONI's Works and HONI's equipment and works located in the Bremner Tunnel are decommissioned and removed from the Bremner Tunnel (the "Term").

3. HONI'S COVENANTS

HONI also covenants and agrees with THESL that during the Term, HONI will:

(a) maintain HONI's Works in good and substantial state of repairs at all times;

(b) perform all work in connection with installing, laying, constructing, using, operating, inspecting, maintaining, repairing, replacing, relocating, reconstructing, altering, renewing or removing HONI's Works or any part or parts of them in accordance with the standard engineering practice in a safe and serviceable manner and so as not to interfere in any way with, or cause any damage to the Bremner Tunnel and/or to any works of THESL now or hereafter constructed in the Bremner Tunnel;

(c) comply with all statutes, by-laws, rules and regulations of every governmental or other competent authority relating in any manner to HONI's Works or to which THESL is bound in respect of the Bremner Tunnel or the exercise of any of the rights granted herein.

(d) prior to the entry of any of HONI's servants, agents, contractors and workmen into the Bremner Tunnel, HONI shall provide notice to THESL's System Operations Centre at telephone number 1-abc-def-ghij ("SOC"). Furthermore, confirmation of leaving the Bremner Tunnel must also be promptly provided to the SOC.

4. THESL'S COVENANTS

THESL covenants and agrees with HONI that during the Term, THESL will:

(a) not abandon, transfer or assign in whole or in part the Bremner Tunnel without providing HONI with reasonable prior notice of such intention. In the event that THESL desires to abandon, transfer or assign all or any part of the Bremner Tunnel, THESL shall provide HONI with written notice of its intent (the "Notice") and include in the Notice any outstanding liabilities and/or obligations with respect to the Bremner tunnel. HONI shall be provided 60 days from the date of the Notice to advise THESL as to whether HONI wishes to assume ownership for Five Dollars ($5.00) of the Bremner Tunnel, including all future liabilities and obligations, but not any then-existing liabilities, if any;

(b) be responsible for maintaining the Bremner Tunnel together with any infrastructure associated with the Bremner Tunnel in accordance with all applicable statutes, by-laws, rules and regulations of every governmental or other competent authority relating in any manner to the Bremner Tunnel.

(c) prior to the entry of any of THESL's servants, agents, contractors and workmen into the Bremner Tunnel, THESL shall provide notice to HONI's Ontario Grid Control Centre - Controller - Sector 3 at telephone number 1-866-384-4743 ("OGCC"). Furthermore, confirmation of leaving the Bremner Tunnel must also be promptly provided to the OGCC.

5. INDEMNITY

(a) Each party (the "Indemnitor") shall be liable for and shall defend, indemnify and save harmless the other party and the other party's successors and permitted assigns, directors, officers, employees, and authorized agents and any other person for whom the Indemnitor is responsible at law (collectively the "Indemnitee") from and against any and all loss, damage or injury to persons or property and all liabilities, costs, suits, charges, claims, losses, expenses (including without limitation legal fees and expenses), fines, damages, and causes of action in connection therewith and of any nature or kind whatsoever, resulting from, arising from or in connection with the Indemnitor's negligence and/or the Indemnitor's breach of this Agreement and/or the negligence or breach of this Agreement by those for whom the Indemnitor is in law responsible.

(b) Notwithstanding any other provision of this Agreement, neither party shall be liable under any circumstances whatsoever to the other party for any economic loss, loss of goodwill, loss of profit, business interruption losses or for any special, indirect or consequential damages, including, but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

(c) The parties acknowledge and agree that this Section 6.0 shall survive termination or expiry of this Agreement.

6. MISCELLANEOUS

(a) HONI shall have the right to assign this Agreement, in whole or in part, with the consent of THESL, such consent not to be unreasonably withheld or delayed and, upon such assignment and/or re-assignment of this Agreement that may occur from time to time, HONI shall be released from all covenants and agreements herein contained. Notwithstanding anything to the contrary, HONI shall be entitled to assign this Agreement to any one of its affiliates, as defined in the Business Corporations Act (Ontario) without the prior consent of THESL and upon such assignment, HONI shall be released from all covenants and agreements herein contained.

(b) Upon the decomissioning of HONI's Works in the Bremner Tunnel, HONI shall, within six (6) month of the said decommissioning, dismantle and remove all of HONI's Works from the Bremner Tunnel.

(c) Save for the notice required in section 4(g) herein, any notice or other writing required or permitted to be given under this Agreement or for the purpose of it shall be in writing and shall be deemed to have been properly given on the date of actual delivery if delivered by hand, five (5) business days after dispatch by registered or certified mail, one day after dispatch by facsimile transmission, addressed to the party to whom it was sent at the address, or facsimile number, of such party set forth below or at such other address or facsimile number as the party shall subsequently designate to the other party by notice given in accordance with this paragraph.

To:

Attn:
Fax:

To: Hydro One Networks Inc.
185 Clegg Road,
Markham Ontario. L6G 1B7
Attn: Joint Use Manager
Fax: (905) 946-6215

(d) This Agreement shall enure to the benefit of and be binding upon the parties hereto and their respecting successors and assigns.

(e) This Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein and the Parties hereto irrevocably attorn to the exclusive jurisdiction of the courts of the Province of Ontario in the event of a dispute hereunder.

(f) No amendment, modification or supplement to this Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

(g) If any provision of this Agreement shall be held, declared or pronounced void, voidable, invalid, unenforceable or inoperative for any reason by any court of competent jurisdiction, government authority or otherwise, such holding, declaration or pronouncement shall not affect adversely any other provision of this Agreement which shall otherwise remain in full force and effect and be enforced in accordance with its terms and the effect of such holding, declaration or pronouncement shall be limited to the territory or jurisdiction in which made.

(h) This Agreement may be executed in one or more counterparts, each of which shall be deemed an original and together shall constitute one and the same agreement. Counterparts may be executed either in original or by electronic means, including, without limitation, by facsimile transmission or by electronic delivery in portable document format (".pdf") or tagged image file format (".tif") and the parties shall adopt any signatures received by electronic means as original signatures of the Parties; provided, however that any party providing its signature in such manner shall promptly forward to the other party an original signed copy of this Agreement which was so delivered electronically.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by affixing their respective corporate seals attested by the signatures of their proper officers duly authorized in that behalf.

HYDRO ONE NETWORKS INC.

Per: ______________________________
Print Name: TBD prior to signing
Print Title: ______________________

I have the authority to bind the Corporation

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Per: ______________________________
Print Name: Ivano Labricciosa
Print Title: Vice-President, Asset Management

Per: ______________________________
Print Name:
Print Title:

I/We have the authority to bind the Corporation

SCHEDULE "A"

[redacted]

[redacted]

[redacted]

1. Each party represents and warrants to the other that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder;

(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate and/or governmental and/or other organizational action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation, a breach or a default under or give rise to termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) its charter or by-law instruments; (ii) any Material contracts or instruments to which it is bound; or (iii) any laws applicable to it;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) the Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;

(f) it is registered for purposes of Part IX of the *Excise Tax Act* (Canada). The HST registration number for Hydro One is 87086-5821 RT0001 and the HST registration number for the Customer is as specified in Schedule "A" of the Agreement; and

(g) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

Part A: Hydro One Connection Work and Customer Connection Work

2. The Customer and Hydro One shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, and using duly qualified and experienced people.

3. The parties acknowledge and agree that:

(a) Hydro One is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Hydro One Connection Work and those required for the construction, Connection and operation of the New or Modified Connection Facilities;

(b) the Customer shall perform the Customer Connection Work, at its own expense;

(c) except as specifically provided in the Agreement, the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, Connection and operation of the Customer's Facilities including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998*;

(d) the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities;

(e) the Customer shall provide Hydro One with Project data required by Hydro One, including, but not limited to (i) the same technical information that the Customer provided the IESO during any connection assessment and facility registration process associated with the Customer's Facilities in the form outlined in the applicable sections of the IESO's public website and (ii) technical specifications (including electrical drawings) for the Customer's Facilities;

(f) Hydro One may participate in the commissioning, inspection or testing of the Customer's Connection Facilities at a time that is mutually agreed by Hydro One and the Customer and the Customer shall ensure that the work performed by the Customer and others required for successful commissioning, inspection or testing of protective equipment is completed as required to enable Hydro One witnessing and testing to confirm satisfactory performance of such systems;

(g) unless otherwise provided herein, Hydro One's responsibilities under the Agreement with respect to the Connection of the New or Modified Connection Facilities to Hydro One's transmission system shall be limited to the performance of the Hydro One Connection Work;

(h) Hydro One is not permitted to Connect any new, modified or replacement Customer's Facilities unless any required Connection authorizations, certificate of inspection or other applicable approval have been issued or given by the Ontario Electrical Safety Authority in relation to such facilities;

(i) Hydro One may require that the Customer provide Hydro One with test certificates certifying that the Customer's Facilities have passed all relevant tests and comply with the *Transmission System Code*, the Market Rules, Good Utility Practice, the standards of all applicable reliability organizations and any Applicable

Laws, including, but not limited to any certificates of inspection that may be required by the Ontario Electrical Safety Authority;

(j) in addition to the Hydro One Connection Work described in Schedule "A", Hydro One shall: provide the Customer with such technical parameters as may be required to assist the Customer in ensuring that the design of the Customer's Facilities is consistent with the requirements applicable to Hydro One's transmission system and the basic general performance standards for facilities set out in the *Transmission System Code*, including Appendix 2 thereof; and

(k) if Hydro One requires access to the Customer's Facilities for the purposes of performing the Hydro One Connection Work or the Customer requires access to Hydro One's Facilities for the purposes of the Customer Connection Work, the parties agree that Section 27.13 of the Connection Agreement shall govern such access and is hereby incorporated in its entirety by reference into, and forms an integral part of the Agreement. All references to "this Agreement" in Section 27.13 shall be deemed to be a reference to the Agreement;

(l) the Customer shall enter into a Connection Agreement with Hydro One or amend its existing Connection Agreement with Hydro One at least 14 calendar days prior to the Connection;

(m) Hydro One shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Hydro One Connection Work are filed in a timely manner; and

(n) the Customer shall use commercially reasonable efforts to ensure that any applications required to be filed to obtain any permits or approvals required under Applicable Laws for the Customer Connection Work or for the construction, Connection and operation of the Customer's Facilities are filed in a timely manner.

4. The following aspects of the Hydro One Connection Work and Hydro One's rights and requirements hereunder are solely for the purpose of Hydro One ensuring that the Customer Facilities to be connected to Hydro One's transmission system do not materially reduce or adversely affect the reliability of Hydro One's transmission system and do not adversely affect other customers connected to Hydro One's transmission system, Hydro One's:

(i) specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) acceptance of power system components on the Customer's side of the Connection Point;
(iii) acceptance of the technical specifications (including electrical drawings) for the Customer's Facilities and/or the Customer Connection Work; and
(iv) participation in the commissioning, inspection or testing of the Customer's Facilities,

The Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the Customer's Facilities.

5. Hydro One shall use commercially reasonable efforts to complete the Hydro One Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Hydro One, acting reasonably;
(c) there are no delays resulting from Hydro One not being able to obtain outages from the IESO required for any portion of the Hydro One Connection Work or from the IESO making changes to the Hydro One Connection Work or the scheduling of all or a portion of the Hydro One Connection Work ;
(d) Hydro One does not have to use its employees, agents and contractors performing the Hydro One Connection Work or the Network Pool Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the *Transmission System Code*) or a Force Majeure Event;
(e) Hydro One is able to obtain the materials and labour required to perform the Hydro One Connection Work with the expenditure of Premium Costs where required;
(f) where Hydro One needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998,* such leave is obtained on or before the date specified as the Approval Date in Schedule "A" of the Agreement;
(g) where applicable, Hydro One received the easement described in Section 24 hereof by the Easement Date specified in Schedule "A" of the Agreement;
(h) Hydro One has received or obtained prior to the dates upon which Hydro One requires any or one or more of the following under Applicable Laws in order to perform all or any part of the Hydro One Connection Work:
    (i) environmental approvals, permits or certificates;
    (ii) land use permits from the Crown; and
    (iii) building permits and site plan approvals;
(j) Hydro One is able, using commercially reasonable efforts, to obtain all necessary land rights on terms substantially similar to the form of the easement that

is attached hereto as Appendix "B" of these Standard Terms and Conditions for the Project, prior to the dates upon which Hydro One needs to commence construction of the Hydro One Connection Work in order to meet the Ready for Service Date;

(k) there are no delays resulting from Hydro One being unable to obtain materials or equipment required from suppliers in time to meet the project schedule for any portion of the Hydro One Connection Work provided that such delays are beyond the reasonable control Hydro One; and

(l) the Customer executed the Agreement on or before the date specified as the Execution Date.

The Customer acknowledges and agrees that the Ready for Service Date may be materially affected by difficulties with obtaining or the inability to obtain all necessary land rights and/or environmental approvals, permits or certificates.

6. Upon completion of the Hydro One Connection Work:

(a) Hydro One shall own, operate and maintain all equipment specified in Schedule "A" of the Agreement under the heading "Ownership"; and

(b) other than equipment referred to in (a) above that shall be owned, operated and maintained by Hydro One, all other equipment provided by Hydro One as part of the Hydro One Connection Work or provided by the Customer as part of the Customer Connection Work shall be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Hydro One and the Customer shall have no right of property therein; and

(ii) any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Hydro One and shall not be or become fixtures and/or part of the Customer's property.

7. The Customer acknowledges and agrees that Hydro One is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Hydro One with regard to Hydro One's requirements to permit Connection of the New or Modified Connection Facilities to Hydro One's transmission system, and shall be installed, maintained and operated in accordance with all Applicable Laws, codes and standards, including, but not limited to, the *Transmission System Code*, at the expense of the Customer.

8. Where Hydro One has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of supply, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Hydro One for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Hydro One's reclosing equipment.

9. The Customer shall provide Hydro One with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Hydro One, within 120 calendar days after the Ready for Service Date. The Customer shall ensure that Hydro One may retain this documentation for Hydro One's ongoing planning, system design, and operating review. The Customer shall also maintain and revise such documentation to reflect changes to the Customer's Facilities and provide copies to Hydro One on demand and as specified in the Connection Agreement.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work

10.1 To the extent that the Pool Funded Cost of the Hydro One Connection Work is not recoverable by Transformation Connection Revenue for the Transformation Connection Pool Work and/or Line Connection Revenue for the Line Connection Pool Work and/or Network Revenue for the Network Customer Allocated Work during the Economic Evaluation Period, the Customer agrees to pay Hydro One a Capital Contribution towards the Pool Funded Cost of the Transformation Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Line Connection Pool Work and/or a Capital Contribution towards the Pool Funded Cost of the Network Customer Allocated Work and any amounts payable to Hydro One under Subsection 12 (a) (i) hereof.

An estimate of the Engineering and Construction Cost (not including Taxes) of the Transformation Connection Pool Work and/or Line Connection Pool Work and/or Network Customer Allocated Work is provided in Schedule "B" of the Agreement.

An estimate of the Capital Contribution for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work is specified in Schedule "B" of the Agreement (plus Taxes). The Customer shall pay Hydro One the estimated Capital Contribution(s) in the manner specified in Schedule "B" of the Agreement.

Within 180 calendar days after the Ready for Service Date, Hydro One shall provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto which shall identify the following:

(i) the actual Engineering and Construction Cost of the Transformation Connection Pool Work;
(ii) the actual Engineering and Construction Cost of the Line Connection Pool Work;
(iii) the actual Engineering and Construction Cost of the Network Customer Allocated Work;
(iv) the actual Engineering and Construction Cost of the Work Chargeable to Customer;
(v) the actual Capital Contribution required to be paid by the Customer for each of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work; and
(vi) the revised Transformation Connection Revenue and/or Line Connection Revenue requirements and/or Network Revenue requirements based on the Load Forecast or the Adjusted Load Forecast, whichever is applicable.

The new Schedule "B" shall be made a part hereof as though it had been originally incorporated into the Agreement.

If an estimate of a Capital Contributions paid by the Customer exceeds the actual Capital Contribution required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, Hydro One shall refund the difference to the Customer (plus Taxes) within 30 days following the issuing of the new Schedule "B". If the estimate of a Capital Contribution paid by the Customer is less than the actual Capital Contributions required to be paid by the Customer for any or all of the Transformation Connection Pool Work, the Line Connection Pool Work and the Network Customer Allocated Work, the Customer shall pay Hydro One the difference (plus Taxes) within 30 days following the issuing of the new Schedule "B".

10.2 Hydro One shall not include the following amounts in the Capital Contributions referenced in Section 10.1, any capital contribution for:

(a) a Connection Facility that was otherwise planned by Hydro One except for advancement costs;
(b) capacity added to a Connection Facility in anticipation of future load growth not attributable to the Customer; or
(c) the construction of or modifications to Hydro One's Network Facilities that may be required to accommodate the New or Modified Connection other than Network Customer Allocated Work unless Hydro One has indicated in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution.

10.3 Notwithstanding Sub-section 10.2(c) above, if Hydro One indicates in Schedule "A" of the Agreement that exceptional circumstances exist so as to reasonably require the Customer to make a Capital Contribution towards the Network Pool Work, Hydro One shall not, without the prior written consent of the Customer, refuse to commence or diligently perform the Network Pool Work pending direction from the OEB under section 6.3.5 of the *Transmission System Code* provided that the Customer provides Hydro One with a security deposit in accordance with Section 20 of these Standard Terms and Conditions.

Until such time as Hydro One has actually begun to perform the Network Pool Work, the Customer may request, in writing, that Hydro One not perform the Network Pool Work and Hydro One shall promptly return to the Customer any outstanding security deposit related to the Network Pool Work.

10.4 If the Customer has made a Capital Contribution under Section 10.1 hereof and where this Capital Contribution includes the cost of capacity on the Connection Facility not needed by the Customer as indicated in Schedule "B" of the Agreement, Hydro One shall provide the Customer with a refund, calculated in accordance with Section 6.2.25 of the *Transmission System Code* if that capacity is assigned to another Load Customer within five (5) years of the In Service Date.

11. Hydro One shall perform a True-Up, based on Actual Load:

(a) at the True-Up Points specified in Schedule "A" of the Agreement; and
(b) the time of disconnection where the Customer voluntarily and permanently disconnects the Customer's Facilities from Hydro One's transmission facilities and the prior to the final True-Up Point identified in (a) above.

For True-Up purposes, if the Customer does not pay a Capital Contribution, Hydro One shall provide the Customer with an Adjusted Load Forecast.

Hydro One shall perform True-Ups in a timely manner. Within 30 calendar days following completion of each of the True-Ups referred to in 11(a), Hydro One shall provide the Customer with the results of the True-Up.

12(a) If the result of a True-Up performed in accordance with Section 11 above is that the Actual Load and Updated Load Forecast is:

(i) less than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore does not generate the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, the Customer shall pay Hydro One an amount equal to the shortfall adjusted to reflect the time value of money within 30 days after the date of Hydro One's invoice therefor; and

(ii) more than the load in the Load Forecast or the Adjusted Load Forecast, whichever is applicable, and therefore generates more than the forecasted Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue required for the Economic Evaluation Period, Hydro One shall post the excess Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue as a credit to the Customer in a notional account. Hydro One shall apply this credit against any shortfall in subsequent True-Up calculations. Where the Customer paid a Capital Contribution in accordance with Section 10.1 hereof, Hydro One shall rebate the Customer an amount that is the lesser of the credit balance in the notional account adjusted to reflect the time value of money, and the Capital Contribution adjusted to reflect the time value of money by no later than 30 days following the final True-Up calculation.

12(b) All adjustments to reflect the time value of money to be performed under Subsection 12(a) above shall be performed in accordance with the OEB-Approved Connection Procedures. As of the date of this Agreement, the time value of money is determined using Hydro One's after-tax cost of capital as used in the original economic evaluation performed in accordance with the requirements of the *Transmission System Code*.

13.1 With respect to the installation of embedded generation (as determined in accordance with Section 11.1 of the *Transmission System Code)* during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.8 of the *Transmission System Code* when carrying out True-Up calculations if the Customer is a Distributor or the requirements of Section 6.5.9 of the Transmission System Code when carrying out True-Up calculations if the Customer is a Load Customer other than a Distributor.

13.2 With respect to energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period Hydro One shall comply with the requirements of Section 6.5.10 of the *Transmission System Code* when carrying out True-Up calculations provided that the Customer demonstrates to the reasonable satisfaction of Hydro One (such as by means of an energy study or audit) that the amount of any reduction in the Customer's load has resulted from energy conservation, energy efficiency, load management or renewable energy activities that occurred during the applicable True-Up period.

14. Hydro One shall provide the Customer with all information pertaining to the calculation of all Engineering and Construction Costs, Capital Contributions and True-Ups that the Customer is entitled to receive in accordance with the requirements of the *Transmission System Code.*

Part C: Work Chargeable to Customer, Network Pool Work and Premium Costs

15.1 The Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Hydro One Connection Work described asWork Chargeable to Customer in Schedule "A" of the Agreement which is estimated to be the amounts specified in Schedule "B" of the Agreement in the manner specified in Schedule "B" of the Agreement.

Hydro One shall identify the actual Engineering and Construction Cost of the Work Chargeable to Customer in the revised Schedule "B" provided to the Customer in accordance with Section 10.1 of this Agreement. Any difference between the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes) and the amount already paid by the Customer shall be paid within 30 days after the issuance of the revised Schedule "B" by:

(a) Hydro One to the Customer, if the amount already paid by the Customer exceeds the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes); or

(b) the Customer to Hydro One, if the amount already paid by the Customer is less than the Engineering and Construction Cost of the Work Chargeable to Customer (plus Taxes).

15.2 Subject to Sections 10.3 and 18 hereof, Hydro One shall perform the Hydro One Connection Work described as Network Pool Work in Part 3 of Schedule "A" of the Agreement at Hydro One's sole expense.

16. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the

Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 10.1 and 15.1 above, the Customer agrees to pay Hydro One's Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Hydro One shall obtain the Customer's approval prior to Hydro One authorizing the purchase of materials or the performance of work that attracts Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Hydro One shall not be liable to the Customer as a result thereof. Hydro One shall invoice the Customer for expenditures of Premium Costs approved by the Customer within 180 calendar days after the Ready for Service Date.

Part D: Right of Customer to By-Pass Existing Load Facilities

17.1 **Obligation to Notify Hydro One of Customer's Intent to Bypass an Existing Load Facility:** If the Customer chooses to exercise its rights under the *Transmission System Code* and the Agreement to bypass the Existing Load Facility, the Customer shall notify Hydro One, in writing, at least 30 days prior to transferring load from the Existing Load Facility Hydro One will then proceed in accordance with Section 6.7 of the *Transmission System Code*.

17.2 **Hydro One has not received a Notice of Customer Intent to Bypass an Existing Load Facility and Customer has Transferred Existing Load:** Where Hydro One determines that the Customer has transferred load from the Existing Load Facility without notifying Hydro One or the OEB, Hydro One will notify the Customer, all other load customers served by the connection facility and the OEB of a potential by-pass situation in accordance with the OEB-Approved Connection Procedures. If the Customer does not intend to by-pass the Existing Load Facility, the Customer must in accordance with the OEB-Approved Connection Procedures:

i. notify Hydro One and the OEB within 30 days of receiving Hydro One's notification of potential by-pass, that it has no intention of by-passing Hydro One's Existing Load Facility;
ii. transfer the load back to the Existing Load Facility within an agreed time period; and
iii. compensate Hydro One for the lost revenues.

17.3 The Customer agrees that Sections 17.1 and 17.2 above shall also be a term of the Connection Agreement.

Part E: Cancellation or Termination of Project and Early Termination of Agreement for Breach

18. Notwithstanding any other term of the Agreement, if at any time prior to the In-Service Date, the Project is cancelled or the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Hydro One, the Customer shall pay Hydro One's Engineering and Construction Cost (plus Taxes) of the Line Connection Pool Work, the Transformation Connection Pool Work, the Network Pool Work, the Network Customer Allocated Work and the Work Chargeable to Customer incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, vendor cancellation costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Hydro One that it is cancelling the Project, Hydro One shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Hydro One shall deduct the actual cost of those individual items of materials being purchased by Hydro One from the Engineering and Construction Costs referred to above.

If Hydro One does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Hydro One, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation; or
(ii) where all or part of the materials have been received by Hydro One but have not been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes) provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iii) where all or part of the materials have been received by Hydro One and have been installed, the Customer shall have the right to require Hydro One, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Hydro One's Engineering and Construction Costs (plus Taxes); and (B) the date that Hydro One removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination or cancellation. The Customer shall also be responsible for any Engineering and Construction Costs (plus Taxes) associated with the removal of the materials that have been installed by Hydro One.

The Customer shall pay Hydro One's Engineering and Construction Costs (plus Taxes) which become payable under this Section 18 within 30 calendar days after the date of invoice.

Part F: Sale, Lease, Transfer or Other Disposition of Customer's Facilities

19. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Hydro One to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement unless Hydro One agrees otherwise, in writing, the Customer shall remain obligated under Sections 10.1 12, 15.1 and 16 hereof. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated under Sections 10.1, 12, 15.1 and 16 for the said time period.

Part G: Security Requirements

20. If Hydro One requires that the Customer furnish security, which at the Customer's option may be in the form of cash, letter of credit or surety bond, the Customer shall furnish such security in the amount and by the dates specified in Schedule "A" of the Agreement. Hydro One shall return the security deposit to the Customer as follows:

(i) security deposits in the form of cash shall be returned to the Customer, together with Interest, less the amount of any Capital Contribution owed by the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities; and

(ii) security deposits in any other form shall be returned to the Customer once the Customer's Facilities are connected to Hydro One's New or Modified Connection Facilities and any Capital Contribution has been paid.

Notwithstanding the foregoing, Hydro One may keep all or a part of the security deposit: (a) where and to the extent that the Customer fails to pay any amount due under the Agreement within the time stipulated for payment; or (b) in the circumstances described in the OEB-Approved Connection Procedures.

Part H: Disputes

21. Prior to the existence of OEB-Approved Connection Procedures either party may refer a Dispute to the OEB for a determination. Once there are OEB-Approved Connection Procedures, all disputes, including, but not limited to, disputes related to:

(a) the cost and the allocation of the costs under this Agreement;
(b) the cost and the allocation of costs of the Hydro One Connection Work and notwithstanding Hydro One's decision not to allocate or to allocate any part of the costs of this work to the Customer at this time; or
(c) any other costs and the allocation of any other costs associated with, related to, or arising out of the connection of the Project to Hydro One's transmission system or Hydro One's policies in respect of connections generally,

shall be dealt with in accordance with the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

22. Before and after the existence of OEB-Approved Connection Procedures, if a dispute arises while Hydro One is constructing the New or Modified Connection Facilities, Hydro One shall not cease the work or slow the pace of the work without leave of the OEB.

23. Hydro One shall refund to the Customer or the Customer shall pay to Hydro One any portion of Capital Contributions, as the case may be, which the OEB subsequently determines should not have been allocated to the Customer or should have been allocated to the Customer by Hydro One but were not, as the case may be, or should have been allocated in a manner different from that allocated by Hydro One in this Agreement.

Part I: Easement

24. If specified in Schedule "A" that an easement(s) is required from the Customer, the Customer shall grant an easement to Hydro One substantially in the form of the easement attached hereto as Appendix "B" of these

Standard Terms and Conditions for the property(ies) described as the Easement Lands in Schedule "A" on or before the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

Part J: Events of Default

25. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 10.1, 12, 15.1, 16 or 18 within the time stipulated for payment;
(b) breach by the Customer or Hydro One of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or Hydro One or of their respective operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer or Hydro One.

For greater certainty, a dispute shall not be considered an Event of Default under this Agreement. However, a Party's failure to comply, within a reasonable period of time, with the terms of a determination of such a dispute by the OEB or with a decision of a court of competent jurisdiction with respect to a determination made by the OEB shall be considered an Event of Default under the Agreement.

26. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in Section 25(c) of the Agreement, for which no notice is required to be given by Hydro One), Hydro One shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Hydro One's reasonable satisfaction within the 30 calendar day period, Hydro One may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Hydro One under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the following:

(i) the sum of the amounts payable by the Customer pursuant to Sections 10.1, 12, 15.1 and where applicable, Section 16 less any amounts already paid by the Customer in accordance with Section 10.1, 12, 15.1 and 16 if this clause is invoked after the In-Service Date; or

(ii) the amounts payable under Section 16 and 18 less any amounts already paid by the Customer in accordance with Sections 10.1, 15.1 and 16 if this clause is invoked prior to the In-Service Date.

27. Upon the occurrence of an Event of Default by Hydro One hereunder (other than those specified in Section 25(c), the Customer shall give Hydro One written notice of the Event of Default and shall allow Hydro One 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Hydro One's sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

28. All rights and remedies of Hydro One and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Hydro One and the Customer respectively at law or in equity, and any one or more of Hydro One's and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Hydro One or the Customer may have or may not have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

Part K: Changes to Transmission Rates

29. In the event that the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement, provided that such new mechanism will not result in an increase in the amounts of Capital Contribution or Security Deposits payable by the Customer to Hydro One hereunder. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate to agree to a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, this shall be considered a dispute under the terms

of this Agreement and the parties shall follow the dispute resolution procedure set out in the OEB-Approved Connection Procedures.

Any settlement on a new mechanism pursuant to this Section 29 shall apply retroactively from the date on which the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate, the Line Connection Service Rate or the Network Service Rate in effect prior to the effective date of any such changes.

Part L: Incorporation of Liability and Force Majeure Provisions

30. PART III: LIABILITY AND FORCE MAJEURE (with the exception of Section 15.5 thereof) and Sections 1.1.12 and 1.1.17 of the Connection Agreement are hereby incorporated in their entirety by reference into, and form an integral part of the Agreement. Unless the context otherwise requires, all references in PART III: LIABILITY AND FORCE MAJEURE TO "this Agreement" shall be deemed to be a reference to the Agreement and all references to the "the Transmitter" shall be deemed to be a reference to Hydro One.

For the purposes of this Section 30, the Parties agree that the reference to:

(i) the Transmitter in lines 3 and 4 of Section 15.1 means the Transmitter or any party acting on behalf of the Transmitter such as contractors, subcontractors, suppliers, employees and agents; and
(ii) the Customer in lines 3 and 4 of Section 15.2 means the Customer or any party acting on behalf of the Customer such as contractors, subcontractors, suppliers, employees and agents.

Part M: General

31. This Agreement is subject to the *Transmission System Code* and the OEB-Approved Connection Procedures. If any provision of this Agreement is inconsistent with the:

(a) *Transmission System Code,* the said provision shall be deemed to be amended so as to comply with the *Transmission System Code;*
(b) OEB-Approved Connection Procedures the said provision shall be deemed to be amended so as to comply with the OEB-Approved Connection Procedures; and
(c) Connection Agreement made between the parties, associated with the new customer connection facilities, on the same subject matter, the Connection Agreement governs.

32. The failure of either party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of either party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

33. Other than as specifically provided in the Agreement, no amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

34. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Hydro One, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice shall be deemed to be received on the date of the fax if received before 3 p.m. on a business day or on the next business day if received after 3 p.m. or a day that is not a business day. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

35. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein.

36. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

37. The Customer shall provide Hydro One with a copy of the Customer's final monthly bills associated

with the transmission of electricity from the Existing Load Facilities and/or the Customer's Facilities or authorize the IESO to provide Hydro One with same. Hydro One agrees to use this information solely for the purpose of the Agreement.

38. **Invoices and Interest:** Invoiced amounts are due 30 days after invoice issuance. All overdue amounts including, but not limited to amounts that are not invoiced but required under the terms of this Agreement to be paid in a specified time period, shall bear interest at 1.5% per month compounded monthly (19.56 percent per year) for the time they remain unpaid.

39. The obligation to pay any amount due hereunder, including, but not limited to, any amounts due under Sections 10.1, 12, 15.1, 16, 18 or 23 shall survive the termination of the Agreement.

Appendix "A": Definitions

In the Agreement, unless the context otherwise requires, terms which appear therein without definition, shall have the meanings respectively ascribed thereto in the *Transmission System Code* and unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Load" means the actual load delivered by Hydro One to the Customer up to the True-Up Point in excess of the Normal Capacity of the Existing Load Facilities.

"Assigned Capacity" is calculated in accordance with Section 6.2.2 of the *Transmission System* Code.

"Adjusted Load Forecast" means a Load Forecast that has been adjusted to the point where the present value of the Transformation Connection Revenue and/or Line Connection Revenue and/or Network Revenue equals the present value of the Pool Funded Cost of the Transformation Connection Pool Work and/or the Pool Funded Cost of the Line Connection Pool Work and/or the Pool Funded Cost of the Network Customer Allocated Work.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 5(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Capital Contribution" means a capital contribution calculated using the economic evaluation methodology set out in the *Transmission System Code.*

"Connect and Connection" has the same meaning ascribed to the term "Connect" in the *Transmission System Code.*

"Connection Agreement" means the form of connection agreement appended to the *Transmission System Code* as Appendix 1, Version 1.

"Connection Facilities" has the meaning set forth in the *Transmission System Code.*

"Connection Point" has the meaning set forth in the *Transmission System Code* and for this project, is as specified in Schedule "A" of the Agreement.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer Connection Risk Classification" is as specified in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the *Transmission System Code*, and includes, but is not limited to any new, modified or replaced Customer's Facilities.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Dispute" means a dispute between the Parties with respect to any of the matters listed in Section 6.1.4 of the *Transmission System Code* where either Party is alleging that the other is seeking to impose a term that is inconsistent or contrary to the *Ontario Energy Board Act*, the *Electricity Act, 1998*, Hydro One's transmission licence or the *Transmission System Code* or refusing to include a term or condition that is required to give effect to the Code.

"Distributor" has the meaning set forth in the *Transmission System Code.*

"Economic Evaluation Period" means the period of five (5) years for high risk connection, ten (10) years for a medium-high risk connection, fifteen (15) years for a medium-low risk connection and twenty-five years for a low risk connection commencing on the In Service Date whichever is applicable to the Customer as specified in Schedule "A" of the Agreement.

"Engineering and Construction Cost" means Hydro One's charge for equipment, labour and materials at Hydro One's standard rates plus Hydro One's standard overheads as well as interest during construction using Hydro One's capitalization rate in effect during the construction period.

"*Electricity Act,* 1998" means the *Electricity Act, 1998* being Schedule "A" of the *Energy Competition Act,* S.O. *1998*, c.15, as amended.

"Existing Load" in relation to the Customer and each of the Existing Load Facilities is equal to the Customer's Assigned Capacity at each of the Existing Load Facilities on the date of this Agreement.

"Existing Load Facility or Existing Load Facilities" means the connection facility(ies) owned by Hydro One as specified in the Existing Load Table in Schedule "A" of the Agreement where the Customer has Existing Load.

"Force Majeure Event" has the meaning ascribed thereto in the Connection Agreement.

"HST" means the Harmonized Sales Tax.

"Hydro One Connection Work" means the work to be performed by Hydro One, which is described in Schedule "A" of the Agreement.

"Hydro One Facilities" means Hydro One's structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunication systems, cables and any other auxiliary equipment used for the purpose of transmitting electricity.

"Hydro One's Property(ies)" means any lands owned by Hydro One in fee simple or where Hydro One now or hereafter has obtained easement rights.

"IESO" means the Independent Electricity System Operator continued under the *Electricity Act, 1998*.

"In Service Date" has the same meaning ascribed to the term "comes into service" in the *Transmission System Code*.

"Incremental Network Load" means the Customer's New Load less the amount of load, if any, that has been by-passed by the Customer at any of Hydro One's connection facilities.

"Interest" means the interest rates specified by the OEB to be applicable to security deposits in the form of cash as specified in Subsection 6.3.11(b) in the *Transmission System Code*.

"Line Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Line Connection Pool Work".

"Line Connection Revenue" means the amount of line connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Line Connection Service Rate during the Economic Evaluation Period.

"Line Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Load Customer" has the meaning set forth in the *Transmission System Code*.

"Load Forecast" means the initial load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities used in the initial economic evaluation for the Economic Evaluation Period.

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Network Customer Allocated Work" means the construction of or modifications to Network Facilities specified in Schedule "A" of the Agreement under the heading "Network Customer Allocated Work" that are minimum connection requirements.

"Network Facilities" has the meaning set forth in the *Transmission System Code*.

"Network Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Network Pool Work".

"Network Revenue" means the amount of network revenue attributable to the Incremental Network Load to be received by Hydro One through the monthly collection of the Network Service Rate during the Economic Evaluation Period.

"Network Service Rate" " means the network service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"New Load" means the load at the New or Modified Connection Facility that is in excess of, for each of the Existing Load Facilities, the lesser of the Existing Load or the Normal Capacity.

"New or Modified Connection Facilities" means the facilities owned by Hydro One as specified in Schedule "A" of the Agreement.

"Normal Capacity" means, where the Customer is:

(a) the only Load Customer supplied by an Existing Load Facility, the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures; and
(b) one of two or more Load Customers served by an Existing Load Facility, the Customer's pro-rated share of the total normal supply capacity of the Existing Load Facility as determined in accordance with the OEB-Approved Connection Procedures.

"OEB" means the Ontario Energy Board.

"OEB-Approved Connection Procedures" means Hydro One's connection procedures as approved by the OEB from time to time.

"Ontario Energy Board Act" means the *Ontario Energy Board Act* being Schedule "B" of the *Energy Competition Act*, S.O. *1998*, c. 15, as amended.

"Pool-Funded Cost" means the present value of the Engineering and Construction Cost and projected on-going maintenance and other related incremental costs (including, but not limited to applicable taxes, and net of tax benefits), of each of the Transformation Connection Pool Work, the Line Connection Pool Work and/or the Network Customer Allocated Work calculated in accordance with the principles, criteria and methodology set out in Appendices 4 and 5 of the Transmission System Code.

"Premium Costs" means those costs incurred by Hydro One in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Hydro One's employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Rate Order" has the meaning ascribed thereto in the *Transmission System Code.*

"Ready for Service Date" means the date upon which the Hydro One Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Standard Terms and Conditions" means these Standard Terms and Conditions for Low Risk Transmission Customer Connection Projects and Appendices "A" and "B" attached hereto.

"Taxes" means all property, municipal, sales, use, value added, goods and services, harmonized and any other non-recoverable taxes and other similar charges (other than taxes imposed upon income, payroll or capital).

"Transformation Connection Pool Work" means the Hydro One Connection Work specified in Schedule "A" of the Agreement under the heading "Transformation Connection Pool Work".

"Transformation Connection Revenue" means the amount of transformation connection revenue attributable to that part of the Customer's New Load to be received by Hydro One through the monthly collection of the Transformation Connection Service Rate during the Economic Evaluation Period.

"Transformation Connection Service Rate" means the line connection service rate approved by the OEB in Hydro One's Rate Order from time to time, or any mechanism instituted in accordance with Section 29.

"Transmission System Code" or "Code" means the code of standards and requirements issued by the OEB on July 25, 2005 that came into force on August 20, 2005 as published in the Ontario Gazette, as it may be amended, revised or replaced in whole or in part from time to time.

"Transmitter's Facilities" has the meaning ascribed thereto in the *Transmission System Code.*

"True-Up" means the calculation to be performed by Hydro One, as a transmitter, at each True-Up Point in accordance with the requirements of Subsection 6.5.4 of the *Transmission System Code.*

"True-Up Point" means the points of time based upon the Customer Connection Risk Classification when Hydro One is required to perform a True-Up as described in Section 11 of these Terms and Conditions.

"Updated Load Forecast" means the load forecast of the New Load in excess of the Normal Capacity of the Existing Load Facilities for the remainder of the Economic Evaluation Period.

"Work Chargeable to Customer" means the Hydro One Connection Work specified in Part 4 of Schedule "A" of the Agreement under the heading "Work Chargeable to Customer".

Appendix "B": Form of Easement

INTEREST / ESTATE TRANSFERRED

The Transferor is the owner in fee simple and in possession of ____
____
____ (the **"Lands"**).

The Transferee has erected, or is about to erect, certain Works (as more particularly described in paragraph 1(a) hereof) in, through, under, over, across, along and upon the Lands.

1 The Transferor hereby grants and conveys to Hydro One Networks Inc, its successors and assigns the rights and easement, free from all encumbrances and restrictions, the following unobstructed and exclusive rights, easements, rights-of-way, covenants, agreements and privileges in perpetuity (the **"Rights"**) in, through, under, over, across, along and upon that portion of the Lands of the Transferor described herein and shown highlighted on Schedule "A" hereto annexed (the **"Strip"**) for the following purposes:

(a) To enter and lay down, install, construct, erect, maintain, open, inspect, add to, enlarge, alter, repair and keep in good condition, move, remove, replace, reinstall, reconstruct, relocate, supplement and operate and maintain at all times in, through, under, over, across, along and upon the Strip an electrical transmission system and telecommunications system consisting in both instances of a pole structures, steel towers, anchors, guys and braces and all such aboveground or underground lines, wires, cables, telecommunications cables, grounding electrodes, conductors, apparatus, works, accessories, associated material and equipment, and appurtenances pertaining to or required by either such system (all or any of which are herein individually or collectively called the **"Works"**) as in the opinion of the Transferee are necessary or convenient thereto for use as required by Transferee in its undertaking from time to time, or a related business venture.

(b) To enter on and selectively cut or prune, and to clear and keep clear, and remove all trees (subject to compensation to Owners for merchantable wood values), branches, bush and shrubs and other obstructions and materials in, over or upon the Strip, and without limitation, to cut and remove all leaning or decayed trees located on the Lands whose proximity to the Works renders them liable to fall and come in contact with the Works or which may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(c) To conduct all engineering, legal surveys, and make soil tests, soil compaction and environmental studies and audits in, under, on and over the Strip as the Transferee in its discretion considers requisite.

(d) To erect, install, construct, maintain, repair and keep in good condition, move, remove, replace and use bridges and such gates in all fences which are now or may hereafter be on the Strip as the Transferee may from time to time consider necessary.

(e) Except for fences and permitted paragraph 2(a) installations, to clear the Strip and keep it clear of all buildings, structures, erections, installations, or other obstructions of any nature (hereinafter collectively called the **"obstruction"**) whether above or below ground, including removal of any materials and equipment or plants and natural growth, which in the opinion of the Transferee, endanger its Works or any person or property or which may be likely to become a hazard to any Works of the Transferee or to any persons or property or which do or may in any way interfere with the safe, efficient or serviceable operation of the Works or this easement by the Transferee.

(e) To enter on and exit by the Transferor's access routes and to pass and repass at all times in, over, along, upon and across the Strip and so much of the Lands as is reasonably required, for Transferee, its respective officers, employees, agents, servants, contractors, subcontractors, workmen and permittees with or without all plant machinery, material, supplies, vehicles and equipment for all purposes necessary or convenient to the exercise and enjoyment of this easement and

(f) To remove, relocate and reconstruct the line on or under the Strip.

2. The Transferor agrees that:

(a) It will not interfere with any Works established on or in the Strip and shall not, without the Transferee's consent in writing, erect or cause to be erected or permit in, under or upon the Strip any obstruction or plant or permit any trees, bush, shrubs, plants or natural growth which does or may interfere with the Rights granted herein. The Transferor agrees it shall not, without the Transferee's consent in writing, change or permit the existing configuration, grade or elevation of the Strip to be changed and the Transferor further agrees that no excavation or opening or work which may disturb or interfere with the existing surface of the Strip shall be done or made unless consent therefore in writing has been obtained from Transferee, provided however, that the Transferor shall not be required to obtain such permission in case of emergency. Notwithstanding the foregoing, in cases where in the reasonable discretion of the Transferee, there is no danger or likelihood of danger to the Works of the Transferee or to any persons or property and the safe or serviceable operation of this easement by the Transferee is not interfered with, the Transferor may at its expense and with the prior written approval of the Transferee, construct and maintain roads, lanes, walks, drains, sewers, water pipes, oil and gas pipelines, fences (not to exceed 2 metres in height) and service cables on or under the Strip (the **"Installation"**) or any portion thereof; provided that prior to commencing such Installation, the Transferor shall give to the Transferee thirty (30) days notice in writing thereof to enable the Transferee to have a representative present to inspect the proposed Installation during the performance of such work, and provided further that Transferor comply with all instructions given by such representative and that all such work shall be done to the reasonable satisfaction of such representative. In the event of any unauthorised interference aforesaid or contravention of this paragraph, or if any authorised interference, obstruction or Installation is not maintained in accordance with the Transferee's instructions or in the Transferee's reasonable opinion, may subsequently interfere with the Rights granted herein, the Transferee may at the Transferor's expense, forthwith remove, relocate, clear or correct the offending interference, obstruction, Installation or contravention complained of from the Strip, without being liable for any damages caused thereby.

(b) notwithstanding any rule of law or equity, the Works installed by the Transferee shall at all times remain the property of the Transferee, notwithstanding that such Works are or may become annexed or affixed to the Strip and shall at anytime and from time to time be removable in whole or in part by Transferee.

(c) no other easement or permission will be transferred or granted and no encumbrances will be created over or in respect to the Strip, prior to the registration of a Transfer of this grant of Rights.

(d) the Transferor will execute such further assurances of the Rights in respect of this grant of easement as may be requisite.

(e) the Rights hereby granted:

(i) shall be of the same force and effect to all intents and purposes as a covenant running with the Strip.

(ii) is declared hereby to be appurtenant to and for the benefit of the Works and undertaking of the Transferee described in paragraph 1(a).

3. The Transferee covenants and agrees to obtain at its sole cost and expense all necessary postponements and subordinations (in registrable form) from all current and future prior encumbrancers, postponing their respective rights, title and interests to the Transfer of Easement herein so as to place such Rights and easement in first priority on title to the Lands.

4. There are no representations, covenants, agreements, warranties and conditions in any way relating to the subject matter of this grant of Rights whether expressed or implied, collateral or otherwise except those set forth herein.

5. No waiver of a breach or any of the covenants of this grant of Rights shall be construed to be a waiver of any succeeding breach of the same or any other covenant.

6. The burden and benefit of this transfer of Rights shall run with the Strip and the Works and undertaking of the Transferee and shall extend to, be binding upon and enure to the benefit of the parties hereto and their respective heirs, executors, administrators, successors and assigns.

IN WITNESS WHEREOF the Transferor has hereunto set his hand and seal to this Agreement, this ___ day of _______ _____________, 200__.

SIGNED, SEALED AND DELIVERED
In the presence of)

)

_______________________________ (seal) _______________________________)

Signature of Witness) Transferor's Signature

)
)
)

_______________________________) _______________________________ (seal)

Signature of Witness Transferor's Signature

)

SIGNED, SEALED AND DELIVERED) Consent Signature & Release of
In the presence of) Transferor's Spouse, if non-owner.

)
)
)

_______________________________) _______________________________ (seal)

Signature of Witness

CHARGEES

THE CHARGEE of land described in a Charge/Mortgage of Land dated ____________________

Between ______________________________ and ______________________________________

and registered as Instrument Number __________________ on ______________________________ does

hereby consent to this Easement and releases and discharges the rights and easement herein from the said

Charge/Mortgage of Land.

Name	Signature(s)	Date of Signatures Y M D
	Per:	

____

____

I/We have authority to bind the Corporation

Revised Schedule "B" – Cecil TS Capacity Increase

SCHEDULE B REVISION DATE

July 24, 2014

READY FOR SERVICE DATE

February 21, 2005

TRANSFORMATION CONNECTION POOL WORK

Transformation Connection Pool Work Estimate: $6,603,000

Actual Transformation Connection Pool Work: $5,774,100

Manner of Payment of Transformation Connection Pool Work: Capital contribution plus guaranteed revenue

Capital Contribution for Transformation Connection Pool Work: $2.0784 Million (Required capital contribution is $2.3364 Million less a credit of $258 Thousand). This $258 Thousand credit is the remaining book value (original costs less depreciation) for the two removed 75 MVA transformers.

Actual Capital Contribution for Transformation Connection Pool Work: $1,251,800

Line Connection Work Estimate: Not Applicable

Non-Poolable Work Estimate: N/A

Manner of Payment for Capital Contribution: The total capital contribution is payable upon completion of Networks work.

Available Capacity: 985.8 MW (includes existing capacity for Cecil TS, John TS, Esplanade TS, Strachan TS and Terauley TS. Capacity is based on 95% of summer 10-day LTR and 90% power factor). The Project will increase capacity at Cecil TS by 50 MVA, or 43 MW, based on 95% of summer 10-LTR and 90% power factor.

Base Load Trigger Point 856.6MW (Based on the product of the existing Available Capacity and average Peak Load Index for January 1998 to December 2000. Peak Load Index is the average monthly peak load divided by the annual peak. The average Peak Load Index for 1998 to 2000 is 0.8688.)

Guaranteed Revenue Date: 2030

GUARANTEED INCREMENTAL TRANSFORMATION CONNECTION REVENUE AND/OR LINE CONNECTION REVENUE

Period: One year following the anniversary of the Ready for Service Date and annually thereafter	New Load** Incremental Load (Average Peak Load) MW	Line Connection Revenue (k$)	Transformation Connection Revenue (k$)
2006	0.0		0.0
2007	0.0		0.0
2008	3.0		53.1
2009	21.3		383.4
2010	39.9		718.5
2011	43.0		774.0
2012	43.0		774.0
2013	43.0		774.0
2014	43.0		774.0
2015	43.0		774.0
2016	43.0		774.0
2017	43.0		774.0
2018	43.0		774.0
2019	43.0		774.0
2020	43.0		774.0
2021	43.0		774.0
2022	43.0		774.0
2023	43.0		774.0
2024	43.0		774.0
2025	43.0		774.0
2026	43.0		774.0
2027	43.0		774.0
2028	43.0		774.0
2029	43.0		774.0
2030	43.0		774.0

Connection and Cost Recovery Agreement

for

Cecil T.S. Capacity Increase

between

Toronto Hydro Electric System Limited

and

Hydro One Networks Inc.

CECIL T.S. - Capacity Upgrade

Toronto Hydro-Electric System Limited (the "Customer") has requested and Hydro One Networks Inc. ("Networks") has agreed to increase the capacity at Cecil T.S. to supply load growth in downtown Toronto (the "Project") on the terms and conditions set forth in this agreement dated April 25, 2002 and the attached Standard Terms and Conditions (T&C V1 ESH 15-25 01-2002) (collectively, the "Agreement").

Project Summary - Overview and Purpose

Hydro One will increase the capacity of Cecil T.S. by replacing the two existing *T3/T4 DESN* transformers rated at 45/60/75 MVA with 60/80/100 MVA units to meet the Customer's forecast load growth. The timing of this capacity increase co-ordinates with the Customer's requirement to upgrade their A5A6 bus to supply this load growth.

Ready-for-Service Date: June 14, 2003 **Term:** **25 years**

Financial Summary (Repayment schedule and Capital Contribution)

- Transformation connection revenue guarantees for 25 years as per schedule "B"
- Capital contribution for revenue shortfall of $2,078,400.00 as per schedule 'B"
- Credit for transformers removed from service $258,000.00 as per schedule 'B"

Special Circumstances

- Transformers ordered in advance to meet project timelines as per the letter of agreement with the Customer dated April 26, 2001.
- IMO approval has been granted
- Hydro One approval is required
- Clause 20 of the Terms & Conditions (by-pass) is intentionally deleted for this project as per the attached amending agreement as this clause does not apply for this work.
- Coordination of schedules and equipment design with the Customer is required due to joint ownership of facilities at Cecil T.S.

The Project schedule is subject to:

a) the Customer executing and returning this Agreement to Networks by no later than April 25, 2002, and
b) All necessary approvals being obtained as outlined under Special Circumstances.

This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement. Schedules "A" and "B" and the Standard Terms and Conditions (T&C V1 ESH 15-25 01-2002) attached hereto are to be read with and form part of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

Anthony Morton
Director – Networks Customer Relations
I have the authority to bind the Corporation.

Customer Name

Joe Bailey
Sr. Vice President -Asset Management
I have the authority to bind the Corporation.

Schedule "A"

Project Scope

Networks Connection Work

Part 1: Non-Poolable Work - N/A

Part 2: Transformation Connection Pool Work

Networks will:

- Replace existing T3 and T4 with 60/80/100 MVA units
- Replace existing T3A4A5 and T4A4A5 13.8 kV breakers with 3000-Ampere units.
- Revise local protections, supervisory control and DACS facilities as required.

Customer Connection Work

The Customer will:

- Replace existing 2000 Amp A5A6 bus and switchgear lineup.
- Coordinate schedules with Hydro One for equipment installation and feeder transfers
- Provide design specifications for Customer equipment to Hydro One
- Participate in Networks' commissioning procedures

Miscellaneous

Documentation Required (following the Project Ready-for-Service date):

- Provide Hydro One with as built designs and drawings for A5A6 bus and Switchgear
- Provide Protection settings

Easement Required: No

Name of Third Party for Easement: N/A

Easement Date: N/A

Easement Lands: N/A

New or Modified Facility: the Customer A5A6 bus and switchgear

Connection Point: Cecil T.S. T3A4A5 and T4A4A5 13.8 kV breakers

Ready for Service Date: June 14, 2003

Execution Date: April 25, 2002

Security Requirements: N/A

Approval Date: N/A (OEB approval not required)

Environmental Assessment: N/A

Revenue Metering: The Customer will:

- **Provide revenue-metering in accordance with IMO rules and regulations.**
- **Provide cabling between instrument transformers and metering cabinet**

- **Obtain easement for metering cabinet**

The Customer may engage Hydro One Networks as its metering Service Provider (MSP) or act as it's own MSP.

The Customer will reimburse Networks for any costs incurred to purchase and install revenue metering or associated equipment, including instrument transformers purchased and installed as part of the T3 and T4 transformer breaker cells.

__Ownership__

A. Networks will own all equipment and facilities installed by Networks as part of the Networks Connection Work in, under, on, over, along, upon, through and crossing Networks' Property(ies), as well as: (NIL)

B. The Customer will own the A5A6 bus and associated switchgear installed by the Customer.

__Customer Notice Information:__

Address: Toronto Hydro-Electric System Limited
14 Carlton Street,
Toronto,
Ontario
M5B 1K5

Attention: Mr. Joe Bailey, P.Eng.
Sr. Vice President – Asset Management

Fax No.: (416) 542-2833

Schedule "B"

Transformation Connection Pool Work Estimate: $6.603 million plus GST

Manner of Payment of Transformation Connection Pool Work: Capital contribution plus guaranteed revenue

Capital Contribution for Transformation Connection Pool Work: $2.0784 Million (Required capital contribution is $2.3364 Million less a credit of $258 Thousand). This $258 Thousand credit is the remaining book value (original costs less depreciation) for the two removed 75 MVA transformers.

Line Connection Work Estimate: Not Applicable

Non-Poolable Work Estimate: N/A

Manner of Payment for Non-Poolable Work: N/A

Manner of Payment for Capital Contribution: The total capital contribution is payable upon completion of Networks work.

Available Capacity: 985.8 MW (Includes existing capacity for Cecil TS, John TS, Esplanade TS, Strachan TS and Terauley TS. Capacity is based on 95% of summer 10-day LTR and 90% power factor.) The Project will increase capacity at Cecil TS by 50 MVA, or 43 MW, based on 95% of summer 10-day LTR and 90% power factor.

Base Load Trigger Point: 856.5 MW (Based on the product of the existing Available Capacity and average Peak Load Index for January 1998 to December 2000. Peak Load Index is the average monthly peak load divided by the annual peak. The average Peak Load Index for 1998 to 2000 is 0.8688.)

Guaranteed Revenue Date: 2028

GUARANTEED INCREMENTAL TRANSFORMATION CONNECTION REVENUE AND/OR LINE CONNECTION REVENUE[1]

Period: Each twelve month period commencing on the Ready for Service Date	**Incremental Load**	**Guaranteed Incremental Line Connection Revenue (k$)**	**Guaranteed Incremental Transformation Connection Revenue (k$)**
2002	0		0
2003	0		0
2004	0		0
2005	0		0
2006	0		0
2007	0		0
2008	8.9		159.3
2009	28.5		513.0
2010	41.2		740.7
2011	43.0		774.0
2012	43.0		774.0
2013	43.0		774.0
2014	43.0		774.0
2015	43.0		774.0
2016	43.0		774.0
2017	43.0		774.0
2018	43.0		774.0
2019	43.0		774.0

2020	43.0		774.0
2021	43.0		774.0
2022	43.0		774.0
2023	43.0		774.0
2024	43.0		774.0
2025	43.0		774.0
2026	43.0		774.0
2027	43.0		774.0
2028	43.0		774.0

Amendment to the Standard Terms and Conditions **April 26, 2002**
(Reference # T&C V1 ESH 15-25 01-2002)

Toronto Hydro-Electric System Limited & Hydro One Networks Inc.

Section 20:

As the Cecil T.S. project does not change Hydro One's ownership of transformers at any of the 5 Transformer Stations in downtown Toronto included in deriving the incremental revenue guarantees, within the context of this Agreement these new facilities can not be used to avoid the Transformation Connection Tariff. Accordingly, the by-pass clause is not applicable to this specific project, and Section 20 is intentionally deleted.

Standard Terms and Conditions for Transmission Customer Connection Projects

1. The Customer agrees to guarantee a minimum amount of revenue to be derived from Incremental Load in accordance with the terms and conditions of the Agreement to hold the Pool harmless as a result of the Project.

2. Subject to Section 23 and the termination rights herein, the Agreement shall be in full force and effect and binding on the parties as of the date of the Agreement (the "Effective Date") and shall expire on the earlier of the Guaranteed Revenue Date and the date that the debt owed by the Customer pursuant to Section 12 is reduced to zero (the "Term").

3. Each party represents and warrants to the other that:

(a) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder; and
(b) the execution of the Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on its part.

Where the New or Modified Facility is owned by the Customer, the Customer represents and warrants to Hydro One Networks Inc. ("Networks") that it has obtained all necessary approvals with respect to the construction of the New or Modified Facility (including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998,c. 15)*) and in order to proceed with the Customer Connection Work.

Part A: Networks Connection Work

4. The Customer and Networks shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, including, but not limited to the requirements of the Electrical Safety Code, and using duly qualified and experienced people.

5. The parties acknowledge and agree that:

(a) Networks is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Networks Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by Networks;

(b) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by the Customer, including those required under the Electrical Safety Code and the Customer shall ensure that it has received all such requisite permits, certificates, reviews and approvals prior to connection;

(c) the Customer will enter into a Connection Agreement with Networks at least 14 calendar days prior to the connection of the New or Modified Facility to Networks' transmission system;

(d) the Customer will ensure that Project data is made available or provided to Networks as required by Networks;

(e) the Customer will ensure that the work performed by the Customer and others required for successful installation, testing and commissioning of protective equipment is completed as required to enable Networks witnessing and testing to confirm satisfactory performance of such systems;

(f) the Customer will provide any hardware required to connect to Networks' transmission system;

(g) the Customer will provide coordination on protection;

(h) Networks' responsibilities under the Agreement with respect to the connection of the New or Modified Facility to Networks' transmission system shall be limited to the performance of the Networks Connection Work;

(i) the Customer shall perform the Customer Connection Work at its own expense;

(j) where the New or Modified Facility is owned by the Customer, the Customer shall provide technical specifications for the New or Modified Facility as required for Networks' reviews. Until Networks has accepted the technical specifications (including electrical drawings) for the New or Modified Facility and accepted the Customer's verification of those portions of the Customer's electrical facilities affecting Networks' transmission system, Networks shall not be bound to connect the New or Modified Facility to Networks' transmission system; and

(k) the Networks Connection Work and Networks' rights and requirements hereunder, including, but not limited to:

(i) Networks' specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) Networks' acceptance of power system components on the Customer's side of the Connection Point; and
(iii) Networks' acceptance of the technical specifications (including electrical drawings) for the New or Modified Facility where the New or Modified Facility is owned by the Customer and/or the Customer Connection Work;

are solely for the protection of Networks' transmission system and that the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer.

6. Networks shall use reasonable efforts to complete the Networks Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Networks, acting reasonably;
(c) there are no delays resulting from Networks not being able to obtain outages from the Independent Electricity Market Operator required for the Networks Connection Work;
(d) Networks does not have to use its employees, agents and contractors performing the Networks Connection Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the Transmission System Code) or an event of force majeure;
(e) Networks is able to obtain the materials and labour required to perform the Networks Connection Work with the expenditure of Premium Costs where required;
(f) where Networks needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998, c. 15)*, such leave is obtained by no later than the date specified as the Approval Date in Schedule "A" of the Agreement;

(g) the Customer executed this Agreement by no later than the date specified as the Execution Date in Schedule "A"; and
(h) Networks obtains internal approval to commit the funds for the Project.

7. Upon completion of the Networks Connection Work:

(a) Networks shall own, operate and maintain all equipment referred to in Schedule "A" of the Agreement; and
(b) other than equipment referred to in (a) above that will be owned, operated and maintained by Networks, all other equipment provided by Networks as part of the Networks Connection Work or provided by the Customer as part of the Customer Connection Work will be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Networks and the Customer shall have no right of property therein;
(ii) that any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Networks and shall not be or become fixtures and/or part of the Customer's property; and
(iii) the right to the benefit of any capital cost allowance determined for capital contribution(s) by the Customer for the equipment referred to in (a) above shall be the Customer's.

8. The Customer acknowledges and agrees that Networks is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Networks with regard to Networks' requirements to permit connection of the New or Modified Facility to Networks' transmission system, and shall be installed, maintained and operated in accordance with all applicable laws, codes and standards, including, but not limited to, the Transmission System Code, at the expense of the Customer. Networks acceptance is solely for the protection of Networks' Facilities.

9. Where Networks has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of feeder connection, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Networks for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Networks' reclosing equipment.

10. The Customer shall provide Networks with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Networks, by no later than 120 calendar days after the Ready for Service Date. The Customer shall ensure that Networks may retain this documentation for Networks' ongoing planning, system design, and operating review. Where the New or Modified Facility is owned by the Customer, the Customer shall also maintain and revise such documentation to reflect changes to the New or Modified Facility and provide copies to Networks on demand and as specified in the Connection Agreement.

11. Nothing contained within the Agreement, including, subsection 13 below shall preclude, prevent, prohibit or operate as a waiver of any of the parties rights to make application to the OEB, participate in any hearings before the OEB or to make any appeals to a Court of competent jurisdiction regarding any decision by the OEB with respect to any costs and the allocation of any costs associated with, related to, or arising out of the connection of the Project to Networks' transmission system or Networks' policies in respect of connections generally.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and Non-Poolable Work

12. The Customer shall pay Networks the Actual Cost of the Networks Connection Work described as the Transformation Connection Pool Work and/or Line Connection Pool Work in Schedule "A" of the Agreement which is estimated to be the amount specified in Schedule "B" of the Agreement (plus applicable taxes) (the "Transformation Connection Pool Work Estimate" and/or the "Line Connection Pool Work Estimate").

The Customer shall pay Networks a capital contribution in the amount specified in Schedule "B" of the Agreement (plus applicable taxes) (the "Capital Contribution") in the manner specified in Schedule "B" of the Agreement for that part of the Transformation Connection Pool Work and/or the Line Connection Pool Work that cannot be supported by revenue guarantees.

The Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work shall be particularly identified by Networks by no later than 180 calendar days after the Ready for Service Date and Networks shall also provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto and that new Schedule "B"shall be made a part hereof as though it had been originally incorporated into the Agreement.

If the Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work exceeds the Transformation Connection Pool Work Estimate and/or the Line Connection Pool Work Estimate, the Customer shall pay an additional capital contribution proportionate to the difference between the Actual Cost and the Transformation Connection Pool Work Estimate and/or the Line Connection Pool Work Estimate (plus applicable taxes) within 30 days after the date of Networks' invoice therefor.

The Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work less any Capital Contribution paid by the Customer is a debt owed to Networks by the Customer and subject to Sections 13 and 14 below, that debt shall be paid by the Customer to Networks on the earlier of the following dates:

(i) the Guaranteed Revenue Date; and
(ii) the date of termination of the Agreement.

13(a). Notwithstanding Section 12, the parties further agree that, provided that the Actual Incremental Transformation Connection Revenue and/or the Actual Incremental Line Connection Revenue received by Networks is equal to or exceeds the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for a specified period, Networks will forgive an amount of the foregoing debt equal to the amount of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question PROVIDED THAT the Customer's peak load met or exceeded the

Available Capacity during at least one month of the twelve month period in question.

13(b). Commencing on the first anniversary of the Ready for Service Date and every year thereafter during the Term, if the Customer's peak load fails to meet or exceed the Available Capacity during at least one month of the a period, the Customer will not receive a credit for that period and the Customer shall pay Networks the Guaranteed Incremental Transformation Connection Revenue specified for the period in question by no later than 30 days after the date of Networks' invoice therefor.

13(c). Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter during the Term, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the previous five periods in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(d). For every period during the term, with the exception of every fifth period commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is less than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall be entitled to carry forward that amount (the "Carry Forward Amount"), which shall be added to the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for the following period to result in a Revised Guaranteed Incremental Transformation Connection Revenue and/or Revised Guaranteed Incremental Line Connection Revenue for the next following period.

Thereafter any reference to:

(I) Guaranteed Incremental Transformation Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Transformation Connection Revenue for the period in question and the Revised Guaranteed Incremental Transformation Connection Revenue; AND
(II) Guaranteed Incremental Line Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Line Connection Revenue for the period in question and the Revised Guaranteed Incremental Line Connection Revenue.

13(e). Notwithstanding Section 13(c) above, if in any period during the Term, the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is greater than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(f) Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is more than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five periods in question, Networks will reduce the amount of debt owing by the Customer by reducing the amount of Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue that must be received by Networks during the next five periods shown in Schedule B of the Agreement such that the total reduction over the next five periods is equal to the excess amount received by Networks. This may have the effect of shortening the Term of the Agreement.

13(g). The Customer acknowledges and. agrees that:

(a) the Incremental Transformation Connection Revenue is distinct revenue that does not include Transformation Connection revenue derived from Base Load Trigger Point or any network revenue; and

(b) the Incremental Line Connection Revenue is distinct revenue that does not include Line Connection revenue derived from Base Load Trigger Point or any network revenue.

14. The Customer shall pay Networks Actual Cost of the Networks Connection Work described as Non-Poolable Work in Schedule "A" of the Agreement which is estimated to be the amount specified in Schedule "B" of the Agreement (plus applicable taxes) in the manner specified in Schedule "B" of the Agreement.

Within 60 days after the Ready for Service Date, Networks shall provide the Customer with a final invoice or credit memorandum which shall indicate whether the amounts already paid by the Customer exceeds or is less than the Actual Cost of the Non-Poolable Work. Any difference between the Actual Cost of the Non-Poolable Work (plus applicable taxes) and the amount already paid by the Customer shall be paid within 30 days after the rendering of the said final invoice or credit memorandum, by Networks to the Customer, if the amount already paid by the Customer exceeds the Actual Cost of the Non-Poolable Work (plus applicable taxes), or by the Customer to Networks, if the amount already paid by the Customer is less than the Actual Cost of the Non-Poolable Work (plus applicable taxes).

15. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 12 and 14 above, the Customer agrees to pay Networks' Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Networks will obtain the Customer's approval prior to Networks' authorizing the purchase of materials or the performance of work that will attract Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Networks will not be liable to the Customer as a result thereof. The Customer shall pay any prior-approved Premium Costs within 30 calendar days after the date of Networks' final invoice therefor, billable at the end of the project. Interest shall be payable at the rate of 18 per cent per year on all overdue payments. The obligation to pay any amount hereunder shall survive the termination of the Agreement.

16(a) If the Project is cancelled, the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Networks, the Customer shall pay Networks' Actual Costs incurred on and prior to the date that the Project is cancelled or the

Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Networks that it is cancelling or deferring the Project, Networks shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Networks shall deduct the actual costs of those individual items of materials being purchased by Networks from the Actual Costs referred to above.

If Networks does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Networks, the Customer shall have the right to require Networks, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Networks's Actual Costs provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral;

(ii) where all or part of the materials have been received by Networks but have not been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Networks's Actual Costs provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iv) where all or part of the materials have been received by Networks and have been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Networks's Actual Costs; and (B) the date that Networks removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any costs associated with the installation and the removal of the materials that have been installed by Networks.

The Customer shall pay Networks' Actual Costs which become payable under this Section within 30 calendar days after the date of invoice.

16(b). If the Customer wishes to defer the Project, the Parties will negotiate the terms of such deferral.

17. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Networks to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement, the Customer shall remain obligated to pay the amounts thereafter payable pursuant to Sections 12, 13, 14, 15 and 16 by the purchaser, lessee or other third party in the case of a transfer or disposition. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated to pay the amounts payable pursuant to Sections 12, 13, 14 and 15 for the said time period.

18. The Customer, whenever required by Networks to do so, shall furnish security satisfactory to Networks for the performance by the Customer of its obligations for pooled and non-pooled costs under the Agreement, and shall maintain the security in full force and effect during the continuance of the Agreement. The security must be in a form acceptable to Networks and may be an irrevocable letter of credit given by a bank chartered in Canada, a surety bond given by a surety company acceptable to Networks, negotiable bonds satisfactory to Networks or a cash deposit. The security provided shall not exceed the remaining amounts owing in respect of the Non–Pool Work and Transformation Connection Pool Work and/or Line Connection Pool Work less any capital contributions.

The Customer, if not in default under the Agreement shall be entitled to the interest payable on negotiable bonds held as security or the interest on cash deposits at the prevailing rate paid by Networks on cash deposits. Where the Customer has furnished any of the forms of security hereinbefore specified, the Customer if not in default as aforesaid shall have the right at any time to substitute for the security any other of the forms of security acceptable to Networks. If at any time the security furnished to Networks becomes unsatisfactory to Networks, the Customer upon request of Networks shall promptly furnish security, within fifteen (15) Business Days of receipt of notice, that is satisfactory to Networks. Security held in regards to the Agreement shall be returned to the Customer once obligations are fulfilled.

Upon or any time after the occurrence or deemed occurrence of an Event of Default and the expiry of the rectification period set forth in Section 23, Networks may do any one or more of the following: (i) exercise its rights and remedies as a secured party with respect to all security, including any such rights and remedies under Applicable Laws then in effect; (ii) exercise its rights of set-off against any and all property of the Customer in the possession of Networks or its agent; (iii) draw on any outstanding letter of credit issued for its benefit; and (iv) liquidate all security then held by or for the benefit of Networks free from any claim or right of any nature whatsoever of the Customer, including any equity or right of purchase or redemption by the Customer. Networks shall apply the proceeds of the collateral realised upon the exercise of any such rights or remedies to reduce the Customer's obligations under the Agreement (the Customer remaining liable for amounts owing to Networks after such application), subject to Networks' obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

Part C:

19. In the event that the Transformation Connection Service Rate or the Line Connection Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate or the Line Connection Service Rate to agree to a new mechanism. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, they shall submit to arbitration, in accordance with the requirements of the Transmission System Code (or the Connection Agreement attached thereto); or if there is no arbitration provision in the Transmission System Code (or the Connection Agreement attached thereto), to the requirements of the *Arbitration Act* (Ontario), as amended, to settle on a new mechanism. The decision of the arbitrator shall be binding on each party with no right of appeal.

The terms of reference of the arbitration shall be to identify a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate or the Line Connection Service Rate.

Any settlement on a new mechanism pursuant to this Section 19 shall apply retroactively from the date on which the Transformation Connection Service Rate or the Line Connection Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate or the Line Connection Service Rate in effect prior to the effective date of any such changes.

20.1 The Customer:

(a) shall not Transmit or Distribute electricity using the Customer's Facilities to any load now or hereafter supplied from Networks' Facilities or Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities, as the case may be, until the date that:

  (i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
  (ii) Networks requires Networks' Facilities to provide transmission services to other Customers or the affected third party requires the Third Party Facilities to supply its customers.

(b) shall not permit any third party to transmit or distribute electricity using or by connecting to the Customer's Facilities or in any other manner, to any load now or hereafter supplied from Networks' Facilities or the Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities until the date that:

  (i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
  (ii) Networks requires Networks' Facilities to provide transmission services to other customers or the affected third party requires the Third Party Facilities to supply its customers.

(c) shall not supply new load growth using the Customer's Facilities or the Third Party Facilities when Networks has spare capacity available at Networks' Facilities to supply such load; and if it does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates by paying as if the new load were supplied from the Networks Facilities. Notwithstanding the foregoing, the Customer will not owe any amounts to the Networks, if the Customer can demonstrate to the satisfaction of the Networks, acting reasonably, that it would have been uneconomic or inefficient for the Customer to supply the load growth in question using Networks' Facilities.

(d) shall cause the purchaser, lessee or other third party to whom the Customer sells, leases, or otherwise transfers or disposes of the Customer's Facilities to enter into an assumption agreement with Networks to assume all of the Customer's obligations under this Section 20.1.

20.2 Nothing contained within this Agreement, including, without limiting the generality of the foregoing, Section 20.2, shall preclude, prevent, prohibit or operate as a waiver of any of the Parties' rights to:

  (i) make application to the OEB;
  (ii) participate in any hearings before the OEB; or
  (iii) make any appeals to a Court of competent jurisdiction regarding any decision by the OEB,

with respect to any matter, issue, thing, interpretation, consideration or consequence whatsoever that is related to:

  A. the Transmission or Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed electricity distributor by the Customer or by a third party using the Customer's Facilities to supply said load;
  B. the interpretation or application of Section 20.1 above; and
  C. the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks facilities other than Networks' Facilities or from facilities of any licensed electricity distributor by any other Customer or by a third party.

20.3 Section 20.1 shall be subject to and applied in accordance with any Order or decision made by the OEB or any court with respect to any matter, issue, thing, interpretation, consideration or consequence that relates to:

  (i) the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed distributor by the Customer or by a third party using the Customer's Facilities to supply said load; and
  (ii) the terms and conditions of Section 20.1.

20.4 With respect to any Order or decision of the OEB or a court relating to the Transmission or Distribution of electricity to any load now or hereafter supplied from facilities other than Networks' Facilities or from the facilities of any licensed distributor by any Customer other than by the Customer or by a third party, the parties acting reasonably shall agree in writing as to application of said Order or decision to Section 20.1 and to any amendments thereto.

20.5 Sections 20.1 to 20.4 inclusive shall survive the termination of this Agreement and will be terms of any Connection Agreement or such other agreement as required by the Transmission System Code that is applicable to the owner and/or operator of the Customer's Facilities.

Part D: Easement

21. If specified in Schedule "A" that an easement is required, the Customer shall or the Customer shall cause the third party specified in Schedule "A" to grant an easement to Hydro One substantially in the form of the easement that will be attached hereto as Appendix "C", if required, for the property described as the Easement Lands in Schedule "A" by no later than the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

The above Easement shall be for a term of 80 years commencing on the In-Service Date provided that in the event that Networks removes the asset that is the subject of the Easement during the 80-year period, Networks shall surrender the Easement at that time. With respect to the Easement, after the expiry of the 80-year period, the parties agree to enter into good faith negotiations for an extension of the Easement term, if one or the other, or both, of the parties so request. Subject to the foregoing, the Easement shall survive the termination of the Agreement.

Part E: Events of Default

22. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 12, 13, 14, 15 or 16 within the time stipulated for payment;
(b) breach by the Customer or Networks of any Material term, condition or covenant of the Agreement;
(c) the making of an order or resolution for the winding up of the Customer or of its operations or the occurrence of any other dissolution or liquidation proceeding instituted by or against the Customer; and

23. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in section 22(c) of the Agreement, for which no notice is required to be given by Networks), Networks shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Networks' reasonable satisfaction within the 30 calendar day period, Networks may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Networks under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by the Customer pursuant to Sections 12, 13, 14, 15 and 16.

24. Upon the occurrence of an Event of Default by Networks hereunder, the Customer shall give Networks written notice of the Event of Default and shall allow Networks 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Networks' sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

25. All rights and remedies of Networks and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Networks and the Customer respectively at law or in equity, and any one or more of Networks' and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Networks or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

In addition to any other remedy provided hereunder, all overdue amounts that are outstanding for longer than 30 days shall bear interest at 18% per annum.

Part F: Connection Agreement and Transmission System Code

26. In the event that the Connection Agreement referred to in Section 5(c) is entered into prior to the effective date of the Transmission System Code, the Parties shall make such amendments to the Connection Agreement as may be necessary to ensure compliance with the mandatory requirements of the Transmission System Code in effect on the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act*, S.O. 1998, c. 15) is proclaimed.

27. Until Networks' has published and the Ontario Energy Board has accepted Networks' procedure and methodology for determining the requirement for a capital contribution in accordance with Section 4.1 of the *Transmission System Code*, any Capital Contributions paid by the Customer under the terms of this Agreement are subject to adjustment with such adjustment to be solely based on the procedure and methodology accepted by the OEB.

Part G: Liability and Force Majeure

28(a) Other than for sums payable under the Agreement, the Customer shall only be liable to Networks and Networks shall only be liable to the Customer for any damages that arise directly out of the willful misconduct or negligence in meeting their respective obligations under the Agreement.

Despite the foregoing, neither Party shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential or incidental damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

For any damage suffered by the Customer prior to the Transmission System Code coming into effect, the total liability of Networks to the Customer for any and all claims for damages under the Agreement whether it arises by statute, contract, tort or otherwise, will not exceed the Actual Cost of the Networks' Connection Work. Once the Transmission System Code comes into effect, Appendix 1, Article 8 of the Transmission System Code shall apply.

This provision shall survive the termination of the Agreement.

28(b). Neither party shall be considered to be in default in the performance of its obligations under the Agreement, except obligations to make payments with respect to amounts already accrued, to the extent that performance of any such obligation is prevented or delayed by any cause, existing or future, which is beyond the reasonable control of, and not a result of the fault or negligence of, the affected party ("Force Majeure") and includes, but is not limited to, system operating conditions mandated by the IMO, strikes, lockouts and any other labour disturbances and manufacturer's delays for equipment or materials required for the Networks Connection Work. The non-affected party shall be relieved of any obligation hereunder during the continuation of the event of Force Majeure.

If a party is prevented or delayed in the performance of any such obligation by Force Majeure, such party shall immediately provide notice to the other party of the circumstances preventing or delaying performance and the expected duration thereof. Such notice shall be confirmed in writing as soon as reasonably possible. The party so affected by the Force Majeure shall endeavour to remove the obstacles which prevent performance and shall resume performance of its obligations as soon as reasonably practicable, except that there shall be no obligation on the party so affected by the Force Majeure where the event of Force Majeure is a strike, lockout or other labour disturbance.

Part H: General

29. No amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

30. The failure of any party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

31. Each party acknowledges and agrees that it has participated in the drafting of the Agreement and that no portion of the Agreement shall be interpreted less favourably to either party because that party or its counsel was primarily responsible for the drafting of that portion.

32. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, South Tower, 10th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Networks, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice will be deemed to be received on the date of the fax if received before 3 p.m. or on the next business day if received after 3 p.m. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

33. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and, subject to Section 19, the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of the Agreement.

34. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

35. The Customer shall provide Networks with a copy of the Customer's final monthly bills associated with Networks' Facilities and/or the Customer's Facilities or authorize the IMO to provide Networks with same. Networks agrees to use this information solely for the purpose of the Agreement.

36. The obligation to pay any amount due and payable hereunder, including, but not limited to, any amounts due under Sections 12, 13, 14, 15 or 16 shall survive the termination of the Agreement.

Appendix "A": Definitions

Throughout the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Cost" means Networks' charge for equipment, labour and materials at Networks' standard rates plus Networks' standard overheads and interest thereon.

"Actual Incremental Transformation Connection Revenue" means the actual amount of transformation connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Actual Incremental Line Connection Revenue" means the actual amount of line connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws", means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any governmental or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 6(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Available Capacity" is that portion of the existing capacity on Networks' Facilities that can effectively and economically serve the Customer's peak load and is as specified in Schedule "B" of the Agreement.

"Base Load Trigger Point" is as specified in Schedule "B" of the Agreement and was determined using the following formula:

Base Load Trigger Point = 3 yr. Avg. PLI * Available Capacity
With:
PLI = [(sum of Twelve Monthly Peaks)/Annual Peak*12]

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Connection Agreement" has the meaning set forth in the Transmission System Code.

"Connection Point" means the point where the New or Modified Facility is connected to Networks' transmission system.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the Transmission System Code, and includes, but is not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer. In addition to the foregoing, Customer's Facilities may include any other assets specified in Schedule "A" of the Agreement.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Distribute" has the meaning ascribed thereto in the *Electricity Act, 1998*.

"Emergency" has the meaning set forth in the Transmission System Code.

"Good Utility Practice" has the meaning set forth in the Transmission System Code.

"Guaranteed Transformation Connection Revenue" means the minimum amount of transformation connection revenue specified in Schedule "B" attributable to the Load to be received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B".

"Guaranteed Line Connection Revenue" means the minimum amount of line connection revenue specified in Schedule "B" of the Agreement attributable to the Load to be received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Guaranteed Revenue Date" means, for the purposes of Section 2 of the Terms and Conditions, the date specified in Schedule "B" of the Agreement.

"IMO Rules" means the Independent Market Operator (IMO) administered Market Rules, including, but not limited to Chapter 6 thereof.

"In Service Date" means the date that the IMO has approved the final connection of the New or Modified Facility.

"Incremental Load" is determined using the following formula:

[(sum of Twelve Monthly Peaks) – (Base Load Trigger Point *12]

"Line Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on Open Access (being the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act, S.O. 1998, c. 15)* comes into force.

"**Line Connection Service Rate"** means Networks' line connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Networks Connection Work" means the work to be performed by Networks which is described in Schedule "A" of the Agreement.

"Networks' Facilities" means collectively the Networks' Facilities – LV and the Networks' Facilities – HV.

"Networks' Facilities – HV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of more than 50 kilovolts.

“Networks’ Facilities – LV” means the facilities owned by Networks specified in Schedule “A” of the Agreement that convey electricity at voltages of 50 kilovolts or less.

“Networks’ Property(ies)” means any lands owned by Networks in fee simple or where Networks now or hereafter has obtained easement rights.

“New or Modified Facility” means the facilities specified in Schedule “A” of the Agreement.

“Premium Costs” means those costs incurred by Networks in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Networks’ employees, agents and contractors perform work on overtime as opposed to during normal business hours.

“Ready for Service Date” means the date upon which the Networks Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer’s disconnect switches must be commissioned prior to this date in order to use them as isolation points.

“Third Party Facilities” means any and all equipment, elements, and facilities of any kind whatsoever owned by someone other than the parties to this connection agreement and that are connected to Networks’ transmission system.

“Transformation Connection Pool” is as defined or referenced in Networks’ transmission rate schedules approved by the OEB on Open Access (being the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule “A” of the *Energy Competition Act, S.O. 1998, c. 15)* comes into force.

“**Transformation Connection Service Rate”** means Networks’ transformation connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

“**Transmission Rate”** has the meaning set forth in the form of Connection Agreement attached to the Transmission System Code.

“Transmission System Code” means the code of standards and requirements issued by the OEB on July 14, 2000, as it may be amended from time to time, setting forth mandatory terms, conditions and obligations regarding connections between the facilities of distributors and the facilities of transmitters in accordance with the requirements of the *Ontario Energy Board Act*, *1998,* including mandatory required terms and conditions for Connection Agreements.

“Transmit” has the meaning ascribed thereto in the *Electricity Act, 1998*.

Appendix "B": Access Provisions

1. When the Customer's staff, its contractors, or agents work at Networks' Facilities or site, Networks' safety and environmental requirements shall be observed by such staff, contractors and agents. As a minimum, all Applicable Laws shall govern such work.

2. The Customer's staff, its contractors, or agents working at Networks' Facilities or site shall be qualified to work around electrical hazards.

3. The Customer's staff, its contractors, or agents shall be entitled to access Networks' Facilities or site, and Networks will grant such access, to carry out work at all reasonable times on reasonable prior notice to Networks, subject to Networks' policies and procedures.

4. If the Customer wishes to have access to Networks' Facilities, the Customer shall notify Networks of the particular work to be undertaken and of the date and time when it proposes to access the relevant Facilities, subject to Networks' policies and procedures. Networks shall not unreasonably withhold access to its Facilities.

5. At any time when the Customer or its representatives are on or in Networks' site, the Customer and its representatives shall:

(a) use all reasonable precautions not to damage or interfere with Networks' site and Facilities;
(b) observe Networks' requirements for reporting occupational health and safety, electrical safety, environmental requirements, technical requirements, and matters of industrial relations; and
(c) neither ask questions, nor give any direction, instruction or advice to any person involved in operating or maintaining Networks' site or Facilities, other than the person whom Networks has designated for that purpose.

6. If the Customer or its representatives cause any loss or damage when given access to Networks', the Customer or its representative shall promptly advise Networks' controlling authority of the loss or damage.

7. The Customer shall not, and shall ensure that its representatives do not, intentionally interfere with any of Networks' Facilities in or on its sites. The Customer shall use reasonable efforts not to cause loss or damage to Networks' Facilities. If the Customer interferes with any of Networks' Facilities, it shall indemnify Networks for reasonable costs and expenses incurred from any resulting loss or damage.

8. In an emergency, Networks may, as far as reasonably necessary in the circumstances, have access to and interfere with the Customers' Facilities. Networks shall use reasonable efforts not to cause loss or damage to the Customer's Facilities. If Networks interferes with any of the Customer's Facilities, it shall indemnify the Customer for reasonable costs and expenses incurred from any resulting loss or damage.

9. Where the Customer requests assistance from Network beyond routine OM&A activities, the Customer shall pay Networks its Actual Costs related to the Customer's staff, contractors or agents accessing Network's Facilities or sites, including, but not limited to, the cost of having a Networks representative accompany the Customer's staff, contractors, or agents accessing Network's Facilities or sites in accordance with the invoices rendered by Networks.

10. The Customer shall indemnify and save harmless Networks from and against all liabilities, damages, suits, claims, demands, costs, actions, proceedings, causes of action, losses, expenses and injury (including death) of any kind or nature whatsoever (the "causes of action") resulting from, caused by or in any manner connected with installed Customer equipment on Networks' Facilities or sites or Customer's staff, its contractors, or agents accessing Network's Facilities or sites including, but not limited to:

(a) causes of actions arising out of health and safety violations or environmental spills;
(b) costs incurred by Networks having to pay other customers due to interruptions caused by the Customer;
(c) damage to Networks equipment;
(d) incremental costs and expenses incurred by Networks related to the Customer's equipment installations, removals, relocations, upgrades, or any other Customer work.

except to the extent that the "causes of action" are caused by the negligence or willful misconduct of Networks.

11. Where Networks staff, contractors, or agents require access to the Customer's Facilities or site, clauses 1 to 10 will apply reciprocally.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2-STAFF-238

Ref 1: Exhibit 2B, Section E7.4, Page 27

<u>Preamble</u>**:**

Table 15: Historical & Forecast Program Costs by Segments includes costs for Hydro One Contributions segment for the 2025 to 2029 forecast period totalling $103M.

QUESTION (A):

a) For each year of the forecast period please provide a list of projects and forecast costs, as well as a categorization of the costs as construction costs or load true-up.

RESPONSE (A):

Table 1: Hydro One Contribution Project List and Annual Expenditures Forecasted Over 2025-2029

Project or Subsegment	Categorization	Forecast				
		2025	2026	2027	2028	2029
Downsview SS	Construction Costs		0.6	1.7	2.9	0.6
Sheppard TS Bus Expansion	Construction Costs		0.5	4.5	5.0	5.0
Manby TS DESN Reconfigurations	Construction Costs		0.5	3.5	4.0	4.0
Basin TS - T3/T5 Upgrade	Construction Costs	1.6				
Duplex TS - T1/T2 Upgrade	Construction Costs	1.6				
Leslie TS - T1 Upgrade	Construction Costs	0.3				
Strachan TS - T14 Upgrade	Construction Costs	0.8				
Scarborough TS - T23 Upgrade	Construction Costs		0.4			
Strachan TS - T13/T15 Upgrade	Construction Costs			1.6		
Duplex TS - T3/T4 Upgrade	Construction Costs				1.6	
Carlaw TS - T1/T2 Upgrade	Construction Costs					1.6
True-Up Costs	Construction and/or True-Up Costs	3.5	2.0	1.3	1.3	1.3
Total	**N/A**	**7.8**	**4.0**	**12.6**	**14.8**	**12.5**

QUESTION (B):

b) For each project please provide:

i. A copy of the agreement between Toronto Hydro and Hydro One.

ii. Load realized for each year of the agreement to date.

iii. Past invoices and calculations from Hydro One for true-payments.

iv. Where there is a load true-up payment due in the period, please provide estimates and calculations from Hydro One for the true-up payment. In the absence of estimates from Hydro One, please provide Toronto Hydro's detailed calculations of the true-up payment.

RESPONSE (B):

Parts (i), (ii), and (iii):

As shown in Table 2 below, all projects in the Hydro One Contributions segment for the 2025-2029 period are presently in the planning phase. In this phase, the project has been proposed by one or both of Toronto Hydro and/or Hydro One, but neither scope of work nor estimates have been developed by Hydro One. Similarly, no agreements or invoices have been provided by Hydro One at this time.

As mentioned in 2B-E7.4 at page 27 of Toronto Hydro's application,[1] the purpose of the Reactive Hydro One Contributions & True-Up Costs subsegment is "to support expansion projects or true-up costs unforeseen at the time of the application". As a result, there are no agreements or invoices in place at this time for this subsegment.

Table 2: Status of Hydro One Contribution Projects Proposed for the 2025-2029 Period

Project	Status
Downsview SS	In Planning Phase
Sheppard TS Bus Expansion	In Planning Phase

[1] Updated January 29, 2024

Project	Status
Manby TS DESN Reconfigurations	In Planning Phase
Basin TS - T3/T5 Upgrade	In Planning Phase
Duplex TS - T1/T2 Upgrade	In Planning Phase
Leslie TS - T1 Upgrade	In Planning Phase
Strachan TS - T14 Upgrade	In Planning Phase
Scarborough TS - T23 Upgrade	In Planning Phase
Strachan TS - T13/T15 Upgrade	In Planning Phase
Duplex TS - T3/T4 Upgrade	In Planning Phase
Carlaw TS - T1/T2 Upgrade	In Planning Phase
Reactive Hydro One Contribution & True-Up Costs	Forecasted

Hydro One has not provided cost estimates for potential future load true-up payments. However, Toronto Hydro has anticipated the potential for load true-up payments for the following projects: Copeland TS Phase 1, Horner TS Expansion, and Runnymede TS Expansion. In the absence of precise information regarding how the load is going to materialize in these areas, Toronto Hydro developed a forecast on a best effort basis using the historical Copeland TS and Cecil TS load true-up payments in the 2020-2024 period as described in its response to 2B-Staff-237. The utility used the average MW of load trued-up (48 MW), the average of $k per MW per year ($3.2k /MW-year), and a 20-year period to derive an estimate of $3.07 million per station, resulting in the $9.4 million forecast (including inflation). Toronto Hydro would like to emphasize that the actual true-ups are entirely contingent on the rate of customer load materialization, which is outside of the utility’s control. Any variances between the forecasted true-ups noted above, and the actual true-ups that take place in the next rate period would be reconciled as part of the proposed Demand-Related Variance Account – Expenditures Sub-Account.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-239

References: Exhibit 2B, Section E6.7.1, Page 2

Preamble:

Under worst performing feeders Toronto Hydro states: "The objective of this segment is to identify feeders performing poorly over a rolling 12-month period and perform work in an effort to mitigate further interruptions."

QUESTION (A):

a) How does Toronto Hydro identify and rank feeders that are performing poorly?

RESPONSE (A):

Toronto Hydro defines and prioritizes poorly performing feeders as described in Exhibit 2B, Section E6.7 at pages 2, 16, and 24.

QUESTION (B):

b) What is the reliability threshold for being included in the Worst Performing list, or is the Worst Performing feeder list comprised of a fixed number of feeders?
   i. If a fixed number, what is that number?
   ii. If a threshold, what is that threshold?
   iii. If a feeder is scheduled to be addressed under either the Back Lot, Box Frame or other programs, will another feeder be added to the Worst Performing Feeder list to replace it?

RESPONSE (B):

There is no fixed number of “Worst Performing Feeders”. Toronto Hydro considers any feeder that meets the threshold as outlined in the evidence referenced in the response to part (a) to be a “Worst Performing Feeder”.

i. Not applicable

ii. Please see response to part (a).

iii. A feeder remains on the Worst Performing Feeder list as long as it meets the criteria regardless of whether it is being addressed via other programs. Prior to issuing work under the Worst Performing Feeder segment, Toronto Hydro checks existing projects to ensure that any proposed asset replacements are not being targeted under any other programs.

QUESTION (C):

c) Please provide the SAIDI and SAIFI for the worst performing feeders over the last 10 years, and the number of feeders that were on the Worst Performing Feeder list for each of the last 10 years.

RESPONSE (C):

Please see Table 1 and Figure 1 below.

Table 1: SAIDI and SAIFI for FESI-7 and FESI-6 Large Customer feeders 2014-2023

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total SAIFI	0.42	0.51	0.43	0.20	0.30	0.19	0.41	0.33	0.40	0.43
Total SAIDI	14.38	17.31	8.97	4.58	6.90	4.25	10.07	6.89	7.85	9.96

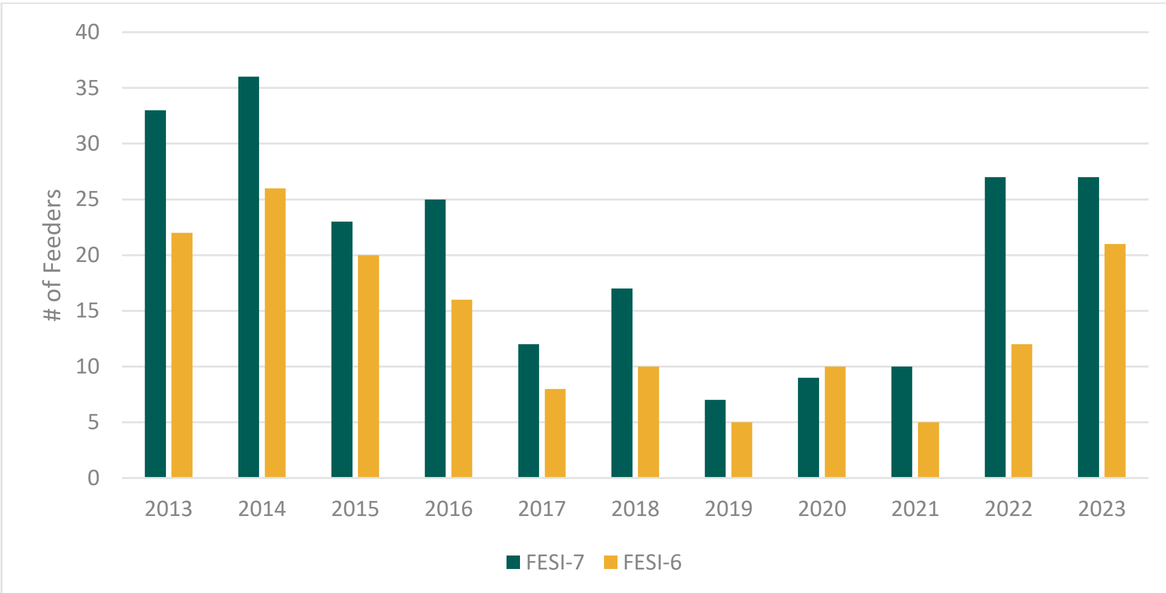


Figure 1: Number of FESI-7 and FESI-6 Large Customer Feeders 2013-2023[1]

QUESTION (D):

d) Please provide the average capital and OM&A spent to improve performance of the worst performing feeders, per year, for the last 10 years. Please discuss the effectiveness of these investments in terms of improved feeder performance.

RESPONSE (D):

Please see Table 2 below for the annual capital and OM&A spending on worst performing feeders.

Table 2: Annual Capital and OM&A Worst Performing Feeder Investments ($ Millions)

Year	Capital	OM&A
2014	3.08	0.63
2015	3.03	1.16
2016	4.09	1.86
2017	2.97	1.36

[1] In drafting this response, Toronto Hydro discovered that Figure 14 from Exhibit 2B, Section E6.7 at page 20 included some incorrect values. The correct values are included here.

Year	Capital	OM&A
2018	3.87	1.08
2019	3.72	1.09
2020	4.19	1.01
2021	3.67	1.10
2022	3.75	1.38
2023	5.71	1.84

On average over the last 10 years, Toronto Hydro has spent $3.8 million in capital and $1.3 million in OM&A investments per year on worst performing feeders. The performance of this program is measured largely by how many "Worst Performing Feeders" there are in a given calendar year. The annual number of FESI-7 and FESI-6 Large Customer feeders are a small subset of the more than 1,500 total feeders that make-up Toronto Hydro's distribution system and have been gradually trending down over the last 10 years as shown in Figure 1 in part (a). There was a noticeable increase in the number of FESI-7 and FESI-6 Large Customer feeders in 2022 and 2023. This is attributed to the increased sensitivity of the Outage Management System in recording interruptions, which is further explained in Exhibit 1B, Tab 2, Section 4 "Reliability Performance".

The Worst Performing Feeder program provides a near-term and cost-effective solution to address emerging issues on targeted feeders which are experiencing a disproportionate number of interruptions. Through this segment, Toronto Hydro replaces assets identified as having a risk of imminent failure before they would be scheduled for replacement under planned renewal programs, mitigating the risk of additional outages for customers already experiencing below-average reliability.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-240

Reference: Exhibit 2B, Section E6.7.1, Page 23

Preamble:

Figure 15: 2019-2029 Reactive Capital Work Requests Actuals and Forecast shows that the number of work requests decreased from 2019 to 2021 and increased slightly in 2022. Toronto Hydro predicts a steady level of work requests over the forecast period.

QUESTION (A):

a) Please explain the trend of work requests in this budget category.

RESPONSE (A):

As described in Exhibit 2B, Section E6.7, the work under the Reactive Capital segment is unplanned, unpredictable and non-discretionary. Hence, the data from year to year can vary significantly since the work is demand driven. The consistent decline in the number of work requests from 2019 to 2021 primarily stems from a reduction in the instances of oil leaks necessitating reactive transformer replacements. As Toronto Hydro continues to substitute non-submersible/non-stainless-steel transformers with stainless steel ones through its renewal programs, Toronto Hydro anticipates this decline in failures to persist and stabilize. Conversely, the incidence of deficiencies prompting reactive pole replacement requests has been increasing, attributed to the increasing number of poles surpassing their useful life and experiencing deteriorating asset condition.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-241

Reference: Exhibit 2B, Section E7.1, Page 1

QUESTION (A):

a) Confirm that the System Enhancements program will reduce the consequence of individual asset failures in many or most cases.
   i. If not confirmed, explain the purpose of the program, since it will not reduce the probability of asset failures.

RESPONSE (A):

Confirmed. Please refer to Exhibit 2B, Section E7.1, Page 5 for specific information on this topic.

Note that Toronto Hydro respectfully disagrees with the premise of part (i) of OEB Staff's question. The System Enhancements program contains a variety of field technology investments which will deliver benefits beyond reducing consequences of failure. The proposed System Observability segment of the program includes adding more sensors, relays and monitoring technology at specific nodes across the distribution grid. Gradually, these technologies will help the utility advance three core capabilities:

1. **Enhanced Fault Location:** Locating faults and other system disturbances faster and more efficiently in order to improve reliability and operate the grid more cost-effectively.
2. **Enhanced Decision-making and Grid Optimization:** Providing greater insight into real-time feeder and asset loading, condition, and other relevant operating characteristics. This assists the utility in managing short- and long-term uncertainty as well as driving optimal real-time operational decisions and longer-term investment planning decisions.
3. **Enhanced Asset Diagnostics:** Greater visibility into high-risk and previously hard-to-monitor assets will improve asset diagnostics, mitigating the risk of asset failure and impacts to personnel safety and environmental damage.

For more information on the multi-faceted benefits of Toronto Hydro's System Enhancements program, please refer to Exhibit 2B, Section E7, and the Intelligent Grid Section of Toronto Hydro's *Grid Modernization Strategy* (Exhibit 2B, Section D5.2.1).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-242

Reference: Exhibit 2B, Section E7.1, Page 1

<u>Preamble:</u>

The proposed Contingency Enhancement investment represents a $113M (568%) increase in segment spending.

QUESTION (A):

a) Please confirm that this increase is necessary to maintain rather than improve system reliability.
    i. If confirmed, please explain how Toronto Hydro has been able to significantly reduce its outage durations over the historical period despite a much slower pace of spending in this segment.
    ii. If not confirmed, please reconcile Toronto Hydro’s strategic decision to increase spending in this segment by 568%, given its residential customers’ preference to maintain reliability and control costs.

RESPONSE (A):

As mentioned in Exhibit 2B, Section E2, "Although Toronto Hydro’s renewal and modernization efforts over the last decade have led to improvements in reliability performance that began in the mid-2000s, more recently this performance has plateaued." The investments in the Contingency Enhancement segment support Toronto Hydro’s complimentary goals of maintaining reliability during the 2025-2029 period while improving reliability and resiliency for the longer-term. For more information, please refer to 2B-Staff-175.

QUESTION (B):

b) Toronto Hydro indicates elsewhere in the Application that Toronto Hydro has already implemented majority of its contingency enhancement plans. Has Toronto Hydro undertaken a benefit-cost analysis demonstrating that the proposed accelerated spending to rapidly complete this plan provides offsetting benefits of equal or greater value to customers?

   i. If yes, please provide the benefit-cost analysis documentation.
   ii. If no, please explain why not.

RESPONSE (B):

Toronto Hydro has not indicated that the majority of its contingency enhancement plans have been implemented. For a discussion regarding benefit-cost analysis related to modernization initiatives, including Contingency Enhancement, please refer to 2B-Staff-170. Pleaser also refer to 2B-Staff-162 for information on the expected long-term benefits of Fault Location Isolation and Service Restoration (‘FLISR’) implementation.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-243

Reference: Exhibit 2B, Section E7.1.1, Page 2

<u>Preamble:</u>

Toronto Hydro states: "Under the Downtown Contingency, this segment provides for plans to add provisions in the downtown core for incremental Toronto Hydro-controlled back-up supply stations… The planned enhancements will provide N-2 (i.e., two station loss-of-supply issues at the same time) operational capability to address serious loss-of-supply scenarios."

QUESTION (A):

a) Please identify all N-2 loss of supply events that have caused significant Downtown customer outage over the past 5 years.

RESPONSE (A):

For the requested time period, the following are major Downtown loss of supply events in which the station-to-station switchgear ties would have reduced the impact on customers:

- A barge crane contact with HONI overhead transmission line on August 11, 2022. This event is described at pages 17-18 of the referenced section.
- A Charles Station loss of supply event on February 1, 2024. This event occurred subsequent to the filing, and is not included in Table 5 of E7.1.3.2.

QUESTION (B):

b) Please identify all Toronto Hydro service areas where Toronto Hydro is proposing to apply an N-2 planning standard going forward.

RESPONSE (B):

The Copeland-Esplanade project described in the referenced program is Toronto Hydro's only proposed interstation switchgear tie at this time. Please refer to part (c) below for more information on N-2 standards.

QUESTION (C):

c) Please identify any other North American utilities Toronto Hydro is aware of which apply a similar N-2 planning standard and explain the circumstances under which the N-2 standard is applied by these utilities.

RESPONSE (C):

N-2 operational capabilities are a common element of distribution system design across North America. N-2 capability is typically established at the distribution level when serving dense service areas and/or critical loads, such as financial centres, hospitals, and transportation infrastructure. Note, for example, that Toronto Hydro's own Horseshoe distribution system has *de facto* N-2 capabilities, as it is designed such that load can be transferred between stations at the feeder level. This configuration is common for urban and suburban distribution utilities. Another example is the secondary network system which Toronto Hydro operates in parts of its dense urban core. Many other utilities around the world operate similar secondary network systems, as well as other, even more robust network grid systems, which offer a very high degree of reliability for critical loads and dense service areas (e.g., Manhattan) and ComEd.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-244

Reference: Exhibit 2B, Section E7.1.2, Page 4

Preamble:

Toronto Hydro states: “Continues to maintain Toronto Hydro’s Total Recorded Injury Frequency (TRIF) measure and safety objectives by installing remote switching, thereby reducing crew exposure to safety risks associated with manual switching.”

QUESTION (A):

a) Please provide a list of switches that have a known safety issue that are subject to a manufacturer’s recall/bulletin or ESA safety alert or product recall. Include the manufacturer, model, make, number in service and if available, link to the public announcement.

RESPONSE (A):

There are no known safety issues related to manufacturer recalls, bulletins or ESA safety alerts for manual switches currently in Toronto Hydro’s distribution system.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-245

Reference: **Exhibit 2B, Section E7.1.3.1, Page 7**

Preamble:

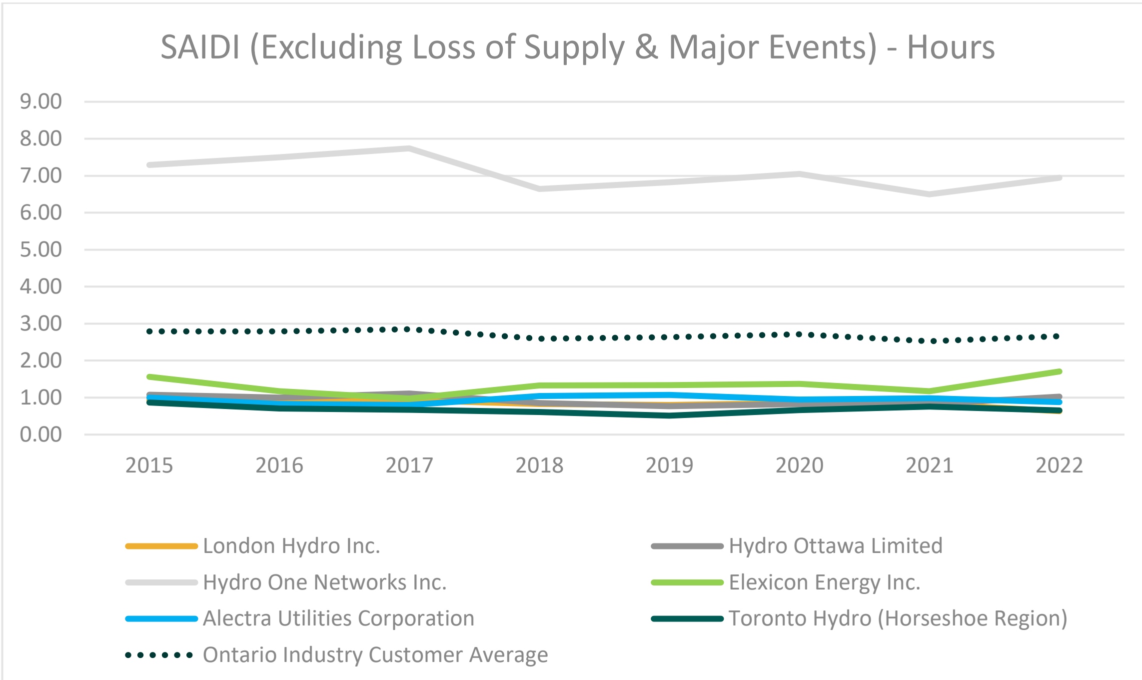
Toronto Hydro states: "This configuration ensures a contingency power source is available for the faulted feeder regardless of whether the fault occurs at the feeder, bus, or station level, effectively reducing the duration of an outage. During the 2018-2022 period, the average duration for outages on feeders with less than three SCADA tie-points was approximately 707 minutes per year per feeder, whereas the average duration of those feeders with three or more SCACA tie-points was approximately 496 minutes."

QUESTION (A):

a) How does Toronto Hydro's SAIDI performance trend for the Horseshoe area compare with the SAIDI trends of its Ontario peers?

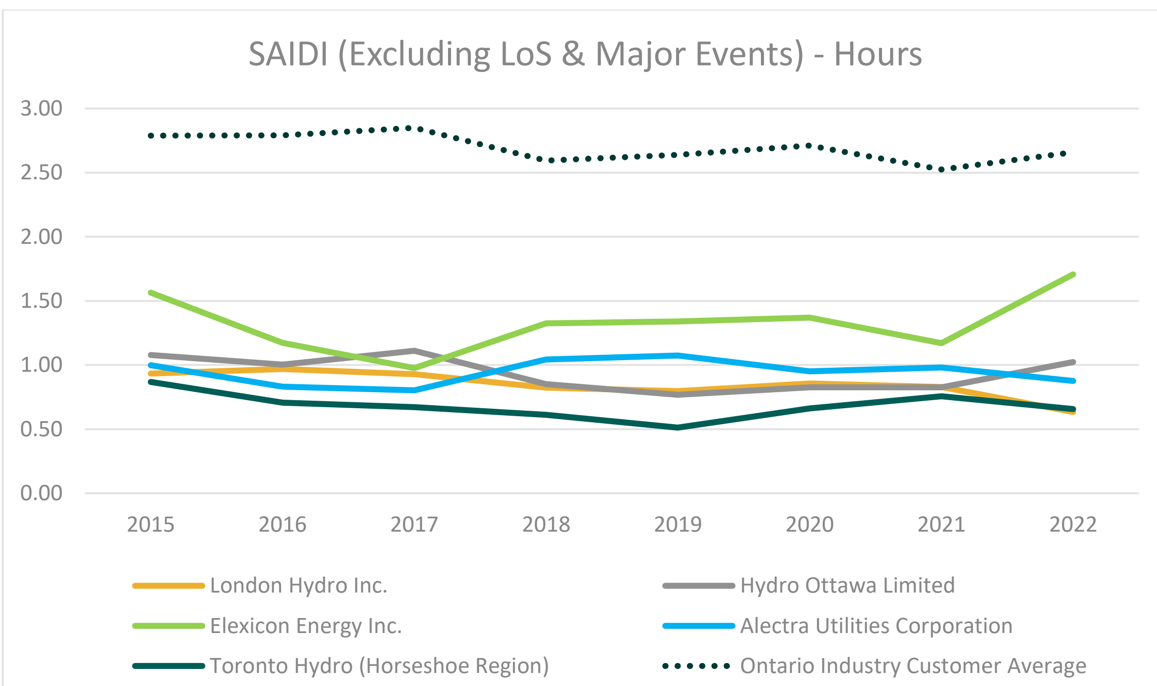
RESPONSE (A):

As seen in Figures 1 and 2 below, Toronto Hydro's Horseshoe Region has shown strong performance in SAIDI (Excluding Loss of Supply and Major Events) in comparison to its peer distributors, and is generally within the range of SAIDI performance of other large distributors in Ontario. This reflects Toronto Hydro's commitment over the years of delivering safe and reliable power to our customers, minimizing the duration of interruptions.



1 **Figure 1: SAIDI Industry Comparison Including HONI (Excluding Loss of Supply and Major Events)**

2



3 **Figure 2: SAIDI Industry Comparison Excluding HONI (Excluding Loss of Supply and Major Events)**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-246

Reference: Exhibit 2B / Section E7.1.3.1 / p. 8

<u>Preamble:</u>

Toronto Hydro states: "This work is expected to result in an average of approximately 12.6 percent reliability improvement on the 94 feeders where SCADA switch installation work is expected to take place. This will result in an average yearly total customer minute out (CMO) reduction from 180,113 during the 2018-2022 period to an improved average yearly total CMO of 162,889. The potential SAIDI improvement as a result of this work is expected to be approximately 0.022 minutes per feeder per year."

QUESTION (A):

a) Please provide the cost in dollars per estimated "customer minute out" reduction for this project and all other projects that reduce customer outage minutes.

RESPONSE (A):

Based on the proposed 2025-2029 Contingency Enhancement Program ($133 million cumulative), Toronto Hydro estimates the CMO reduction over the rate period (2025-2029) to be approximately 2.6 million minutes, resulting in an effective cost of $50.95 per CMO reduced over 2025-2029. With an expected useful life of 30 years (Exhibit 2A, 2022 Depreciation Study, Pg. 48/383), considering average historical reliability performance and forecasted increases in number of customers (Exhibit 3, Tab 1, Schedule 1), the lifetime CMO reduction is estimated to be 37 million minutes, with an effective cost of $3.58 per CMO reduced over the lifetime of the assets (i.e., SCADA switches and reclosers).

Refer to Exhibit 1B, Tab 3, Schedule 1, Page 56-62 along with respective Table 22, 23, 24 and 25 for a benefit-cost analysis applying to all of Toronto Hydro's reliability-related investments in the 2025-2029 Distribution System Plan.

QUESTION (B):

b) Please explain how making incremental investments to materially reduce CMOs aligns with Toronto Hydro's stated strategy of making necessary expenditures to maintain rather than materially improve reliability.

RESPONSE (B):

Please refer to 2B-Staff-242 and 2B-Staff-175.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-247

Reference: Exhibit 2B, Section E7.2.1, Page 1

Preamble**:**

Toronto Hydro states: "The NWS strategy for the 2025-2029 period is focused on being flexible and adaptable to help system planners respond to load growth while navigating the underlying uncertainty that stems from changing demand patterns and increased reliance on electrification. This strategy builds on Toronto Hydro's experience utilizing DERs to reduce peak demand, helping to defer grid expansions or, in most cases, avoid grid expansions should demand not materialize as expected (e.g., lower than expected demand, fluctuating demand)."

QUESTION (A):

a) Please quantify by technology type the alignment of energy production by the DERs presently installed in Toronto Hydro's service area with the summer and winter peak demand hours on Toronto Hydro's distribution system.

RESPONSE (A):

As outlined in Exhibit 2B Section E7.2, Toronto Hydro plans for and procures third-party capacity in the form of dispatchable demand response to complement standard system planning approaches. The utility is unable to provide the requested data as Toronto Hydro does not procure energy (kWh) from DERs.

QUESTION (B):

b) Given the response to the prior question, please describe the effectiveness of Toronto Hydro's existing DER portfolio in mitigating capacity constraints encountered by Toronto Hydro during summer and winter peak demand periods.

RESPONSE (B):

Toronto Hydro does not control third-party owned, non-dispatchable DERs and thus cannot rely upon these assets to meet system needs (capacity needs or otherwise) on demand. Until a DER owner enters into a binding agreement with Toronto Hydro (via LDR procurement) to provide a specific service to the grid, Toronto Hydro will not consider this DER as a reliable system tool. As part of its Local Demand Response program, Toronto Hydro procured 8 MW of dispatchable demand response capacity between 2018-2020, 4 MW between 2022-2023, and 6 MW in 2024.

The non-wires solutions considered for the 2025-2029 rate period are described in Exhibit 2B Section E7.2. Toronto Hydro's use of NWSs is targeted and focuses on credible capital deferral opportunities, and thus, the application of these solutions is limited to instances where such deferral opportunities can be identified and measured. The use case identified at this time is limited to bus-level load transfer deferral or avoidance. This can be achieved through the procurement of dispatchable demand response from aggregators or customers. Toronto Hydro is agnostic to the technology (type of DER) or approach (load curtailment) utilized by aggregators or customers to deliver this demand response capacity. Participants are compensated based on measured and verified performance, utilizing the methodology outlined in IESO's Market Manual 12 – Issue 16.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-248

Reference: Exhibit 2B / Section E7.2.1 / p. 1

Preamble:

Toronto Hydro states: "NWSs are viewed as additive to conventional utility expansion strategies, enabling Toronto Hydro to expand its planning toolbox to include additional strategies for keeping up with load growth."

QUESTION:

Please provide examples of DERs or other Non-Wires Solutions presently existing on Toronto Hydro's system that enabled it to avoid more costly wires solutions to address system constraints.

i. Please quantify the cost savings for each of the examples.

RESPONSE:

The non-wires solutions considered for the 2025-2029 rate period have been outlined in detail in Exhibit 2B Section E7.2. Please refer to Toronto Hydro's responses to 1B-Staff-88 and 1B-Staff-89 for more information about the utility's non-wires strategy, investments and proposed incentives. Please also see Toronto Hydro's responses to other Staff interrogatories asking similar questions about the use of non-wires in planning: 2B-Staff-154, 2B-Staff-169, 2B-Staff-173, 2B-Staff-253, 2B-Staff-255.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-249

Reference: Exhibit 2B, Section E7.2.2.1, Page 19

Preamble:

Toronto Hydro states: "Toronto Hydro will build on its experience with BESS to move from individual pilot projects towards a standardized approach for design and deployment. The planned deployments will target areas with grid constraints to enable Renewable Energy Generation (REG) connections."

QUESTION:

Please quantify the capital and operating cost impacts of developing BESS using presently available commercial technology to address outage durations. Please express your answer in terms of average annual dollars per unit SAIDI improvement.

RESPONSE:

As outlined in Exhibit 2B Section E7.2.2, the use case for the proposed ESS deployments is to enable future renewable generation connections, not to address outage durations. As such, at this time, Toronto Hydro is unable to quantify the cost impacts of BESS to address outage duration. Toronto Hydro is currently undertaking preliminary engineering studies to assess the feasibility of utilizing BESS for the purpose of outage management and if appropriate, will evaluate the cost-effectiveness of this potential use case in the future.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-250

Reference: Exhibit 2B, Section E7.2.2, Pages 18-35
EB-2018-0165, OEB Decision and Order, Pages 114-115, 119

Preamble:

Toronto Hydro has proposed an expanded Energy Storage System as part of its Non-Wires Solutions for 2025-2029 to assist in providing distribution-level grid support. Toronto Hydro forecasts expenditures of $22.5 million over the 2025-2029 period to support the deployment of 9 projects with an aggregate capacity of 10.2 MW.

As part of the OEB's Decision in EB-2018-0165 it provided direction that it expected Toronto Hydro to respond to as part of any future application that seeks approval of Renewable Enabling Investments and Energy Storage Systems, including evidence of the benefits to power quality, reliability and capacity and an assessment of appropriate sharing of benefits for ESS projects as part of future requests for funding for provincial rate protection.

QUESTION (A):

a) Please discuss the pace of the BESS investment strategy. In particular, please provide more detail regarding the process Toronto Hydro will undertake in determining when to proceed with a BESS investment during the 2025-2029 term, including how Toronto Hydro plans to overcome the challenges faced in the recent past (siting, supply chain, integration into the existing system, low vendor interest).

RESPONSE (A):

As described in Exhibit 2B Section 7.2.2, Toronto Hydro intends to install front-of-the-meter, utility-owned and operated ESS to enable renewable DER connections. This plan is informed by a systematic analysis of feeders experiencing instability related to high-penetrations of renewable

DERs, which identified nine priority feeders to be targeted for ESS deployment. To ensure that ESS remains the appropriate solution, the analysis will be re-run to confirm the conditions of the feeder prior to project development. The methodology utilized is in compliance with the IEEE-1547-2022.

Of the challenges faced in 2020-2024, siting continues to be the most challenging. To manage this risk, Toronto Hydro is actively pursuing various pathways such as decommissioned Municipal Stations, private land opportunities, and public land opportunities in collaboration with the City of Toronto. For the remaining constraints, please refer to exhibit 2B Section 7.2.2.4 Page 28-30.

QUESTION (B):

b) Please discuss the status of the technical requirements currently in development to support the standardized process of ESS design and procurement, including what Toronto Hydro is using as the basis for the technical requirements.

RESPONSE (B):

As indicated in Exhibit 2B Section E7.2.2.4, Toronto Hydro has completed a technical specification review with respect to ESS technologies, which is continuously updated. The following list of engineering standards and codes have been used as a basis for Toronto Hydro's standardized technical specification document:

- Canadian Standards Association (CSA):
  - C22.2 No. 31 Switchgear Assemblies
  - C22.2 No. 94 Special Purpose Enclosures 2, 3, 4 and 5
  - C22/2 No. 193 High Voltage Full-load Interrupter Switches
  - CAN 3-C13 Instrument Transformers
  - C22.3 No 9 Interconnection of distributed resources and electricity supply systems
- Electrical and Electronic Manufacturers Association of Canada (EEMAC):
  - G8-3.2 Metal Clad and Station-type Switchgear
  - G10-1 Revenue Metering Equipment in Switchgear Assemblies
- Institute of Electrical and Electronic Engineers (IEEE):

  - Std 48 Test Procedures and Requirements for High Voltage AC Cable Terminations
  - C37.74 Standard Requirements for Subsurface, Vault, and Padmounted Load-Interrupter Switchgear and Fused Load-Interrupter Switchgear for Alternating Current Systems up to 38 kV
  - 386 Standard for Separable Insulated Connector Systems for Power Distribution Systems above 600 V
  - Std 80 Outdoor Grounding Requirements
  - C37.20.2 IEEE Standard for Metal-Clad Switchgear
  - C57.12.28 IEEE Standard for Pad-Mounted Equipment-Enclosure Integrity
  - 519 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems
  - 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (if applicable)
  - 1584 Guide for Performing Arc Flash Hazard Calculations
- ANSI/CAN/UL:
  - UL9540 Energy Storage Systems and Equipment
  - UL1741 Standard for Inverters, converters, Controllers and Interconnection
  - System Equipment for Use with Distributed Energy Resources (if applicable)
  - UL1642 Lithium Batteries
  - UL1973 Batteries for Use in Stationary Application
  - ANSI C37 series of Standards
- International Standard (IEC):
  - IEC 62933-2-1 Electrical Energy Storage (EES) Systems

QUESTION (C):

c) Please discuss how maintenance costs have been incorporated into the overall cost proposal for the ESS plan.

RESPONSE (C):

Maintenance costs for Toronto Hydro-owned ESS associated with annual inspection, testing, and cleaning are included in the Preventative and Predictive Stations Maintenance program forecast (Exhibit 4, Tab, 2, Schedule 3).

QUESTION (D):

d) Please provide more information on how the annual forecast BESS expenditures were developed, including the increase in planned expenditures in 2027 relative to other years.

RESPONSE (D):

The plan for BESS deployment focuses on deploying small-scale projects in 2025 and 2026 where potential sites have already been identified. Larger capacity systems will be deployed later on in the rate period. Toronto Hydro expects to carry the lessons learned from the smaller into the 2027 projects.

QUESTION (E):

e) Please provide more information on the how the total proposed cost of $22.5 million is broken out between that which is allocated to Toronto Hydro's rate base (i.e. six percent or $1.6 million) and that the remaining funding component through the provincial renewable enabling improvement revenue stream.

RESPONSE (E):

Please see Tables 1 and 2 for the capital expenditures and in-service additions 94/6 percent split, respectively. The in-service addition amounts are reflected in the Socialized Renewable Energy Generation Investments line item in Appendix 2-BA, Exhibit 2A, Tab 1, Schedule 2.

Table 1: Capital Expenditure 94/6 Split ($ Millions)

	2025	2026	2027	2028	2029	Total
Capital Expenditures (Rate Base at 6%)	0.2	0.2	0.5	0.2	0.2	**1.4**
Capital Expenditures (Socialized Renewable Energy Generation Investments at 94%)	3.3	3.4	7.1	3.6	3.8	**21.2**
Total	**3.6**	**3.6**	**7.5**	**3.8**	**4.0**	**22.5**

Note: Variances due to rounding may exist

Table 2: In-Service Additions 94/6 Split ($ Millions)

	2025	2026	2027	2028	2029	Total
In-Service Additions (Rate Base at 6%)	-	-	0.9	-	0.5	**1.4**
In-Service Additions (Socialized Renewable Energy Generation Investments at 94%)	-	-	13.9	-	7.3	**21.2**
Total	**-**	**-**	**14.8**	**-**	**7.8**	**22.5**

Note: Variances due to rounding may exist

QUESTION (F):

f) Please provide an assessment of the appropriate sharing of benefits for the proposed BESS projects between Toronto Hydro's customers and broader electricity customers across Ontario for those amounts requested to be recovered under the provincial renewable enabling improvement funding component.

RESPONSE (F):

Please see Exhibit 2A, Tab, 5, Schedule 1, section 2.2 (Energy Storage) for the requested assessment.

QUESTION (G)

g) Please discuss the nature of the proposed BESS investments and indicate if any are proposed to be behind-the-meter. If so, please discuss the nature of these projects and the anticipated benefits.

RESPONSE (G):

All proposed energy storage investments are front-of-meter.

QUESTION (H):

h) Please discuss the analysis Toronto Hydro has undertaken to understand the pace of battery technology evolution. As part of your response, please address how Toronto Hydro will assess the long-term viability and performance of battery technologies installed. Please also discuss the risk mitigation efforts to avoid investing in technologies that become obsolete in a short period of time.

RESPONSE (H):

Toronto Hydro has conducted an Energy Storage System (ESS) Technology Evaluation as referenced in Exhibit 2B Section E7.2, page 31 which took a technology agnostic approach to analyzing the available market options with renewable enablement as the primary use-case. The approach focused on the assessment of storage technologies (not just electrochemical storage) with relation to physical footprint, modularity, technology maturity, market availability, environmental impact, performance and financial metrics among others. The evaluation referenced supplier engagements that Toronto Hydro conducted as well as similar studies by the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

Toronto Hydro periodically updates the evaluation to assess the long-term viability of available storage technologies and ensures review of the available technologies ahead of each procurement to mitigate the risk of investing in technologies that may become obsolete before the deployment end-of-life. Toronto Hydro maintains awareness of the rapidly changing landscapes in storage technology development through industry engagements with suppliers.

QUESTION (I):

i) The ESS strategy is being prioritized to reduce the minimum load to generation ratio for specific feeder stations. Please discuss the process Toronto Hydro proposes to undertake to assess the performance and reliability of planned BESS investments to ensure they meet or exceed performance requirements.

RESPONSE (I):

Toronto Hydro will use real-time feeder loading and generation data to perform measurement and verification to ensure the MLGR ratio is within compliance with the IEEE-1547-2022, utilizing standard IEEE methodologies.

QUESTION (J):

j) Please discuss the consideration of life cycle environmental impacts of the planned BESS investments, including the process to disposing of batteries after their useful life.

RESPONSE (J):

Toronto Hydro has conducted a storage technology evaluation of the different options and assessed the environmental impacts of each within business-specific applications. Toronto Hydro actively considers alternative storage technologies during its procurements that are more sustainable and easier to recycle whilst also balancing the performance requirements and market maturity to ensure service reliability.

QUESTION (K):

k) Please discuss how Toronto Hydro proposing to assess how potential BESS projects contribute to the resilience and security of Toronto Hydro’s system.

RESPONSE (K):

The primary use case of Toronto Hydro’s proposed BESS projects is renewable enablement. Enhancing Toronto Hydro’s grid resilience and security through BESS is currently being evaluated through on-going engineering studies and will be pursued as a secondary use case if appropriate.

QUESTION (L):

l) Please discuss how current and future ESS projects may contribute to the Local Demand Response program, if at all.

RESPONSE (L):

The non-wires solutions considered for the 2025-2029 rate period have been outlined in detail in Exhibit 2B Section E7.2. Toronto Hydro's use of NWSs is targeted and focuses on credible capital deferral opportunities, and thus, the application of these solutions is limited to instances where such deferral opportunities can be identified and measured.

Toronto Hydro would not utilize its own front-of-the-meter ESS assets to participate in a competitive, market-based program such as LDR. The ESS assets could provide targeted peak-shaving benefits to the connected feeder, however, this would occur outside of the LDR program.

QUESTION (M):

m) Please provide a project schedule and expected completion date for the Optimal Planning Program developed in partnership with Toronto Metropolitan University.

RESPONSE (M):

The Optimal Planning Program developed in partnership with the Toronto Metropolitan University's Centre for Urban Energy (in Exhibit 2B Section E7.2, page. 20) was concluded in June 2023. This project was successful in developing a technology agnostic tool to help evaluate the net benefits associated with various ESS configurations and ownership models.

The project also developed a software tool, which is utilized by Toronto Hydro to analyze the opportunity to layer use-cases for a given ESS deployment and helps determine the ESS sizing. The tool can also aid in quantifying potential wholesale market revenues (i.e. IESO services) should the decision be made to pursue such activities in the future.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-251

Reference: Exhibit 2B, Section E7.2.2.3, Pages 21-22

Preamble:

With regards to Toronto Hydro's commentary on "Renewable Enabling BESS"

QUESTION:

Must increased REG penetration in Toronto Hydro's service area be accompanied by associated ESS developments to avoid creating system capacity deficiencies? Please discuss.

i. If yes, quantify the revenue requirement impacts of the associated ESS needed to support the anticipated REG developments over the test period.

RESPONSE:

As described in Exhibit 2B, Section E7.2.2.3, Toronto Hydro's pre-application process enables the discovery of potential distribution system issues that must be addressed to accommodate a proposed DER. High penetration of renewable energy generation sources on one feeder can lead to grid instability if not managed appropriately. This does not mean that all feeders will experience these issues. As noted in Table 14 of Exhibit 2B, Section E7.2.2.3, Toronto Hydro has identified 23 feeders that are currently of concern, and an additional 24 that could experience issues by 2029. Based on this analysis, 9 priority feeders have been selected and the expenditure plans related to the ESS requirements have been provided in Exhibit 2B, Section E7.2.2.4. The associated costs have been captured in the current filed application documents (see Table 18, Exhibit 2B, Section E7.2.2.4). The associated revenue requirement can be found in Exhibit 2A, Tab 5, Schedule 2, Appendix "OEBAppendices 2-FA-FB - EnergyStorage_20231117.XLSM"

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-252

Reference: Exhibit 2B, Section E7.4, Appendix A, page. 6

Question (A):

a) Toronto Hydro is anticipating overall area load growth for the Downsview area of 40-70% due mainly to electrification of heating and transportation. Please provide a load forecast for the Downsview area (for each station) that breaks out the heating and transportation demand. Please also confirm what percentage of the transportation demand is due to EVs and the percentage due to electrification of public transit.

RESPONSE (A):

Please note that the referenced range is not forecast; it refers to growth modelled by the Future Energy Scenarios (FES), which was used to stress-test the need for Downsview TS in accordance with the least regrets planning approach outlined in the evidence at Exhibit 2B, Section D4. For more information about the Downsview area station bus load forecast please see the response to 2B-Staff-256.

Please note that Toronto Hydro's capital plan for Downsview TS was developed using the "25 Year Forecast" as provided in Exhibit 2B, Section E7.4, App A p. 7, as per Toronto Hydro's application evidence update submitted on January 29. As discussed, the 25 Year Forecast was produced by adding 70% of the demand forecast produced by a preliminary study from DPM Energy to Toronto Hydro's 10-year System Peak Demand Forecast. Please note additionally that Toronto Hydro's System Peak Demand Forecast does not model heat loads due to the decarbonization of heat. Finally, the DPM Energy study does not provide an estimate for heating demand separate from overall building demand. For these reasons, Toronto Hydro is not able to provide a forecast for the heating demand for the Downsview area.

The EV demand for each station is provided in Table 1. Regarding public transit, Toronto Hydro has also included the Finch West LRT in its load forecast (not shown in Table 1), contributing an additional 5.3 MVA to Bathurst TS.

Table 1 : EV Load by Station Forecasted for the Downsview Area (MVA)

Station	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bathurst TS	0.0	0.0	0.0	0.1	0.1	0.3	1.5	2.8	4.1	5.5	6.8	8.2	9.6
Fairbank TS	0.2	0.4	0.8	1.2	1.8	2.7	4.2	5.7	7.2	9.0	10.8	12.9	15.1
Fairchild TS	0.2	0.3	0.6	0.9	1.6	2.6	3.6	4.6	5.7	7.0	8.4	10.4	12.4
Finch TS	0.4	1.1	2.1	3.2	4.7	6.6	9.2	12.0	14.6	17.7	21.1	24.6	28.6

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-253

Reference: Exhibit 2B / Section E7.4 / App A / pp. 18, 19

QUESTION (A):

a) Please confirm that the cost of option 6 - New TS incudes the cost of load transfers that will need to be implemented to manage local station capacity at 90% until Downsview TS comes into service. i. If not confirmed, please provide the total cost of Downsview TS that takes necessary load transfers into account.

RESPONSE (A):

The cost of option 6 – New TS does not include the cost of load transfers. Please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

QUESTION (B):

b) Please update Table 4-Summary of Options to include the total costs of each of the options. If this is not feasible, please explain why not.

RESPONSE (B):

Please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

QUESTION (C):

c) Did Toronto Hydro consider the use of non-wires options in the area including flexibility options and energy storage solutions to defer the need for a new TS?

i. If yes, please provide the benefit cost analysis.

ii. If not, why not.

RESPONSE (C):

Toronto Hydro has considered the use for non-wires options in the Downsview Area. However as discussed in 2B-E7.4 App A pp. 11, non-wires options are not capable of addressing the magnitude of load growth forecasted for the Downsview Area. Ultimately, new station capacity is required to supply the loads and electrical energy needs of the Area, especially upon considering that flexibility options and energy storage solutions do not provide net electrical energy.

Instead, Toronto Hydro has chosen to combine the complementary strengths of wires and non-wires options to meet the needs of the Downsview Area. Toronto Hydro is proposing to construct Downsview TS to meet the long term needs of the Area, but is forecasting the station to be complete in approximately 10 years: Q4 2033. Until Downsview TS is ready, Toronto Hydro is proposing to manage station loading through its Load Demand (wires) and Non-Wires Solutions (non-wires) Programs. In particular, Toronto Hydro's Non-Wires Solutions Program is proposing to target the Finch TS service area with Flexibility Services (previously "Local Demand Response"). Please see 2B-E7.2.1.3 for more details.

Regarding the request for a benefit cost analysis, please refer to Toronto Hydro's response to interrogatory 2B-SEC-59.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-254

References: Exhibit 2B, Section E7.4, App B, p. 6

QUESTION (A):

a) Toronto writes that it is anticipating Scarborough area load will grow by 75-105 % due mainly to electrification of heating and transportation. Please provide a 20-year demand and energy forecast for the area that breaks out heating, EV charging, and public transit for each station.

RESPONSE (A):

This project is no longer in scope in this proceeding, as Toronto Hydro retracted the request related to Scarborough TS (Exhibit 2B, Section E7.4 at Appendix B) through the evidence update which was submitted on January 29, 2024.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-255

REFERENCES: Exhibit 2B, Section E7.4, App B, Pages 18,19

QUESTION (A):

a) Please confirm that the cost of option 5 - New DESN incudes the cost of load transfers that will need to be implemented to manage local station capacity at 90% until the new DESN comes into service. If not confirmed, please provide the total cost accounting for load transfers.

QUESTION (B):

b) Please update Table 7-Summary of Options Outcomes to include the total cost of each option.

QUESTION (C):

c) What non-wires options were considered in this area to defer the need for the new DESN? ii. Please provide the benefit cost analysis.

RESPONSE (A), (B), AND (C):

This project is no longer in scope in this proceeding, as Toronto Hydro retracted the request related to Scarborough TS,[1] through the evidence update which was submitted on January 29, 2024.

[1] Exhibit 2B, Section E7.4, Appendix B

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-256

Reference: **Exhibit 2B, Section E7.4.1, Page 1**

<u>Preamble:</u>

Toronto Hydro states: "A demand study of the Downsview area has forecasted a load demand of 195 MW by 2035."

QUESTION (A):

a) Assuming the Downsview TS is not constructed, please provide the summer and winter planning capacity and forecast peak summer and winter demand for each year from 2030 - 2035 for Bathurst TS, Finch TS, Fairchild TS and Fairbank TS.

RESPONSE (A):

Tables 1 and 2 below respectively show the summer and winter peak forecasts for the Downsview Area, assuming Downsview TS is not constructed, over 2030-2035. Please note that building heating loads are not included in the forecasts shown in Tables 1 and 2, as noted in the evidence in Exhibit 2B, Section D4 and in the response to 2B-Staff-153.

Table 1: 2030-2035 Summer Forecast for the Downsview Area without Downsview TS

Station	Summer LTR (MW)	2030	2031	2032	2033	2034	2035
Bathurst TS	361	76%	77%	78%	80%	81%	83%
Fairbank TS	182	92%	96%	98%	99%	101%	102%
Fairchild TS	346	70%	71%	71%	71%	71%	71%
Finch TS	366	96%	99%	100%	101%	101%	102%
Area Non-Coincident %	**1255**	**83%**	**85%**	**85%**	**86%**	**87%**	**88%**

Table 2: 2030-2035 Winter Forecast for the Downsview Area without Downsview TS

Station	Winter LTR (MW)	2030	2031	2032	2033	2034	2035
Bathurst TS	389	66%	66%	68%	69%	70%	72%
Fairbank TS	202	72%	74%	76%	77%	78%	80%
Fairchild TS	389	59%	59%	59%	59%	59%	59%
Finch TS	394	80%	82%	82%	83%	84%	84%
Area Non-Coincident %	**1374**	**69%**	**70%**	**71%**	**71%**	**72%**	**73%**

QUESTION (B) :

b) When is Downsview area forecast to become winter peaking?

RESPONSE (B):

Toronto Hydro's 10-Year System Peak Demand Forecast does not forecast the Downsview areas to become winter peaking within the 10-Year Period. In a scenario where building heating loads are modelled, such as those being explored through long-term regional planning, the Downsview areas could become winter peaking by 2040.

QUESTION (C) :

c) What is the annual duration of the period in which demand is forecast to exceed the available Bathurst TS, Finch TS, Fairchild TS and Fairbank TS planning capacity in each year from 2030 to 2035?

RESPONSE (C):

The System Peak Demand Forecast, which is the basis for the capacity planning process both at the distribution level and for Regional Planning at the needs assessment stage, does not include a demand duration station forecast.

QUESTION (D) :

d) Please explain how the summer and winter planning capacity is determined for each of the above substations.

RESPONSE (D):

As stated in Hydro One's 2022 Needs Assessment Report at page 12: "Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station". Toronto Hydro uses the same capacity, the summer LTR, as the summer capacity for the transformer stations supplying its service territory. Similarly, Toronto Hydro uses the Hydro One winter LTR as the winter capacity for the transformer stations supplying its service territory.

QUESTION (E) :

e) Assuming all equipment is in service what is the operational capacity at each of these substations in each year from 2030 to 2035?

RESPONSE (E):

Please see the response to d) above. Consistent with Hydro One definitions, Toronto Hydro defines transformer station capacity as the LTR of a single transformer; or equivalently for a DESN where two transformers supply load in parallel, the LTR capacity under the loss of one transformer (N-1). Toronto Hydro's capacity planning process, consistent with the Regional Planning process, does not give consideration to capacity when all equipment is in service.

QUESTION (F)

f) What is the probability of a contingency exceeding the operational capacity at each of these substations in each year from 2030 to 2035?

RESPONSE (F):

Please see the response to part (c) above. Toronto Hydro has forecasted when peak demand is forecasted to exceed Summer LTR, as shown in Table 1.

QUESTION (G) :

g) Please provide any risk analysis that Toronto Hydro has undertaken to determine the risk of not being prepared to serve all loads in the Downsview Area post 2030.

RESPONSE (G):

Please see the Downsview TS Business Case in Exhibit 2B, Section E7.4 at Appendix A (updated January 29, 2024) for the risk analysis. Toronto Hydro has taken the Downsview Area Secondary Plan into consideration by producing the 25 Year Forecast (Table 2), and has considered the possible impacts of electrification by leveraging the Future Energy Scenarios (FES). These tools were used to assess when capacity constraints would (per the 25 Year Forecast) or could (per the FES) be encountered. Following that, Toronto Hydro assessed 6 options, described pages 9-19, to determine if and how it would be able to manage the risk of capacity constraints. Through this analysis, Toronto Hydro concluded that it would only be able to manage all loads in the Downsview Area in the long term by investing in its proposed Downsview TS.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-257

Reference: Exhibit 2B, Section E8.1, Pages 1, 4, 6

Preamble:

Toronto Hydro notes the following regarding EDC 1, "for example, EDC 1 will continue to require at least two to three shutdowns per year to allow for the execution of necessary and essential facilities operations and maintenance activities aiming to safeguard the integrity of the location."

QUESTION (A):

a) Please clarify the sentence above, what kinds of operations and maintenance activities need to be undertaken at EDC 1 owing to its particular site condition.

RESPONSE (A):

A number of construction and planned maintenance activities are required at the facility housing EDC 1, which necessitate power shutdowns. Examples of these activities include tying in the electric feed for new or replaced equipment (like electric vehicle chargers or electric-powered roof top units replacing a gas unit), and planned shutdowns for routine building maintenance. The shutdowns triggered by these activities affect the synchronising switchboard, which eliminates the backup generator redundancy and thus increases the risk of sudden failure of EDC 1 for the duration of the shutdown.

QUESTION (B):

b) Would these same activities and mitigations not need to be undertaken at EDC 2 or the newly proposed site?
    i. If yes, how does Toronto Hydro propose to manage these issues and what are the related costs?

RESPONSE (B):

No, the building power shutdowns due to operations and maintenance uniquely affect EDC 1 only because the facility housing EDC 1 has a shared generator that supports both the main building and the EDC. Any similar activities do not affect EDC 2 nor would they affect the proposed site. EDC 2 is currently aligned with Tier II requirements of the Uptime Institute's Tier Classification System and the proposed EDC will align with Tier III requirements, meaning both locations will feature independent generator backup dedicated to the data centre alone. This independence would fortify the redundancy of EDC 2 and the proposed EDC, eliminating the current risks and costs associated with EDC 1 being impacted by shutdowns in its current location.

QUESTION (C):

c) Please provide a table that shows EDC1, EDC2 and the new site's square footage and how each of the sites compare in capital cost/square footage.

RESPONSE (C):

Toronto Hydro is unable to provide the capital costs for EDC 1 and EDC 2 because the utility no longer has any records dating back to their construction. The proposed EDC's cost has been shown in the currency of the year of project completion.

Table 1: Proposed EDC Cost

Location	Square feet	Capital Cost ($ million)	$/sq. f.t
EDC 1	3,530	Unavailable	
EDC 2	8,700	Unavailable	
Proposed EDC	11,500	72.0	6,260

QUESTION (D):

d) Is the proposed cost of $72M for a new EDC site an all-in cost? In other words, does this cost include facilities and IT infrastructure and security?

i. If not, please provide the all in cost for the new EDC.

RESPONSE (D):

Yes, the proposed cost of $72 million is the all-in cost including inflation.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-258

Reference: Exhibit 2B, Section E8.1, Page 7

Preamble:

Toronto Hydro notes that the assets at EDC 1 will be retired.

QUESTION (A):

a) Could the existing assets at EDC 1 be used to reduce the costs of assets needed at the new proposed location?
   i. If yes, what are the related cost savings and are they included in the proposed costs of the new EDC?
   ii. If no, why not?

RESPONSE (A):

Toronto Hydro does not expect that it can use existing assets at EDC 1 to reduce the costs of assets needed at the new proposed location for the following reasons:

1. While construction is ongoing at the proposed new EDC location, EDC 1 must remain in operation to maintain redundancy with EDC 2.
2. The assets constituting EDC 1 are at or beyond useful life and their reuse would not yield any material savings or benefits over their replacement.
3. Reusing the assets constituting EDC 1 at the proposed new EDC location would require investments in additional electrical equipment, which would materially add to project costs.

QUESTION (B):

b) How do the EDC 1 assets compare in age and useful life to assets at EDC 2? Please provide this information in a table and aggregate by asset type, as necessary.

RESPONSE (B):

Table 1: Useful Life Comparison- EDC 1 and EDC 2 Assets

Asset	EDC 1		EDC 2	
	Useful Life, Years	Years Remaining	Useful Life, Years	Years Remaining
Computer Room Air Conditioning Units	15	12	15	5
Fire Protection	20	-9	25	14
Controller	15	1	30	2
Fire Alarm Panel	15	9	15	4
Generator	25	11	25	15
Windows	45	11	N/A	N/A

Note: A negative number in years remaining indicates the number of years the asset has exceeded its useful life.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-259

References: **Exhibit 2B, Section E8.1, Page 8**
Exhibit 2B, Section E8.1, Page 11

<u>Preamble:</u>

Toronto Hydro notes the Tier Classification System of the Uptime Institute.

QUESTION (A):

a) Is Toronto Hydro required to abide by certain Tier Classification requirements?
   i. If yes, what are these requirements?
   ii. What standard, legislation and/or guidance governs the operations of Toronto Hydro's EDCs?

RESPONSE (A):

Although there is no governing body that mandates Toronto Hydro's compliance with the Uptime Institute's Tier Classification System, the utility recognizes significant value in designing and planning its EDC components in accordance with a body of internationally recognized data centre standards.

Toronto Hydro follows key design and operation standards with respect to its EDCs, including:

- **TIA-942**: Telecommunications Industry Association's standardizing the design and implementation of data centre infrastructure, and operations with guidelines on reliability, scalability, efficiency of cabling, network architecture, power distribution, cooling system and security measures.
- **Uptime Institute's Tier Standards**: These standards affect both design and operations through their guidelines specifying tier classification, redundancy, cooling efficiency, and

operational best practices to minimize downtime and ensure consistent availability of critical IT services.

- **ISO/IEC 27001**: This international standard specifies the requirements for establishing, implementing, maintaining, and continually improving an information security management system (“ISMS”) within the context of the organization's overall business risks. Implementing this standard provides the EDC with robust security controls, risk management processes, and continual monitoring and improvement measures, enhancing the security posture of the EDC and protecting sensitive information from threats and vulnerabilities.
- **ANSI/BICSI 002**: This standard provides guidelines for data center design and implementation, covering aspects such as cabling, pathways, spaces, and grounding. The structured and standardized approach to infrastructure design leads to improved performance, scalability, and manageability of the EDC.
- **ASHRAE Guidelines**: The American Society of Heating, Refrigerating and Air-Conditioning Engineers provides guidelines for data center environmental conditions, including temperature, humidity, and airflow management. These conditions are crucial for maintaining optimal operating conditions and equipment reliability, ensuring energy efficiency equipment longevity and overall reliability of the EDC facility.

QUESTION (B):

b) What is the Tier Classification for EDC 2, and how does that compare to the classification proposed for the proposed EDC?
   i. If they will be different, will EDC2 need to be upgraded to a new classification?
   ii. If yes, when would this upgrade need to take place and at what cost?

RESPONSE (B):

EDC 2 is a Tier II classification and the proposed EDC will be aligned to a Tier III classification. The primary difference between Tier II and III is how the EDC and the electrical distribution interact with the backup generator. Both tiers feature two backup generators, but under the Tier II classification both generators are tied into a single distribution path, meaning a failure at that distribution path, such as a failure of the synchronization switchboard, input switchboard, or emergency switchboard would result in system failure. Under Tier III, each generator has its own distribution path to the EDC, providing greater redundancy between the two backup generators and better resiliency for the EDC.

Toronto Hydro currently does not estimate any material benefits to upgrading EDC 2 to a new classification, as the assets that constitute EDC 2 are relatively newer and remain within their useful lives.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-260

References: Exhibit 2B, Section E8.1, Page 18

Preamble:

With respect to EDC redundance and replacing EDC 1, Toronto Hydro states that, "A complete EDC failure would result in all of Toronto Hydro's business applications becoming unresponsive and non-functional. In the event of a distribution system outage, this would have cascading and substantial financial and economic impacts on customers within the City of Toronto."

QUESTION:

a) Please confirm that this comment refers to failure of both EDC sites and not just EDC 1, given that there are two locations to provide back up capability in the event of one site failing?

RESPONSE:

Confirmed. However, 1:1 redundancy will be lost in approximately 5 years time as described in 2B, E8.1, pg 16-17

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-261

Reference: Exhibit 2B, Section E8.1, Page 21

<u>Preamble:</u>

Toronto Hydro is requiring $72 million over the 2025-2029 rate period to relocate the existing EDC 1 to the new site and be operational by 2029.

QUESTION:

a) Please provide a table showcasing the progressive spending for the EDC relocation over the next 5 years

RESPONSE:

The following table outlines the estimated annual spend of the total EDC project.

Table 1: Estimated Annual Spend of the Total EDC Project

EDC: Forecast					
Year	**2025**	**2026**	**2027**	**2028**	**2029**
Forecasted Spend	$5.4M	$16.5M	$22.5M	$20.6M	$7.0M

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-262

Reference: Exhibit 2B, Section E8.1, Page 28

QUESTION:

a) Please provide the benefit-cost analysis that justified Toronto Hydro's selected option for the new EDC.

RESPONSE:

Please refer to section E8.1.4 "Options Analysis/Business Case Evaluation" of Exhibit 2B, Section E8.1.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-263

References: **Exhibit 2B, Section E8.1, Pages 23-24**
Exhibit 2B, Section D8
Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs[1]

Preamble:

On November 2, 2023, the OEB released a letter regarding a new Accounting Order to establish a deferral account to record cloud computing implementation costs. Amongst other things, the establishment of the generic deferral account allows utilities to perform optimized planning by allowing cloud computing implementation costs to be recovered outside of a rate rebasing year and potentially reduces rate impacts through a disposition period.

QUESTION (A):

a) Please provide the forecasted capital and OM&A spend on cloud computing solutions for the 2025-2029 period at the project level.

RESPONSE (A):

All currently forecasted spend on cloud computing solutions for the 2025-2029 rate period fall under OM&A. Toronto Hydro notes that while cloud computing is typically treated as an OM&A expense, the accounting treatment is unique to each contract and may also result in the costs being treated as capital. Please also refer to Toronto Hydro's response to interrogatory 2A-PP-24, subpart (c).

Table 1 below outlines the forecasted 2025- 2029 OM&A spend on cloud computing solutions, all included In the Information Technology OM&A program budget:[2]

Table 1: 2025-2029 IT forecasted OM&A spend on cloud computing solutions:

	$ Millions				
	2025 Forecast	**2026 Forecast**	**2027 Forecast**	**2028 Forecast**	**2029 Forecast**
Cloud Implementation	5	5.5	6	6.5	7
Cloud Subscription Fees	4.4	5.2	5.7	6.3	7
Total	**9.4**	**10.7**	**11.7**	**12.8**	**14**

Toronto Hydro is currently unable to break down this information at the project level because the development of specific cloud-based solutions for 2025–2029 rate period is still ongoing as part of the utility's IT investment planning process.[3] As part of that process, Toronto Hydro must assess and evaluate whether or not on-premise cloud technology is suitable to fulfill its business needs. The utility's above forecast is based on 2020-2024 expenditures on cloud-based solutions at an aggregate level.

QUESTION (B):

b) Please discuss whether Toronto Hydro has assessed the impact of having a generic account available for cloud computing implementation costs in their 2025-2029 plan. If not, why not.

    i. Please discuss any barriers to implementing cloud-based solutions as a result of the analysis.

RESPONSE (B):

[2] Exhibit 4, Tab 2, Schedule 17.
[3] The process is outlined in Exhibit 2B, Section D8, subsection D8.5 at p. 7-10.

Given that the proposed five-year OM&A funding through the Revenue Growth Factor[4] includes a forecast for incremental cloud implementation and subscription costs,[5] Toronto Hydro decided not to pursue a deferral account for 2025-2029 in this regard.

In the unfortunate event that parties oppose the custom funding request for OM&A and the OEB is inclined to entertain such a request, Toronto Hydro would seek alternative relief for a generic account to capture variances for cloud-related costs (implementation and subscription costs) to ensure that the utility is able to fund these prudent and necessary expenditures and reduce the financial barriers to adopting cloud-based solutions.

QUESTION (C):

c) In light of the new deferral account is Toronto Hydro reassessing its position on cloud computing as an alternative to the EDC project?

RESPONSE (C):

No, Toronto Hydro is not reassessing its position on cloud computing as an alternative to the EDC relocation project, as the new deferral account does not mitigate the reliability and operational risks that a cloud-based solution would introduce relative to an on-premises solution. As discussed in Toronto Hydro's options analysis for the EDC relocation project,[6] the introduction of a cloud-based solution would make the utility dependent upon its vendor(s) to manage the reliability and business continuity of the EDC, which is beyond Toronto Hydro's risk tolerance given the critical functions performed by the EDC. Operational Technology (OT) systems such as Supervisory Control and Data Acquisition ("SCADA") and the Network Management System ("NMS") are critical systems that ensure reliability of Toronto Hydro's daily operations. By having these systems on Toronto Hydro's premises as opposed to on the cloud, Toronto Hydro has full control and flexibility to manage the reliability of its critical operations as outlined in Exhibit 2B, Section E 8.1.4.3.2 pg 25-

[4] Exhibit 1B, Tab 2, Schedule 1.
[5] Exhibit 4, Tab 2, Schedule 17.
[6] Exhibit 2B, Section E8.1, subsection 8.1.4.3 at pages 25-26.

26. In addition, the introduction of a cloud-based solution to EDC 1 or the proposed EDC would render existing systems in EDC 2 incompatible with the new cloud-based components, triggering the need for further investments.

QUESTION (D):

d) In light of the new deferral account and the expanding number of cloud computing offerings, would Toronto Hydro consider reducing the size of the new EDC by implementing more cloud computing solutions? Please explain and include financial impacts to the new EDC project, as well as potential future savings for the existing EDC.

RESPONSE (D):

For the reasons discussed in the response to subpart (c) and the options analysis in Exhibit 2B, Section E8.1, Toronto Hydro does not consider full or partial implementation of cloud computing solutions to be a feasible alternative.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-264

Reference: Exhibit 2B, Section E8.2, Pages 8, 9, 11, 14, 17

Preamble:

With respect to Toronto Hydro's proposed Facilities Management and Security Investments and Figures 3, 4, 5, 8 and 16, and fire alarm systems.

QUESTION (A):

a) Please confirm whether the pictures included in the figures references above that depict architectural, structural and mechanical and plumbing deterioration are in fact outliers and not representative of the majority of facilities managed by Toronto Hydro?

RESPONSE (A):

The pictures used throughout Exhibit 2B, Section E8.2 are representative of the majority of stations facilities managed by Toronto Hydro and are not outliers.

QUESTION (B):

b) Please explain in detail how Toronto Hydro has been managing these facilities prudently given the state of the deterioration at some of these facilities as depicted in the figures.

RESPONSE (B):

As discussed in detail in Toronto Hydro's Facilities Asset Management Strategy,[1] the utility employs a comprehensive asset management approach that monitors and records the condition of facilities assets on an ongoing basis and at varying intervals as appropriate, in accordance with applicable legislative and technical standards. This approach provides Toronto Hydro central visibility into

[1] Exhibit 2B, Section D6.

conditions of its building assets at all times and supports the utility's decision-making by pinpointing the most critical needs by building system via a ranked, quantified evaluation of assets.

However, Toronto Hydro is also bound by fiscal prudence and the regulatory framework to prioritize its facilities investments in a manner that delivers that optimum value to ratepayers. As the OEB itself noted, "*it is particularly important that planning be optimized in terms of the trade-offs between capital and operating expenditures, and that investments be prioritized and paced in a way that results in predictable and reasonable rates.*"[2] Given the vintage of the majority of Toronto Hydro's facilities,[3] the deterioration of a portion of facilities assets is unavoidable; the real challenge is to optimize costs and prioritize asset replacements in a prudent manner, which the utility accomplishes through the application of its Facilities Asset Management Strategy.

[2] OEB Handbook for Utility Applications (October 13, 2016), p. 13.
[3] Exhibit 2B, Section D6, p. 7, lines 11-13 and Section E8.3, p. 25, lines 9-12.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-265

Reference: Exhibit 2B, Section E8.2, Page 2, 26

Preamble:

In describing general plant investments related to work centres, Toronto Hydro states it plans to invest to decarbonize in line with its Net Zero 2040 Strategy.

QUESTION (A):

a) What are the annual capital expenditures in Facilities Management and Services related to Toronto Hydro's Net Zero 2040 Strategy?

RESPONSE (A):

Approximately $31.8 million of the Facilities Management and Services capital budget will be directed to work centre GHG emissions reduction initiatives by replacing end of life natural gas fired assets in accordance with Toronto Hydro's Facilities Asset Management Strategy.[1] Please refer to the below table for an estimated annual breakdown.

Table 1: Estimated Annual Breakdown

Program/Segment ($M)	2025	2026	2027	2028	2029	2025-29
Facilities Decarbonization Strategy	6.1	6.3	6.4	6.4	6.6	**31.8**

[1] Exhibit 2B, Section D6.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-266

References: **Exhibit 2B, Section E8.3, Pages 3-4**

EB-2018-0165, Decision and Order, December 19, 2019, Page 104

Preamble:

In reference 2 the OEB directed Toronto Hydro "to provide more detailed cost benefit analysis between EV, hybrid and combustion engines for its fleet program for future rebasing applications. In addition, the OEB directs Toronto Hydro to develop utilization measures beyond fleet use in standard hours." In response to the cost benefit analysis, Toronto Hydro's evidence stated that various phasing and cost options were analyzed for electrifying its fleet and the results of this analysis informed Toronto Hydro's procurement strategy for EVs and hybrid vehicles.

Question (A):

a) Please provide a copy of the analysis done to assess the costs and benefits between EVs, hybrids and combustion engine vehicles and the results of this analysis.

RESPONSE (A):

Toronto Hydro continues to work on obtaining disclosure consent from the third parties that authored the report on EV Phase-In. Once consent is obtained, Toronto Hydro will update this interrogatory response. Following the commissioning of this third-party report, Toronto Hydro further calibrated its business plan in support of the Fleet and Equipment Services capital program for 2025-2029, in view of material developments since the analysis was undertaken, such as the COVID-19 pandemic, EV pricing and availability, global supply chain challenges, and the Net Zero by 2040 mandate.

QUESTION (B):

b) Please explain Toronto Hydro's proposal for developing utilization measures beyond fleet use in standard hours.

RESPONSE (B):

For a discussion of the current metric, please refer to Exhibit 2B, Section E8.3, subsection 8.3.3.4 "Business Operations Efficiency" at pages 9-11. The previous utilization measure known as "standard utilization percentage" only considered vehicle usage during the standard field operations working hours of 7:30 am- 3:30 pm, which excluded vehicle utilization for units that operated outside of these hours such as shift workers, early starts, alternate shift schedules, overtime, etc. and as such, was not a true reflection of vehicle utilization. The old method of calculation was based on the number of hours the vehicle is utilized outside of its home zone between the hours of 7:30 am- 3:30 pm, divided by 8. By contrast, the current "days used" metric that Toronto Hydro adopted in the 2020-2024 rate period removes the limitations of a specific shift schedule and looks at daily usage throughout the month.

Toronto Hydro-Electric System Limited
EB-2023-0195
2B-Staff-266
Appendix A
FILED: March 11, 2024
(110 Pages)

FINAL
REPORT
October
2021

Electric Vehicle Phase-in Plan

PREPARED FOR TORONTO HYDRO-ELECTRIC SYSTEM LTD.

AUTHORS: ROGER SMITH, MATTHEW PITTANA, JANA CERVINKA. CHIEF DATA ANALYST: HUGH ROBERTS

RICHMOND
Sustainability Initiatives

TABLE OF CONTENTS

Terms and Abbreviations

BAU – Business-as-usual
BEV – Battery-electric vehicle
BET – Battery-electric truck
CAC – Criteria air contaminants; a cause of ground level smog
CAFE – Corporate average fuel economy
Capex – Capital expense
CO_2 or CO_2e – Carbon dioxide or carbon dioxide equivalent
Downtime – Period when a vehicle is unavailable for use during prime business hours
EV – Electric vehicle
EVSE – Electric vehicle supply equipment
FAR™ – Fleet Analytics Review™ (Fleet Challenge Excel software tool)
GHG – Greenhouse gas (expressed in CO_2 equivalent tonnes)
HD or HDV – Heavy-duty vehicle (Classes 7-8)
HEV – Hybrid-electric vehicle
ICE – Internal combustion engine
KPI – Key performance indicator
LCA – Lifecycle analysis
LD or LDV – Light-duty vehicle
LMHD – Light-, medium-, and heavy-duty vehicle
LTCP – Long-term capital planning
MD or MDV – Medium-duty vehicle (Classes 3-6)
MHD or MHDV – Medium- and heavy-duty vehicle (Classes 3-8)
MHEV – Mild hybrid-electric vehicle
MT – Metric tonne
OEM – Original equipment manufacturer
Opex – Operating expense
PHEV – Plug-in hybrid electric vehicle
PM – Preventative maintenance
ROI – Return-on-investment
Solution – A technology, best management practice, or strategy to reduce fuel use and GHGs
TCO – Total cost of ownership
WACC – Weighted average cost of capital
ZEV – Zero-emission vehicle

Disclaimer

This Electric Vehicle Phase-in Plan (including any enclosures and attachments), has been prepared for the exclusive use and benefit of Toronto Hydro-Electric System Limited and solely for the purpose for which it is provided. Unless Richmond Sustainability Initiatives (RSI) provides prior written consent, no part of this report may be reproduced, distributed, or communicated to any third party. RSI does not accept liability if this report is used for an alternative purpose from which it is intended, nor to any third party in respect of this report.

Analysis in this report is based on fleet data prepared by Toronto Hydro. RSI is not responsible for errors or omissions, or for the results obtained from the use of this information. All information in this site is provided as-is, with no guarantee of completeness, accuracy, timeliness, or the results obtained from its use.

The information in the report is not an alternative to legal, financial, taxation, or accountancy advice from appropriately qualified professionals. For specific questions about any legal, financial, taxation, accountancy or other specialized matters, Toronto Hydro should consult appropriately qualified professionals. Without prejudice to the generality of the foregoing paragraph, we do not represent, warrant, undertake, or guarantee that the use of guidance in the report will lead to any particular outcomes or results.

...

Foreword

This Electric Vehicle Phase-in Plan (also referred to as the Plan), has been prepared for Toronto Hydro-Electric System Limited (herein referred to as Toronto Hydro or the utility) by Richmond Sustainability Initiatives (RSI) of Toronto, Ontario and its project team Fleet Challenge (FC), collectively referred to as RSI-FC. We have included this foreword because we feel it is important for readers of this report to first have a full understanding of the situation and context.

The Plan is based on our team's detailed data analysis of one-year of historical data for 385 Toronto Hydro fleet vehicles as submitted by the utility.

The RSI-FC team has made considerable effort to make the Electric Vehicle Phase-in Plan as meaningful and relevant as possible to Toronto Hydro. Our team analyzed and evaluated baseline fleet results and modelled an electric vehicle transition that makes economic sense and is reasonably attainable in the medium- to long-term. Results of scenario analysis are presented for the utility's consideration.

Our analysis for battery-electric vehicle (BEV) phase-in has been completed using a specialized software tool that was developed by RSI-FC, which is referred to as the Fleet Analytics Review™ (FAR). FAR has been designed to efficiently estimate the cost-benefit and GHG emissions-reduction potential of many best management practices and fuel-reduction solutions that have been proven to be beneficial to commercial and municipal fleets, including BEVs.

The Electric Vehicle Phase-in Plan provides a viable roadmap for consideration by Toronto Hydro's management, which can be implemented from 2022 through to 2037. Due to the limited availability of BEVs in the short-term, we have modelled BEV phase-in over a 15-year budget period following the year 2022 (i.e., from 2023-2037).

In addition to our electric vehicle phase-in analysis, we conducted a unit-by-unit analysis to determine electric vehicle supply equipment (EVSE), or charging infrastructure, requirements for Toronto Hydro's fleet, using an EVSE costing software tool.

We have made every effort to ensure that the business assumptions and estimates employed in our analysis are as accurate as possible – based on our years of experience working with commercial and municipal fleets, market research, and valuable input from Toronto Hydro Fleet Management.

Fossil fuel-use reduction translates directly to greenhouse gas reduction[1] (hereafter referred to as GHG reduction, carbon reduction, or CO_2 reduction); therefore, all references to fuel savings include the consequential GHG impacts (i.e., increase or decrease).

[1] The terms greenhouse gas, GHG, carbon, CO_2e, and CO_2 are synonymous for the purposes of this report.

Cautious Approach

Long-term capital planning (LTCP) for electric vehicles is dependent on the *speed and degree* of implementation. There are various uncertainties with electric vehicles that would modify capital expenses (Capex), operating expenses (Opex), and GHG reductions, including:

- Future BEV acquisition costs;
- Unexpected charging infrastructure costs (such as inadequate electrical capacity in facilities); and
- The timing of transitioning specific segments of the fleet based on market conditions (i.e., availability and supply).

For these reasons, our team, with input from Toronto Hydro Fleet Management, took a cautious approach with BEV acquisition costs by adding premiums ranging from 48% to 100% (lower ratios for light-duty units and higher ratio for medium- and heavy-duty units) for BEVs over internal combustion engine (ICE) counterparts. There is a strong likelihood that the acquisition cost of BEVs will decline with time as both supply increases and as battery technology continues to improve, and we have modelled this for the utility's consideration.

Challenges to Electric Vehicle Transition

The reality is that electric vehicle transition will require a degree of extra effort and cost to implement, as well as new operational challenges that must be resolved. The successful planning and execution of installing the correct charging infrastructure, including Level 2 electric vehicle charging stations and/or Level 3 direct current (DC) fast-charging stations, is of paramount importance for the smooth phase-in of electric vehicles into Toronto Hydro's fleet. Moreover, electric vehicles offer a different experience for operators in terms of both driving and re-fuelling (charging); therefore, change management is a critical piece of successful electric vehicle transition.

GHG Emissions Calculation Methods

Internationally, there are two standard reporting methods for vehicle GHG emissions modelling: (1) tailpipe combustion, and (2) fuel lifecycle (sometimes referred to as fuel cycle or well-to-wheel). Modelling of fuel lifecycle GHG emissions of motor fuels is used to assess the overall GHG impacts of the fuel, including each stage of its production and use, in addition to the fuel actually used to power a vehicle. Modelling of tailpipe emissions includes only the emissions produced by the vehicle itself through combustion. Lifecycle GHG emissions are, therefore, greater than tailpipe emissions.

While lifecycle emissions have been established for most fuel types, lifecycle emissions are often difficult to quantify for electric vehicles because of the different mixes of electricity sources in different jurisdictions and at different times of day (i.e., fossil-fuel based, nuclear, and renewables). Given that most electricity in the City of Toronto comes from nuclear power, as well as for simplicity of our analysis, we employed the tailpipe combustion method. Using this method, BEVs emit zero emissions. Although not providing a complete well-to-wheel picture of GHG emissions, the results of our modelling employing the tailpipe combustion method gives a clear indication as to the degree of GHG reduction potential through transitioning the fleet to BEVs.

...

Executive Summary

In September 2021, Toronto Hydro engaged Richmond Sustainability Initiatives – Fleet Challenge (RSI-FC) of Toronto, Ontario, to develop an Electric Vehicle Phase-in Plan for its fleet assets.

Through the development and implementation of an Electric Vehicle Phase-in Plan, RSI-FC aims to assist Toronto Hydro in realizing:

- A long-term capital budget plan for phasing in battery-electric vehicles (BEVs) and charging infrastructure;
- A fleet asset management strategy for selecting which internal combustion engine (ICE) vehicles are the best candidates to replace with BEVs based on a data-driven assessment and return-on-investment (ROI);
- Improved fuel efficiency and reduced fuel cost;
- Reduced GHG and air pollutant emissions; and
- Continued leadership in environmental sustainability.

About Richmond Sustainability Initiatives

Since 2005, RSI-FC has collaborated with fleet managers, technology providers, subject matter experts, and auto manufacturers to find viable solutions, technologies, and best management practices for reducing operating costs and vehicle emissions. From the beginning, we have remained a self-supporting and independently funded program without commercial biases or influences, providing fleet review and consulting services to dozens of leading private and public sector fleets in Canada and the United States.

About Fleet Analytics Review™

For the development of the Electric Vehicle Phase-in Plan, RSI-FC employed our innovative, leading-edge data-modelling techniques and our proprietary software, Fleet Analytics Review™ (FAR). FAR is a software tool designed and developed by our company specifically for complex fleet planning. FAR enables our team to develop short- to long-term green fleet plans and strategies by calculating GHG emissions reductions and return-on-investment (ROI) for various best practices and technologies – all driven by actual historical data. In turn, this allows us to evaluate the business case of each solution and provide meaningful recommendations for long-term capital planning (LTCP).

Vision, Goal, and Objectives

The vision for the Electric Vehicle Phase-in Plan is to assist Toronto Hydro in transitioning its fleet to battery-electric vehicles (BEVs) through a streamlined fleet asset management strategy and long-term capital budget plan. With this vision in mind, the goal is to provide an ambitious, yet feasible, roadmap for the utility to phase-in BEVs and achieve significant GHG emissions reductions in a fiscally responsible manner. To guide Toronto Hydro in achieving this goal, we have thoroughly analyzed the utility's in-scope fleet data and we have identified various paths for electrification with varying degrees of speed and implementation.

The objectives of the Electric Vehicle Phase-in Plan were to:

(1) Present findings of RSI-FC's Electric Vehicle Survey to gauge the current view and opinions of employees on battery-electric vehicles and charging requirements;

(2) Develop a fleet and GHG emissions baseline for current fleet assets;

(3) Data-model various fleet electrification pathways over a 15-year budget cycle and estimate their impacts (Operating expenses, Capital expenses, and GHG emission reductions) relative to the baseline;

(4) Data-model electric vehicle supply equipment (EVSE) requirements on a unit-by-unit basis and estimate charger costs over a 15-year budget cycle; and

(5) Create a fleet electrification plan, both in terms of BEV phase-in and charging infrastructure, that is achievable, based on ROI and in consideration of the utility's fleet budget constraints – with a degree of ambition.

Electric Vehicle Survey Results

Based on results and comments expressed in the electric vehicle survey, it is clear that Toronto Hydro Fleet's user-group stakeholders are, overall, very supportive of the transition to electric vehicles.

Although views are mostly similar, there are some differences in opinions between the management and driver/operator cohorts regarding views of electric vehicles. Generally, drivers/operators are more doubtful/unaware of the capabilities and benefits of modern-day electric vehicles.

Regarding charging requirements, both groups are generally undecided about the adequacy of Level 2 (slow) charging for the fleet, and feel more strongly about the use of Level 3 (fast) charging. RSI-FC's analysis of Toronto Hydro's charging requirements based on Level 2 charging (see *Section 7*) addresses this very concern.

In terms of change management approaches, survey results show that driver/operators are moderately supportive of BEV test drives but are highly in favour of BEV orientation, while managers are in strong support of both options. Efforts in familiarizing employees with driving and charging

BEVs would likely close knowledge gaps, hesitancies, and resistance towards this technology, allowing for a more seamless transition over the coming years.

Baseline Analysis

The Electric Vehicle Phase-in Plan is based on our team's detailed data analysis of one-year of historical data for **385 Toronto Hydro fleet vehicles** as submitted by the utility.

Key fleet-wide results from the one-year review period (August 2020 to July 2021) are shown below:

- There were 211 gasoline-powered units, 160 diesel-powered units, 1 plug-in hybrid-electric (PHEV) units, and 13 battery-electric vehicle (BEV) units.
- All units were owned.
- The original purchase price for the fleet was $48,630,000.
- The current-day estimated replacement cost (like-for-like replacements) was $67,549,000.
- The estimated market/trade-in value was $22,359,540.
- The total cost of preventive maintenance (PM) was $481,389.
- The total cost of reactive repairs was $1,663,860.
- The estimated total cost of fuel was $757,168.
- The total cost of repairs and maintenance, fuel, capital, and downtime was $4,399,845.
- Total kilometres-travelled was 1,796,605.
- Total fuel used was 633,851 litres.
- Total tailpipe GHG emissions were 1,624 metric tonnes CO_2e.
- The average unit annual mileage was 4,667 km.
- The average fuel consumption for the entire fleet was 56.6 l/100km.
- The average unit age was 6.7 years.

Business Case Optimization & Capex Benchmarking

In 2017, a lifecycle analysis (LCA) study was undertaken by RSI-FC for each vehicle category at Toronto Hydro to determine optimized economic lifecycles. After modelling the baseline with optimized economic lifecycles, it was apparent that some vehicles deliver better return-on-investment (ROI) than others. Lower ROI would result if a vehicle, still in good condition, was replaced prematurely; value will be lost.

The approach used by RSI-FC was to defer some vehicles to ensuing capital budget years to ensure full value is received from each unit. In our data-modeling, without knowledge of the physical condition of units due for replacement based on vehicle ages, our analysts selectively and strategically made deferrals for units showing low/no ROI over the budget cycle to maximize operating expense (Opex) benefits and balance year-over-year capital expenses (Capex). As a result, the annual capital budget over the 15-year cycle ranged from $5.3-7.9 million and averaged $6.2 million.

This step was intended to provide a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – and as a comparison for long-term capital planning for BEV phase-in.

BEV Phase-in Scenario Results

RSI-FC data-modelled several fleet electrification pathways, or scenarios, for Toronto Hydro – ranging from aggressive to conservative – and we calculated the potential impacts of each relative to the 2020-21 baseline. Details of our approaches and scenario results, as well our analysis for electric vehicle supply equipment (EVSE) requirements, are provided in *Sections 6 and 7*.

These “what-if” scenarios assessed the potential outcomes if each electrification pathway being modelled was in place for the same types of vehicles, the same number of vehicles, travelling the same number of kilometres as the baseline period.

Our modelling estimated annual capital costs as well as operating cost impacts and GHG emissions reductions relative to 2020-21 baseline. In *Table 1* (below), results are summarized and include average annual Capital expenses (Capex) over the budget cycle, average annual Operating expense (Opex) changes over the budget cycle relative to the baseline, and annual tailpipe GHG reduction by 2037 relative to the baseline. Due to the limited availability of BEVs in the short-term, we have modelled BEV phase-in over a 15-year budget period following the year 2022 (i.e., from 2023-2037).

On the positive side of the analysis, the most aggressive fleet electrification scenarios have the potential to reduce Toronto Hydro’s fleet tailpipe GHG emissions by **100% by 2034** – before the end of the modelling period. The more cautious and fiscally prudent scenarios have the potential to reduce Toronto Hydro’s fleet tailpipe GHG emissions by just over **70% by 2037** – with the potential to achieve even greater results should more internal combustion engine (ICE) units be replaced with BEVs towards the end of the modelling period, depending on pricing outcomes for BEVs compared to ICEs.

Firm acquisition costs for battery-electric medium- and heavy-duty trucks are unknown at this time, but initially expected to be significantly more than today’s standard ICE trucks. This is reflected in our modelling based on discussion with Toronto Hydro Fleet Management. Moreover, BEV prices for all classes are expected to decrease over time and possibly reach parity with standard gas and diesel trucks; however, the timing for this is unknown. To model the possible implications of BEV price reductions over time, we applied a sliding scale to both the aggressive and fiscally prudent BEV phase-in scenarios (*Table 1*, below).

Due to the significantly higher acquisition costs *currently* anticipated for soon-to-emerge electric trucks, and owing to the fact that Toronto Hydro is, like all municipal utility fleets, a low-mileage operation, the fuel cost savings from a transition to electric vehicles will not offset the additional vehicle capital costs in many vehicle applications, resulting in a forecasted increase in operating expenses as shown in *Table 1*.

Note: The significantly higher operating expenses shown in Table 1 are due to the significantly increased cost of capital for acquiring new vehicles based on year-over-year book values of units.

Table 1: Summary of fleet-wide results of scenario analysis over the period 2022-2037 relative to the 2020-21 baseline.

FAR #	FAR Scenario Description	Implementation Timing[2]	Average Annual Vehicle Replacement Capex[3] [4]($ millions)	Average Annual Opex[5] [6] Impacts Over Baseline ($ millions)	Annual Tailpipe GHG Reduction[7] Over Baseline (tonnes CO_2e)	Annual Tailpipe GHG Reduction Percentage Over Baseline
1	Optimized lifecycles	2022 - 2037	6.7	+0.94	41	2.5%
2	Optimized lifecycles + ROI (benchmarking scenario)	2022 - 2037	6.2	+0.89	37	2.3%
3.1	BEV phase-in: aggressive and cautious pricing	2022 - 2037	*10.7	+3.23	1,623	100%
3.2	BEV phase-in: aggressive and optimistic pricing (sliding scale)	2022- 2037	*7.6	+2.29 (**est.)	1,623	100%
4.1	BEV phase-in: balanced, cautious pricing, more ICE replacements	2022-2037	8.3	+1.77	1,146	71%
4.2	BEV phase-in: balanced, optimistic pricing (sliding scale), more ICE replacements	2022-2037	7.0	+1.49 (**est.)	1,146	71%
5	BEV phase-in: balanced, cautious pricing, few ICE replacements due to greatly extended lifecycles	2022-2037	9.8	+2.31	1,503	93%

* Note that both of these scenarios involve significant Capex "spikes" in the short- to medium-term.

* Estimated based on applying a sliding scale in BEV pricing.

Electric Vehicle Supply Equipment Planning

Based on our analysis of Toronto Hydro's charging requirements, 381 out of 385 units would be capable of fully recharging during overnight off-peak hours with the use of lower-power Level 2 chargers. Therefore, our recommendation is to focus on Level 2 charging for every unit on a nightly basis, and evaluate higher-power (Level 3) charging for higher-mileage units.

[2] For data-modelling purposes, fleet-wide implementation is modelled over the period from 2022-2037 for the same types of vehicles, the same number of vehicles, travelling the same number of kilometres as the 2020-2021 baseline.
[3] Average annual Capital expenses (Capex) for the entire modelling period (2022-2037), including compounding inflation for each year at current rate of inflation.
[4] For BEV charging infrastructure, additional capital costs were estimated separately using an EVSE costing tool.
[5] Average annual Operating expenses (Opex) for the entire modelling period (2022-2037) , including compounding inflation for each year at current rate of inflation.
[6] For data-modelling purposes, Opex includes the annual cost of capital based on year-over-year book values of units.
[7] Annual GHG reduction by the end of the modelling period (2037) is relative to the 2020-2021 baseline.

Our charger costing outlook, based on a balanced BEV phase-in approach, shows that Toronto Hydro's fleet would be 100% BEV-ready by 2034 based on the current size of the fleet. Given our estimations, this translates to an average annual charger cost (excluding infrastructure) of about $74,000 per year for the next 13 years.

Preparing for a Battery-Electric Vehicle Future

Vehicle investments are long-term; units purchased today will remain in service for up to a decade or longer. ICE vehicles are quickly becoming outdated as BEVs rapidly take over. Globally, numerous jurisdictions have already legislated the end of the ICE – some as soon as 2030. On January 28, 2021, General Motors pledged to cease building gasoline and diesel cars, vans, and SUVs by 2035. Even more recently, on June 29, 2021, the Canadian government announced a mandatory target for all new light-duty cars and passenger trucks sales to be zero-emission by 2035, accelerating Canada's previous goal of 100 percent sales by 2040[8]. ICE vehicles purchased today for a fleet with a current-day value in the millions of dollars may be nearly worthless when ICEs become obsolete.

BEVs have a fraction of the moving parts of an ICE vehicle, cost far less to maintain, offer better performance, and can have a much lower total cost of ownership (TCO) for higher-mileage applications. For these reasons, if the condition of currently-owned Toronto Hydro fleet ICE vehicles will allow, we suggest prolonging their lifecycles until BEV replacements are available.

Today, only light-duty (cars, SUVs), transit buses, and refuse trucks (the latter of which are not applicable to this study) are available in BEV models. However, by the mid 2020s the types of vehicles that comprise a major portion of the Toronto Hydro fleet, including pickups and vans, will likely be available as BEVs. Therefore, the time is now to **begin preparing for the transition to BEVs** by investing in electric vehicle supply equipment (EVSE) while awaiting suitable BEVs to become readily available.

[8] Source: https://www.canada.ca/en/transport-canada/news/2021/06/building-a-green-economy-government-of-canada-to-require-100-of-car-and-passenger-truck-sales-be-zero-emission-by-2035-in-canada.html

Summary of Recommendations

In *Table 2* (below), we summarize our recommendations for Toronto Hydro's Electric Vehicle Phase-in Plan in terms of both (1) capital planning for transitioning the fleet to electric and (2) electric vehicle supply equipment (EVSE) requirements. Moreover, we have included recommendations on collaboration/partnerships and risk/change management for creating a culture of receptiveness to innovation and forward thinking.

Table 2: Summary of recommendations for Toronto Hydro's Electric Vehicle Phase-in Plan

Area/ Topic	Recommendations
Battery-Electric Vehicle Phase-In	(1) Through a lens of an aggressive BEV phase-in, allocate the majority of fleet capital spending on BEVs for appropriate vehicle categories as BEV models become available. (2) Through a lens of a balanced, selective BEV phase-in and fiscal prudence, prioritize replacement of ICE units with BEVs *that would maximize ROI* – typically ones that have relatively high annual mileage. (3) For units due for replacement that are still in good condition, conduct a temporary pause on purchasing new internal combustion engine (ICE) vehicles for the short term – 1-2 years for pickups, 2-3 years for medium- and heavy-duty vehicles (MHDVs) – while awaiting battery-electric vehicle (BEV) counterparts to become available and taking into consideration procurement timelines. Extend ICE lifecycle whenever possible. (4) Employ a strategy that calls for increased capital spending upfront (i.e., in the next few years) for ICE units in greatest need of replacement, in an effort to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements and allow for balanced, within-budget capital spending on BEVs down the road. Consider applying the decision matrix used by our team to determine which units to replace with ICE units in the short-term. (5) Conduct pilot projects for several BEV types when they become available (e.g., pickups, passenger minivans, etc.) to track range capabilities and cost savings and assess the units' performance for all seasons and varying weather conditions.

Area/ Topic	Recommendations
	(6) Assuming the pilot projects are successful, acquire BEVs in bulk to replace units that would provide the greatest ROI. (7) Closely monitor the acquisition costs for BEVs and re-evaluate the business case (cost-benefit) for individual units as prices change/ decline. (8) Consider purchasing plug-in hybrid vehicles (PHEVs) for lower-mileage units which would be able to fulfil daily duties on battery-power only and recharge overnight – essentially functioning like fully-electric vehicles.
Electric Vehicle Supply Equipment	(1) Over the next 10+ years, allocate capital towards chargers (and charging infrastructure, which is outside the scope of this study) required for the transition to BEVs for all vehicle categories. (2) Focus on Level 2 charging for every unit on a nightly basis, and evaluate higher-power charging (Level 3) for higher-mileage units. (3) Our general recommendation is for two Level 3 chargers be installed at each of the main Work Centers (Commissioners Work Center, Rexdale Work Center, and Milner Work Center) as a risk management strategy for time-dependent and/or urgent situations. However, without knowledge of the intricacies and specific use cases for each fleet vehicle, our secondary recommendation is to identify the most appropriate Work Centers for investment in higher-power (Level 3) charging, i.e., ones that consist of vehicles that may not always rely on overnight charging only. (4) Monitor upcoming funding opportunities from NRCan's Zero Emission Vehicle Infrastructure Program (ZEVIP), which may greatly offset the capital costs required to install charging infrastructure (outside the scope of this report). (5) Assess existing electrical capacity at facilities to determine whether substantial upgrades for charging multiple vehicles are required, as well as standby generator capacities

Area/ Topic	Recommendations
	(outside the scope of this report). A qualified electrical professional should be consulted to assess the situation and make recommendations. (6) Explore supplying power to each site/garage on two separate feeds from the grid to reduce the risk of local failure taking power away from the whole site. (7) To mitigate the risk of power grid failure or local failure at a site/garage, ensure backup generators have sufficient capacity to deal with short power outages, and assess the need for higher-capacity generators for longer outages. (8) Explore solar energy technology options to supply energy for EV charging to reduce GHG emissions that may be produced from the electricity supply used for charging. (9) Provide or expand on current high-voltage safety awareness and/or skills training to include operating and maintaining Toronto Hydro's electric vehicle charging stations, and closely monitor the launch of new electric vehicle fleet technician training programs.
Collaboration/Partnership Approaches	(1) Engage in internal partnerships within and across departments, such as multi-departmental funding applications for charging infrastructure, or sharing of BEV pilot program results to determine vehicles requirements and specifications (e.g., real-world range, real-world charging needs) ahead of large purchasing decisions involving many units. (2) Engage in external partnerships (e.g., other utilities in Ontario) for potential collaborations, such as joint specification writing and/or joint tenders and sharing of BEV pilot program results through working groups. (3) Leverage the knowledge gained on BEV transition (e.g., procurement of vehicles and charging infrastructure) through organizational memberships such as the Clean Air Partnership or the Canadian Utility Fleet Council (CUFC).
Risk/Change Management Approaches	(1) Develop BEV educational and outreach materials for employees and operators summarizing the reasons and benefits of transitioning to BEVs.

Area/ Topic	Recommendations
	(2) Invite frontline employees to take BEV test drives to familiarize them with fully-electric vehicles and charging, as well as to give them first-hand experience of improved performance (e.g., instant torque, little noise, regenerative braking). (3) Provide operators with a BEV orientation before releasing new models into the fleet to enable them to become familiar with the different driving experience (e.g., instant torque, little noise, regenerative braking), as well as to alleviate/eliminate any apprehension or uncertainties such as range anxiety. (4) As is recommended for the phasing in of BEVs, we recommend pilot projects for several BEV types as they become available (e.g., pickups, passenger minivans, etc.) to track range capabilities and cost savings and assess the units' performance for all seasons and varying weather conditions.

. . .

Section 1: Introduction and Background

Climate change is a critical and urgent global issue. The United Nations defines climate change as "a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods[9]." The term includes major changes in temperature, precipitation, or wind patterns, among others, that occur over several decades or longer[10].

Greenhouse gases (GHGs) produced by human activity is the largest contributor to climate change. GHGs are gaseous compounds (such as carbon dioxide) that absorb infrared radiation, trap heat in the atmosphere, increasing global temperature and thus contributing to the greenhouse effect[11]. While there are several GHGs[12] to consider, when calculating emissions the most commonly used measure is carbon dioxide equivalent (CO_2e)[13]. This combines the effects of all the major GHGs into a single, comparable measure.

Over the past several decades, scientific evidence of climate change, also referred to as global warming due to the increasing temperatures of the global climate system, has been vast and unequivocal. Thus, the Paris Agreement (the Agreement, the Accord) was established with a goal of keeping global warming below two (2) degrees Celsius compared with preindustrial times. The Agreement entered into force on November 4th 2016. Canada is a signatory and, as so, has established aggressive carbon-reduction targets and plans.

In addition to climate change, emissions from engine exhausts also contribute to ground-level air pollution and human health risk. Criteria air contaminants (CACs) contribute to smog, poor air quality, and acidic rain. CACs include several gases, particulate matters and volatile organic compounds[14]. In scientific studies, CACs have been linked to increased risks of respiratory and cardiovascular diseases as well as certain cancers. The World Health Organization reports that in 2012 around seven million people died as a result of air pollution exposure; one in eight of total global deaths were linked to air pollution[15]. According to the American Medical Association, globally, an estimated 3.3

---

[9] Source: United Nations Framework Convention on Climate Change 1992:
https://unfccc.int/files/essential_background/background_publications_htmlpdf/application/pdf/conveng.pdf
[10] Source: EPA. https://www3.epa.gov/climatechange/glossary.html
[11] Source: https://www.merriam-webster.com/dictionary/greenhouse%20gas
[12] GHGs include, but are not limited to carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulphur hexafluoride (SF_6), nitrogen trifluoride (NF_3), perfluorocarbons (PFCs), and hydrofluorocarbons (HFCs).
[13] "Carbon dioxide equivalent is a measure used to compare the emissions from various greenhouse gases based upon their global warming potential. For example, the global warming potential for methane over 100 years is 21. This means that emissions of one million metric tonnes of methane is equivalent to emissions of 21 million metric tonnes of carbon dioxide." Source: https://stats.oecd.org/glossary/detail.asp?ID=285
[14] CACs include Total Particulate Matter (TPM), Particulate Matter with a diameter less than 10 microns (PM10), Particulate Matter with a diameter less than 2.5 microns (PM2.5), Carbon Monoxide (CO), Nitrogen Oxides (NOx), Sulphur Oxides (SOx), Volatile Organic Compounds (VOC), and Ammonia (NH3).
[15] Source: http://www.who.int/mediacentre/news/releases/2014/air-pollution/en/

million annual premature deaths (5.86% of global mortality) are attributable to outdoor air pollution[16], although ambient air pollution has been regulated under national laws in many countries.

Socially responsible institutional, commercial, and industrial fleets can play an important role in reducing GHG emissions and air pollution.

Fleet Sector Impact

Low-carbon transportation is essential to both short-term GHG and fuel-use reduction and long-term decarbonization of the economy. In 2020, the transportation sector accounted for about 25% of greenhouse gas (GHG) emissions in Canada, second only to the oil and gas sector[17]. Utilities can play a key role in cutting emissions by transitioning their fleets to low-carbon and/or electric vehicles, while saving fuel and maintenance costs.

The transition to battery-electric vehicles (BEVs) of all classes will be a game-changer as these vehicles take up more of the market in the next several years, both in terms of operational cost savings and the deep GHG emission reductions required to curb the most severe impacts of climate change. Significant and growing commitments to integrating BEVs into fleet operations will be a driving force in the transition to BEVs[18]. Moreover, continued improvements in range capability and charging infrastructure will accelerate the electrification of fleets.

About Richmond Sustainability Initiatives

Since 2005, Richmond Sustainability Initiatives – Fleet Challenge (RSI-FC) has collaborated with fleet managers, technology providers, subject matter experts, and auto manufacturers to find viable solutions, technologies, and best management practices for reducing operating costs and vehicle emissions. From the beginning, we have remained a self-supporting and independently funded program without commercial biases or influences, providing fleet review, strategies and management consulting services to dozens of leading private and public sector fleets in Canada and the United States.

Through the combination of our experience and the use of our Fleet Analytics Review™ (FAR) software tool, we are delivering an advanced Electric Vehicle Phase-in Plan for Toronto Hydro that is provides numerous electrification pathways based on the speed of BEV transition and BEV prices.

[16] Source: https://jamanetwork.com/journals/jama/article-abstract/2667043
[17] Source: https://climateactiontracker.org/countries/canada/
[18] Source: ChargePoint. Trends & Prediction in Fleet Electrification [pdf]. June 2020.

Background

Toronto Hydro owns and operates the electricity distribution system that provides electricity to approximately 785,000 customers in the City of Toronto, which has a population base of approximately 3.0 million people. The utility delivers about 17 per cent of the electricity consumed in the province of Ontario.[19]

The Electric Vehicle Phase-in Plan will help chart a path of environmental sustainability and the reduction of GHGs through an ambitious, yet feasible, roadmap – keeping in mind budget constraints, return-on-investment (ROI), availability of BEVs of various types, and procurement timelines.

Toronto Hydro has already deployed numerous BEVs into its fleet (Chevrolet Bolts). The Plan is the next logical step in these environmental initiatives; Fleet Management can utilize the scenario analysis provided in this report for fleet replacement strategies and long-term capital planning.

Vision, Goal, and Objectives

The vision for the Electric Vehicle Phase-in Plan is to assist Toronto Hydro in transitioning its fleet to battery-electric vehicles (BEVs) through a streamlined fleet asset management strategy and long-term capital budget plan. With this vision in mind, the goal is to provide an ambitious, yet feasible, roadmap for the utility to phase-in BEVs and achieve significant GHG emissions reductions in a fiscally responsible manner. To guide Toronto Hydro in achieving this goal, we have thoroughly analyzed the utility's in-scope fleet data and we have identified various paths for electrification with varying degrees of speed and implementation.

The objectives of the Electric Vehicle Phase-in Plan were to:

(1) Present findings of RSI-FC's Electric Vehicle Survey to gauge the current view and opinions of employees on battery-electric vehicles and charging requirements;

(2) Develop a fleet and GHG emissions baseline for current fleet assets;

(3) Data-model various fleet electrification pathways over a 15-year budget cycle and estimate their impacts (Operating expenses, Capital expenses, and GHG emission reductions) relative to the baseline;

(4) Data-model electric vehicle supply equipment (EVSE) requirements on a unit-by-unit basis and estimate charger costs over a 15-year budget cycle; and

[19] Source: https://www.torontohydro.com/about-us/company-overview

(5) Create a fleet electrification plan, both in terms of BEV phase-in and charging infrastructure, that is achievable, in consideration of the utility's fleet budget constraints – with a degree of ambition.

...

Section 2: Electric Vehicle Survey

Our organization recognizes the value of stakeholder engagement and user group participation in any go-forward plans under consideration by our clients. With that focus in mind, RSI-FC set out to gain staff perspectives and opinions from Toronto Hydro's Fleet user groups on electric vehicles and charging requirements.

RSI-FC understands the importance of hearing the opinions of *all* stakeholders, including both management and staff. It was clearly communicated to all survey recipients that their responses were confidential and anonymous; as so, they were encouraged to express their opinions freely.

We are aware that online surveys are not always the ideal method for collecting opinions and gathering information. It is known in the industry that people are often reluctant to provide their personal opinions in this manner; typically, survey response rates are known to only be in the 10 to 15% range. However, due to the Covid-19 pandemic, in-person meetings are not currently possible. Knowing that feedback from stakeholders is important for go-forward planning, as a workaround we opted to instead conduct a web-based online survey. During the last year and a half we have received some valuable feedback from online surveys, as it does give participants a sense of freedom to speak candidly and voice any concerns.

A unique survey was designed for management and drivers/operators to highlight differences in opinions and views, as well as to help inform our recommendations. In total, we received 66 responses (42 from management group and 24 from driver/operator group) out of 330 surveys sent to designated internal staff, which translates to an overall response rate of 20% – well above the typical industry range of 10-15%. We were pleased that responses were insightful and of high-quality, providing us with valuable feedback which we will outline and discuss in this section. Key figures of survey results can be found in *Appendix A*.

Breakdown of Participant Roles & Vehicles Driven

- For the management survey, about two thirds of respondents were either directors/managers or supervisors, with the remaining participants in various roles ranging from analysts to field operators. Over 40% of respondents drive either a cars or pickups, another 40% drive a van, and several respondents drive single bucket aerial trucks.
- For the driver/operator survey, there was a wide spectrum of respondents' roles ranging from certified crew leaders to technologists to mechanics. Over 40% of vehicles driven by respondents were pickups and passenger minivans, with the remaining covering a range of vehicle types from cars to cube vans to single/double bucket aerial trucks.

Views on Battery-Electric Vehicles

- There is strong agreement in both the management and driver/operator groups participants that BEVs can travel far enough to meet daily needs and are capable of performing job duties (mean scores ranging from 4.1/5 and 4.3/5).

- There is strong agreement in the management group that there is sufficient heating and cooling in BEVs (mean score of 4.0/5). However, the driver/operator group is generally undecided on this matter (mean score of 3.3/5).

- There is strong agreement in both groups that BEVs are safe to drive and charge, with some more hesitancy in driver/operator group (median scores of 5/5 and 4/5 in the management and driver/operator groups, respectively).

- Overall, both groups are undecided as to whether BEVs costs less to operate and will save money for Toronto Hydro (mean scores of 3.8/5 and 3.6/5 in the management and driver/operator groups, respectively).

- There is strong agreement in both groups that BEVs cause less pollution than standard gas and diesel vehicles, with slightly stronger agreement in the driver/operator group (mean scores of 4.1/5 and 4.3/5 in the management and driver/operator groups, respectively).

- In both groups, there is a lack of consensus and a wide range of opinions as to whether BEVs of the type Toronto Hydro requires are available now or will be available in the near future (mean scores of 3.7/5 and 3.6/5 in the management and driver/operator groups, respectively).

Views on Charging Requirements

- Overall, in both groups, there is a lack of agreement as to whether investing in Level 2 charging infrastructure would be sufficient for most of the BEV charging needs of Toronto Hydro (mean scores of 3.5/5 and 3.4/5 in the management and driver/operator groups, respectively).

- About 60% of respondents in both groups agree or strongly agree that investing in Level 3 charging infrastructure would be required to fulfil Toronto Hydro's BEV charging needs. Overall, there is slightly stronger agreement on this topic in the management group (mean score of 3.9/5 and 40% of respondents strongly agree) than in the driver/operator group (mean score of 3.8/5 and more than 40% of respondents undecided).

- In both groups, there is a lack of consensus and a wide range of opinions as to whether high-voltage safety awareness and/or training would be needed for operating and maintaining Toronto Hydro's electric vehicle charging stations (mean scores of 3.1/5 and 2.8/5 in the management and driver/operator groups, respectively).

Views on Change Management

- The majority of respondents in both groups agree that Toronto Hydro employees and operators would benefit from BEV educational and outreach materials (mean scores of 3.8/5 and 3.7/5 in the management and driver/operator groups, respectively), with stronger agreement in the management group (over 62% agree/ strongly agree vs. just under 55% in the driver/operator group).

- There is stronger agreement in the management group than the driver/operator group that Toronto Hydro operators would benefit from BEV test drives (mean scores of 4.2/5 and 3.8/5, respectively). Eighty (80) percent of management participants agree or strongly agree with this idea, versus under 60% in the driver/operator group.

- In both groups, there is strong agreement that operators would benefit from BEV orientation provided before releasing new models into the fleet (mean score of 4.0/5 for both groups). Seventy-five (75) percent of management participants and about 80% of driver/operator participants agree or strongly agree with this idea.

Comments & Concerns

At the end of the survey, participants were given the opportunity to provide their own comments in a "freestyle" section that allowed for additional thoughts and ideas on transitioning to electric vehicles.

There were several common thoughts and/or concerns from participants, including:

- Ensuring there is sufficient EV range in the winter for high-mileage vehicles.

- Ensuring there is a full charge to start the day, particularly for high-mileage vehicles in the winter when ranged is reduced.

- The benefit of Level 3 charging for particular applications, including vehicles taken home on standby as well as vehicles used in field operations.

- The benefit and successful application of electric light-duty vehicles (cars, pickups, and vans) in the fleet, but concern over the viability of larger electric trucks including bucket trucks and line trucks.

We have selected the following comments that were, overall, representative of participants' view on the matters of moving towards an electric fleet:

"As a utility, Toronto Hydro should be an early adopter of EV technology."

"I would love to see a shift in electric vehicles at Toronto hydro mainly, pickups, vans and small cars at the start and then move to a half and half system on our buckets and cranes"

"The only issue [with the Chevrolet Bolt] is with winter range which is approx 225k. If I take the vehicle home on Standby, I typically will have no range to do crew visits the following day and have enough range take it home again. There is also not enough time to charge it sufficiently. This is where I think a Level 3 charger might be of benefit."

"In general, I believe this is the right way to go. Only concern is that my team (metering) does a fair number of KMs per day. Need to ensure that even at -40, there is sufficient charge for the day and that overnight charging will consistently ensure the team starts with a full charge."

"YES electric vehicles and charging stations would be great, I think a job aid would be better than formal training"

"[EVs are] good to have but we will always need a good number of combustion engines. If there is an ice storm or other rolling blackouts, gas and diesel powered trucks will be invaluable"

Synopsis

Based on the results of this survey and participant comments, it is clear that Toronto Hydro Fleet's user-group stakeholders are, overall, very supportive of the transition to electric vehicles.

Although views are mostly similar, there are some differences in opinions between the management and driver/operator cohorts regarding views of electric vehicles. Generally, drivers/operators are more doubtful/unaware of the capabilities and benefits of modern-day electric vehicles.

Regarding charging requirements, both groups are generally undecided about the adequacy of Level 2 (slow) charging for the fleet, and feel more strongly about the use of Level 3 (fast) charging. RSI-FC's analysis of Toronto Hydro's charging requirements based on Level 2 charging (see *Section 7*) addresses this very concern.

In terms of change management approaches, survey results show that driver/operators are moderately supportive of BEV test drives but are highly in favour of BEV orientation, while managers are in strong support of both options. Efforts in familiarizing employees with driving and charging

BEVs would likely close knowledge gaps, hesitancies, and resistance towards this technology, allowing for a more seamless transition over the coming years.

Section 3: General Approach and Methodology

RSI-FC maintains that fleet asset management plans must be sustainable – both environmentally and financially. For this reason, RSI-FC's approach to developing Toronto Hydro's Electric Vehicle Phase-in Plan is based on data-modelling of the current situation, data-modelling of optimized unit lifecycles considering return-on-investment (ROI), and assessing a number of electrification pathways to find a viable and financially prudent approach for the utility to transition its fleet to BEVs.

To achieve optimal efficiency in completing this type of analysis, our team developed Fleet Analytics Review™ (FAR), a software tool designed specifically for complex green fleet planning and evaluation of short- to long-term fuel-reduction strategies, including BEV transition, both in terms of cost savings and GHG reductions.

About Fleet Analytics Review™

Fleet Analytics Review™ (FAR) is a user-friendly, interactive decision support tool. FAR was designed to aid our team and fleet managers in developing short- to long-term green fleet plans by calculating the impacts of vehicle replacement and fuel-reduction solutions on operating costs, cost of capital, and GHG emissions. Moreover, it is used for long-term capital planning (LTCP) through an approach that works to balance, or smoothen, annual capital budgets and avoid cost spikes if possible. For a detailed FAR description, please see *Appendix B*.

Using optimized economic lifecycles, fuel-saving options, including switching to BEVs, are modelled for units due for replacement to determine if they can deliver operating cost savings over subsequent fiscal years and, if so, the potential GHG emissions reductions. In FAR, operating costs include fuel costs, repair and maintenance costs, and the cost of capital of acquiring units based on their year-over-year book values.

Transitioning to BEVs is the ultimate GHG reduction strategy for a fleet. In our analysis for Toronto Hydro, we modelled tailpipe emissions reduction; therefore, switching a unit to battery-electric reduces fuel consumption by 100% applying this method. However, in terms of life cycle GHG emissions, BEVs are "fuelled" by electricity needed to charge the battery, which can indirectly use fossil fuel depending on the source of electricity.

FAR will be licensed in perpetuity to Toronto Hydro for its internal use post-project. The FAR model is dynamic, and users can easily run future scenarios (such as assessing different vehicle types, fuels, or technologies) to see how such decisions impact operating expenses – ahead of their implementation, thereby heading off potentially costly errors.

Steps to Producing Electric Vehicle Phase-in Plan

RSI-FC employs a multi-step approach in low-carbon, green fleet planning. In Toronto Hydro's Electric Vehicle Phase-in Plan, the steps included:

1) **Baseline Analysis.** At the outset, it is crucial to confidently know the current fleet baseline in terms of several key performance metrics including acquisition and operating costs, fuel economy, and GHG emissions. For this step, we complete a FAR baseline analysis.

   For Toronto Hydro, we received baseline data of the in-scope fleet from Fleet Management. The dataset provided to our team included a list of units, makes/models/years, asset values and ages, asset descriptions, fuel types, fuel costs, repair costs, and maintenance costs for a one-year review period (2019). We loaded this input data into FAR and completed baseline analysis.

2) **Lifecycle Analysis.** With RSI-FC's proprietary lifecycle analysis (LCA) software tool, our team inputs a fleet's historical data to calculate the optimal economic lifecycles for each vehicle category in the fleet.

   For Toronto Hydro, we completed an LCA study for all vehicle categories in 2017 to determine optimized economic lifecycles. With support from Toronto Hydro Fleet Management, optimized economic lifecycles determined from this study were applied to the 2020-21 FAR baseline.

3) **Business Case Optimization.** Once optimized lifecycles have been modelled in FAR, it often becomes very apparent that some vehicles deliver better return-on-investment (ROI) than others. One reason is that some vehicles that are due for replacement may have had lighter usage than other similar age units. For vehicles in better condition, service life can be extended to optimize the total cost of ownership (TCO). Lower ROI would result if a vehicle, still in good condition, was replaced prematurely; value will be lost. Fleet managers everywhere must make tough vehicle replace-or-retain decisions like this each year to optimize and stretch the use of available capital. Using RSI-FC's ROI-based approach to deferrals, year-over-year long term capital budgets can be better balanced.

   For Toronto Hydro, the approach used by RSI-FC's data analysts was to *defer* replacement of some vehicles to the ensuing capital budget years to ensure full value is received from each unit. Ideally, this step should be completed by Fleet staff based on vehicle condition assessments and to balance go-forward annual capital budgets. Without any knowledge of vehicle condition, for this step our team deferred any units which, based on the data provided, were shown to have lower operating costs (including cost of capital) than if replaced.

This step was intended to provide a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – as a comparison for long-term capital planning for BEV phase-in.

4) **Battery-Electric Vehicle Phase-in Planning.** Although there are numerous advantages of BEVs, few, if any fleets would – or could – replace all their internal combustion engine (ICE) units immediately with BEVs given capital budgets constraints and the fact that BEV offerings are quite limited at this time. This means that BEVs must be phased in over many years. For this reason, we data-model the gradual impacts of fleet BEV adaptation on a 15-year phased-in basis.

   Phasing in of BEVs should occur based on optimized economic lifecycles and balanced long-term budgets through business case optimization (see Step 3). In other words, the first units to be replaced with BEVs should be those that have been assessed as the optimal candidate vehicles that will deliver the best ROI. These are typically units with higher utilization and fuel consumption.

   However, given the currently limited availability of BEVs as well as the long procurement timelines once models do become available for purchase, BEV phase-in planning becomes a balancing exercise between: (1) extending the life of ICE vehicles until BEV counterparts are expected to arrive (i.e., in-service years); and (2) immediately replacing due units that have high utilization and/or relatively high repair costs with ICE vehicles.

   For Toronto Hydro, our team used FAR to conduct a granular, unit-by-unit assessment of BEV replacement – both as a short-term financial risk-reduction strategy and a long-term capital planning strategy. Based on baseline data provided, we decided (for modelling purposes only) which units to replace with ICE vehicles and which to replace with BEVs through extension of their lifecycles, keeping in mind the fiscal years for which the type/categories of BEVs are expected to be in-service based on procurement timelines.

   Given the higher acquisition costs of BEVs compared to ICE vehicles, which were applied to our modelling in consultation with Toronto Hydro Fleet Management, lower-mileage units are unlikely to deliver ROI if replaced with a BEV. Fortunately, these would also generally be the units that have a relatively small impact on GHG emissions reductions. However, ROI is dependent on BEV pricing outcomes. There is a strong likelihood that the acquisition cost of BEVs will decline with time as both supply increases and as battery technology continues to improve, and we have modelled this scenario for the utility's consideration.

5) **Electric Vehicle Supply Equipment Planning.** Our team developed an EVSE planning tool for Toronto Hydro to inform long-term capital planning (LTCP) for the utility's charging

infrastructure needs, based on Level 2 charging and battery capacity estimations. We also estimated the costs of electric vehicle chargers (not complete infrastructure) over the modelling period from 2022-2037, based on the current size and mileage of Toronto Hydro's fleet and a balanced, fleet-wide BEV phase-in.

RSI-FC's position is that fleets should not be keeping up with the demand for electric vehicle supply equipment (EVSE) based on the number of new BEVs added; rather, EVSE installation should be *outpacing* demand to allow for a smooth and seamless transition. Therefore, we have estimated the number of Level 2 chargers required to outpace the influx of new BEVs into Toronto Hydro's fleet.

...

Section 4: Baseline Analysis

A fleet baseline analysis provides a starting point for setting targets and measuring progress towards fuel- and GHG-emissions reduction. It is important that a baseline is as accurate as possible as it provides a snapshot of the current state of a fleet and is the foundation of a fleet management plan.

The Electric Vehicle Phase-in Plan is based on our team's detailed data analysis of one-year of historical data for **385 Toronto Hydro fleet vehicles** as submitted by the utility. RSI-FC collected baseline data of Toronto Hydro's fleet from Fleet Management. The dataset provided to our team included a list of units, makes/models/years, asset values and ages, asset descriptions, fuel types, repair costs, and maintenance costs for a one-year review period (2019). Our team then loaded input data into our proprietary software, Fleet Analytics Review™ (FAR), and completed a baseline analysis.

RSI-FC diligently collected and analyzed vehicle data provided by Toronto Hydro and made careful estimations and assumptions where needed. Key fleet-wide results from the one-year review period (August 2020 to July 2021) are shown below:

- There were 211 gasoline-powered units, 160 diesel-powered units, 1 plug-in hybrid-electric (PHEV) units, and 13 battery-electric vehicle (BEV) units.
- All units were owned.
- The original purchase price for the fleet was $48,630,000.
- The current-day estimated replacement cost (like-for-like replacements) was $67,549,000.
- The estimated market/trade-in value was $22,359,540.
- The total cost of preventive maintenance (PM) was $481,389.
- The total cost of reactive repairs was $1,663,860.
- The estimated total cost of fuel was $757,168.
- The total cost of repairs and maintenance, fuel, capital, and downtime was $4,399,845.
- Total kilometres-travelled was 1,796,605.
- Total fuel used was 633,851 litres.
- Total tailpipe GHG emissions were 1,624 metric tonnes CO_2e.
- The average unit annual mileage was 4,667 km.
- The average fuel consumption for the entire fleet was 56.6 l/100km.
- The average unit age was 6.7 years.

The baseline analysis sets the foundation for the next stages of the Electric Vehicle Phase-in Plan, starting with long-term capital planning (LTCP) for like-for-like replacements to determine a capital budgeting benchmark. The next stage involved modelling several electrification pathways for Toronto Hydro's fleet to provide an ambitious, yet feasible, roadmap for the utility to phase-in BEVs and achieve significant GHG emissions reductions in a fiscally responsible using a structured, methodical approach.

...

Section 5: Business Case Optimization and Capex Benchmarking

Providing capital to replace units each year with new vehicles is essential for any organization that relies on its fleet to provide its core services to customers. A guideline for fleet replacement is to invest capital at the rate of depreciation. For example, if vehicles are depreciated over ten years, then 10% of the total fleet replacement cost (current NPV) would be required each year to maintain the fleet's average age at the desirable level.

For Toronto Hydro, based on the current-day estimated replacement cost (like-for-like replacements) determined in the baseline analysis, about $6.8M would be required every year if vehicles are depreciated over 10 years. However, this guideline is only valid if performance indicators such as uptime and fuel-efficiency are satisfactory. If not, a one-time increase in spending would help bring the fleet's average age and performance up to an acceptable level.

Moreover, specific categories of vehicles have, on average, differing optimal lifecycles. Decisions to shorten or extend lifetimes of individual units are, of course, dependent on vehicle condition, mileage, and identification of "lemons" in a fleet. A lifecycle analysis (LCA) study conducted by RSI-FC in 2017 helped to provide Toronto Hydro with a data-driven method of optimizing lifecycles for vehicle categories.

To establish a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – as a comparison for long-term capital planning for BEV phase-in – our team conducted a Capex balancing exercise by deferring units shown to have low ROI if replaced prematurely.

2017 Lifecycle Analysis Summary

In 2017, a lifecycle analysis (LCA) study was undertaken by RSI-FC for each vehicle category at Toronto Hydro to determine optimized economic lifecycles. The LCA study took into consideration the cost of downtime (as caused by reduced reliability), the year-to-year "rollup" of weighted average cost of capital (WACC), inflation, worker cost/hour, salvage and market values, inflation, and average kilometres-driven data.

A discounted cash flow analysis was completed for each vehicle category to complete the LCA. Net present value (NPV) was calculated for outgoing cash flows (vehicle purchase cost, maintenance cost, the impact of downtime on driver productivity cost, improved fuel efficiency of a new vehicle compared to the old vehicle) and incoming cash flows (vehicle residual value) to calculate the total lifecycle cost for various vehicle retention periods.

With support from Toronto Hydro Fleet Management, optimized economic lifecycles determined from this study were applied to the 2020-21 baseline – serving as a starting point for the Electric Vehicle Phase-in Plan. The results from the 2017 study are summarized in *Table 3*.

Table 3: 2017 Lifecycle Analysis Results Applied to 2020-21 Baseline

Vehicle Category	Optimal Lifecycle Calculated through LCA (years)
Car	9
Cargo Minivan	7
Passenger Minivan	9
Full Size Van	10
Pickup	9
SUV	8
Cube Van	12
Single Bucket Aerial Device	12
Single Bucket Van Mount Aerial Device	11
Cable Truck	11
Crane Truck	10
Dump Truck	8
Line Truck	13
Double Bucket Aerial Device	14
Digger Derrick	13

Vehicle Condition Assessments

Replacement cycles should be considered a guideline only, as some vehicles in poor or unsafe condition may require replacement before the criteria are met. Conversely, some vehicles that exceed the criteria may be in good condition and may not warrant replacement. Fleet managers, of course, need to exercise judgment and fleet management principles in either advancing replacement or delaying replacement of individual vehicles case by case. A thorough ground-up and top-down physical assessment of each vehicle's condition, in conjunction with routine shop visits for preventive maintenance inspections, would serve to inform decisions around extending vehicle lifecycles during the waiting period for BEV models.

Recommendation

- In the context of BEV phase-in and determining which unit lifetimes to extend and which to not, our recommendation is to store vehicle condition information in Excel format or another database for easy access and tracking of summaries and/or analyses. A simple rating system such as a numerical 1 to 5 indexing where 1 = poor condition and 5 = good condition would greatly assist in determining the highest priority units for ICE replacement. If each vehicle's condition rating (1 to 5) was posted in each vehicle's profile in Excel or a software program, it could be easily accessed for capital budget planning.

Long-Term Capital Planning

After modelling the baseline with optimized economic lifecycles, the Fleet Analytics Review™ (FAR) software tool enables methodical, well-informed business decisions for long-term capital planning (LTCP) purposes.

Vehicle data provided by Toronto Hydro for the baseline year (2020-21) was input into FAR, and the tool calculated capital budgets for the ensuing fifteen years driven by vehicle lifecycles based on the optimized economic lifecycles that were calculated from the 2017 LCA study.

On a unit-by-unit basis, FAR calculates:

(1) Whether replacing units due for replacement would save Toronto Hydro operating expenses (Opex) or cost additional money; and
(2) The GHG-reduction impacts of vehicle replacements.

The tool also calculates and displayed the costs (operating and capital) and GHG impacts of those decisions for the fleet as a whole.

Typical of most fleets, year one of Toronto Hydro's LTCP showed a cost spike caused by previously deferred vehicles (see results in next sub-section). Replacement of some of these units can be again delayed because they are still in good serviceable condition, have low mileage, or perhaps have just received a costly refurbishment that will extend the unit's life. These decisions, which are typical for fleet managers everywhere that must adhere to a capital spending limit, can be aided by using FAR which displays to the user whether cost-savings are possible by replacing a unit.

In FAR, replacement of units shown not to provide return-on-investment (ROI) can be deferred to following years until replacement yields a net decrease in Opex or until replacement is deemed necessary from a financial risk reduction point-of-view – as units kept well beyond their optimal lifecycle have a greater chance of unexpected repair costs. Following this method, a fleet manager can balance go-forward annual capital expenses (Capex) and avoid year-over-year cost spikes. This approach can keep the average age of the fleet at an acceptable level, provide the lowest cost and highest uptime, and reduce emissions through strategically acquiring new (lower emission) vehicles.

While historical data in FAR demonstrates whether a business case exists for vehicle replacement, the final step, of course, in LTCP depends on fleet management personnel's expertise through vehicle condition assessments, as explained earlier. *No software tool can supplant this crucial human role in capital budget planning.*

For modelling purposes only, our team conducted a Capex balancing exercise by deferring units shown to have low ROI if replaced prematurely. This established a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – as a comparison for long-term capital planning for BEV phase-in (covered in *Section 6*).

Optimized Economic Lifecycles – Results

FAR Scenario One modelled a 15-year budget cycle based on Toronto Hydro's optimized economic lifecycles determined in the 2017 LCA study.

As illustrated in *Figure 1* (below), it was estimated that, in 2022, $15.3 million would be required to replace all due or past-due units with new like-for-like vehicles (no BEVs at this stage). It should be noted that numerous vehicles in the Toronto Hydro fleet are *beyond the current planned age* for replacement – *significant "catch-up" is required to modernize the fleet.* In ensuing years, far fewer vehicles require replacement, bringing down capital spending to as little as $1.7 million in 2027. However, there is an uneven capital spend projected throughout the budget period.

Figure 1: Projected capital budget (blue), deferred spending (red), and total capital budget (green) for optimized economic lifecycles from 2022-2037

Balanced Capex – Results

Once optimized economic lifecycles were modelled, it became apparent that some vehicles deliver better ROI than others. Some vehicles in the fleet may have received lighter usage than other similar age units, which may have been worked harder. Vehicles in better condition and/or with lower mileage can have their service life extended to optimize their lifetime total cost of ownership (TCO).

Lower ROI would result if a vehicle, still in good condition, was replaced prematurely; value will be lost.

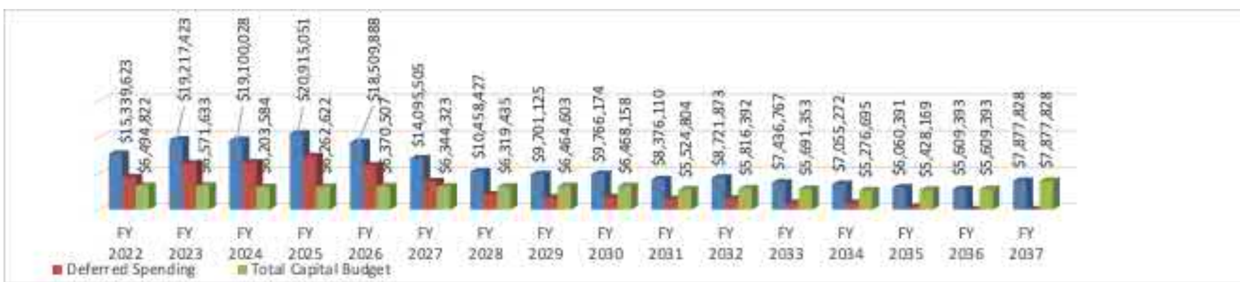
For FAR Scenario Two, the approach used by RSI-FC was to defer some vehicles to ensuing capital budget years to ensure full value is received from each unit. As third-party consultants without access to information to vehicle condition, and to reduce and apportion the required capital for vehicle replacement over a more extended period, we opted to defer using the following criteria:

(1) Units with low/no ROI
(2) Units that have most recently became due for replacement (to ensure past-due units get higher priority for replacement)
(3) Lower-accumulated mileage units (to ensure that higher-mileage units are replaced first)

Using this prioritization protocol, we selectively and strategically made deferrals over the budget cycle to maximize Opex benefits and balance Capex to the best of our ability. As a result, Capex is much more balanced over the budget cycle than FAR Scenario One.

As illustrated in *Figure 2* (below), the net result was an average annual capital budget of $6.2 million with annual amounts ranging from $5.3-7.9 million with clustering around $6-6.5 million, as compared to the much wider and more fluctuating range over the budget period for optimized economic lifecycles only as in FAR 1 (*Figure 1*, above).

Figure 2: Projected capital budget (blue), deferred spending (red), and total capital budget (green) for balanced Capex from 2022-2037



Recommendation

- Consider using RSI-FC's Fleet Analytics Review™ (FAR) software tool to extract maximum value from each vehicle by assessing whether cost-savings are possible by replacing a unit.

Section 6: Electric Vehicle Phase-in Planning

The primary objective of the Electric Vehicle Phase-in Plan was to analyze Toronto Hydro's in-scope fleet data and identify and assess electrification pathways with varying degrees of implementation and pricing outcomes.

RSI-FC first prepared the baseline from data provided by the utility for the review period (2019), including capital expenses (Capex) and operating expenses (Opex) for all units. From the baseline, we modelled a 15-year budget cycle (to 2037) for optimized economic lifecycles determined through lifecycle analysis (LCA), and then balanced Capex by deferring units shown to have low return-on-investment (ROI) if replaced prematurely. This established a data-driven benchmark for a balanced long-term capital budget if *like-for-like* replacements were to be made – as a comparison for long-term capital planning for BEV phase-in.

Starting from the baseline, we modelled a number of fleet electrification scenarios ranging from aggressive and over-budget to balanced and within budget – to demonstrate a spectrum of pathways. Although BEV phase-in is the most effective long-term GHG reduction strategy for a fleet, the reality is that there are currently higher upfront costs associated with the transition; therefore, it must be done in a fiscally responsible manner.

Based on our modelling, lower-annual mileage units at Toronto Hydro are unlikely to deliver ROI if replaced with a BEV at this time. To provide a viable BEV phase-in plan, our team strategically modelled the replacement of overdue lower-annual mileage units with internal combustion engine (ICE) vehicles in an effort to still achieve GHG emissions reductions while keeping within budget constraints. Moreover, we modelled replacement of overdue units that showed high usage and/or relatively high repair costs with ICEs as a financial risk-reduction strategy.

Overview of Battery-Electric Vehicles

Here, we provide an overview BEVs, including their benefits and expected market availability for different classes. More details on BEVs and charging can be found in *Appendix C*.

Why BEVs?

Air quality is a growing concern in many urban environments and has direct health impacts for residents. Tailpipe emissions from internal combustion engines are one of the major sources of harmful pollutants, such as nitrogen oxides and particulates. Diesel engines in particular have very high nitrogen oxide emissions and yet these make up the majority of the global fleet. As the world's urban population continues to grow, identifying sustainable, cost-effective transport options is becoming more critical. Battery-electric vehicles (BEVs) are one of the most promising ways of reducing harmful emissions and improving overall air quality in cities.

Globally, numerous jurisdictions have already legislated the end of the ICE – some as soon as 2030. On January 28, 2021, General Motors pledged to cease building gasoline and diesel cars, vans, and SUVs by 2035. Even more recently, on June 29, 2021, the Canadian government announced a mandatory target for all new light-duty cars and passenger trucks sales to be zero-emission by 2035, accelerating Canada's previous goal of 100 percent sales by 2040[20]. ICE vehicles purchased today for a fleet with a current-day value in the millions of dollars may be nearly worthless when ICEs become obsolete.

Fleet managers who operate BEVs will see reduced maintenance and fuel costs. BEVs have considerably fewer parts than internal combustion engine (ICE) vehicles. A drivetrain in an ICE vehicle contains more than 2,000 moving parts, compared to about 20 parts in an BEV drivetrain. This 99% reduction in moving parts creates far fewer points of failure, which limits and, in some cases, eliminates traditional vehicle repairs and maintenance requirements, creating immense savings for fleet managers. BEVs do not require oil changes or tune-ups, do not require diesel exhaust fluid (DEF), and their brake lining life is greatly extended over standard vehicles due to regenerative braking.

In recent years, BEV range has been considerably extended, thereby providing much wider BEV applications and reducing range anxiety. Today, many light-duty BEV models have EPA-estimated ranges exceeding 400 km, which provide much greater reliability when travelling longer distances.

The time required to charge BEVs is dependent on charging speed and battery size. For a battery-electric car or SUV, a full charge using a Level 2 charger takes several hours, but charging from a nearly depleted battery to 70% at a fast (Level 3) charging station can take only 30 minutes[21]. However, heavy-duty trucks charged between 50 and 100 kW (equivalent to DC fast charging) would potentially take several hours to charge[22] due to their much larger battery size.

Although recharging a BEV can take significantly longer than refuelling a conventional vehicle, most charging in a low-mileage fleet like Toronto Hydro can be done overnight in off-peak hours via Level 2 charging. Please see *Section 7* for details on RSI-FC's analysis of Toronto Hydro's charging requirements.

Battery-Electric Light-Duty Vehicles

There are multiple light-duty cars and SUVs currently on the market; current examples include the Nissan Leaf, Chevrolet Bolt (13 units currently owned and operated by Toronto Hydro), Kia Soul, and the Tesla Model 3. All with sufficient range for fulfilling daily duties, these vehicles have demonstrated that electrification is not only possible, but also convenient and within an acceptable and affordable

[20] Source: https://www.canada.ca/en/transport-canada/news/2021/06/building-a-green-economy-government-of-canada-to-require-100-of-car-and-passenger-truck-sales-be-zero-emission-by-2035-in-canada.html
[21] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/
[22] Source: https://www.plugincanada.ca/electric-bus-faq/

price range, particularly when considering fuel and maintenance cost savings over the vehicle's lifetime.

The "workhorses" of utility fleets like Toronto Hydro are light-duty pickup trucks and vans. For Toronto Hydro's fleet, pickups and Class 1 and 2 vans comprise about 42% of the vehicles based on the data provided (84 pickups and 78 light-duty vans out of a total of 385 vehicles). Therefore, BEV options in the light-duty pickup and van categories have the potential to make a significant impact on the utility's fleet operating cost savings and GHG emissions reduction. At this time, there are no BEV pickups or vans available for purchase. However, several manufacturers, including General Motors and Ford, are preparing for BEV pickups and vans to enter the market in 2022.

Battery-Electric Trucks

Medium- and heavy-duty battery-electric trucks (BETs) are quickly being developed by many manufacturers. Almost all truck manufacturers have announced plans to launch battery-electric trucks in these classes soon, which will likely become available for purchase by 2023. However, several manufacturers are taking orders now, including Lion Electric, Tesla, and Navistar.

Like all BEVs, BETs offer a multitude of benefits with some additional ones given their size and load, including:

- Less noise pollution
- Zero tailpipe GHG emissions
- Oil-free operation with very few moving parts
- Simple, low-maintenance electric powertrain with few components
- Longer lasting brakes due to regenerative braking system
- Potential to significantly extend range due to high regenerative braking from carrying heavy loads[23]. The heavier the truck load, the greater the energy produced from regenerative braking.
- Overnight recharging when the vehicle is not in operation and when demand for electricity is lower, which reduces energy costs
- Massive savings potential in total energy costs and service costs

[23] Source: https://www.firstpost.com/tech/science/worlds-largest-electric-vehicle-is-a-110-tonne-dump-truck-that-needs-no-charging-7190131.html

BEVs – Feasibility Considerations

- Caution must be exercised to ensure longer charging times do not create operational challenges. However, most charging in a low-mileage fleet like Toronto Hydro can be done overnight via Level 2 charging. Please see *Section 7* for details on RSI-FC's analysis of Toronto Hydro's charging requirements.

- Extreme cold temperatures can significantly reduce range in BEVs due to heating of the cabin and heating of the battery itself[24]. Therefore, it is important to account for this when purchasing BEVs to ensure sufficient range is provided to cover a day's worth of routes in the heart of winter. However, in a low-mileage fleet like Toronto Hydro this would likely not pose an operational issue for most units. Please see *Section 7* for details on RSI-FC's analysis of Toronto Hydro's charging requirements.

- Power grid failure or local failure at a site/garage could pose a significant risk to Toronto Hydro's operations. To mitigate this risk, backup generators can deal with short power outages. For longer outages, larger generators would be needed, but this would come at a very expensive cost.[25]

BEV Phase-in Approaches

RSI-FC data-modelled several fleet electrification scenarios ranging from aggressive and over-budget to balanced and within budget – to provide a spectrum of options that Toronto Hydro can use to inform their purchasing decisions.

For each scenario, FAR calculated annual GHG emissions, operating costs, and capital requirements from 2022 to 2037 – providing multiple long-term capital planning (LTCP) outlooks based on the speed and degree of implementation of BEVs into Toronto Hydro's fleet. These "what-if" scenarios assess the potential outcomes of BEV phase-in for the same vehicles, the same number of vehicles, travelling the same number of kilometres as the baseline period.

For balanced scenarios considering budget constraints, our team used Fleet Analytics Review™ (FAR) to conduct a granular, unit-by-unit assessment of BEV replacement – both as a short-term financial risk-reduction strategy and a long-term capital planning (LTCP) strategy. Based on baseline data provided, we decided (for modelling purposes only) which units to replace with ICE vehicles and which to replace with BEVs through extension of their lifecycles, keeping in mind the fiscal years for which the type/categories of BEVs are expected to be in-service based on procurement timelines provided by Toronto Hydro (*Table 4*).

[24] Source: https://www.geotab.com/blog/ev-range/
[25] Source: https://www.plugincanada.ca/electric-bus-faq/

Table 4: Toronto Hydro procurement timelines for different vehicle types

Vehicle Type	Timeline from RFP Submission to Final In-service Date
Light-duty	~1 year
Medium-duty	~2 years
Heavy-duty	~3 years

For both the aggressive and balanced BEV phase-in scenarios, units due for replacement showing low ROI in our FAR modelling were deferred to subsequent fiscal years in an effort to minimize operating expenses (Opex) and optimize capital expenses (Capex). Moreover, for modelling purposes we opted to extend the optimal lifecycles for all light-duty vans to 12 years and pickups to 11 years – as a strategy employing a temporary pause (when appropriate) on replacing ICE van and pickups, which comprise a very large portion of Toronto Hydro's fleet, until equivalent BEV models are expected to be in-service.

Aggressive, Fleet-wide BEV Phase-in

The aggressive approach to BEV phase-in involved fleet-wide replacement with BEVs and shortened procurement timelines. For demonstration and comparative purposes, this scenario shows what a higher-pace transition would look like from a capital budgeting perspective with lower-than-expected market availability and/or wait times for new vehicles.

Expected BEV in-service years in our modelling, based on shortened procurement timelines than the ones provided by Fleet Management, are as follows:

- SUVs: orders placed immediately and models in-service 2022 onward (less than 1-year wait time)
- LD vans and pickups: orders placed in 2022 and models in-service 2023 onward (1-year wait time)
- MDVs: orders placed in 2023 and models in-service 2024 onward (1-year wait time)
- HDVs: orders placed in 2023 and models in-service 2024 onward (1-year wait time)

Balanced, Selective BEV Phase-in

The balanced approach to BEV phase-in involved more ICE replacements (for appropriate units, mainly HDVs) as well as in-service based on procurement timelines provided by Toronto Hydro. The purpose of this exercise was to align with Toronto Hydro's procurement timelines and stay within capital budget constraints while *still* achieving significant GHG emissions reductions by the end of the modelling period (i.e., 2030s).

Taking this approach, the budget is much more balanced year-over-year than the aggressive BEV phase-in approach, and does not require significantly more capital spending as compared to the like-for-like replacement benchmark (see results and comparisons in the next sub-section). This approach employs a strategy that calls for increased capital spending upfront (i.e., in the next few years) to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements, which allows for balanced capital spending on BEVs down the road.

Expected BEV in-service years in our modelling, based on more cautious order dates for LD vehicles, as well as (longer) procurement timelines provided by Fleet Management, are as follows:

- SUVs: orders placed in 2022 and models in-service 2023 onward (1-year wait time)
- LD vans and pickups: orders placed in 2023 and models in-service 2024 onward (1-year wait time)
- MDVs: orders placed in 2023 and models in-service 2025 onward (2-year wait time)
- HDVs: orders placed in 2023 and models in-service 2026 onward (3-year wait time)

We made the presumption that fossil-fuelled vehicle replacements would be in-service over shorter timelines than BEVs at the beginning of the budget period – reasoning that some replacements have already been confirmed are thus "in queue." Otherwise, there would be a pent-up demand for overdue units in the short- to mid-term creating an unavoidable spike in Capex.

Although we have made every effort to ensure that the business assumptions and estimates employed in our analysis are as accurate as possible, we acknowledge that FAR is not intended to be accounting-accurate but rather provide Toronto Hydro a viable pathway for achieving electrification of its fleet in consideration of budget constraints and procurement timelines.

To select the units to replace with ICEs, we created a "decision matrix" containing key indicators from Toronto Hydro's fleet baseline data that helped to highlight which units were most suitable candidates for ICE replacement. These indicators include:

- Lifetime kms (flagged if greater than 120,000 km)

- Review period kms (flagged if less than 5,000 km; this would indicate low ROI with BEV replacement as well as low impact in terms of GHG reduction)

- Preventive Maintenance/reactive repair ratio (flagged if less than 0.25; this would give an indication of vehicle condition based on data only and flag potential cases where a unit should be replaced sooner)

- Lifecycle remaining (flagged if the unit is due for replacement before expected BEV in-service years)

- Lifecycle remaining plus 2-yr deferral (flagged if, with a 2-yr deferral, the unit is due *still* due before expected BEV in-service years)

The various "flags" allow for an informed, structured method of holistically deciding, for modelling purposes, which vehicles should be replaced with ICE units due to high usage and/or relatively high repair costs, and which vehicles should be replaced with ICE units simply because they have such low-kms and, therefore, have much less ROI and contribute relatively little GHG emissions. Of course, as described in *Section 5*, a physical assessment of each vehicle's condition would be required to inform decisions around which units to replace with ICE units and which to extend lifecycles during the waiting period for BEV models.

The overall purpose of completing and applying this exercise to the FAR modelling was to obtain results that stay within Toronto Hydro's budget while still achieving high GHG emissions reduction. It would be very possible to fully convert the fleet to electric by 2040 – or perhaps sooner – depending on BEV pricing outcomes, as will be outlined next.

BEV Pricing – Cautious

In discussion with Toronto Hydro Fleet Management and based on current MSRP ratios when comparing BEVs to conventional ICE vehicles, we have applied the following BEV/ICE acquisition cost ratios to our modelling:

- SUVs: 1.48
- Pickups: 1.74
- Full size vans: 1.66
- Medium-duty units: 1.75
- Minivans: 1.57 (since there is no EV option currently in the market, the ratio was estimated to be between SUVs and full size vans)
- Heavy-duty units: 2 (this is a cautious estimation that includes the cab/chassis and body portions)

We have applied these ratios to the entire modelled budget period for both the aggressive and balanced BEV phase-in scenarios as a cautious pricing approach that does not assume any future BEV price reduction.

Based on these BEV/ICE acquisition cost ratios, the current-day estimated BEV replacement cost for Toronto Hydro's fleet is $127.7M as compared to the current-day estimated like-for-like (i.e., ICE) replacement cost of $67.5M – about an 89% increase.

BEV Pricing – Sliding Scale

For both the aggressive and balanced BEV phase-in scenarios, we then applied a “sliding scale” for BEV price reduction (starting from the initial ratios listed above) to model potential outcomes for more optimistic pricing.

We believe that providing both cautious and optimistic pricing outcomes will provide Toronto Hydro with better value through a range of possibilities – as the current reality is that we cannot firmly predict future outcomes regarding BEV pricing.

However, there is reason to expect BEV prices to steadily decline in coming years as supply increases and battery technology improves. This is provided in a 2018 Bloomberg New Energy Finance report that modelled a costing outlook for electric buses vs diesel buses, and demonstrated cost parity by 2030 mainly due to future cost reductions of the battery pack[26]. With this information, it is conceivable that BEVs of all classes would follow suit.

In consideration of modelling constraints as well as gradual price reduction to better reflect what would be expected should BEVs steadily decline, the logic of the sliding scale is as follows:

- In 2022, status quo BEV/ICE pricing ratios (ratios listed above) as discussed and agreed upon with Toronto Hydro, have been applied to our modelling.

- BEV/ICE price parity is expected, for modelling purposes, to occur in one decade (10 years) starting from 2023 for all units; therefore, price parity would be reached by 2032 (2023+9yrs).

- For modelling purposes, BEV/ICE ratios are reduced at a fixed rate for each year of the 10-year period until price parity is achieved. For example, heavy-duty units (with an BEV/ICE cost ratio of 2) would have a ratio reduction of 0.1 per year until the BEV/ICE cost ratio is approximately 1 (i.e., BEV and ICE prices are approximately equal).

- Taking into consideration procurement timelines:
  - HDVs show approximate price parity in our modelling by 2032+3yrs=2035
  - MDVs show approximate price parity in our modelling by 2032+2yrs=2034
  - LDVs show approximate price parity in our modelling by 2032+1yrs=2033

- Taking into consideration procurement timelines:
  - HDV price reduction starts in 2023+3yrs=2026 (year that earliest models would be in-service) and ends in 2035. Approximate price parity is continued for the duration of the modelling.

[26] Source: Bloomberg New Energy Finance. Electric Buses in Cities: Driving Towards Cleaner Air and Lower CO_2 [pdf]. March 29, 2018.

- MDV price reduction starts in 2023+2yrs=2025 (year that earliest vehicles would be in-service) and ends in 2034. Approximate price parity is continued for the duration of the modelling)
- LDV price reduction starts in 2023+1yrs=2024 (year that earliest vehicles with price reduction would be in-service) and ends in 2033. Approximate price parity is continued for the duration of the modelling.

Given the complexity of the FAR, the method employed to practically apply a sliding scale to our modelling, provided that *initial* acquisition costs are raised by inflation each fiscal year, was to:

(1) Divide the replacement costs in a given year by the agreed-upon *initial* ratios; and

(2) Multiply the replacement costs by a reduced ratio that scales over time (as explained earlier) to yield a reduced cost every year until approximate price parity with ICE counterparts is reached after 10 years.

Multiplication factors for LD, MD, and HD units have been included for each fiscal year in FAR and applied to all respective annual replacement costs. The factors remain constant once approximate price parity is achieved (as noted above).

Applying the sliding scale to the balanced BEV phase-in scenario provides a more complete and reasonable picture of what a balanced phase-in may look like if prices come down (see results in next sub-section). With cautious pricing and a sliding scale applied to both the aggressive and balanced BEV phase-in approaches, we have provided a spectrum of BEV phase-in scenarios that can be used to better inform future vehicle purchasing decisions, including:

- FAR 3.1 – aggressive, fleet-wide BEV phase-in with cautious pricing
- FAR 3.2 – aggressive, fleet-wide BEV phase-in with sliding scale
- FAR 4.1 – balanced, selective BEV phase-in with cautious pricing
- FAR 4.2 – balanced, selective BEV phase-in with sliding scale

Balanced, Fleet-wide BEV Phase-in

For demonstration purposes only, we have included one additional FAR scenario (FAR 5) which is a balanced, nearly complete transition to BEVs with far fewer ICE replacements than FAR 4.1 and 4.2. Phasing in BEVs using this approach require lifecycles to be extended far longer than planned (for modelling purposes) in an effort to pause the purchase of ICE vehicles until BEV replacements are available. Although we have modelled this to demonstrate what a *balanced and near 100%* BEV phase-in may look like for Toronto Hydro's fleet, we do not recommend extending lifecycles to such degree from a financial risk-reduction perspective.

BEV Phase-in Scenario Results

Our modelling estimated annual capital costs as well as operating cost impacts and GHG emissions reductions relative to 2020-21 baseline. In *Table 5* (below), results are summarized and include average annual Capital expenses (Capex) over the budget cycle, average annual Operating expense (Opex) changes over the budget cycle relative to the baseline, and annual tailpipe GHG reduction by 2037 relative to the baseline. Due to the limited availability of BEVs in the short-term, we have modelled BEV phase-in over a 15-year budget period following the year 2022 (i.e., from 2023-2037).

Note: The significantly higher operating expenses shown in Table 5 are due to the significantly increased cost of capital for acquiring new vehicles based on year-over-year book values of units.

Table 5: Summary of fleet-wide results of scenario analysis over the period 2022-2037 relative to the 2020-21 baseline.

FAR #	FAR Scenario Description	Implementation Timing[27]	Average Annual Vehicle Replacement Capex[28] [29]($ millions)	Average Annual Opex[30] [31] Impacts Over Baseline ($ millions)	Annual Tailpipe GHG Reduction[32] Over Baseline (tonnes CO_2e)	Annual Tailpipe GHG Reduction Percentage Over Baseline
1	Optimized lifecycles	2022 - 2037	6.7	+0.94	41	2.5%
2	Optimized lifecycles + ROI (benchmarking scenario)	2022 - 2037	6.2	+0.89	37	2.3%
3.1	BEV phase-in: aggressive and cautious pricing	2022 - 2037	*10.7	+3.23	1,623	100%
3.2	BEV phase-in: aggressive and optimistic pricing (sliding scale)	2022- 2037	*7.6	+2.29 (**est.)	1,623	100%
4.1	BEV phase-in: balanced, cautious pricing, more ICE replacements	2022-2037	8.3	+1.77	1,146	71%
4.2	BEV phase-in: balanced, optimistic pricing (sliding scale), more ICE replacements	2022-2037	7.0	+1.49 (**est.)	1,146	71%
5	BEV phase-in: balanced, cautious pricing, few ICE replacements due to greatly extended lifecycles	2022-2037	9.8	+2.31	1,503	93%

* Note that both of these scenarios involve significant Capex “spikes” in the short- to medium-term.

* Estimated based on applying a sliding scale in BEV pricing.

The most aggressive fleet electrification scenarios have the potential to reduce Toronto Hydro’s fleet tailpipe GHG emissions by **100% by 2034** – before the end of the modelling period. The more cautious and fiscally prudent scenarios have the potential to reduce Toronto Hydro’s fleet tailpipe

[27] For data-modelling purposes, fleet-wide implementation is modelled over the period from 2022-2037 for the same types of vehicles, the same number of vehicles, travelling the same number of kilometres as the 2020-2021 baseline.

[28] Average annual Capital expenses (Capex) for the entire modelling period (2022-2037), including compounding inflation for each year at current rate of inflation.

[29] For BEV charging infrastructure, additional capital costs were estimated separately using an EVSE costing tool.

[30] Average annual Operating expenses (Opex) for the entire modelling period (2022-2037) , including compounding inflation for each year at current rate of inflation.

[31] For data-modelling purposes, Opex includes the annual cost of capital based on year-over-year book values of units.

[32] Annual GHG reduction by the end of the modelling period (2037) is relative to the 2020-2021 baseline.

GHG emissions by just over **70% by 2037** – with the potential to achieve even greater results should more ICE units be replaced with BEVs towards the end of the modelling period, depending on pricing outcomes for BEVs compared to ICEs.

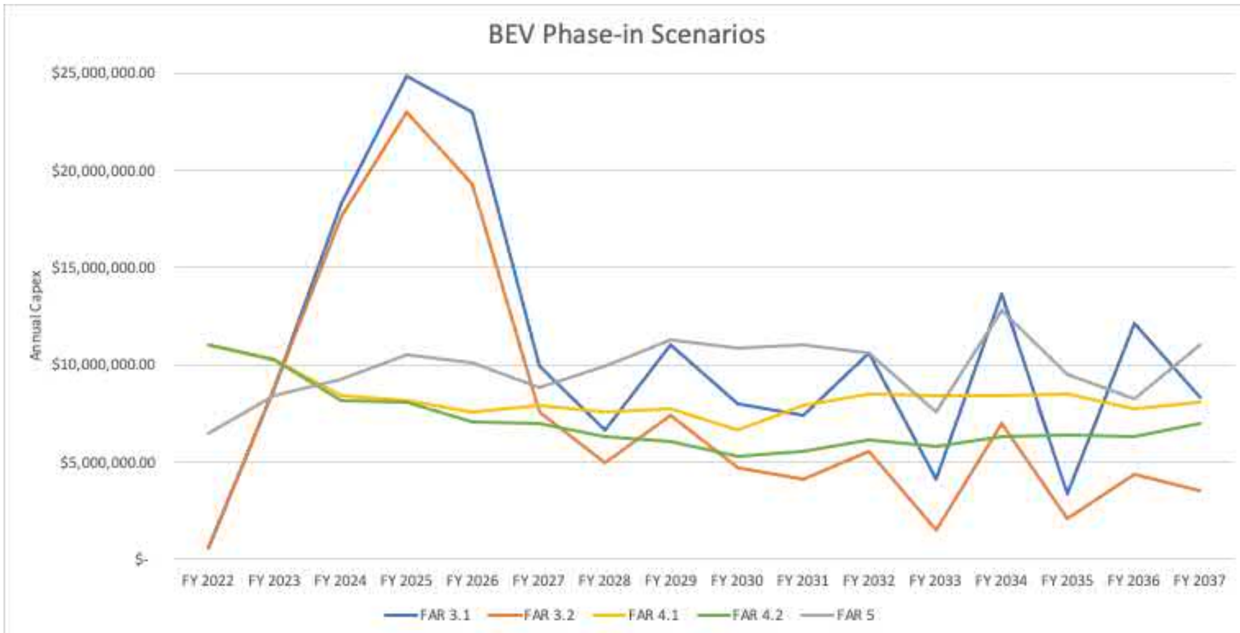
For the aggressive, fleet-wide BEV phase-in scenarios, average annual Capex is projected to be **$10.7M/yr** with cautious pricing (i.e., constant BEV/ICE ratios) and decrease to **$7.6M/yr** with the sliding scale in pricing. However, for both scenarios Capex is still very imbalanced and front-loaded (i.e., higher values in the short- to mid-term).

The balanced, selective BEV phase-in scenarios avoid annual Capex "spikes" and keep within annual budget constraints. Even with this approach, it will take significantly more capital to transition to BEVs based on current prices discussed with Toronto Hydro Fleet Management, with a modelled average annual Capex of **$8.3M/yr**. If price parity is gradually reached by the 2030s, average annual Capex is projected to decrease to **$7.0M/yr**. This value is approaching the projected annual Capex for like-for-like replacements of **$6.2M/yr**, although is based on a 70% GHG reduction achievement by 2037.

Note: Lower BEV prices over time mean that there is potential to achieve greater emissions reductions than what is modelled if ICE units, initially replaced with ICE units, are replaced with BEVs in their next replacement cycle.

In *Figure 3* (below), a breakdown of projected annual Capex based on the aggressive and balanced BEV phase-in approaches are shown as a time series from 2022-2037. Depicting the results graphically demonstrates year-over-year changes as well as differences in Capex variability between the scenarios.

Figure 3: BEV phase-in scenario results from 2022-2037



There are several features of the scenarios that become apparent when viewing *Figure 3*, as described below:

- The sliding scale in BEV pricing applied to FAR Scenarios 3.2 and 4.2 is demonstrated visually through lower annual Capex, starting in the year 2024, compared to FAR 3.1 and 4.1.

- The aggressive BEV phase-in scenarios (FAR 3.1 & 3.2) employ a strategy of deferring more units in the short-term, resulting in a pent-up demand for overdue units which are modelled to be replaced with BEVs. Consequently, there are significant Capex spikes modelled from years 2024-2027.

- The balanced BEV phase-in scenarios (FAR 4.1 & 4.2) employ a strategy that calls for increased capital spending upfront (i.e., in the next few years) for ICE units in greatest need of replacement, in an effort to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements and allow for balanced, within-budget capital spending on BEVs down the road.

- FAR 5, the balanced *and* fleet-wide BEV phase-in scenario, employed a strategy of extending lifecycles far longer than planned in an effort to pause the purchase of ICE vehicles until BEV replacements are available. In addition to introducing financial risk through unexpected repair costs and increased likelihood of serious failure, this approach results in at or over-budget spending in many years of the modelling period.

Section 7: Electric Vehicle Supply Equipment Planning

RSI-FC maintains the position that electric vehicle supply equipment (EVSE) should not be treated as a direct corporate vehicle capital expense, but rather as a facilities/properties capital expense. As per the feedback provided by Toronto Hydro Fleet Management, EV chargers are a Fleet expense and charging infrastructure development is the responsibility of Facilities.

With this in mind, we have developed an EVSE planning tool for Toronto Hydro, separate from Fleet Analytics Review™ (FAR), to inform long-term capital planning (LTCP) for the utility's charging infrastructure needs, based on Level 2 charging and battery capacity estimations described in this section. Our team has estimated the costs of electric vehicle chargers (not complete infrastructure) over the modelling period from 2022-2037, based on the current size and mileage of Toronto Hydro's fleet and a balanced, fleet-wide BEV phase-in.

EVSE & Asset Management

RSI-FC maintains that EVSE should be a capital asset paid for, owned, and managed from the budget of the corporate facilities/properties department. Therefore, the capital cost of charging equipment should not be directly posted to the fleet department; this aligns with Toronto Hydro's approach as per discussion with Fleet Management.

EVSE is an asset (an attribute/enhancement) that increases the market value of the facility/property where fleet vehicles are parked. Moreover, EVSE costs should be a capital expense for the facility's corporate "owner" (usually this is a facilities/properties department), not the vehicle's corporate "owner" (which is usually a fleet department). This is different than in the non-corporate world where the battery-electric vehicle (BEV) owner is often the same owner as the property owner, such as is the case for personal cars and homes. The benefit of this concept is that, unlike vehicles that depreciate quickly, facilities assets are generally depreciated over far longer periods – sometimes up to 20, 30 or more years. Long depreciation periods translate to lower annual costs, thereby making a better business case for electric vehicles.

Today, there is a lot of focus on asset management best practices for corporations, including the public sector. It is a contemporary asset management best practice that property-related costs, including capital and operating expenses, should be expense items managed by the responsibility centre that manages the asset, in this case the corporate facilities/properties department. The facilities/properties department can then apportion and transfer these costs to their internal users of each property, such as a fleet department.

In a “full cost recovery” business model as we espouse, the facilities/properties department must recover sufficient revenue to fully offset the costs of owning and managing the property, including the installation, use, and maintenance of EVSE.

Regarding the electricity needed to charge BEVs, we have included the cost of electricity as a “fuel” cost under operating expenses in FAR. However, the same asset management principles can be applied. In an ideal full cost recovery business model, the facilities/properties department would transfer electricity costs to its user departments for the amount used in each period. The EVSE would meter the amount of electricity used by each BEV – just like the amount of gas or diesel used by each internal combustion engine (ICE) vehicles is tracked with fuel pump meters.

EVSE Planning Tool

Capabilities

RSI-FC’s EVSE planning tool is user-friendly, including programmable and automated formulas for determining charging requirements on a unit-by-unit basis. The planning tool:

- Lists units based on their stored locations.
- Is based on estimated daily kms-travelled by each unit, derived from kms-travelled during the review period divided by the number of working days in year.
- Is based on each unit having access to one charger every night during off-peak hours (7pm-7am).
- Allows programmable upper and lower estimates of range that can be adjusted up or down for data-modelling purposes, in consideration of heating/cooling in cold- or hot-weather conditions as well as on-board accessory electrical DC loads such as lights, laptops, etc., that may diminish available driving range.
- Calculates the daily charging time required to return to near-full charge for vehicles of all classes by allowing for programmable estimates of BEV battery capacity, charger current, and charger voltage.
- Calculates the nightly electrical demand in kWh and cost, assuming all units will charge each night during off-peak hours.
- Allows programmable acquisition costs for chargers (or chargers plus infrastructure if desired) for each unit.

The tool simplifies charging rate (kms of range added per hour) by estimating it to be constant for all battery charge levels. This is, strictly speaking, not entirely reflective of reality; charging rate slowly diminishes as battery levels approach 100%. However, applying a constant charging rate does provide a very reasonable approximation, especially considering that we have modelled daily charging requirements based on 90% maximum battery charge levels – as a best practice for optimizing battery life.

Charging rate is dependent on the battery capacity of a vehicle and varies significantly with different vehicle types and battery sizes. The tool allows the user to change the battery size on a unit-by-unit basis if needed (i.e., by comparing a make/model of BEV that is equipped with larger/smaller battery size than another make/model), which makes the calculator even more accurate.

Estimations

The inputs chosen in the EVSE tool are based on a number of estimations in terms of charging level and battery capacity for different unit types. These can be easily modified by the user according to the specific charging infrastructure installed as well as actual specifications for BEV replacement units. We have included the following estimations in our EVSE modelling:

- Battery size/capacity estimates were based on class/ vehicle type, including:
    - 60 kWh for cars
    - 80 kWh for SUVS, pickups, passenger minivans, Class 1/2a cargo minivans
    - 100 kWh for Class 2b vans
    - 150 kWh for MDVs (Class 3-6 units)
    - 300 kWh for HDVs (Class 7-8 units)

- Upper range estimates (i.e., *actual* driving distance, not advertised range) were based on class/ vehicle type, including:
    - 320 km for cars
    - 300 km for SUVs, pickups, passenger minivans, Class 1/2a cargo minivans
    - 280 km for Class 2b vans
    - 250 km for MDVs (Class 3-6 units)
    - 250 km for HDVs (Class 7-8 units)

- Lower range estimates were based on a 50% reduction of upper range estimates for all units.

- Charger current and voltage estimates were based on a lower-power Level 2 charger, as well as the amps of current allowed by most BEVs[33]) including:

[33] Source: (https://www.chargepoint.com/en-ca/resources/how-choose-home-ev-charger/#:~:text=Most%20EVs%20can%20take%20in,of%20range%20in%20an%20hour.)

- Current: 32 amps
- Voltage: 240 volts

- The charging rate (kms range added per hour) was estimated by dividing driving range by the time for full charge. The time for full charge (i.e., 0 to 100%) was estimated by dividing battery capacity by charging power (calculated from current and voltage) and adding a 10% inefficiency[34 35].

- Return-to-base battery levels are based on a starting charge of 90%, as a best practice for optimizing battery life.

- The time available for overnight charging was estimated as 12 hours during off-peak hours (7pm-7am).

Flagged Units

Overall, based on our pragmatic analysis, the majority of units (381 out of 385 units) in Toronto Hydro's fleet would be capable of fully recharging during overnight off-peak hours with the use of lower-power Level 2 chargers. In fact, most units would be able to recharge is much less time than units are parked; the average time to recharge to 90% battery level for all 385 units is an estimated 2.7 hours.

Our team flagged any units that, based on low capacity Level 2 charging, would either: (1) risk too low of a return-to-base charge; or (2) require too much time to recharge during off-peak hours. These include:

- One pickup unit (0408V) estimated to finish the work day at less than 20% battery charge (starting from 90%). A potential solution is to purchase battery-electric pickups with larger batteries, and thus higher range capabilities, for relatively higher-mileage pickups like this unit.

- Four Class 8 single bucket units (0757V, 0387V, 0952V, & 0950V) estimated to require more than 12 hours to recharge to 90% battery level. A potential solution is to install higher-power chargers for relatively higher-mileage Class 8 units to increase the charging rate per hour.

Level 3 Charging

Level 3, direct-current (DC) fast chargers, which charge at much higher amperage and voltage than Level 2 chargers, are recommended in the case of time-dependent duties/responsibilities when

[34] Source: https://www.caranddriver.com/shopping-advice/a32600212/ev-charging-time/
[35] Source: https://www.inchcalculator.com/widgets/?calculator=electric_car_charging_time

overnight charging is not an option, as well as for emergency situations such as extreme weather events. Additionally, if a vehicle operator forgets to plug in their vehicle overnight, a Level 3 charger would be required to avoid and/or minimize the loss of productivity during work hours. It is important to note that DC fast charging installation requires a commercial electrician[36] and costs an estimated $50,000 - $200,000 for equipment and installation[37]; therefore, the need for Level 3 charging should be carefully assessed.

Given the fact that 86% of Toronto Hydro fleet vehicles are parked at three Work Centers – Commissioners Work Center, Rexdale Work Center, and Milner Work Center – our general recommendation is for two Level 3 chargers be installed at each of these main locations to as a risk management strategy for time-dependent and/or urgent situations as described above. However, without knowledge of the intricacies and specific use cases for each fleet vehicle, our secondary recommendation is to identify the most appropriate Work Centers for investment in higher-power charging, i.e., ones that consist of vehicles that may not always rely on overnight charging only.

EVSE Charger Costing Outlook

Our team estimated the costs of electric vehicle chargers (not infrastructure) over the modelling period from 2022-2037, based on a balanced, fleet-wide BEV phase-in taking FAR Scenarios 4.1 and 4.2 as the minimum speed of transition. Please see *Table 6* (overleaf) for details and a description of our approach/method and estimations below for Toronto Hydro's fleet.

To determine the number of Level 2 (L2) chargers required to be installed annually over the modelling period for a smooth transition of the entire Toronto Hydro fleet to BEVs, our approach/method and estimations were as follows:

- A fleet should not be keeping up with the demand for EVSE based on the number of new BEVs added; rather, EVSE installation should be *outpacing* demand to allow for a smooth and seamless transition. Therefore, we have estimated the number of L2 chargers required to outpace the influx of new BEVs into the fleet.

- The purchase of chargers ahead of the addition of BEVs also makes use of the delay in purchasing BEV pickups, vans, and medium- and heavy-duty (MHD) vehicles based on availability and procurement timelines – to optimize the use of capital investment in EVSE to ensure ample capacity for charging down the road.

- EVSE is based on the current size of Toronto Hydro's fleet.

[36] Source: https://calevip.org/electric-vehicle-charging-101
[37] Source: https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf

- FAR Scenarios 4.1 and 4.2 (balanced, selective phase-in approach) were considered to establish the minimum speed of transition to BEVs; the number of chargers required to be installed for each fiscal year outpace the number of BEVs integrated into Toronto Hydro's fleet according to these scenarios.

- In addition to the previous bullet point, we have considered the number of chargers for a complete, fleet-wide transition to BEVs.

  FAR Scenarios 4.1 and 4.2 model a transition of about 73% of Toronto Hydro's fleet to battery-electric by the year 2033 – 282 battery-electric units, including the 13 Chevrolet Bolts currently in the fleet, out of a total of 385 units. After 2033, the number of BEVs added to the fleet reflects *second replacement cycles for existing BEVs*.

  However, for the purpose of modelling the phase-in of chargers for a fleet-wide adoption of BEVs, we have taken the number of BEVs added to the fleet after 2033 to demonstrate *new BEVs replacing ICE vehicles* – in anticipation of the complete electrification of Toronto Hydro's fleet by the mid- to late-2030s (see tan-coloured rows in *Table 6*).

- We have cautiously estimated the cost of chargers only to be $2500/charger. This cost does not include infrastructure which would vary according to the charger level.

Importantly, existing electrical capacity at sites may require substantial upgrades for charging multiple vehicles, and/or new or upgraded standby generators to provide for emergencies, both of which may significantly add to infrastructure costs (outside the scope of this report). A qualified electrical professional should be consulted to assess the situation and make recommendations.

Based on our EVSE analysis and taking the balanced BEV phase-in approach as a realistic and fiscally responsible strategy, Toronto Hydro's fleet would be 100% BEV-ready by 2034 – based on the current size of the fleet (385 vehicles, see *Table 6*). Given our estimations, this translates to an average annual charger cost (excluding infrastructure) of about $74,000 per year for the next 13 years.

Table 6: Fleet-wide EVSE long-term charger costing outlook

Year # of BEV Phase-in Plan	Year of BEV Phase-in	Location	Number of BEVs added to Fleet (per balanced phase-in plan)	Cumulative Number of BEVs added to Fleet (per balanced phase-in plan)	Number of BEVs Serviced by each Charger	Estimated Number of Chargers Required for Purchase (to outpace BEVs added)	Cumulative Number of Chargers Purchased	Estimated Cost per Charger	Total Annual Cost of Chargers	Cumulative Cost of Chargers
1	2022	All Fleet Parking Sites	1	1	1	30	30	$2,500	$75,000	$75,000
2	2023	All Fleet Parking Sites	9	10	1	30	60	$2,500	$75,000	$150,000
3	2024	All Fleet Parking Sites	41	51	1	30	90	$2,500	$75,000	$225,000
4	2025	All Fleet Parking Sites	12	63	1	30	120	$2,500	$75,000	$300,000
5	2026	All Fleet Parking Sites	20	83	1	30	150	$2,500	$75,000	$375,000
6	2027	All Fleet Parking Sites	22	105	1	30	180	$2,500	$75,000	$450,000
7	2028	All Fleet Parking Sites	48	153	1	30	210	$2,500	$75,000	$525,000
8	2029	All Fleet Parking Sites	38	191	1	30	240	$2,500	$75,000	$600,000
9	2030	All Fleet Parking Sites	16	207	1	30	270	$2,500	$75,000	$675,000
10	2031	All Fleet Parking Sites	37	244	1	30	300	$2,500	$75,000	$750,000
11	2032	All Fleet Parking Sites	27	271	1	30	330	$2,500	$75,000	$825,000
12	2033	All Fleet Parking Sites	8	279	1	30	360	$2,500	$75,000	$900,000
13	2034	All Fleet Parking Sites	13	292	1	25	385	$2,500	$62,500	$962,500
14	2035	All Fleet Parking Sites	17	309	1		385	$2,500	$0	$962,500
15	2036	All Fleet Parking Sites	15	324	1		385	$2,500	$0	$962,500
16	2037	All Fleet Parking Sites	34	358	1		385	$2,500	$0	$962,500

NRCan's Zero Emission Vehicle Infrastructure Program

The Government of Canada is committed to helping accelerate the decarbonization and electrification of our transportation sector, and charging infrastructure is a key component to achieving this. Natural Resources Canada (NRCan) has pledged to invest $130 million from 2019-2024 to further expand the country's charging network, particularly level 2 and higher stations, through its Zero Emission Vehicle Infrastructure Program (ZEVIP).

The funding is being delivered through cost-sharing contribution agreements for eligible projects, including:

- BEV charging infrastructure in parking areas intended for public use (e.g., service stations, restaurants, libraries, etc.);
- On-street charging infrastructure;
- Workplace charging infrastructure;
- On-road light-duty vehicle fleets;
- On-road medium- or heavy-duty vehicle fleets;
- Charging infrastructure for multi-unit residential buildings (MURBs); and
- Public transit charging infrastructure.

RFPs for ZEVIP are currently closed as per the program website[38]; however, we recommend that Toronto Hydro regularly checks for updates and openings to new funding application periods.

NRCan's contribution through this program will be limited to 50% of total project costs up to a maximum of $5M per project. The maximum funding and approximate costs for each type of charging infrastructure is shown in *Table 7* (directly taken from NRCan's website with costs and charging rates from the City of Toronto's Electric Vehicle Strategy Report[39]):

[38] Source: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation/zero-emission-vehicle-infrastructure-program/21876
[39] Source: https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf

Table 7: Specifications for NRCan's Zero Emission Vehicle Infrastructure Program, plus approximate total costs and charging rates

Type of Infrastructure	Output	Maximum NRCan Funding	Total Costs (Equipment + Installation)	Approximate Charge Rate Per Hour (LD vehicles)
AC Level 2 (208/240V) Connectors	3.3 kW - 19.2kW	Up to 50% of total project cost, to a maximum of $5,000 per connector*	$5,000 - $10,000	40 km
DC Fast Charger	20 kW - 49 kW	Up to 50% of total project cost, to a maximum of $15,000 per fast charger	-	-
DC Fast Charger	50 kW and above	Up to 50% of total project cost, to a maximum of $50,000 per fast charger (50 kW-99 kW) and $75,000 per fast charger (100 kW and above)	$50,000 - $200,000	300+km

* To calculate the funding for level 2 chargers, each connector can count as a unit towards the minimum of 20 chargers if each connector can charge a vehicle at the same time.

Section 8: Recommendations & Additional Considerations

In this section, we provide our recommendations for the Electric Vehicle Phase-in Plan, in terms of both (1) capital planning for transitioning the fleet to electric and (2) electric vehicle supply equipment (EVSE) requirements. Moreover, we have included recommendations on collaboration/partnerships and risk/change management for creating a culture of receptiveness to innovation and forward thinking. We have also included considerations on batteries as well as additional fuel-reduction solutions.

Battery-Electric Vehicle Phase-In

(1) Through a lens of an aggressive BEV phase-in, allocate the majority of fleet capital spending on BEVs for appropriate vehicle categories as BEV models become available.

(2) Through a lens of a balanced, selective BEV phase-in and fiscal prudence, prioritize replacement of ICE units with BEVs *that would maximize ROI* – typically ones that have relatively high annual mileage.

(3) For units due for replacement that are still in good condition, conduct a temporary pause on purchasing new internal combustion engine (ICE) vehicles for the short term – 1-2 years for pickups, 2-3 years for medium- and heavy-duty vehicles (MHDVs) – while awaiting battery-electric vehicle (BEV) counterparts to become available and taking into consideration procurement timelines. Extend ICE lifecycle whenever possible.

(4) Employ a strategy that calls for increased capital spending upfront (i.e., in the next few years) for ICE units in greatest need of replacement, in an effort to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements and allow for balanced, within-budget capital spending on BEVs down the road. Consider applying the decision matrix used by our team to determine which units to replace with ICE units in the short-term.

In the context of BEV transition planning, prioritizing units for immediate ICE replacement that have been kept (well) past their optimized economic lifecycle is a financial risk-reduction strategy. These units have the highest cost of continued ownership, are most likely to have unexpected repair costs, and are most likely to have a serious failure that requires more repair than the remaining values – potentially taking them out of service and dropping their salvage/resale value to (near) zero.

(5) Conduct pilot projects for several BEV types when they become available (e.g., pickups, passenger minivans, etc.) to track range capabilities and cost savings and assess the units' performance for all seasons and varying weather conditions.

(6) Assuming the pilot projects are successful, acquire BEVs in bulk to replace units that would provide the greatest ROI.

(7) Closely monitor the acquisition costs for BEVs and re-evaluate the business case (cost-benefit) for individual units as prices change/ decline.

(8) Consider purchasing plug-in hybrid vehicles (PHEVs) for lower-mileage units which would be able to fulfil daily duties on battery-power only and recharge overnight – essentially functioning like fully-electric vehicles.

Electric Vehicle Supply Equipment

(1) Over the next 10+ years, allocate capital towards chargers (and charging infrastructure, which is outside the scope of this study) required for the transition to BEVs for all vehicle categories.

(2) Based on our analysis of Toronto Hydro's charging requirements, 381 out of 385 units would be capable of fully recharging during overnight off-peak hours with the use of lower-power Level 2 chargers. Therefore, our recommendation is to focus on Level 2 charging for every unit on a nightly basis, and evaluate higher-power charging (Level 3) for higher-mileage units.

(3) Our general recommendation is for two Level 3 chargers be installed at each of the main Work Centers (Commissioners Work Center, Rexdale Work Center, and Milner Work Center) to as a risk management strategy for time-dependent and/or urgent situations. However, without knowledge of the intricacies and specific use cases for each fleet vehicle, our secondary recommendation is to identify the most appropriate Work Centers for investment in higher-power (Level 3) charging, i.e., ones that consist of vehicles that may not always rely on overnight charging only.

(4) Monitor upcoming funding opportunities from NRCan's Zero Emission Vehicle Infrastructure Program (ZEVIP), which may greatly offset the capital costs required to install charging infrastructure (outside the scope of this report).

(5) Assess existing electrical capacity at facilities to determine whether substantial upgrades for charging multiple vehicles are required, as well as standby generator capacities (outside the scope of this report). A qualified electrical professional should be consulted to assess the situation and make recommendations.

(6) Explore supplying power to each site/garage on two separate feeds from the grid to reduce the risk of local failure taking power away from the whole site[40].

---

[40] Source: https://www.plugincanada.ca/electric-bus-faq/

(7) To mitigate the risk of power grid failure or local failure at a site/garage, ensure backup generators have sufficient capacity to deal with short power outages, and assess the need for higher-capacity generators for longer outages.

(8) Explore solar energy technology options to supply energy for EV charging to reduce GHG emissions that may be produced from the electricity supply used for charging. Our recommendation is to pursue rooftop (as opposed to canopy) solar energy systems, as this provides renewable energy for the entire building/facility as opposed to charging stations only – which more holistically achieves GHG emissions reductions and allows for additional benefits such as vehicle-to-grid (V2G) technology and battery energy storage (see more details in next sub-section).

(9) Provide or expand on current high-voltage safety awareness and/or skills training to include operating and maintaining Toronto Hydro's electric vehicle charging stations, and closely monitor the launch of new electric vehicle fleet technician training programs. A pilot for a new EV Maintenance Training Program for automotive technicians was successfully completed at BCIT and is available to the public[41]. There is also an Electric Vehicle Technology Certificate Program offered by SkillCommons, managed by the California State University and its MERLOT program, which offers free and open learning materials on electric vehicle development, maintenance, alternative/renewable energy, and energy storage[42].

Collaboration/Partnership Approaches

With the transition to BEVs in the early stages and expected to gain significant momentum in the short- to mid-term, we recommend that Toronto Hydro strengthen current partnerships and establish new partnerships – both internal and external – to leverage knowledge and resources and better prepare for the transition by undertaking the following actions:

(1) Engage in internal partnerships within and across departments, such as multi-departmental funding applications for charging infrastructure, or sharing of BEV pilot program results to determine vehicles requirements and specifications (e.g., real-world range, real-world charging needs) ahead of large purchasing decisions involving many units.

(2) Engage in external partnerships (e.g., other utilities in Southern Ontario) for potential collaborations, such as joint specification writing and/or joint tenders and sharing of BEV pilot program results through working groups.

[41] Source: https://commons.bcit.ca/news/2019/12/ev-maintenance-training/
[42] Source: http://support.skillscommons.org/showcases/open-courseware/energy/e-vehicle-tech-cert/

(3) Leverage the knowledge gained on BEV transition (e.g., procurement of vehicles and charging infrastructure) through organizational memberships such as the Clean Air Partnership or the Canadian Utility Fleet Council (CUFC).

Risk/Change Management Approaches

(1) Develop BEV educational and outreach materials for employees and operators summarizing the reasons and benefits of transitioning to BEVs, in terms of the environment (improved air quality and greatly reduced lifecycle GHG emissions), reduced fuel and maintenance expenses (the business case), improved performance (e.g., instant torque, little noise, regenerative breaking), greater reliability due to fewer moving parts than internal combustion engine (ICE) vehicles, and continuously expanding charging infrastructure. This should include dispelling myths about BEVs, such as potential negative and/or false perceptions on battery safety, battery life, battery end-of-life, and vehicle performance – facilitating a cultural shift from fossil-fuelled vehicles to clean, zero-tailpipe emission BEVs.

(2) Invite frontline employees to take BEV test drives to familiarize them with fully-electric vehicles and charging, as well as to give them first-hand experience of improved performance (e.g., instant torque, little noise, regenerative braking).

(3) Provide operators with a BEV orientation before releasing new models into the fleet to enable them to become familiar with the different driving experience (e.g., instant torque, little noise, regenerative braking), as well as to alleviate/eliminate any apprehension or uncertainties such as range anxiety.

(4) As is recommended for the phasing in of BEVs, we recommend pilot projects for several BEV types as they become available (e.g., pickups, passenger minivans, etc.) to track range capabilities and cost savings and assess the units' performance for all seasons and varying weather conditions.

Additional Considerations

Battery Replacement, Energy Storage, and Battery Disposal

Global lithium-ion battery demand has risen dramatically over the last ten years, and this is expected to only be the "tip of the iceberg" as we are only at the beginning of the electric vehicle revolution.

Most, if not all, battery-electric vehicle (BEV) manufacturers have an eight-year or 100,000 mile (160,000 km) warranty on their batteries – whichever one (i.e., vehicle age or distance travelled) comes first[43]. However, the current prediction is that a BEV battery will last from 10-20 years,

[43] Source: https://www.myev.com/research/ev-101/how-long-should-an-electric-cars-battery-last

depending on usage, before it needs to be replaced[44]. Consumer Reports estimates that the average BEV battery pack's lifespan is around 200,000 miles (320,000 km), which is nearly 17 years of use if driven 12,000 miles (19,200 km) per year. As a comparison, the average annual mileage for all Toronto Hydro fleet vehicles is under 5,000 km. Therefore, in most cases, BEVs will reach their end-of-life before there is a need for battery replacement.

When battery capacity falls below 80%, drivers may start to see a decline in range[45] – which would most likely occur at or after the typical vehicle replacement age because battery degradation is a very gradual process[46]. Once the BEV battery capacity becomes undesirable for powering a vehicle, it can be used to power a building by contributing to a battery storage system, which stores energy from a battery that can be used at a later time[47]. For example, if a building is powered by renewable energy such as wind or solar, an "old" BEV battery can be used to store energy produced while the wind is blowing or the sun is shining, and then release the stored energy during low-wind periods or at night. This method of generating electricity has multiple benefits, including:

- An effective way of continuing the life of an old BEV battery;
- Reducing energy used from the grid, thereby reducing energy costs; and
- Increasing energy security when using renewables, which have variable energy outputs, by releasing stored energy during off-peak times.

When batteries reach the end of their working life, they can be recycled, which typically involves separating out valuable materials such as cobalt and lithium salts, stainless steel, copper, aluminium, and plastic. Currently, about half of the materials in a BEV battery pack are recycled, but with BEVs expected to undergo an explosion in popularity over the next decade or so, car manufacturers are looking to improve this[48]. Moreover, battery recycling companies have emerged with the growing need for electric vehicle battery recycling, as well as due to the shortage of domestic critical raw materials including lithium, cobalt, and nickel[49].

End-of-lifecycle lithium-ion batteries are first brought to facilities, known as "spokes," which physically separate materials (e.g., shredded metals, mixed plastics, etc.) – much like municipal material recycling facilities (MRFs). These separated materials are then brought to centralized locations, known as "hubs," where battery-grade end products, i.e., the original raw materials (metals) are produced. In May 2020, the lithium-ion battery recycling company Li-Cycle opened a

---

[44] Source: https://www.edfenergy.com/electric-cars/batteries
[45] Source: https://www.edfenergy.com/electric-cars/batteries
[46] Source: https://www.myev.com/research/ev-101/how-long-should-an-electric-cars-battery-last
[47] Source: https://www.edfenergy.com/electric-cars/batteries
[48] Source: https://www.edfenergy.com/electric-cars/batteries
[49] Source: Li-Cycle Corporate Presentation, July 21 [non-confidential]

"spoke" facility in Kingston, Ontario with a capacity to process 5,000 tonnes of lithium-ion batteries per year. [50]

Utilities like Toronto Hydro will have the option of packaging and coordinating the shipment of end-of-lifecycle electric vehicle batteries to battery recycling companies, with preliminary cost estimates of 1-2 CAD per kilogram – depending on the size of the battery pack and the cathode materials.

Hybrid-Electric Vehicles

As discussed with Toronto Hydro Fleet Management, there are plans for increasing the number of hybrid units into the fleet with hybrid SUVs, pickups, and vans. Purchasing hybrid vehicles is an effective interim solution considering there is (1) currently limited and/or no BEV availability in the market for these vehicle types and (2) expected long procurement timelines for upcoming BEV models.

Hybrid Electric Vehicles (HEVs) use two or more distinct types of power, such as an internal combustion engine (ICE) and a battery-powered electric motor as the modes of propulsion, albeit with very limited range when in electric mode. When an HEV accelerates using the ICE, a built-in generator creates power which is stored in the battery and used to run the electric motor at other times. This reduces the overall workload of the ICE, significantly reducing fuel consumption and extending range. Examples of HEVs include the Toyota Prius and Ford Fusion Hybrid. [51]

Plug-In Hybrid Electric Vehicles (PHEVs) use rechargeable batteries, or another energy storage device, that can be recharged by plugging into an external source of electric power. PHEVs can travel considerable distances in electric-only mode, typically more than 25 km and up to 80 km for some models, due to their much higher battery capacity than HEVs. When the battery power is low (usually ~80% depleted), the gasoline ICE turns on and the vehicle functions as a conventional hybrid. Such vehicles typically have the same range as their gasoline counterparts. Examples of PHEVs include the Chevrolet Volt and Toyota Prius Prime.[52]

Given that Toronto Hydro is a very low-mileage fleet, it is conceivable that many PHEVs would be able to fulfil daily duties on battery-power only and recharge overnight – essentially functioning like fully-electric vehicles.

Feasibility Considerations

- Given the combination of an internal combustion engine (ICE) and a battery-powered electric motor in HEVs, there is little or no preparation required ahead of acquiring these vehicles,

[50] Source: Li-Cycle Corporate Presentation, July 21 [non-confidential]
[51] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/
[52] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/

making these attractive purchasing options while BEV supply and charging infrastructure catch up to demand.

- PHEVs may be plugged into a level one or two charger (120 V outlet or 240 V outlet, respectively), with the later achieving a much faster charging speed. However, if a charger is not readily available, the ICE will allow the vehicles to act as regular hybrids, eliminating any range anxiety.

Best Management Practices

Toronto Hydro may want to implement and/or improve its best management practices (BMPs) while transitioning its fleet to battery-electric – as interim solutions to reducing fuel usage and costs as well as GHG emissions. Summaries of the BMPs we are recommending as additional considerations are summarized below. For a complete description of all BMPs researched by RSI-FC, please see *Appendix D*.

Light-Weighting

Lighter vehicles consume less fuel, produce less emissions, and can carry larger payload. However, light-weighting may overstress some vehicles, increasing maintenance demand and lifecycle cost; therefore, fleet must exercise caution before choosing which vehicles to proceed with a light-weighting enhancement.

Low-Rolling Resistance Tires

Rolling resistance is the energy lost from drag and friction of a tire rolling over a surface[53]. The phenomenon is complex, and nearly all operating conditions can affect the final outcome. For heavy trucks, an estimated 15-30% of fuel consumption is used to overcome rolling resistance.

A 5% reduction in rolling resistance would improve fuel economy by approximately 1.5% for light and heavy-duty vehicles. Installing low-rolling resistance (LRR) tires and/or auto-inflation systems can help fleets reduce fuel costs. It important to ensure proper tire inflation in conjunction with using LRR tires.

Tires and fuel economy represent a significant cost in a fleet's portfolio. In Class 8 trucks, approximately one-third of fuel efficiency comes from the rolling resistance of the tire. The opportunity for fuel savings from LRR tires in these and other vehicle applications is substantial.

According to a North American Council for Freight Efficiency (NACFE) report, the use of LRR tires, in either a dual or a wide-base configuration, is a good investment for managing fuel economy.

[53] Source: https://afdc.energy.gov/conserve/fuel_economy_tires_light.html

Generally, the fuel savings pay for the additional cost of the LRR tires. In addition, advancements in tire tread life and traction will reduce the frequency of LRR tire replacement.

Anti-Idling Policy and Technologies

Idling in a utility fleet is unavoidable for reasons including cab climate control for workers as well as for vehicles equipped with power takeoff (PTO) driven ancillary equipment, such as aerial devices, digger-derricks and cranes. That said, *avoidable and unnecessary* idling is not acceptable.

An idling-reduction policy is a way to motivate fleet drivers to limit unnecessary idling. However, for an idling-reduction policy to be successful continuous enforcement such as spot-checks and fuel use tracking must be present. An idling-reduction policy could be used as an overarching commitment to idling reduction that is carried out though driver training and motivation sessions, rather than an initiative on its own.

There are several idling-reduction technologies available that can aid in idle reduction, including auxiliary power units (APU), stop/start devices, auxiliary cab heaters, battery backup systems, and block heaters/ engine preheaters. Their functionality, potential, and costs vary considerably and are described in *Appendix D* (FAR models a cost of $5,000 for all vehicle categories). To reap the most benefits of any idling-reduction technology, installation should always be accompanied by behavioural solutions of driver training and motivation.

Driver Eco-Training

Driver training to modify driver behaviours and ongoing motivation to continue good behaviours are crucial components of successful idling-reduction programs. While most drivers understand the vehicle idling issue, many continue their inefficient practice of excessive idling due to lack of knowledge and/or motivation.

Driver training can be used to optimize the use of idle reduction technologies. The technologies can reduce idling but the drivers have the ability to override the technologies. Proper training can aid in utilizing the technologies to their full potential.

Further, driver training can promote good practices while on the road including progressive shifting, anticipating traffic flow, and coasting where possible.

Route Planning/Optimization and Trip Reduction

In addition to enhanced vehicles specifications and improved driver behaviours, fuel consumption and exhaust emissions can be further reduced through route planning/optimization and trip reduction.

Route planning software can be used optimize multi-stop trips. It can also be used for idling reduction initiatives by integrating GPS tracking software to monitor driver activity in real-time. Moreover, reporting and analytics features within route planning software can help with identifying when a fleet vehicle requires maintenance to ensure optimal fuel efficiency and thus minimize cost and emissions.[54]

Google™ Maps recently announced their mapping/guidance systems will soon feature and advise drivers of the lowest GHG-emission routes to their destinations. By embracing this technology where possible/practical in Toronto Hydro's fleet, and perhaps combining its use with a corporate policy or directive for employees to minimize their trips where possible, emissions (and costs) could be minimized.

...

[54] Source: https://blog.route4me.com/2020/05/carbon-emissions-reduction-route-optimization-helps-cut-tons-carbon-emissions/

Section 9: Overview and Discussion

In Toronto Hydro's Electric Vehicle Phase-in Plan, we presented:

(1) Findings of RSI-FC's Electric Vehicle Survey to gauge the current view and opinions of employees on battery-electric vehicles and charging requirements;

(2) Key results of the 2020-21 fleet and GHG emissions baseline for current fleet assets;

(3) Modelling results for various fleet electrification pathways over a 15-year budget cycle including their impacts on Operating expenses, Capital expenses, and GHG emission reductions relative to the baseline;

(4) Modelling results for electric vehicle supply equipment (EVSE) requirements on a unit-by-unit basis and an estimation of charger costs over a 15-year budget cycle; and

(5) Recommendations for a balanced, structured BEV phase-in as well as charging infrastructure planning.

Capex Benchmarking

Based on optimized economic lifecycles, it was estimated that, in 2022, $15.3 million would be required to replace all due or past-due units with new like-for-like vehicles (no BEVs at this stage). It should be noted that numerous vehicles in the Toronto Hydro fleet are beyond the current planned age for replacement – *significant "catch-up" is required to modernize the fleet.*

Starting with optimized economic lifecycles and then selectively and strategically making deferrals over the 15-year budget cycle to maximize Opex benefits, or return-on-investment (ROI) resulted in a much more balanced Capex over the 15-years. The net result was an average annual capital budget of $6.2 million with annual amounts ranging from $5.3-7.9 million with clustering around $6-6.5 million, as compared to the much wider and more fluctuating range over the budget period for optimized economic lifecycles only.

This step was intended to provide a benchmark for a balanced long-term capital budget if like-for-like replacements were to be made – and as a comparison for long-term capital planning for BEV phase-in.

Synopsis of Electric Vehicle Phase-in Plan

Starting from the baseline, we modelled a number of fleet electrification scenarios ranging from aggressive and over-budget to balanced and within budget – to demonstrate a spectrum of pathways. Although BEV phase-in is the most effective long-term GHG reduction strategy for a fleet, the reality is that there are currently higher upfront costs associated with the transition; therefore, it must be done in a fiscally responsible manner.

Based on our modelling, lower-mileage units at Toronto Hydro are unlikely to deliver ROI if replaced with a BEV at this time. Fuel cost savings, for many units, are not great enough to offset the increased cost of capital due to relatively low mileage. Of course, the higher the kilometres travelled, the stronger the business case for BEVs becomes. There is a strong likelihood that the acquisition cost of BEVs will decline with time as both supply increases and battery technology continues to improve, and we have modelled this for Toronto Hydro's consideration.

BEV Phase-in Approaches and Scenario Results

The aggressive BEV phase-in approach employs a strategy of deferring more units in the short-term, resulting in a pent-up demand for overdue units which are modelled to be replaced with BEVs. Consequently, there are significant Capex spikes in the short- to medium-term.

To provide a balanced and viable BEV phase-in plan, our team strategically modelled the replacement of overdue lower-mileage units with internal combustion engine (ICE) vehicles in an effort to still achieve significant GHG emissions reductions while keeping within budget constraints. Moreover, we modelled replacement of overdue units that showed high usage and/or relatively high repair costs with ICEs as a financial risk-reduction strategy.

The balanced BEV phase-in approach employs a strategy that calls for increased capital spending upfront (i.e., in the next few years) for ICE units in greatest need of replacement, in an effort to modernize Toronto Hydro's fleet with like-for-like (i.e., ICE) replacements and allow for balanced, within-budget capital spending on BEVs down the road.

The aggressive fleet electrification scenarios have the potential to reduce Toronto Hydro's fleet tailpipe GHG emissions by **100% by 2034** – before the end of the modelling period. The more cautious and fiscally prudent scenarios have the potential to reduce Toronto Hydro's fleet tailpipe GHG emissions by just over **70% by 2037** – with the potential to achieve even greater results should more ICE units be replaced with BEVs towards the end of the modelling period, depending on pricing outcomes for BEVs compared to ICEs.

For the aggressive, fleet-wide BEV phase-in scenarios, average annual Capex is projected to be **$10.7M/yr** with cautious pricing (i.e., constant BEV/ICE ratios) and decrease to **$7.6M/yr** with the sliding scale in pricing. However, for both scenarios Capex is very imbalanced and front-loaded (i.e., higher values in the short- to mid-term).

The balanced, selective BEV phase-in scenarios avoid annual Capex "spikes" and keep within annual budget constraints. Even with this approach, it will take significantly more capital to transition to BEVs based on current prices discussed with Toronto Hydro Fleet Management, with a modelled average annual Capex of **$8.3M/yr**. If price parity is gradually reached by the 2030s, average annual Capex is projected to decrease to **$7.0M/yr**.

For units due for replacement that are still in good condition, we are recommending a temporary pause on purchasing new internal combustion engine (ICE) vehicles for the short term – 1-2 years for pickups, 2-3 years for medium- and heavy-duty vehicles (MHDVs) – while awaiting battery-electric vehicle (BEV) counterparts to become available and taking into consideration procurement timelines.

Our position is that fleets should re-consider buying new fossil-fuelled units, when possible, because ICE vehicles will quickly become an outdated and archaic technology, and there will soon be BEV replacement options. The purchase of new ICE vehicles now, whether gasoline or diesel, means that a fleet, like Toronto Hydro's fleet, will commit to using new fossil-fuelled vehicles for approximately the next decade when zero tailpipe emissions BEVs are just around the corner.

A phased-in approach is recommended for Toronto Hydro to transition to a BEV fleet for fiscal responsibility reasons, in addition to this being the only option for fleets over the next few years. Utility replacement cycles are long-term – up to 10 or 12 years – or more for some vehicles. Therefore, a BEV phase-in plan over the long term is needed for a balanced approach to capital spending.

EVSE Planning

Over the next 10+ years, we recommend allocating capital towards chargers (and charging infrastructure, which is outside the scope of this study) required for the transition to BEVs for all vehicle categories.

Based on our analysis of Toronto Hydro's charging requirements, 381 out of 385 units would be capable of fully recharging during overnight off-peak hours with the use of lower-power Level 2 chargers. Therefore, our recommendation is to focus on Level 2 charging for every unit on a nightly basis, and evaluate higher-power (Level 3) charging for higher-mileage units.

It is also critical to assess existing electrical capacity at facilities to determine whether substantial upgrades for charging multiple vehicles are required (outside the scope of this report). A qualified electrical professional should be consulted to assess the situation and make recommendations.

High-Impact BEV Options

The "workhorses" of utility fleets like Toronto Hydro are light-duty pickup trucks and vans. For Toronto Hydro's fleet, pickups and Class 1 and 2 vans comprise about 42% of the vehicles based on the data provided (84 pickups and 78 light-duty vans out of a total of 385 vehicles). At this time, there are no BEV pickups or vans available for purchase. However, several manufacturers, including General Motors and Ford, are preparing for BEV pickups and vans to enter the market in 2022. Therefore, BEV options in the light-duty pickup and van categories have the potential to make a relatively early and significant impact on the utility's fleet operating cost savings and GHG emissions reduction – ahead of the introduction of medium- and heavy-duty battery-electric trucks.

Appendix A: Electric Vehicle Survey Results

Views on Battery-Electric Vehicles

Figure 4: Views on range capabilities – management group

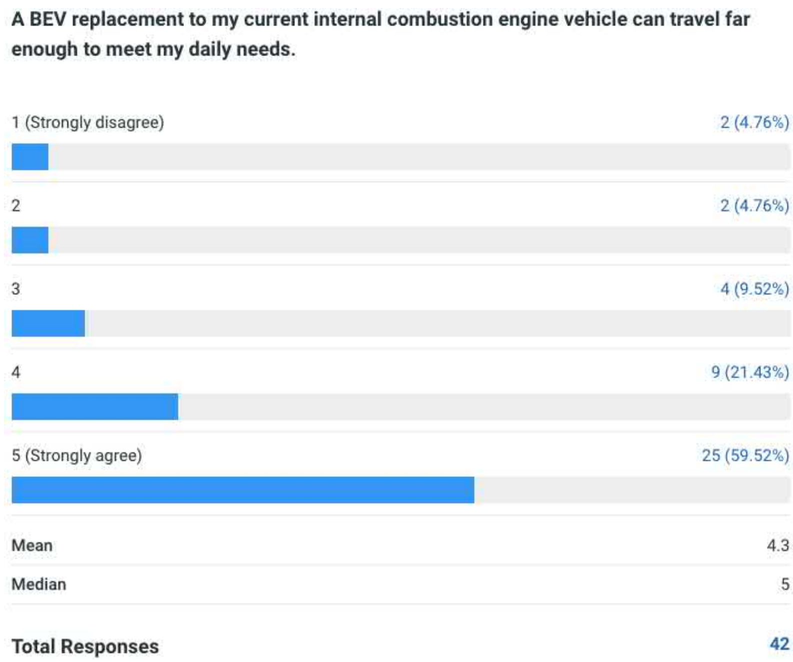


Figure 5: Views on range capabilities – driver/operator group

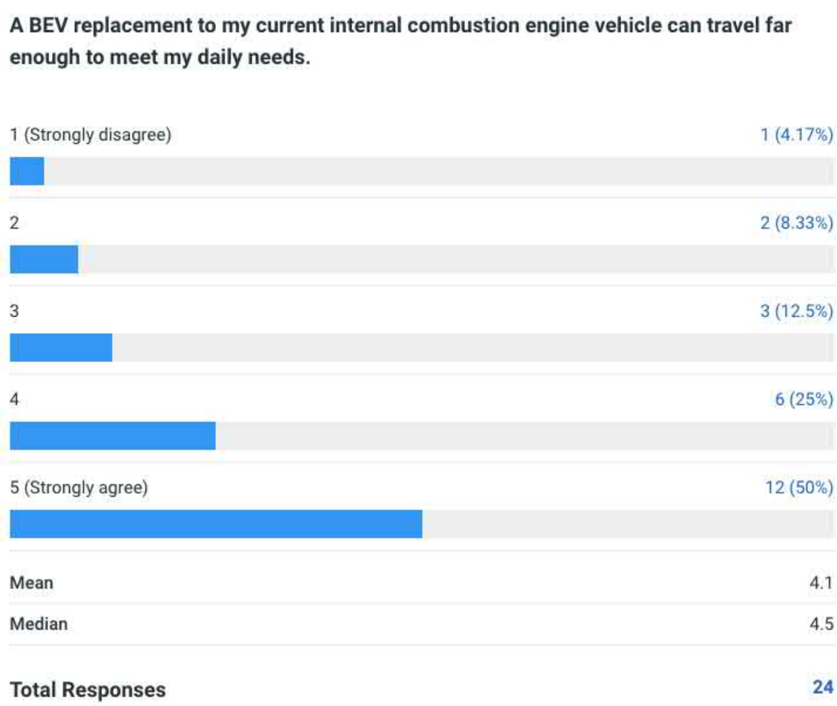


Figure 6: Views on air conditioning – management group

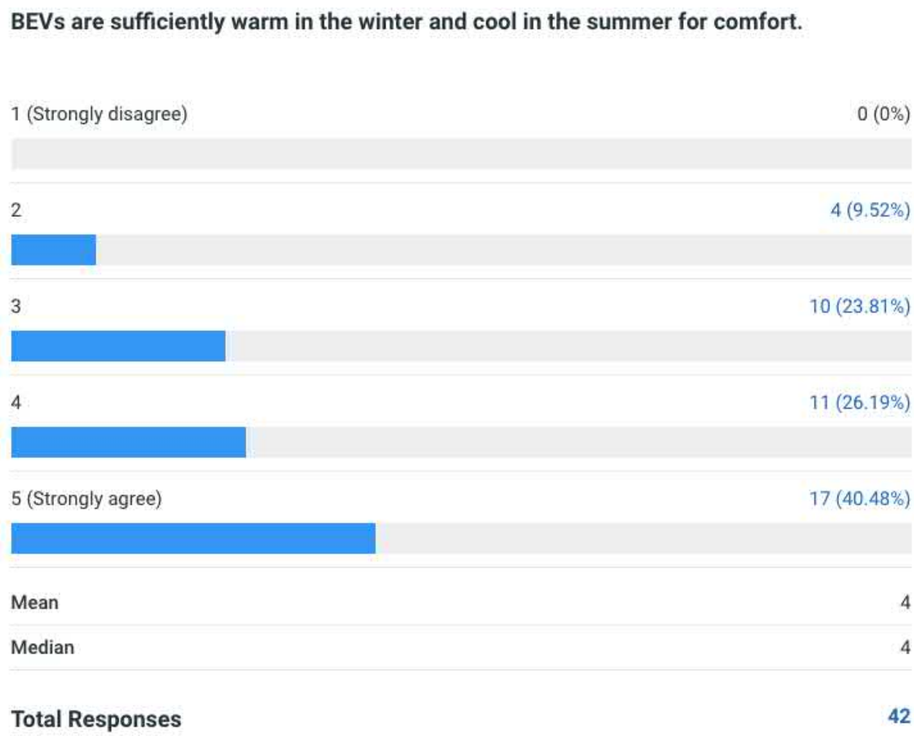


Figure 7: Views on air conditioning – driver/operator group

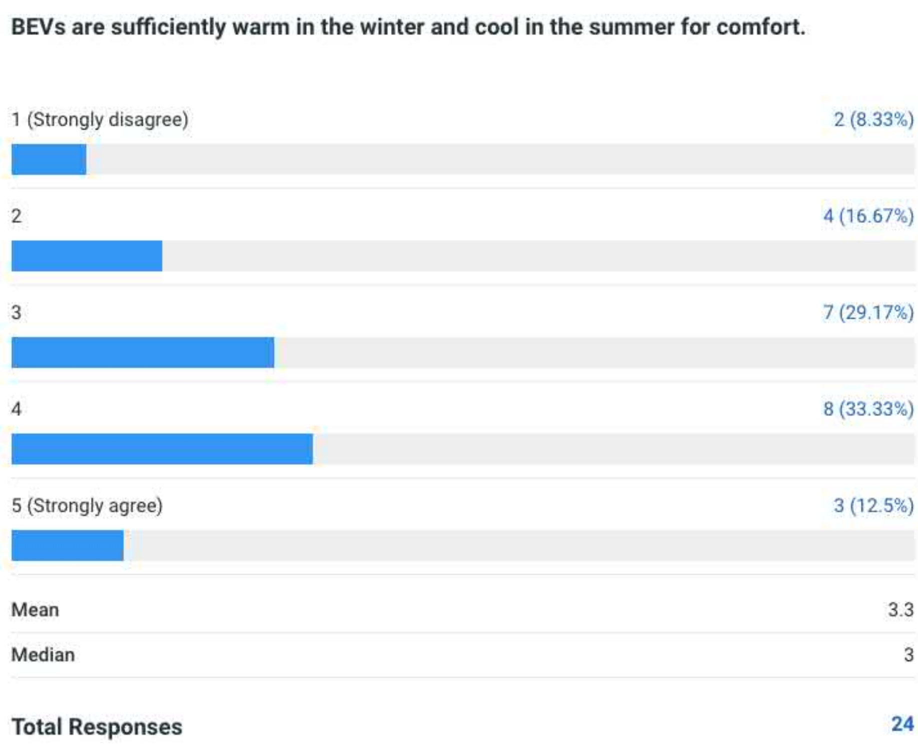


Figure 8: Views on safety – management group

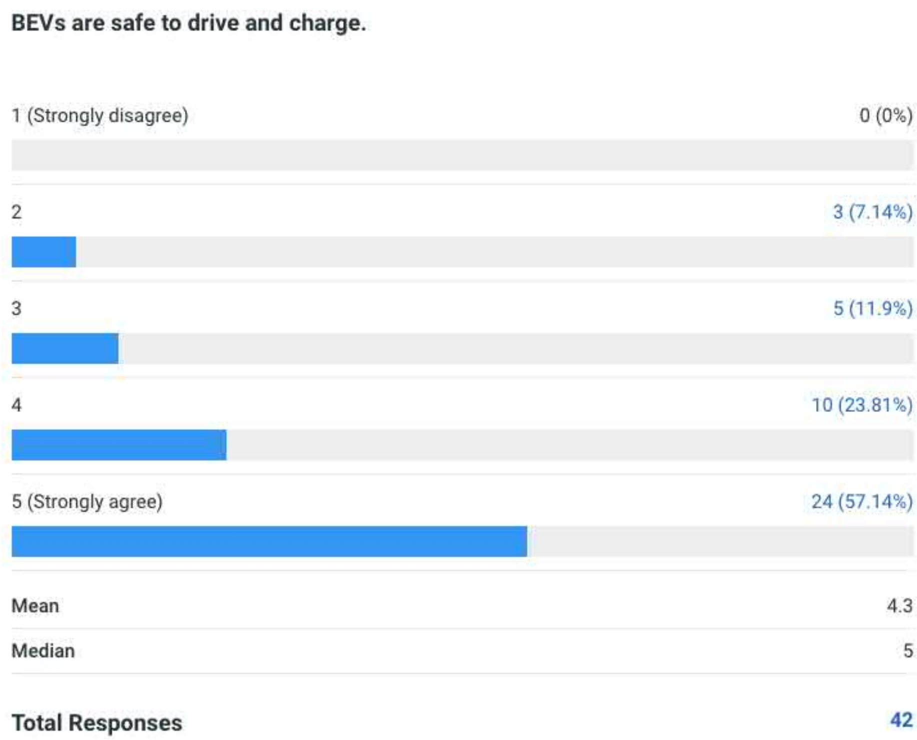


Figure 9: Views on safety – driver/operator group

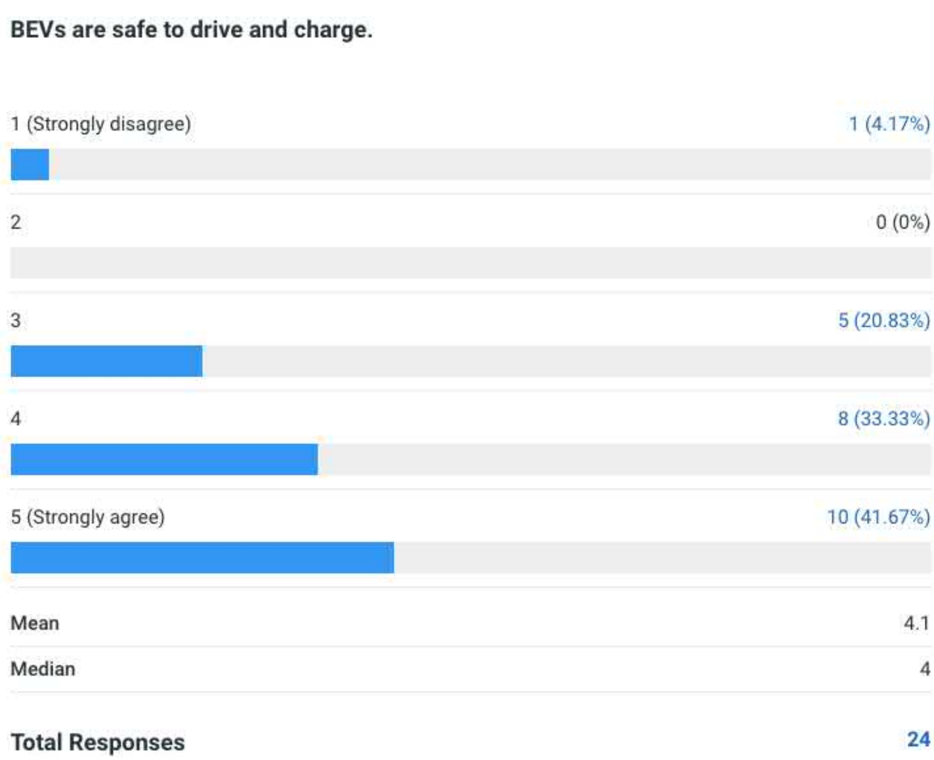


Figure 10: Views on costs – management group

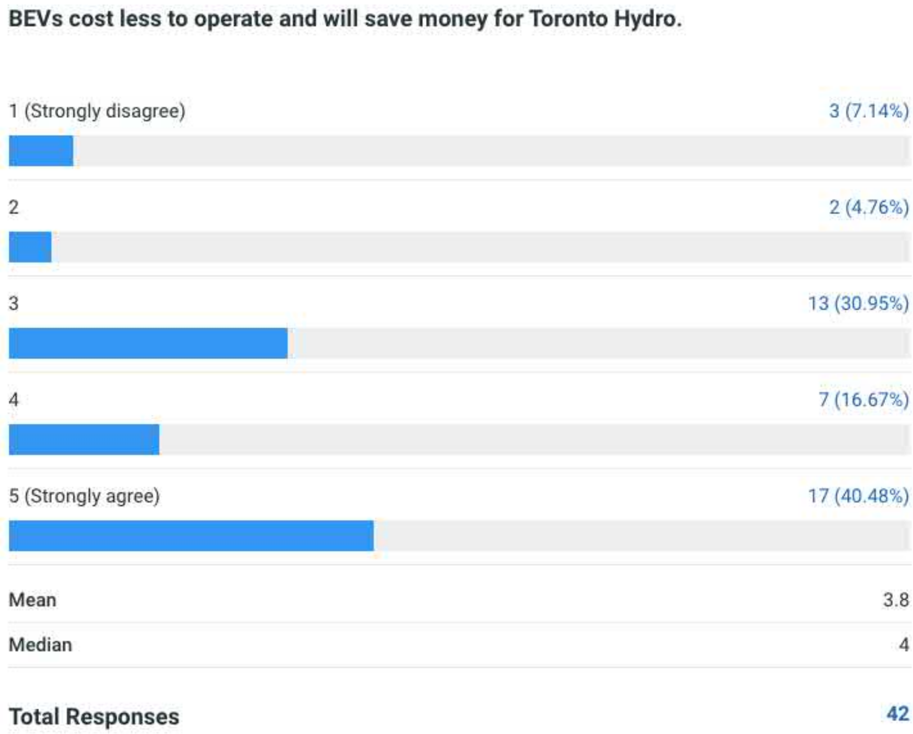
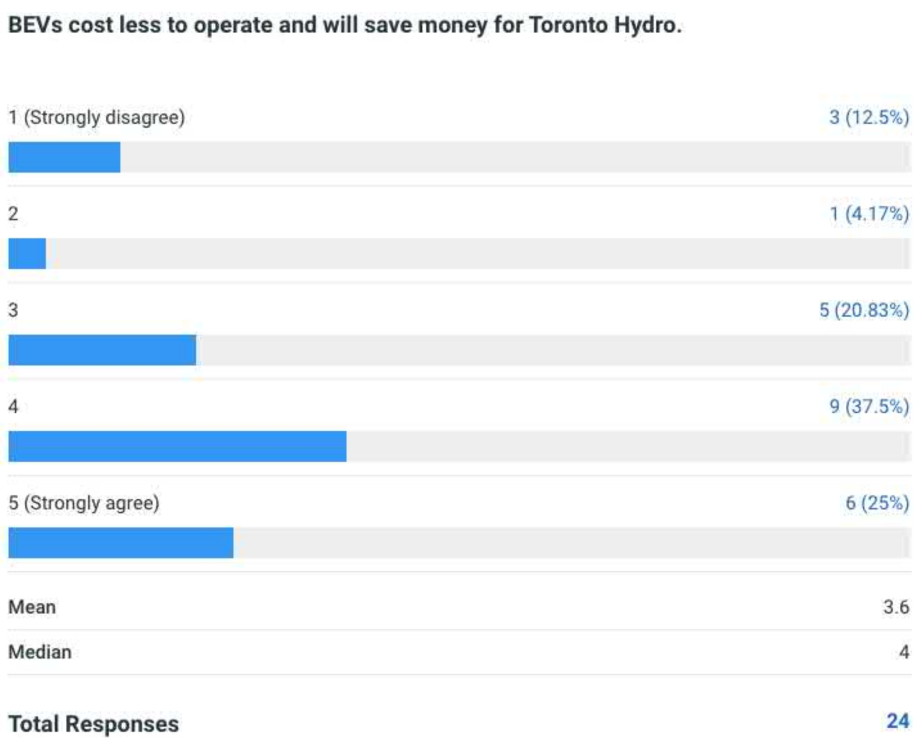


Figure 11: Views on costs – driver/operator group



Views on Charging Requirements

Figure 12: Views on Level 2 charging – management group

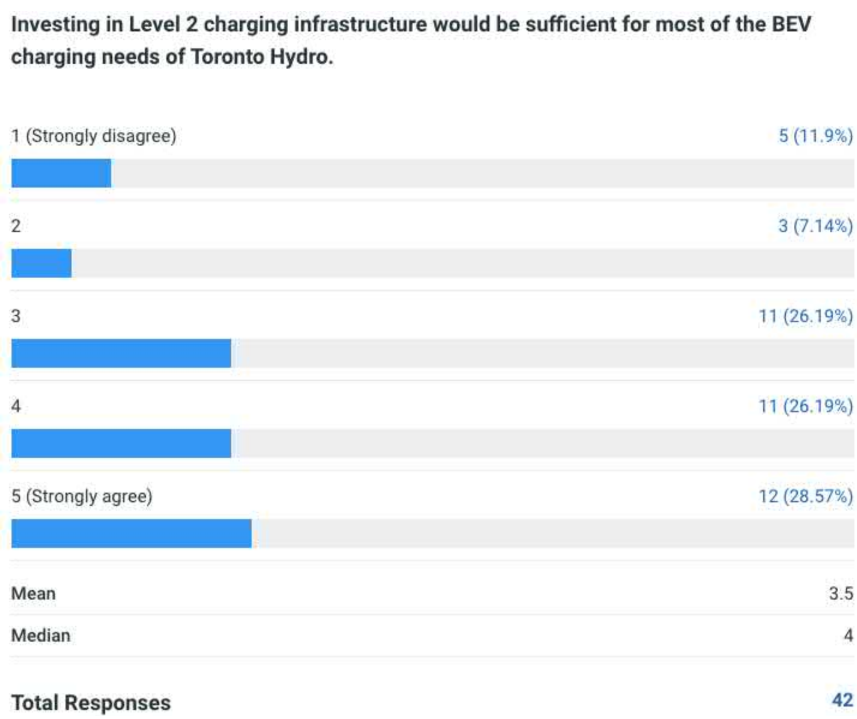


Figure 13: Views on Level 2 charging - driver/operator group

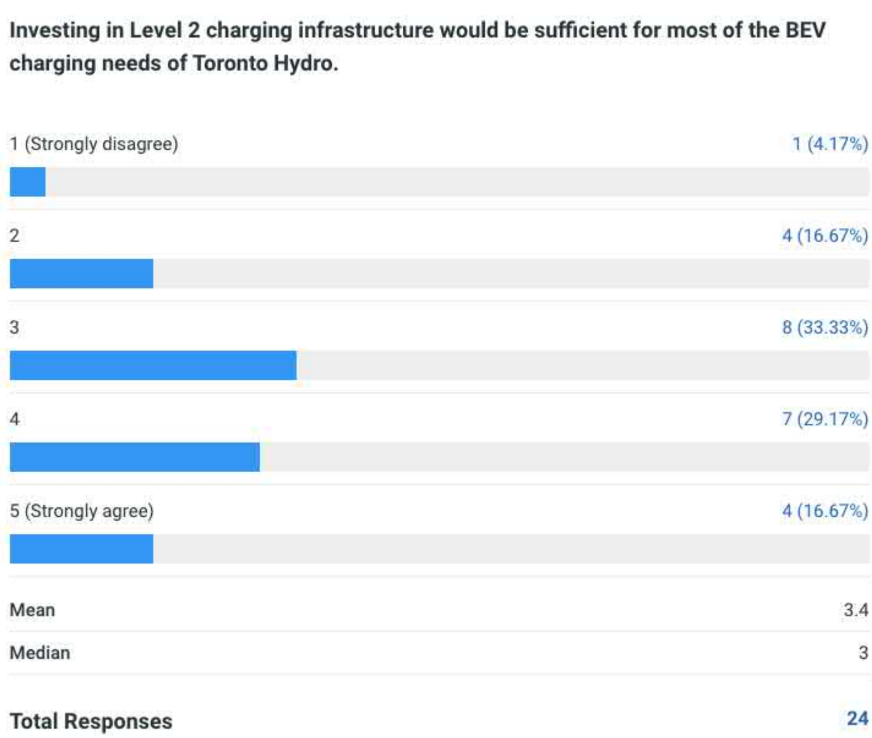


Figure 14: Views on Level 3 charging – management group

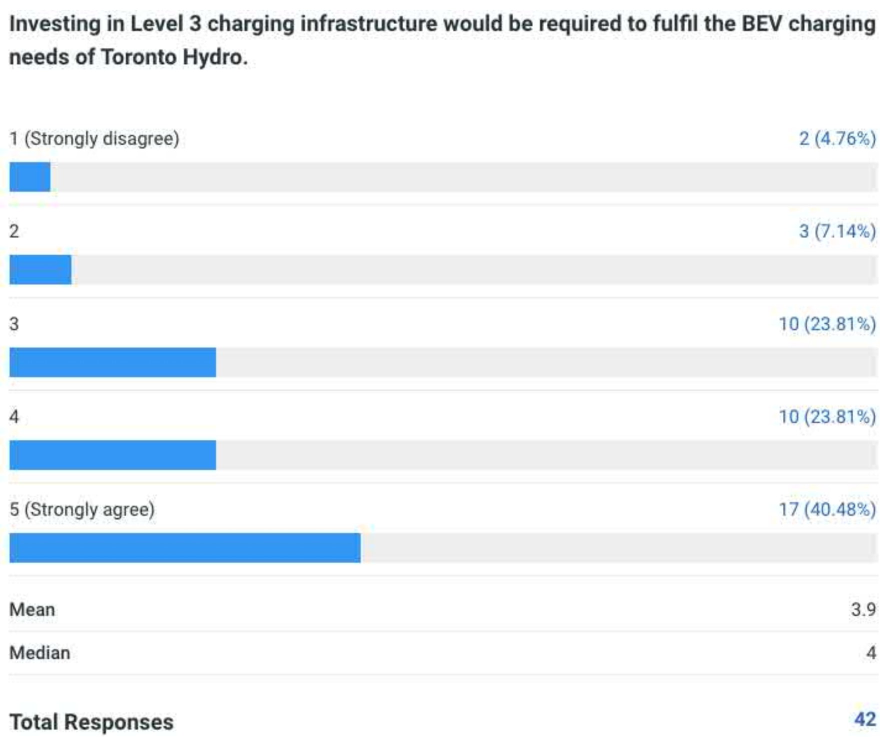
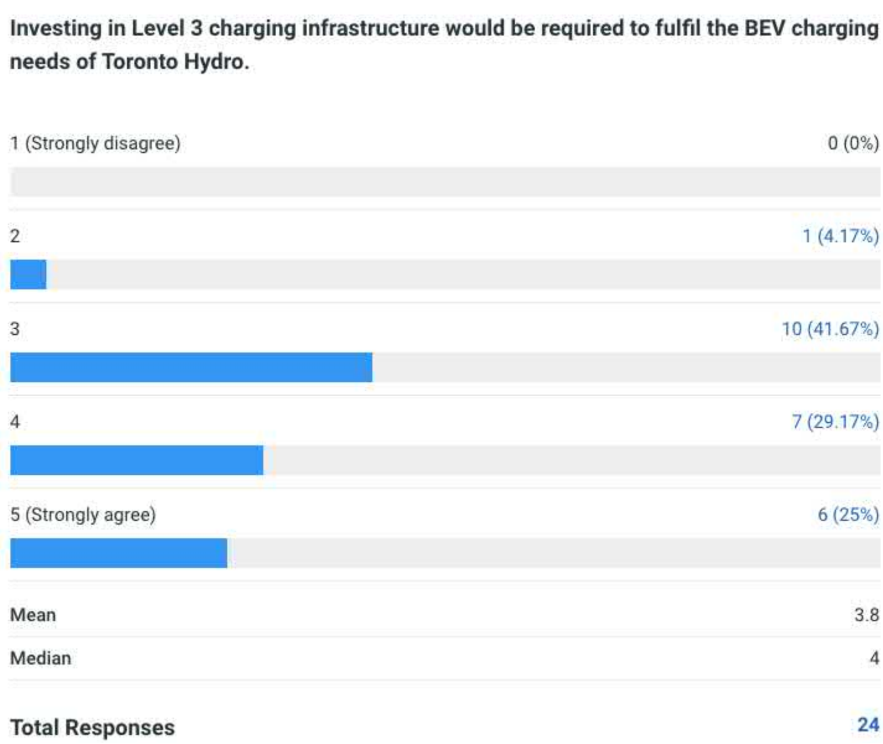


Figure 15: Views on Level 3 charging – driver/operator group



Views on Change Management

Figure 16: Views on test drives – management group

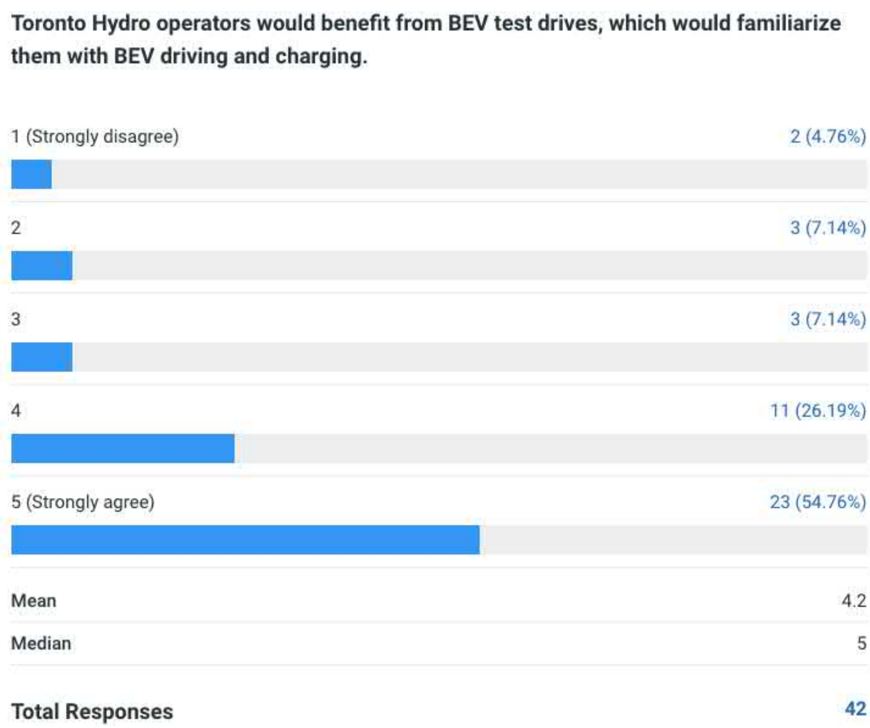


Figure 17: Views on test drives – driver/operator group

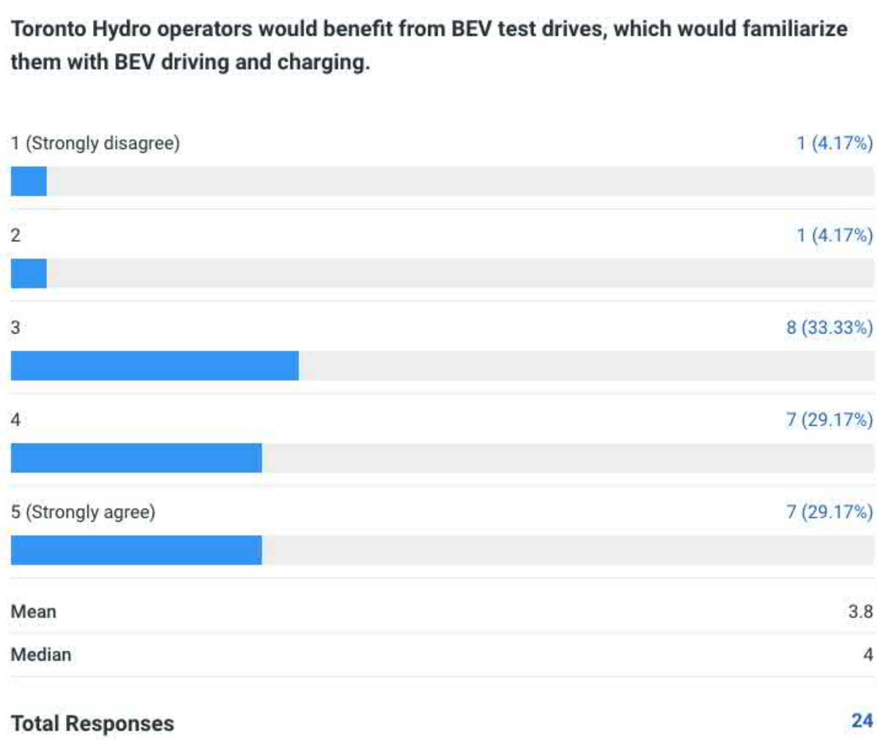


Figure 18: Views on orientation – management group

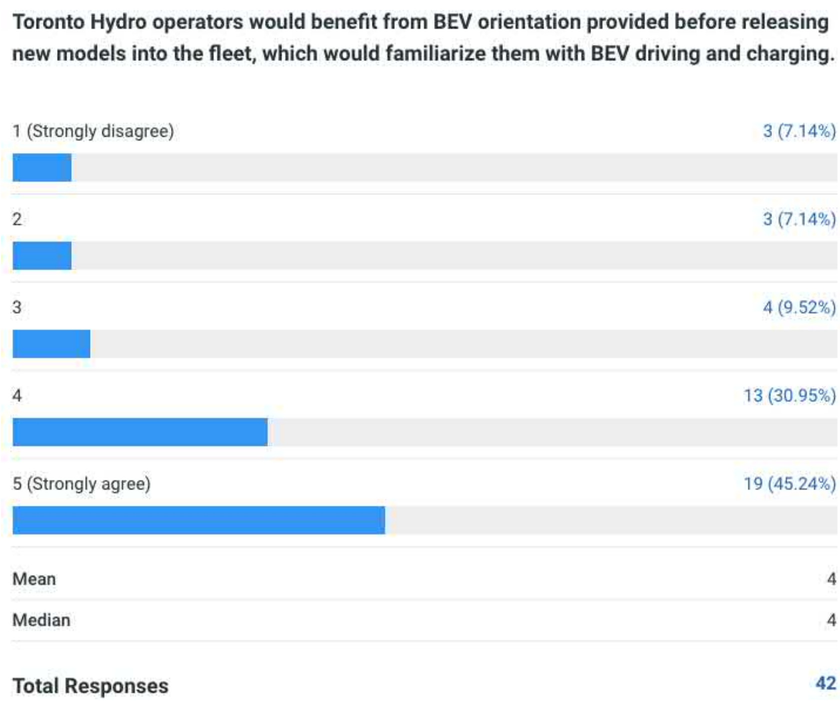
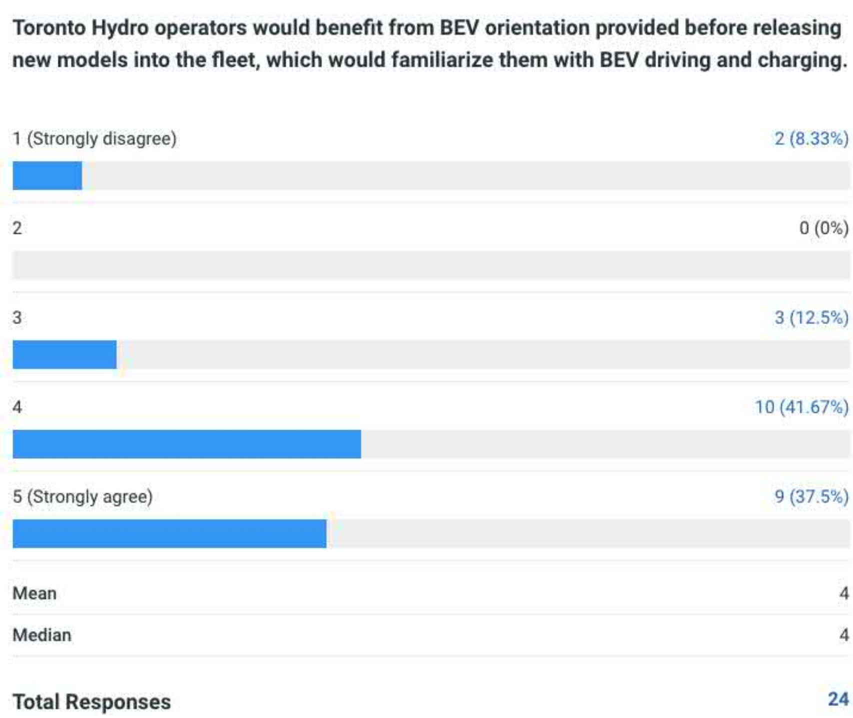


Figure 19: Views on orientation – driver/operator group



Appendix B: Fleet Analytics Review™

Fleet Analytics Review™ (FAR) is a user-friendly, interactive decision support tool designed to aid our team and fleet managers in developing short- to long-term green fleet plans by calculating the impacts of vehicle replacement and fuel-reduction solutions on operating costs, cost of capital, and GHG emissions. Moreover, it is used for long-term capital planning (LTCP) through an approach that works to balance, or smoothen, annual capital budgets and avoid cost spikes if possible.

FAR is a complex, sophisticated MS Excel software developed by the RSI-FC team in 2016. Since its inception, FAR has been used by our team as the foundational analysis platform for our work in helping fleets with green fleet planning and the transition to low-carbon fuels/technologies.

Clients to date for which reports were completed using FAR include:

- Municipality of Strathroy-Caradoc (2021)
- City of Brampton (2021)
- City of Hamilton (2021)
- City of Kawartha Lakes (2020)
- Durham Region (2020)
- Town of Gander (2020)
- Town of Whitby (2020)
- Town of Aurora (2019)
- NW Natural Gas Distribution, Portland, OR, USA (2018)
- The County of Middlesex Centre (2017)
- The Region of Peel (2017)
- The Town of Enfield, CT, USA (2017)
- Toronto Hydro-Electric System Limited (2017)
- Winnipeg Airport Authority (2017)
- Greater Toronto Airport Authority (2016)
- Oxford County (2016)
- The City of Vaughan (2016 - 2018)

Purpose

The core functionality of the FAR software is to calculate the financial and GHG reduction impacts of vehicle replacements, operational improvements, and low-carbon fuels/technologies for a fleet.

In the context of assessing fleet modernization, FAR is especially useful in calculating the operating expense (Opex) impacts of vehicles being retained in the fleet beyond their viable age and with diminishing salvage values. Aged, older-technology vehicles consume more fuel, produce more

GHGs, usually cost more to operate, are less reliable, and may also present a safety risk. FAR automatically calculates and quantifies these impacts in a defensible business case format.

For fuel-reduction solutions under consideration by fleet management as a means of saving fuel costs and avoiding GHGs, including best management practices (BMPs), alternate or renewable fuels (natural gas, propane, biodiesel, etc.), and EVs (battery-electric, plug-in hybrid, or hybrid), FAR calculates the cost-benefit of the investment in vehicle upgrades, vehicle conversion costs, fuelling infrastructure, or EV charging infrastructure, i.e., whether these solutions would yield a net operating cost reduction, unit-by-unit and fleet-wide.

Approach

The FAR software tool employs a holistic approach – all relevant factors and controllable expenses are considered in its analysis. The data points in our approach include energy equivalency factors of each alternative fuel type (compared to a fossil diesel fuel baseline), vehicle upgrade costs, alternately-fuelled vehicle acquisition (or vehicle retrofit) capital costs, vehicle maintenance considerations (higher or lower maintenance demand), fuel system/charging infrastructure capital costs, and any additional expenses for storage, handling & dispensing the fuel(s). All of these factors are modelled within the context of planned vehicle lifecycles – a total cost of ownership (TCO) approach.

The FAR process uses historical cost metrics and vehicle operating data (i.e., miles/km-driven, fuel usage, repair and maintenance costs, unit age, cost of capital, downtime, residual value, etc.) to establish not only the fleet's fuel usage and GHG emissions baseline, but also financial and service levels (i.e., utilization, availability/uptime) performance.

FAR highlights "exception" units, vehicles that are performing in a sub-standard way in terms of cost and performance, thus potentially enabling management to identify the reason(s) and take appropriate action(s).

Go-Forward Fuel-Reduction Solutions

With the FAR baseline established, the software is used to analyze go-forward fuel-reduction solutions. FAR takes into consideration the Opex implications and determines whether Opex reductions will offset any capital expenses (Capex) including vehicle upgrades, vehicle conversions, "up-charges" for premium vehicles (e.g., EVs), and investment in infrastructure.

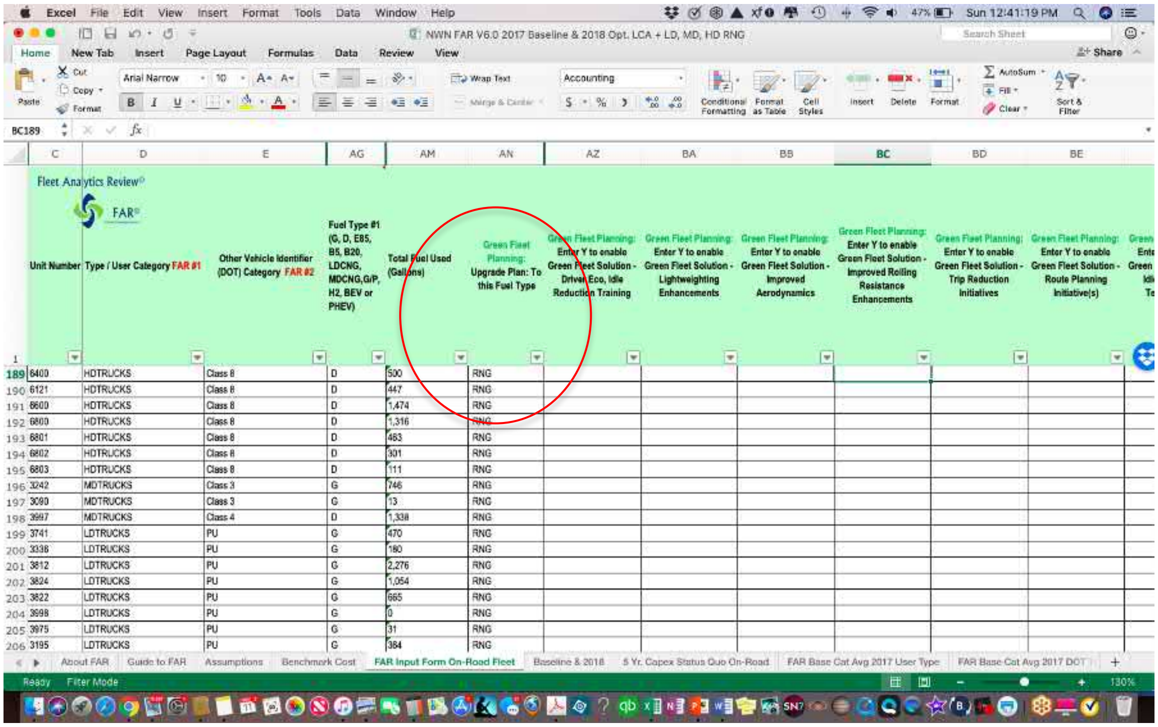
The FAR analysis includes, but is not limited to:

- The fuel usage and cost differential (+ or -) for the fuel type selected vs the current type (if applicable)
- The energy-efficiency difference
- The unit cost of upgrade for the fuel-saving technology
- The unit cost of conversion to the selected fuel type
- The cost of fueling infrastructure for the selected fuel type apportioned evenly to the chosen vehicles for the fuel-switch
- The cost of charging infrastructure for EVs apportioned evenly to the chosen vehicles to be replaced
- The cost of capital for vehicle replacement for the selected fuel type

FAR then calculates whether a cost-savings or return-on-investment (ROI) would result within the remaining lifecycle for each of the vehicles selected for the vehicle upgrade or fuel switch.

Figure 20 shows a sample screen capture from FAR demonstrating the FAR fuel-switching capabilities. In this example, the user is switching several light-, medium-, and heavy-duty trucks from their current fuel source to renewable natural gas (RNG), and this is accomplished simply by selecting the vehicle(s) to be evaluated and then choosing (in this example) RNG from a drop-down list.

Figure 20: Sample Screen Capture of FAR Showing Fuel-Switching Options



	Unit Number	Type / User Category FAR #1	Other Vehicle Identifier (DOT) Category FAR #2	Fuel Type #1 (G, D, E85, B5, B20, LDCNG, MDCNG,G/P, H2, BEV or PHEV)	Total Fuel Used (Gallons)	Green Fleet Planning: Upgrade Plan: To this Fuel Type	Green Fleet Planning: Enter Y to enable Green Fleet Solution - Driver Eco, Idle Reduction Training	Green Fleet Planning: Enter Y to enable Green Fleet Solution - Lightweighting Enhancements	Green Fleet Planning: Enter Y to enable Green Fleet Solution - Improved Aerodynamics	Green Fleet Planning: Enter Y to enable Green Fleet Solution - Improved Rolling Resistance Enhancements	Green Fleet Planning: Enter Y to enable Green Fleet Solution - Trip Reduction Initiatives	Green Fleet Planning: Enter Y to enable Green Fleet Solution - Route Planning Initiative(s)
189	6400	HDTRUCKS	Class 8	D	500	RNG						
190	6121	HDTRUCKS	Class 8	D	447	RNG						
191	6600	HDTRUCKS	Class 8	D	1,474	RNG						
192	6800	HDTRUCKS	Class 8	D	1,316	RNG						
193	6801	HDTRUCKS	Class 8	D	463	RNG						
194	6802	HDTRUCKS	Class 8	D	301	RNG						
195	6803	HDTRUCKS	Class 8	D	111	RNG						
196	3242	MDTRUCKS	Class 3	G	746	RNG						
197	3090	MDTRUCKS	Class 3	G	13	RNG						
198	3997	MDTRUCKS	Class 4	D	1,338	RNG						
199	3741	LDTRUCKS	PU	G	470	RNG						
200	3336	LDTRUCKS	PU	G	180	RNG						
201	3812	LDTRUCKS	PU	G	2,276	RNG						
202	3824	LDTRUCKS	PU	G	1,054	RNG						
203	3822	LDTRUCKS	PU	G	665	RNG						
204	3998	LDTRUCKS	PU	G	0	RNG						
205	3975	LDTRUCKS	PU	G	31	RNG						
206	3195	LDTRUCKS	PU	G	384	RNG						

FAR is user-friendly and intuitive; it is based on standard off-the-shelf MS Excel. It is dynamic, and users can run future scenarios (such as assessing different vehicle types, fuels, or engine/drivetrain combinations) to see how such decisions impact Opex ahead of their implementation, thereby mitigating risk and heading off potentially costly errors.

Recent Enhancements and Upgrades to FAR™

FAR V30.5 (beta) features upgrades and enhancements to the functionalities of the FAR tool. These include:

Fuel-Efficient Green Fleet Planning Tools – Fuel Switching. FAR now includes several powerful "Green Fleet Planning" tools. One of these tools is used to estimate the financial and GHG impacts of switching vehicle fuels from fossil-based (gas or diesel) to alternate or renewable fuels or BEVs.

In the Input Form, FAR analysts may make choices as to fuel-switching (for example, changing all gas or diesel-powered vehicles in specific categories to E85, B5-B100 biodiesel, hybrid, plug-in hybrid, battery-electric, CNG, or even hydrogen fuel cells). FAR calculates the net cost and GHG reduction of the fuel-switch being considered, taking into consideration not just the fuel/electricity costs, but the change in fuel efficiency, as well infrastructure costs such as installing a CNG fueling station, electric vehicle chargers, etc.

Enhanced Vehicle Replacement Cost-Benefit Analysis. Comparisons and analysis regarding either (a) aging a vehicle (or vehicles) that are now due for replacement for another year or (b) going ahead and replacing the vehicle(s) is now based on the actual average historical peer fleet cost data from our proprietary municipal fleet database.

In FAR, when a vehicle is due for replacement, it calculates the annual cost for a new replacement vehicle (including the capital, fuel, repairs, PM, and downtime) and then compares that amount to the actual average cost for a similar vehicle —that is one-year older (from our peer fleet database). FAR now displays the cost-benefit of replacing each unit that is due for replacement in the 5+ year Capex plan tab – in blue font each vehicle that will save Opex if it is replaced, and red font if it will incur more Opex. This marks a significant change in FAR and eliminates all guesswork or sketchy assumptions and supplants it with real peer fleet operating cost data by model year and vehicle categories we have collected since 2006.

Fuel-Usage and GHG Reduction for New Vehicles. For each vehicle that is due for replacement, FAR now shows the potential fuel-usage and GHG reduction.

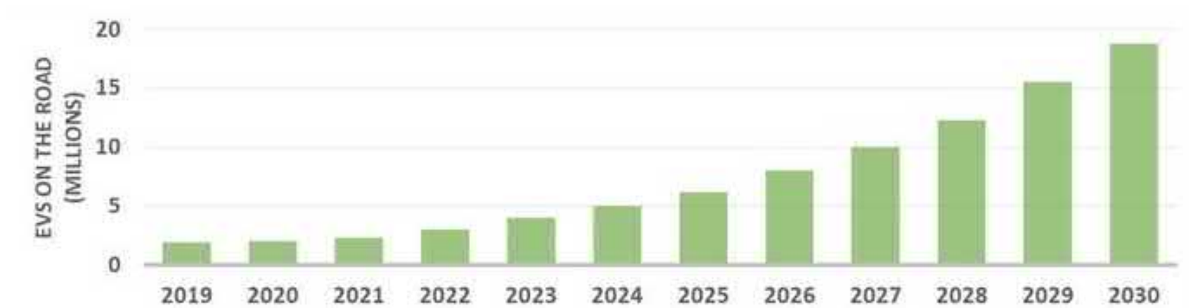
...

Appendix C: Details on Electric Vehicle Technologies

Over the past decade, electric transportation technologies including hybrid-electric vehicles (HEVs), plug-in hybrid electric vehicles (PHEVs), and battery-electric vehicles (BEVs), have been rapidly developing and quickly gaining popularity in the market. Electric vehicle (EV) technologies offer significantly reduced or no tailpipe emissions and vastly improved energy efficiency.

Today, EVs have reached their tipping point and sales are booming while the public vehicle charging infrastructure rapidly grows. Demand for EVs accelerated during the 2010s and is expected to continue accelerating during the 2020s, as shown in *Figure 21* for the United States.

Figure 21: Forecasted EV Growth in US (Source: Edison Electric Institute)



For fleet managers looking to reduce their annual fuel budget and corporate emissions, battery-electric, hybrids, and plug-in hybrids are a good option. Savvy fleet managers will seek applications where the type of vehicle used will deliver sufficient fuel cost savings to offset their additional cost of capital and, after the vehicles are fully depreciated (usually ~5 years), deliver net cost savings until the end of their economic lifecycle (often ~10 years).

There are a number of light-duty electric vehicle technologies currently available in the market. They include:

- **Mild Hybrid Electric Vehicles (MHEVs)**, which are equipped with internal combustion engines (ICEs) and a motor-generator in a parallel combination allowing the engine to be turned off whenever the vehicle is coasting, braking, or stopped and which restart quickly. MHEVs use a smaller battery than full hybrid electric vehicles (HEVs, see below) and do not have an exclusively electric mode of propulsion; rather, the motor-generator has the ability to both create electricity and boost the gas engine's output, resulting in better performance and reduced fuel use. Examples of MHEVs are the Honda Insight and the 2019 Ram 1500. [55]

[55] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/

- **Hybrid Electric Vehicles (HEVs)**, which use two or more distinct types of power, such as an ICE and a battery-powered electric motor as the modes of propulsion, albeit with very limited range when in electric mode. When an HEV accelerates using the ICE, a built-in generator creates power which is stored in the battery and used to run the electric motor at other times. This reduces the overall workload of the ICE, significantly reducing fuel consumption and extending range. Examples of HEVs include the Toyota Prius and Ford Fusion Hybrid. [56]

- **Plug-In Hybrid Electric Vehicles (PHEVs)**, which use rechargeable batteries, or another energy storage device, that can be recharged by plugging into an external source of electric power. PHEVs can travel considerable distances in electric-only mode, typically more than 25 km and up to 80 km for some models, due to their much higher battery capacity than hybrids. When the battery power is low (usually ~80% depleted), the gasoline ICE turns on and the vehicle functions as a conventional hybrid. Such vehicles typically have the same range as their gasoline counterparts. Examples of PHEVs include the Chevrolet Volt and Toyota Prius Prime.[57]

- **Battery-Electric Vehicles (BEVs)**, or all-electric vehicles, which are propelled by one or more electric motors using electrical energy stored in rechargeable batteries. BEVs are quieter than ICE vehicles and have no tailpipe emissions. In recent years, BEV range has been considerably extended, thereby providing much wider BEV applications and reducing range anxiety. Today, many BEV models have EPA-estimated ranges exceeding 400 km, which provide much greater reliability when travelling longer distances. Recharging a BEV can take significantly longer than refuelling a conventional vehicle, with the difference depending on the charging speed. For a light-duty vehicle, a full battery charge using a Level 2 charger takes several hours, but charging from a nearly depleted battery to 70% at a fast (Level 3) charge station can take only 30 minutes[58]. Examples of light-duty BEVs include the Nissan Leaf, Chevrolet Bolt, Kia Soul, and Tesla Model 3.

While commercial battery-electric (BEV) pickups, trucks and vans are still limited/ have not yet arrived in the market, options are expected to become more plentiful in the next few years. Medium and heavy-duty battery-electric trucks are quickly being developed by many manufacturers. Demand for those offered by Tesla, Volvo, Freightliner, and others exceeds current supply and will soon be available for fleet purchase. Battery-electric buses and refuse trucks are currently available for purchase.

---

[56] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/
[57] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/
[58] Source: https://www.autotrader.ca/newsfeatures/20180410/types-of-electric-vehicles-explained/

Plug-in hybrid electric vehicles would also be an excellent solution for a low-mileage, return-to-base fleet like Toronto Hydro. PHEVs have a much larger all-electric range as compared to conventional first-generation hybrid vehicles, and they eliminate any range anxiety that may be associated with all-electric vehicles because the combustion engine works as a backup when the batteries have become depleted. For fleet vehicles that return to base each night, PHEVs (as well as BEVs) are ideal for overnight, Level 2 charging. It is entirely conceivable that low-mileage PHEVs could be driven every day almost entirely on electric power, functioning like fully-electric vehicles.

Zero Emission Battery-Electric Vehicles

There is no question that BEVs are taking over traditional internal combustion engine (ICE) vehicles in a big way. Some jurisdictions have already legislated the end of ICEs. If they haven't done so already, fleet managers should start making plans for BEVs now.

While their upfront costs will be higher, BEVs have increasingly proven to be a viable solution to rising fuel costs and emissions. Since BEVs have few moving parts, tune-ups or oil changes are never required, and they seldom, if ever, require brake relining due to regenerative braking. And, best of all, they burn zero fuel.

Since the release of the first mass-produced BEV, the Nissan Leaf, which debuted in 2010 with an EPA range estimated at only 73 mi or 117 km[59], there has been a surge in lithium-ion battery production leading to a drastic decline in prices. Today, several more affordable BEV models have ranges exceeding 400 km, which provide much greater reliability when travelling longer distances. For example, the 2020 Tesla Model 3 Standard Plus has an EPA-estimated range of 402 km[60], while the 2020 Chevrolet Bolt has an EPA-estimated range of 417 km[61].

There has also been significant expansion in charging infrastructure through publicly available charging stations. As of early 2020, there were nearly 5,000 charging outlets across Canada, and Natural Resources Canada is investing $130 million from 2019-2024 to further expand the country's charging network, making range anxiety even less of a barrier to BEV ownership.

In addition to battery-electric pickups that are soon to emerge, battery-electric buses and emerging battery-electric medium- and heavy-duty trucks such as those planned by Tesla, Volvo, Freightliner, and other manufacturers are attracting considerable interest because of their the elimination of tailpipe GHG and CAC emissions, in addition to the potential for significant maintenance and fuel cost savings. In *Figure 22*, we see that the OEMs are quickly ramping up with other types of

[59] Source: https://www.mrmoneymustache.com/the-nissan-leaf-experiment/
[60] Source: https://www.tesla.com/en_ca/model3
[61] Source: https://www.chevrolet.com/electric/bolt-ev

commercial EV trucks (medium- and heavy-duty truck categories) that are suited for municipal work environments and utilities.

Figure 22: Total EV OEMs by 2023 (Source: Calstart)

Fleet managers who operate battery-electric trucks and buses can see massive savings in maintenance and fuel costs. BEVs have considerably fewer parts than internal combustion engine (ICE) vehicles. A drivetrain in an ICE vehicle contains more than 2,000 moving parts, compared to about 20 parts in an BEV drivetrain. This 99% reduction in moving parts creates far fewer points of failure, which limits and, in some cases, eliminates traditional vehicle repairs and maintenance requirements, creating immense savings for fleet managers. BEVs do not require oil changes or tune-ups, have no diesel exhaust fluid (DEF), and their brake lining life is greatly extended over standard vehicles due to regenerative braking. Though each fleet's electrification journey will be different, the transition to electric power can offer significant cost reductions over the long term.

A new study[62] quantified what commercial EV-makers have been saying for years: electric trucks and buses are a triple win. They save money for fleet operators, and reduce both local air pollution and GHG emissions. The study, which was commissioned by the National Resources Defense Council (NRDC) and the California Electric Transportation Coalition, and conducted by the international research firm ICF, looked at the value proposition for fleet operators of battery-electric trucks and buses (BETs).

Today, BETs have an upfront price premium compared to legacy diesel trucks and buses. However, the costs of battery packs and other components are rapidly falling, and the study found that, by

[62] Source: Posted January 2, 2020 by Charles Morris (https://chargedevs.com/author/charles-morris/) & filed under Newswire (https://chargedevs.com/category/newswire/), The Vehicles (https://chargedevs.com/category/newswire/the-vehicles/)

2030 or earlier, electric vehicles will offer a lower total cost of ownership (TCO) for nearly all truck and bus classes, even without incentives.

In *Table* 8, we provide a summary of the strengths and weaknesses of BEVs.

Table 8: Strengths and Weaknesses of BEVs

Strengths	Weaknesses
- Well-designed, no noise, few moving parts, long warranties - Little/no maintenance - Government grants and incentives may be available - Effectively eliminates need for idling-reduction initiatives - Very positive driver feedback - Very positive public opinions - Potential for significant lifecycle GHG emissions, depending on electricity source	- High capital cost particularly for battery-electric trucks/buses - Limited availability of new battery-electric trucks - Potentially significant capital costs required for charging infrastructure, particularly if 480V (DCFC) charging equipment is installed - Existing electrical capacity at facilities may require significant upgrades for charging multiple vehicles - Potential driver range anxiety that may require a change management approach - Although unlikely, potential for costly battery replacements in aged BEVs

Air Quality and Upstream Emissions

Air quality is a growing concern in many urban environments and has direct health impacts for residents. Tailpipe emissions from internal combustion engines are one of the major sources of harmful pollutants, such as nitrogen oxides and particulates. Diesel engines in particular have very high nitrogen oxide emissions and yet these make up the majority of the global bus fleet. As the world's urban population continues to grow, identifying sustainable, cost-effective transport options is becoming more critical.

Battery-electric vehicles (BEVs) require electricity to recharge the batteries; therefore, electricity is effectively a "fuel" in these types of vehicles. Battery-electric vehicles (BEVs) may be defined as zero emissions vehicles (ZEVs) since the California Air Resources Board (CARB) defines a ZEV as a vehicle that emits no exhaust gas from the onboard source of power[63]. However, CARB's definition accounts for pollutants emitted at the point of the vehicle operation and the clean air benefits are usually local. Depending on the source of the electricity used to recharge the batteries, air pollutant emissions are shifted to the location of the electricity generation plants. For example, if electricity used for charging vehicles comes primarily from "dirty" sources such as coal, lifecycle vehicle emissions will result.

[63] Source: California Air Resources Board (2009-03-09). "Glossary of Air Pollution Terms: ZEV"

From a broader perspective, to have almost none or zero well-to-wheel emissions, the electricity used to recharge the batteries must be generated from renewable or clean sources such as wind, solar, hydroelectric, or nuclear power. In other words, if BEVs are recharged from electricity generated by fossil fuel plants, they cannot truly be considered as ZEVs. Upstream emissions should be considered when evaluating the effectiveness of ZEVs in reducing emissions. Generally, when considering upstream emissions from electricity supply, BEVs still emit more than 50% less GHG emissions than their gasoline or diesel counterparts[64], and in some cases emit over 80% less in a grid composed of mostly renewable electricity[65]. This level of emissions reduction is what cities need in order to collectively achieve the "deep decarbonization" necessary to mitigate the most serious impacts of climate change.

Charging Technologies

The time it takes to charge a BEV is dependent on a multitude of factors, including:

- The type (level) of charger used (i.e., Level 1, 2, or 3);
- The vehicle's technology (i.e., the maximum amount of current allowed by the vehicle, in amps);
- Battery capacity (generally increases with vehicle size);
- Driving range (dependent on battery capacity and vehicle size)
- Starting charge level (charging rate slowly diminishes as battery levels approach 100%)

The charging rate is expressed in kilometers/miles of range per hour of charging. It is estimated by dividing driving range by the time for a full charge (i.e., 0 to 100%) and is dependent on the battery capacity of a vehicle, varying significantly with different vehicle types and battery sizes (see *Table 9*, below). The time for a full charge is estimated by dividing battery capacity, in kWh, by charging power (calculated from current and voltage) and adding a 10% inefficiency[66] [67].

Characteristics of the varying levels of chargers ranging from Level 1-3 are shown for LD vehicles in *Table 9*[68]:

[64] Source: https://www.eei.org/issuesandpolicy/electrictransportation/Pages/default.aspx
[65] Source: https://blog.ucsusa.org/rachael-nealer/gasoline-vs-electric-global-warming-emissions-953
[66] Source: https://www.caranddriver.com/shopping-advice/a32600212/ev-charging-time/
[67] Source: https://www.inchcalculator.com/widgets/?calculator=electric_car_charging_time
[68] Source: https://calevip.org/electric-vehicle-charging-101

Table 9: Characteristics of BEV charging levels for different vehicle classes

BEV Charging Levels	Outlet Voltage	Amperage	Added Range Per Hour		
			LD	MD	HD
Level I	120V	12-16 amps	5-10 km	< 5 km	< 2 km
Level II	240V	16-40 amps	22-56 km	10-25 km	5-12 km
Level III	480+V	100+ amps	>200 km	> 70 km	> 35 km

Level 1 chargers can be plugged right into a standard outlet. They are the most economical option for private owners; however, at such a low charging rate it is usually not practical to use Level 1 chargers exclusively. For example, it would take about 40 hours to fully charge a light-duty BEV with a range of 400 km starting at 20% battery (80 km range remaining).

Level 2 chargers are common in private households as well as public spaces such as mall parking lots. They incur an installation cost but are similar to common 240V installations such as the outlets that power clothes dryers. For a light-duty BEV with a range of 400 km and at 20% battery (80 km range remaining), it would take about eight hours to fully charge. Level 2 charging is usually done overnight during the off-peak period. Installing Level 2, 240V chargers, including the wiring infrastructure involved, typically range in cost from around $1,500-10,000, depending on electrical system requirements. The vast majority of the time, BEV owners only need a Level 2 charger; the exception is when travelling longer distances and/or not returning-to-base at the end of the work day. Another possible exception is for heavy-duty vehicles that take longer to charge due to their battery size. For these applications, much faster charging rates are required through Level 3 charging.

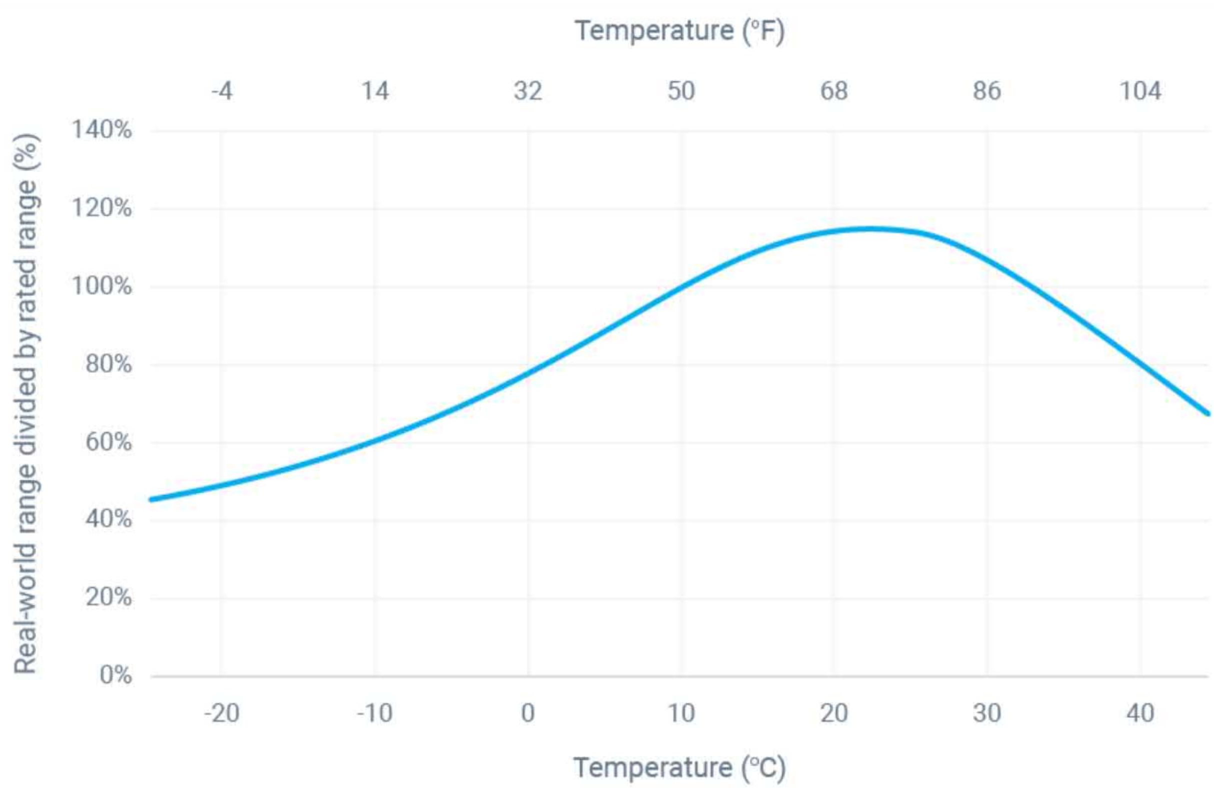
Level 3, or direct current fast chargers (DCFCs), requiring inputs of 480+ volts and 100+ amps (50+ kW)[69], are specialized systems designed to quickly charge vehicles and provide flexibility to owners travelling longer distances or in need of a partial quick charge. For a light-duty BEV with a range of 400 km and at 20% battery (80 km range remaining), it would typically take less than one hour to fully charge. Installations of DCFCs require a commercial electrician due to the electrical load and wiring requirements[70]. The costs for installing a Level 3 DCFC vary greatly. Costs for a fast-charging station are dependent on the electrical supply available at the chosen charging site, site preparation costs including trenching, cable runs, and many other installation considerations. Equipment and installation costs for DC fast charging stations can range from $50,000 to $200,000[71].

[69] Source: https://calevip.org/electric-vehicle-charging-101
[70] Source: https://calevip.org/electric-vehicle-charging-101
[71] Source: https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf

Impact of Temperature on Battery Performance

Canadians enjoy the ebbs and flows of seasonality and extreme temperatures. BEV range is adversely affected by cold and hot temperatures because of auxiliary heating and cooling – that is, heating/cooling the vehicle cabin, and heating/cooling the battery itself to maintain optimal performance. Batteries are susceptible to temperature fluctuations which hinder, but in some cases helps, range. For example, on a typical winter day in central Canada with a temperature at -15°C, range can drop by over 50% of the EPA estimated range, meaning that a BEV with a range of 400 km will only be able to drive 200 km (*Figure 23*, below). Conversely, at temperatures in the low-twenties, range can significantly exceed the EPA-estimated range given that other conditions are optimal (e.g., starting temperature, terrain, and driver habits). With some preparation and knowledge, owners and operators of BEVs can mitigate the effects of temperature on performance by pre-conditioning their vehicle (i.e., warming up or cooling down before use) as well as keeping their vehicle plugged in when temperatures are extreme; this allows the system to maintain battery temperature controls and also prolongs battery life.[72]

Figure 23: The Effects of Temperature on BEV Range



[72] Source: https://www.geotab.com/blog/ev-range/

Training Options and Recommendations

While there is a paucity of BEV technician training in Canada, due to the rapid onset of electric mobility we suspect that reality will soon change. A pilot for a new EV Maintenance Training Program for automotive technicians was successfully completed at BCIT and is available to the public[73].

There is an Electric Vehicle Technology Certificate Program offered by SkillCommons, managed by the California State University and its MERLOT program, which offers free and open learning materials electric vehicle development, maintenance, alternative/renewable energy, and energy storage[74]. There is also a Hybrid and Electric Vehicles course offered at Centennial College in Toronto, which appears to focus more on hybrid systems than fully electric vehicles[75].

Before BEVs are deployed in a fleet to any great extent, we recommend high-voltage training for technicians. Published high-voltage guidelines specific to vehicle technicians servicing BEVs are not readily available through traditional sources. However, we suggest that anyone working with high voltage in any format, including BEVs, should be provided guidance on applying Occupational Health & Safety Management System fundamentals. This includes a "plan, do, check, and act" philosophy while working with energized electrical equipment[76]. Such training is available for non-electrical workers from Lineman's Testing Laboratories (LTL) of Weston, Ontario. LTL offers an awareness-level course for non-electrical workers which is claimed by the company to provide a basic-level understanding of workplace electrical safety.

Aside from awareness training, fleet technicians should also have access to, and be trained on the use of, electrical-specific personal protective equipment (PPE). Such PPE would include tested and certified non-conductive gloves as well as non-conductive tools and equipment as a last line of defence, ensuring all such gear is appropriately used and maintained. Protective gloves and other PPE, as well as non-conductive tools, must be re-tested periodically to ensure safety.

BEV Summary

For light-duty vehicles and buses, and soon for medium- to heavy-duty trucks, BEVs have excellent potential for a fleet due to the following:

- Significant lifecycle GHG emissions reductions

[73] Source: https://commons.bcit.ca/news/2019/12/ev-maintenance-training/
[74] Source: http://support.skillscommons.org/showcases/open-courseware/energy/e-vehicle-tech-cert/
[75] Source: https://db2.centennialcollege.ca/ce/coursedetail.php?CourseCode=CESD-945
[76] Source: https://training-ltl.ca/

- Significant reduction in operational costs due to elimination of fuel consumption, low costs for electricity, and minimal maintenance costs

- Relatively low charging infrastructure costs in comparison to infrastructure costs for other fuel-reduction / emission-reducing technologies such as compressed natural gas (CNG)

In planning for BEV phase-in, it would be prudent to consider installing at least one Level 3, direct current fast charger (DCFC) for high-mileage units and/or units that do not return-to-base on a regular basis. Moreover, such a fast charger would enable fleet management staff to relatively quickly charge their vehicles in situations where plugging in for overnight charging may not been possible or for emergency situations. For heavy-duty BEVs, it is important to consider that, depending on available amperage, a full charge may take several hours even with DCFCs.

Evaluation of the fleet to identify vehicles that have a potential for a replacement with a BEV should be completed. Furthermore, change management is recommended to be part of the transition process to help drivers accept and adapt to BEVs and overcome any lingering range anxiety.

Appendix D: Details on Best Management Practices

Here, we provide further details on many of the best management practices (BMPs) modelled in FAR, which have been researched by RSI-FC, and are effective interim solutions to reducing fuel usage and costs as well as GHG emissions.

Best management practices include: (1) enhanced vehicle specifications – vehicle choice and/or vehicle upgrades – which lower fuel consumption, lower GHG emissions, and improve overall performance; (2) proper maintenance procedures including tire inflation systems; and (3) fleet operational improvements including:

- Idling reduction initiatives
- Driver training to educate drivers on efficient driving practices
- Ongoing feedback and motivation to maintain good driving habits
- Route planning and optimization, including trip reduction, minimization, or elimination

Enhanced Vehicle Specifications at a Glance

There are a number of vehicle specifications that can aid in fuel-use and emissions reductions. *Table 10* lists sample vehicle specifications and their respective impacts.

Table 10: Strengths and Weaknesses of Enhanced Vehicle Specifications

Specification	Strengths	Weaknesses
Smaller Vehicles	Consume less fuel and thus have reduced emissions	Might not always be suitable for the job
Lighter Vehicles	Consume less fuel, produce less emissions, and can carry larger payload (e.g., if a truck is lighter by “x” pounds/kg, it can carry a commensurately increased payload), which increases efficiency	Light weighting may overstress some vehicles, increasing maintenance demand and lifecycle cost
Aerodynamically Designed Vehicles	Reduces fuel consumption and emissions	Minimal effectiveness in urban setting, high cost, increased maintenance demand for some solutions

Specification	Strengths	Weaknesses
Low Rolling Resistance (LRR) Tires and Wide-base Tires	Reduces fuel consumption and emissions, reduce frequency of tire replacement	Potential for on-road service issues, axle loading restrictions in some jurisdictions with wide-base tires
Electronically Controlled, Programmable Diesel Engines	Allow tailoring/minimizing power and torque needs, road speed, and idle time limits therefore reducing fuel consumption and emissions	Seldom give problems, however when they do, often require specialized and costly diagnostic skills (might need to be outsourced) with potentially protracted downtime
Idling-Reduction Devices	Reduces idle time and therefore lowers fuel use and emissions	Actual idling reduction benefits are dependent on the use of technologies by drivers, some who resent intervention by such devices; some may feel devices could cause a safety concern

Fleet Downsizing

Getting a fleet's "house in order" should include shedding any under-utilized vehicles, so that stranded capital tied up in low-usage units can be re-applied to fleet modernization and new electric vehicles (EVs). When exception data demonstrates that a vehicle's usage has been less than the organization's acceptable minimum threshold, the vehicle is incurring cost without serving a purpose. Hence, the vehicle is a liability, unless it has some redeeming value, i.e., a special-purpose or backup vehicle for emergencies, or a unit reserved for peak periods.

Low-usage units should be routinely and regularly reviewed to determine if there are more cost-effective ways of accomplishing the corporate end-goal. If a specific vehicle is used infrequently, management should be empowered to consider creative solutions for a less costly travel mode, e.g., an inter-departmental vehicle sharing arrangement, a 3rd party service-provider, video conferencing, use of employee's vehicles, etc.

A fleet's first step in cost reduction is to reduce the total number of low-utilization vehicles. Management should undertake a review to determine if some vehicles can be eliminated through early decommissioning.

Right-Sizing

In days past, some fleet managers subscribed to the adage "identify the size of truck you really need for the job — and then buy one bigger." Today, we know this is anachronistic thinking that led to fleets with oversized vehicles, poorer fuel economy, and higher operating costs and GHG emissions.

Instead, savvy fleet managers are leaving the old approach behind and employing the correct and most efficient approach, which is to right-size fleet vehicles – that is, correctly specify the size of vehicle for the job at hand, which leads to lower overall operating costs.

Job Suitability

The types of vehicles and the equipment staff members are fitted should be aligned with the vocational and load requirements. For example, a passenger sedan would be completely unsuitable for plowing snow or carrying loads of anything other than people. Rather, fleet vehicles types are matched specifically to the tasks at hand; in this case, a light-duty truck would be required for snow removal in, for example, parking lots.

Choose the Size Down When Appropriate

Downsizing is a recommended best management practice which results in a lower total cost of ownership (TCO). An example is acquiring light-duty (Class 2a) vans and pick-ups as opposed to heavier-duty units (Class 2b), which have higher acquisition and maintenance costs.

Another example is with heavy-duty units; selecting a single-axle plow-dump unit, which has inherently lower operating costs than a tandem-axle unit, is recommended when appropriate (i.e., when the specific task at hand, or job suitability, is fulfilled by either unit).

Accounting for Limited Space

Limited space for roads, as a result of urban development and densification, may lead to an increased number of traffic roundabouts. Roundabouts pose unique problems for snowplows as well as refuse and recycling trucks because of tight turning movements and lack of adequate space to maneuver. Single axle units are shorter in overall length and, therefore, turn in a smaller radius than tandem or tridem axle units. They also cost less to acquire and maintain. The disadvantages are that single axle trucks may have less traction/control in slippery conditions and have less load-carrying capacities, such as salt/sand or waste (less productivity). However, in urban, low-speed, traffic-congested environments with limited space, such as roundabouts, single axle plows or refuse/recycling trucks will have an advantage over multi-axle units. In this example, it is important to weigh the pros and cons for different sized vehicles; when space is tight, it is often recommended to go smaller when it is safe (i.e., at low speeds) and productivity is acceptable.

Right-Sizing Summary

In summary, it is important for a fleet to consider the following in regard to right-sizing:

- Ensure that fleet vehicles are matched specifically to the tasks at hand (i.e., are job suitable) in terms of both vocation and load requirements.
- When multiple sized units fulfil a task equally well, choose the size down.
- When space is limited, it is often best to choose smaller units, given that it is safe to do so and that the productivity level is acceptable.

Low-Rolling Resistance Tires

Rolling resistance is the energy lost from drag and friction of a tire rolling over a surface[77]. The phenomenon is complex, and nearly all operating conditions can affect the final outcome. With the exception of all-electric vehicles, it is estimated that 4%–11% of light-duty vehicle fuel consumption is used to overcome rolling resistance. All-electric passenger vehicles can use approximately 23% of their energy for this purpose. For heavy trucks, this can be as high as 15%–30%.

A 5% reduction in rolling resistance would improve fuel economy by approximately 1.5% for light and heavy-duty vehicles. Installing low-rolling resistance (LRR) tires can help fleets reduce fuel costs. It is also important to ensure proper tire inflation (see sections below).

Tires and fuel economy represent a significant cost in a fleet's portfolio. In Class 8 trucks, approximately one-third of fuel efficiency comes from the rolling resistance of the tire. The opportunity for fuel savings from LRR tires in these and other vehicle applications is substantial.

According to a North American Council for Freight Efficiency (NACFE) report, the use of LRR tires, in either a dual or a wide-base configuration, is a good investment for managing fuel economy. Generally, the fuel savings pay for the additional cost of the LRR tires. In addition, advancements in tire tread life and traction will reduce the frequency of LRR tire replacement.

[77] Source: https://afdc.energy.gov/conserve/fuel_economy_tires_light.html

Automatic Tire Inflation Systems

Proper tire inflation pressure is critical to the optimal operation of a commercial vehicle. Underinflated tires result in decreased fuel efficiency and increased tire wear[78]. A 0.5-1.0% increase in fuel consumption is seen in vehicles running with tires underinflated by 10 psi. Appropriate pressure reduces tire wear, increases fuel efficiency, and leads to fewer roadside breakdowns due to tire failures. An example of an automatic tire inflation system (ATIS) is shown in *Figure 24*.

Figure 24: Automatic Tire Inflation System (courtesy NACFE)

In the U.S., a large truckload carrier with 5,000 tractors and 15,000 trailers averaging 124,000 miles a year on tractors and 41,000 miles on trailers, conducted a fuel economy test with 60 trucks pulling trailers without tire inflation systems and 75 trucks matched with trailers with the systems installed. The results of the test showed a 1.5% improvement in fuel consumption for trucks with ATIS.

Tire Inflation with Nitrogen

Nitrogen is said to permeate tire walls up to four times slower than air. Tires will lose one to two psi over one month versus the six months it takes a nitrogen-filled tire to lose that same amount of pressure. As a result, the time spent adjusting the tire pressure is reduced.

Supporters of nitrogen for tire inflation claim better tire pressure retention. This is believed to result in:

- A smoother ride
- Improved steering and braking
- Reduced risk of blowouts by as much as 50 percent[79]
- Increased tires tread life by up to 30 percent, improving the tire's life and its grip to the road[80]
- Reduced fuel consumption by up to 6%[81]

---

[78] Source: https://nacfe.org
[79] Source: http://www.gonitrotire.com
[80] Source: http://www.gonitrotire.com
[81] The fuel consumption reduction estimates vary considerably. Enviro-fleets, A guide to helpful resources, June 2010, report an improvement of up to 10%, but the industry standard is between 3% and 6%.

It must be noted that it is not the nitrogen itself that improves the fuel efficiency, but rather the enhanced retention of inflation pressure over time[82]. Reduced tire pressure leads to increased fuel consumption. Therefore, if vehicle tire pressure is well monitored, there might not be a fuel consumption benefit of using nitrogen.

Idling Reduction

Idling reduction is an important concern for all leading fleets that are looking to optimize costs and reduce the environmental impact. Utility fleet vehicles left idling for no apparent reason are seen by the public as being wasteful and polluting. These negative messages are potentially damaging to the reputation of any utility.

Fuel consumption from idling of heavy-duty vehicles is significant. While we acknowledge there are times when idling is simply unavoidable, the U.S. Department of Energy estimates that unnecessarily idling heavy-duty vehicles wastes from half to one U.S. gallon (1.89 to 3.79 liters) or more per hour. Some fleets idle 30 to 50% or more of their operating time[83]. These are several main approaches to idling reduction, including:

- Idling-reduction policy
- Driver training and motivation
- Idling-reduction awareness and fact-based training
- Incentive programs
- Ongoing driver education
- The use of idling reduction devices, including:
    - Auxiliary power units (APU)
    - Stop/start devices
    - Auxiliary cab heaters
    - Battery backup systems
    - Block heaters / engine preheaters

Idling-Reduction Policy

An idling-reduction policy is a way to motivate fleet drivers to limit unnecessary idling. However, for an idling-reduction policy to be successful continuous enforcement such as spot-checks and fuel use tracking must be present. An idling-reduction policy could be used as an overarching commitment to idling reduction that is carried out though driver training and motivation sessions, rather than an initiative on its own.

[82] Source: NHTSA Report, 2009: https://one.nhtsa.gov/DOT/NHTSA/NRD/Multimedia/PDFs/.../2009/811094.pdf
[83] Source: FC Best Practices Manual 2008

When Engine Idling is Unavoidable

There are times when idling is unavoidable. These include:

- Cab heating/ventilation and air conditioning (HVAC)
- Power for critical equipment (such as the use of a PTO for ancillary equipment)
- Maintaining brake air pressure (MD and HD trucks)

It is important to differentiate between *unnecessary* idling and idling that is *unavoidable* due to operational requirements. The focus of all idling-reduction initiatives should be to reduce and, ideally, eliminate *unnecessary* idling and to explore alternatives of how to limit idling for operational purposes with solutions that do not impede with operations, but offer environmental and economic benefits.

Idling Reduction Devices

There are several idling-reduction technologies available that can aid in idle reduction. Their functionality, potential, and costs vary considerably and are described in *Table 11.* To reap the most benefits any idling-reduction technology, installation should always be accompanied by behavioural solutions of driver training and motivation.

Table 11: Idling Reduction Devices and Their Associated Costs

Technology	Description	Cost Estimates
Auxiliary Power Units (APU)	An APU consists of a small engine that provides power to heat and cool the cab, as well as to power accessories, heat the engine, and charge the start battery. DC-powered APU systems are also available.	APUs can cost anywhere from ~$8,500 to ~$10,000. Annual maintenance cost is estimated as high as $500.
Stop/Start Devices (Idle-Stop systems)	A stop/start system automatically shuts down and restarts the internal combustion engine to reduce the amount of time the engine spends idling. This technology is particularly useful for vehicles that spend significant amounts of time waiting at traffic lights or frequently come to a stop in traffic jams.	Stop/start devices typically are part of OEM hybrid vehicle systems, but more recently has also been introduced in regular combustion engine vehicles to reduce fuel consumption. Such devices can also be purchased separately (offered by companies like Bosch that also manufacturers OEM devices)

Technology	Description	Cost Estimates
		and their costs average at about $300-$350.
Auxiliary Cab Heaters	There are two types: (1) Gas- or diesel-fired auxiliary air heater: In most cases, it is fitted in the cab, drawing in cab air through a blower and heating it. (2) Gas- or diesel-fired auxiliary coolant heater: It is installed in a vehicle's engine compartment and enables the vehicle's own coolant circuit to work without the use of the entire engine. Such water-based auxiliary heaters use small amounts of fuel to heat up the liquid in the air-exchange system and provide warm air in the cabin. Compared to air-based auxiliary heaters, the advantage of water-based auxiliary heaters is that they also warm the engine in the process (similarly to block heaters), thus enhancing starting performance. Auxiliary coolant heaters are manufactured by companies like Webasto and Espar.	~$1,250 +
Battery Backup Systems	A battery backup system powers electric devices (emergency lights, etc.) without drawing power from the primary battery. The system consists of adding an isolator and an additional battery to a vehicle's electric system. When the vehicle is off, the isolator prevents power being drawn from the primary battery and instead uses the alternate battery to power any electronic systems. When the vehicle is running, both batteries are recharged; charging to the start battery is prioritized and it is charged first.	The system costs between $400-$600 plus the price of a battery which varies based on the required capacity.

Technology	Description	Cost Estimates
Block Heater / Engine Preheater	Engine block heaters use power from electrical outlets in corporate facilities, where vehicles are parked overnight to heat the engine block. The block heater on timer can be set to switch-on a few hours before the vehicle is used to warm up the engine block. This decreases required warm-up idling time. This is a very low-cost option, and a necessity in Canadian winters; however, it is limited to reducing warm-up idling only.	Block heaters cost between \$70 and \$150 and have a negligible annual maintenance cost.

Emissions Reduction Potential

Despite the wide selection of idling reduction solutions, when it comes to internal combustion engines, there is no technology that completely eliminates CO_2 and other emissions. Only battery-electric and hydrogen fuel cell vehicle technologies can eliminate tailpipe emissions. Idling-reduction initiatives can be helpful in reducing unnecessary idling in the short and medium term, and as a segue to gradual transition to electric trucks and, potentially, hydrogen fuel cells in the long-run.

Driver Training and Motivation

Idling-Reduction Training and Incentives

Driver training to modify driver behaviours and ongoing motivation to continue good behaviours are crucial components of successful idling-reduction programs. While most drivers understand the vehicle idling issue, many continue their inefficient practice of excessive idling due to lack of knowledge and/or motivation.

Driver training can be used to optimize the use of idle reduction technologies. The technologies can reduce idling but the drivers have the ability to override the technologies. Proper training can aid in utilizing the technologies to their full potential.

In addition to establishing corporate idling reduction policies, behaviour-based approaches for idling reduction include:

- Idling-reduction training for drivers; and
- Incentive programs to encourage drivers to limit idling.

For best results, these approaches should be used in conjunction. Regardless of the approach, the greatest impact pledges of idling-reduction should be made in a public forum. Moreover, idling-reduction targets should be customized as various fleet vehicles may have different operating requirements and will benefit from targets that accurately reflect their work environment. Beginning from a measured starting point, progress should be evaluated at regular intervals to modify and adapt the approach if progress is not occurring.

Driver Eco-Training

Driver eco-training should be fact-based and aimed at increased awareness and promotion of good practices. Typically, eco-training courses address the following areas:

- Progressive shifting (or use of automated transmissions)
- Starting out in a gear that doesn't require using the throttle when releasing the clutch
- Shifting up at very low RPM
- Block shifting where possible (e.g., shifting from third to fifth gear)
- Maintaining a steady speed while driving
- Using cruise control where appropriate
- Anticipating traffic flow
- Coasting where possible
- Braking and accelerating smoothly and gradually
- Avoiding unnecessary idling

Driver eco-training programs vary considerably. They can be organized as short (typically an hour long) information sessions/workshops or can be considerably longer and involve more hands-on activities. Extended training can vary in length from a half to a full day, or can also be scheduled into shorter sessions over a period of time.

Online Training

Online training courses are gaining popularity thanks to their flexibility. This trend has accelerated due to the Covid-19 pandemic and the need for social distancing measures. It is strongly recommended that discussion sessions among the drivers be organized to review training topics to deepen their understanding and provide a forum for questions and concerns. The individual responsible for the idling reduction incentives program could facilitate such sessions.

In-Person Training

In-person driver eco-training courses vary greatly in length, depth, and format. These courses offer a more personalized approach, facilitate immediate discussion, and typically allow for practical application. For best results, eco-training could be combined with professional driver improvement training.

NRCan SmartDriver Training Series

SmartDriver provides free, practical training to help Canada's commercial and institutional fleets lower their fuel consumption, operating costs, and harmful vehicle emissions. Fleet energy-management training that helps truckers, transit operators, school bus driver, and other professional drivers is claimed by NRCan to improve fuel efficiency by up to 35 percent. RSI-FC highly recommends NRCan's SmartDriver training: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation/greening-freight-programs/smartdriver-training-series/21048

Continuous Motivation

Studies have demonstrated that driver training benefits, although significant, are likely to diminish over time. Ongoing feedback and motivation is recommended as a preventive measure. This can include:

(1) **Tracking Idling to Provide Feedback to Drivers**

- Monitoring the progress of any initiative is crucial not only to determine the impact, but to also provide feedback to the drivers to provide them the opportunity to modify their behaviour.

- Practices that track and report fuel consumption establish a valuable monitoring basis. Knowledge and comprehensive factual information can help build a stronger business case and "buy-in" for idling reduction.

- Telematics technologies help managers and drivers track idling and provide measurable data to manage goals. Such technologies, however, can be expensive as they typically use GPS systems and OBD monitoring devices.

(2) **Implementing a Corporate Idling Reduction Policy**

- It is our opinion that in most cases drivers want to "do the right things." By ramping up communications about excessive idling and instituting a clear idling policy, a reduction of unnecessary idling will likely result.

(3) Ongoing Information Campaigns and Reminders

- In general, information campaigns are low-cost, easy to manage, and lead to a more knowledgeable and receptive public. To raise awareness of the issues these can be initiated even before driver training commences. Numerous resources that address idling awareness issues are available free of charge and ready to implement.

(4) Non-Monetary Incentives Programs

- There are a few approaches that can aid in motivating drivers to continue to apply the skills gained during eco-training. Competition among departments/teams to reduce idling can be an effective approach. Periodic recognition of high-performers can be either public or private. An example of a non-monetary reward might be the donation to a charity in the amount of the lowest idling department's fuel cost savings.

Summary and Potential Impact

Driver training is an initiative that attempts to change an individual's behaviour and thus the results are hard to predict and the variance is large. A multitude of aspects, such as the current level of driver education and driving practices, the level of idling, corporate culture and policy, and individual receptiveness and willingness to change will influence results. It is estimated that driver training has a potential to reduce vehicle fuel consumption by anywhere from 3% to 35%, with the typical results between 5% and 10%.

Route Planning and Optimization

In addition to vehicle upgrades, proper maintenance, driver training, and continuous motivation to maintain good driving habits, a fleet can further minimize fuel consumption and exhaust emissions through route planning and optimization. Route planning software can be used optimize multi-stop trips. There are different software available for categories in both public and private fleets (e.g., service dispatch software, courier software, trucking software, etc.)[84].

Route planning software used for delivery services ensures the minimum driving time for multi-stop trips by using advanced algorithms to arrive at the optimal route that provides the highest collective reduction in total driving time and, consequently, fuel consumption. This can also mean fewer vehicles and less traffic on the road at one time.[85]

[84] Source: https://www.capterra.com/route-planning-software/
[85] Source: https://blog.route4me.com/2020/05/carbon-emissions-reduction-route-optimization-helps-cut-tons-carbon-emissions/

Route planning software can also be used for idling reduction initiatives by integrating GPS tracking software to monitor driver activity in real-time. Moreover, reporting and analytics features within route planning software can help with identifying when a fleet vehicle requires maintenance to ensure optimal fuel efficiency and thus minimize cost and emissions.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-267

References: **Exhibit 2B, Section E8.3, Pages 3-4**

EB-2018-0165, Decision and Order, December 19, 2019, Page 104

<u>Preamble:</u>

In reference 2 the OEB directed Toronto Hydro "to provide more detailed cost benefit analysis between EV, hybrid and combustion engines for its fleet program for future rebasing applications. In addition, the OEB directs Toronto Hydro to develop utilization measures beyond fleet use in standard hours." In response to the cost benefit analysis, Toronto Hydro's evidence stated that various phasing and cost options were analyzed for electrifying its fleet and the results of this analysis informed Toronto Hydro's procurement strategy for Evs and hybrid vehicles.

QUESTION (A):

a) Please provide a copy of the analysis done to assess the costs and benefits between Evs, hybrids and combustion engine vehicles and the results of this analysis.

RESPONSE (A):

Please refer to Toronto Hydro's response to 2B-Staff-266(a).

QUESTION (B):

b) Please explain Toronto Hydro's proposal for developing utilization measures beyond fleet use in standard hours.

RESPONSE (B):

Please refer to Toronto Hydro's response to 2B-Staff-266(b).

QUESTION (C):

c) Please indicated the number of units and associated percentage of internal combustion engines vehicles to be replaced by Evs.

RESPONSE (C):

Toronto Hydro will replace 115 of 264 (approximately 44%) internal combustion engine ("ICE") units from 2025 to 2029 with electric/hybrid vehicles, depending on market availability and vehicle suitability.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-268

Reference: **Exhibit 2B, Section E8.3, Page 7**
Exhibit 2B, Section E8.3, Page 2

QUESTION (A):

a) Please provide Toronto Hydro's fleet asset management plan.

RESPONSE (A):

Toronto Hydro's Fleet Asset Management strategy is explained in subsection E8.3.1.1 of Exhibit 2B, Section E8.3.[1]

QUESTION (B):

b) Please provide several representative examples of life cycle analyses for short term (0-2 year) turnover assets, and long-term turnover (2-7years) assets.

RESPONSE (B):

Longer-term asset planning (2-7 years) relies primarily on the Life Cycle Analysis ("LCA") for forecasting purposes; this is also referred to as the "first step" in subsection E8.3.1.1 of Exhibit 2B, Section E8.3.[2] Short-term asset planning (0-2 years) happens as the vehicle gets closer to replacement period; this is referred to as the "second step" in subsection E8.3.1.1 of Exhibit 2B, Section E8.3.[3] This planning step takes into account the condition of the vehicle, end-user feedback, and utilization to determine if a replacement is required.

[1] At p. 2-3.
[2] At p. 2.
[3] *Ibid*.

For example, When the initial planning was completed in 2017/2018 for dump trucks, Toronto Hydro had six 2009 model units in its fleet planned for replacement in 2023 (3 units) and 2024 (3 units) according to the LCA. The LCA for this type of vehicle recommended replacement between 8-12 years.

Prior to initiating competitive bidding for these vehicles, Toronto Hydro determined that 2 of the vehicles were no longer required and would not be replaced, and that the condition of the remaining four vehicles was still rated as fairly good condition. As such, the utility determined to defer the replacements into 2025-2026 and review again at a later date. There was also consideration given for the specialized nature of these vehicles (used in very specific applications), feedback from end-users, and the relatively low mileage.

As another example, the LCA for 9 sports utility vehicles ("SUVs") units indicated a replacement after 8 years. Toronto Hydro had deferred their purchase with a batch of SUVs replaced in 2021; however, subsequent condition assessments for these units indicated that they would need to soon be replaced due to deteriorating conditions. These were ultimately replaced in 2022 (3 units) and 2023 (6 units).

QUESTION (C):

c) Are corrosion related impacts a major driver of fleet turnover?

   i. If yes, what actions does Toronto Hydro take to mitigate corrosion related impacts to its fleet?

RESPONSE (C):

As discussed on page 7 of Exhibit 2B, Section E8.3, corrosion can pose safety and reliability risks, lead to vehicles being decommissioned earlier than expected, and typically impacts vehicles that are near end of life. Vehicles receive rust proofing inhibitor prior to delivery from the vendor when they are purchased. Toronto Hydro is currently evaluating 3 methods of corrosion prevention for future implementation. A test group of 18 vehicles have been designated for evaluation. Six vehicles will receive one of the following rust proofing methods: electronic module, one-time rust proofing application, and yearly rust proofing application until end of life to determine the most effective method.

QUESTION (D):

d) What fleet vehicles does Toronto Hydro outsource?

   i. For outsourced fleet vehicles, do the forecast capital costs for the test period include outsourcing costs?

   ii. For outsourced fleet vehicles, please provide benefit-cost analysis.

RESPONSE (D):

Toronto Hydro does not outsource any vehicles.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-269

Reference: Exhibit 2B, Section E8.3, p. 4

Preamble:

Toronto Hydro writes that "In view of the size and dense urban nature of its service territory, Toronto Hydro estimates that all vehicle types (ICE, EV, and hybrid) would perform at the same level of reliability."

Question (A):

a) Please provide several representative examples of when the above statement would and would not be true in the Toronto Hydro service territory for heavy-duty vehicles.

RESPONSE (A):

As discussed in Exhibit 2B, Section E8.3,[1] Toronto Hydro is currently exploring the procurement of fully electric heavy-duty vehicles in small numbers and on a pilot basis. The market availability of these types of vehicles remains relatively low and further field experience is required to analyze the reliability and performance of these units under normal and emergency operating conditions. Nonetheless, given its relatively small service territory at approximately 631 kilometre squares[2] and low vehicle travel times, Toronto Hydro estimates that hybrid and electric vehicles will have sufficient range and battery capacity to perform at the same level as internal combustion engine vehicles. The utility will continue to monitor and evaluate the field performance of all hybrid and electric heavy-duty vehicles as needed.

Question (B):

[1] At page 5, lines 1-7.
[2] Exhibit 1B, Tab 1, Schedule 1, Table 1 at p. 8.

b) How will Toronto Hydro ensure that its EV fleet maintains its ability to be dispatched during prolonged power outages?

    i. What are the limitations of the selected strategy with regards to the geographic extent and duration of power outages?

RESPONSE (B):

Toronto Hydro plans to keep its battery hybrid and electric vehicles at full charge when not in use to ensure effective operation at the beginning of prolonged power outages. The utility already has a number of charging infrastructure in operation at its work centres and plans to continue investing in such infrastructure, including Level 3 chargers, as part of the capital expenditures outlined in Exhibit 2B, Section E8.2. Toronto Hydro has contingency plans in place to ensure that electric vehicle charging infrastructure at its facilities will continue to operate during prolonged power outages and will continue to explore alternative methods to ensure business continuity, such as external charging infrastructure, mobile charging technologies, and other power sources.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-270

Reference: Exhibit 2B, Section E8.3, Page 12

Question (A):

a) Please reconcile the apparent change in Heavy-Duty vehicle unit cost between 2025 and 2027 (year 2025, 13 vehicles to be replaced at a cost of $7M, and in 2027, 23 vehicles to be replaced at a cost of $7.7M)?

RESPONSE (A):

Unit costs within the heavy-duty category vary widely depending on the specific vehicles being replaced, as this category includes a very diverse range of vehicles such as crane trucks, derricks, single and double bucket trucks, cube trucks, etc. In addition, progress payments for heavy-duty vehicles that require significant equipment fitting and customization can cause variations in unit costs over multi year delivery cycles.

QUESTION (B):

b) Please provide total number of assets owned by Toronto Hydro under each of the categories of Heavy Duty, Light Duty and Equipment.

RESPONSE (B):

There are currently 149 heavy-duty vehicles, 210 light-duty vehicles, and 69 equipment units in Toronto Hydro’s fleet.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-271

Reference: Exhibit 2B, Section E8.3, p. 18

QUESTION (A):

a) Please provide the benefit-cost analysis that shows that option 2 "sustainment" is the preferred solution of the three options considered.

   i. If a benefit-cost analysis was not performed please provide the quantitative analysis justifying the selection of the preferred solution.

RESPONSE (A):

The options analysis in Exhibit 2B, Section E8.3, subsection E8.3.5 "Options Analysis / Business Case Evaluation ("BCE")" details the benefits and costs that informed Toronto Hydro's selection, including estimated costs, average fleet age, and greenhouse gas emissions under each option.[1] Please also refer to Toronto Hydro's response to 2B-SEC-59.

[1] Exhibit 2B, Section E8.3, Table 8 at p. 18.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-272

Reference: Exhibit 2B, Section E8.4, Pages 18, 19

Preamble:

With respect to hardware volumes that are proposed to be replaced.

QUESTION (A):

a) Please provide the percentage and number of units indicated in Table 5 that fall within the 4, 5, 6 and 7 year age buckets.

RESPONSE (A):

As of 2024, the units for the 2020-2024 rate period are aged as follows.

Table 1: Unit Ages for the 2020-2024 Rate Period

Asset Category	IT Hardware	4 years		5 years		6 years		7 years	
		Units	%	Units	%	Units	%	Units	%
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	168	33%	153	30%	36	7%	15	3%
	Linux x86 Virtual Servers	111	35%	105	33%	25	8%	6	2%
	Windows Virtual Servers	967	40%	870	36%	121	5%	121	5%
Endpoint Assets (Units)	*Personal Computing Devices*	577	25%	138	6%	46	2%	-	0%
	Printers & Plotters	36	20%	22	12%	9	5%	-	0%

QUESTION (B):

b) Please also indicate the percentage of hardware that is still operational, and vendor supported.

RESPONSE (B):

Table 2: Percentage of Hardware Operational and Vendor Supported

Asset Category	IT Hardware	Operational & vendor support available
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	92%
	Linux x86 Virtual Servers	95%
	Windows Virtual Servers	89%
Endpoint Assets (Units)	*Personal Computing Devices*	98%
	Printers & Plotters	100%

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2B-STAFF-273

Reference: Exhibit 2B, Section E8.4, Page 24

Preamble:

With regards to the $11.5M proposed in spending under Regulatory Compliance.

QUESTION (A):

a) Please provide the list of regulatory compliance initiatives that occurred during the 2020-2024 period, the total capital cost of each, and the capital cost of each that is potentially recovered through a revenue recovery mechanism other than existing rates (for example, a DVA).

RESPONSE (A):

Toronto Hydro provides a table below with the Regulatory Initiatives occurring during 2020-2024 below.

Regulatory Initiatives	Description	Project capital cost (2020-2024), $ Millions[1]	Funding Source
Customer Choice	Providing residential and small business customers the choice between Time-of-Use ("TOU") and Tiered prices (EB-2020-0152)	$0.8	DVA
Ultra Low Overnight TOU	Implementation of the Ultra Low Overnight ("ULO") pricing option for eligible customers on the Regulated Price Plan ("RPP") (O. Reg. 393/07)	$2.2	DVA

[1] Includes 2020-2023 actuals and 2024 bridge.

Centralize Billing Solution for Bi-directional Smart Metering Data	Collection, management and improved utilization of smart metering data for behind-the-meter distributed energy resources (ERO#: 019-6521)	$0.8	Rates
COVID-19 Energy Assistance Program ("CEAP")	COVID-19 relief for eligible residential and small business customers (EB-2020-0162/0185)	$0.6	Rates
Green Button	Implementation of the Green Button data standards and customer access platform (EB-2021-0183)	$2.4	DVA
OEB customer service rules	Implementation of requirements relating to Phase 1 of the OEB's Customer Service Rules Review (EB-2017-0183)	$1.1	Rates
Transition to Utility Work Protection Code	Implementation of changes required for Toronto Hydro's transition to the Utility Work Protection code	$2.8	Rates
	TOTAL IT/OT Regulatory Compliance COST	**$10.7**	

QUESTION (B):

b) Please provide a list of incremental regulatory compliance initiatives that Toronto Hydro expects to comply with over the next five years, and their associated costs.

RESPONSE (B):

As regulatory compliance initiatives are triggered by third party requirements and can be announced at any time, Toronto Hydro cannot predict the specific incremental regulatory compliance initiatives that it will be required to comply with in the next 5 years. However, as outlined on page 24 of Exhibit 2B, Section E8.4, Toronto Hydro anticipates undertaking approximately six regulatory compliance initiatives in the 2025-2029 rate period with an estimated total cost of $11.5 million, based on the utility's historical experience and costs in the 2020-2024 rate period, as discussed in the response to subpart (a).

QUESTION (C):

c) Why are these incremental initiatives necessary beyond current regulatory program spending?

RESPONSE (C):

The incremental initiatives funding is required to meet new compliance-related initiatives, beyond current regulatory requirements. Please refer to lines 1-11 of page 14 of Exhibit 2B, Section E8.4 for a discussion of the non-discretionary nature of these expenditures given the legislative and regulatory requirements and public policy-driven changes mandated by the Government of Ontario, the OEB, and other authorities.