ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order or orders approving or fixing just and reasonable distribution rates and other charges, effective January 1, 2020 to December 31, 2024.

EB-2018-0165

CROSS-EXAMINATION COMPENDIUM

PANEL 3

DISTRIBUTED RESOURCE COALITION

July 10, 2019

EB-2018-0165

PANEL 3 COMPENDIUM

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Investment Description

The DER Integration investments planned over the 2020-2024 DSP period are driven by expected increasing adoption of DER in Alectra Utilities' service territory and the significant challenges and opportunities that such a trend presents for the utility's distribution system and for its customers. At least 4,100 MW of DERs have already been contracted or installed in Ontario in the last 10 years[142]. This does not include an unrecorded amount of load control, behind-the-meter energy storage and demand response capacity that can also be regarded as DERs. This DER capacity growth closely rivals the 5,600 MW net growth in transmission-connected generation added during that same time period. Some estimates indicate that the most of the newly installed generation (transmission and distribution connected generation) could be on the distribution side as soon as 2023 in certain parts of the world, such as the U.S.[143] For example, in the United States, the most recent edition of the U.S. Energy Information Administration's (EIA) Long-Term Energy Outlook projects DERs to be the fastest growing segment of America's electricity industry generating capacity for the next 30 years[144].

In its own service territory, Alectra Utilities has connected over 5,409 renewable projects including FIT, microFIT, and commercial and residential net metering installations comprising over 147.9 MW of potential generation: 564 FIT contracts with 108.4 MW of installed capacity and 4,845 microFit contracts with 39.5 MW of installed capacity. Forecasts of these DER technologies indicate that North America is expected to install 260.1 GW of solar photovoltaic (PV) between 2018 and 2027 at a compound annual growth rate (CAGR) of 14.0%[145] . In terms of EVs, there were 83,000 EVs on the road in Canada as of Q3 2018[146] and one third of Ontario EVs,

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[142] IESO. (2018). 2018 Electricity Data. Retrieved from http://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data.

[143] John, J. (2018). Distributed Energy Poised for 'Explosive Growth' on the US Grid. *Green Tech Media*. Retrieved from https://www.greentechmedia.com/articles/read/distributed-energy-poised-for-explosive-growth-on-the-us-grid#gs.kd4L=NM

[144] United States Energy Information Administration, "Annual Energy Outlook 2019", January 24, 2019 Table: Electricity Generating Capacity, Case: Reference case

[145] Navigant. 2018. Market Data: Solar PV Global Forecasts. Retrieved from https://www.navigantresearch.com/reports/market-data-solar-pv-global-forecasts

[146] Fleet Karma. (2018). Electric Vehicle Sales Update Q3 2018, Canada. Retrieved from https://www.fleetcarma.com/electric-vehicles-sales-update-q3-2018-canada/

approximately 10,000 vehicles, are in Alectra's service territory[147]. With Ontario EV sales increasing 60% year-over-year for the past five years[148], Alectra could expect a higher adoption of EVs in its service territory in the next few years. These increasing trends across many DER technology sectors further demonstrate the need for Alectra Utilities to adopt platforms that will enable DERs to contribute to grid services and energy markets and provide value to customers.

The increasing adoption rates of DERs are driven by the following global mega trends:

1. Rapid technological innovation driving down the costs of various energy technologies
2. Changing customer preferences - desiring more energy options, control, engagement and customization
3. Increasing threats of climate change pushing the de-carbonization of energy systems
4. Intensifying urbanization

Energy Technology Cost Curves

In 1970, the average cost of solar PV was \$100/Watt (W) and every year since the cost of solar has reduced by 11.5%[149]. Now in certain parts of the world, solar cost is \$0.30/W[150]. In Ontario, the cost of solar is \$3.07/Watt as of 2019[151] and is expected to continue to follow the declining cost curve experienced in other markets. Similarly, lithium ion battery costs have reduced by 20% per year between 2010-2016[152]. Electric vehicles ("EVs") have been and will continue to benefit from declining lithium ion battery costs as Bloomberg New Energy Finance predicts that EVs will become cost competitive against comparable combustion engines as early as 2024[153]. Finally, Ernst and Young estimates that the north eastern regions of North America are 13 years away

[147] Ontario Ministry of Transportation
[148] Fleet Karma. (2018). Electric Vehicle Sales Update Q3 2018, Canada. Retrieved from https://www.fleetcarma.com/electric-vehicles-sales-update-q3-2018-canada/
[149] Seba, T. (2017) Clean Disruption of Energy and Transportation, Clean Energy Action Conference, June 8 2017
[150] Seba, T. (2017) Clean Disruption of Energy and Transportation, Clean Energy Action Conference, June 8 2017
[151] Energy Hub. (2019). Cost of Solar Power in Canada 2019. Retrieved from https://energyhub.org/cost-solar-power-canada/
[152] Seba, T. (2017) Clean Disruption of Energy and Transportation, Clean Energy Action Conference, June 8 2017
[153] Bloomberg New Energy Finance. (2018). Electric Vehicle Outlook 2018. Retrieved from https://bnef.turtl.co/story/evo2018?teaser=true.

from reaching cost parity between off-grid customer solar-storage and customers staying on the grid and paying their utility's electricity bills[154]. Within another 8 years it is estimated that the north eastern region of North America will have a completely decentralized electricity system as the cost of transporting electricity will exceed the cost of generating and storing it locally[155] .

Intensifying Urbanization

The United Nations estimates that 70% of the world population will live in urban areas by 2050[156]. Canada already surpasses this threshold as 81% of the population lives in urban areas[157]. Alectra Utilities serves some of the fastest growing neighbourhoods in Canada: Markham's population is expected to increase by 52% by 2041, Brampton's by 50% and Guelph's by 45%[158]. Given this rapid intensification and urbanization in Alectra Utilities' service territory, Alectra Utilities can expect to experience high levels of load growth in these areas. DERs can provide an alternative to infrastructure investments or help increase power quality as the populations in the communities it serves increase.

The need to proactively manage DERs within Alectra Utilities' distribution system

As customer preferences with respect to energy evolve in favour of more choice and greater control and customization, traditional distribution system planning and operation needs to change as well. While rapid technological innovation is driving down the costs of energy technologies, an increasing level of DER penetration will impact how the traditional distribution system will be operated. These changes must be understood and represented in the planning and operation of the distribution system through higher visibility of assets, effective communication, and coordinated activities. DERs pose potential challenges in terms of: increased intermittent generation; unexpected fluctuations in supply and demand; and the potential for stranded assets. The following is an overview of the key areas of focus to understand the nature of DERs and their impact on the distribution system:

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[154] EY. Alectra September 2018. Presentation.
[155] EY. Alectra September 2018. Presentation.
[156] United Nations. (2018). 68% of the world population projected to live in urban areas by 2050, says UN. Retrieved from https://www.un.org/development/desa/en/news/population/2018-revision-of-world-urbanization-prospects.html.
[157] Statistics Canada. (2018). Canada goes urban. Retrieved from https://www150.statcan.gc.ca/n1/pub/11-630-x/11-630-x2015004-eng.htm.
[158] Appendix A13 - Stations Capacity, Table 3

Ramping and Variability: Certain types of DERs create significant changes in power requirements, such as morning and evening solar ramp ups/down that are different than those historically experienced by the distribution system. Readiness of the distribution system for planning, installation, and operation of DER resources is an ongoing need as the generation resource mix evolves on both transmission and distribution systems.

Reactive Power: Modern technologies, including inverters for new rooftop solar PV installations, have the capability to support voltage and ride-through voltage excursions. Use of these capabilities will be increasingly important to support the reliability of both the transmission and distribution systems.

Frequency Ride-Through: As DERs are added to the system, frequency and voltage ride-through capabilities become more important and must be considered both locally and for bulk electric system to improve the reliability.

System Protection: High levels of DER with inverters can also result in a reduction of short circuit current, which can make it more difficult for protection devices to detect and clear system faults. Hence, the implications of DERs as part of system protection must be taken into consideration while planning the distribution systems.

Visibility and Control: Many DERs are generally not visible to the utility. The lack of visibility and control is not only a challenge for operations, but must also be accounted for in the planning of the distribution system. At higher penetration levels, the need for DER visibility and control becomes increasingly critical.

Interconnection Requirements: Interconnection requirements are evolving with increasing DER penetration. Consequently, a number of DER classes with very different dynamic behaviours will emerge in the distribution system. It will be important to understand this information, at least in aggregate, so that the dynamic characteristics can be modeled correctly for system planning.

Potential Risks to Reliability: With increased DER adoption, the effect of these resources presents certain reliability challenges that require careful understanding and measured actions. This leads to a need for further study to better understand the impacts, and how those effects can be included in planning and operation of the distribution system.

Data on installed and projected DER units is needed for reliability modeling purposes. Important data for modeling includes information on the location, type, size, configuration, interconnection characteristics, disturbance response characteristics, and schedule of operation of the equipment. DER generation profiles would also improve the accuracy of modeling results rather than forcing models to assume worst-case scenarios.

Utilities require sufficient levels of reliability measures, from on-line resources, for reliable operation of the distribution system. It is not necessary that all resources provide services at all times, but if conventional resources are off-line or replaced by DERs, it may be increasingly important to use DERs for active power control and essential reliability services.

<u>Voltage Fluctuation:</u> Frequent power variations due to intermittent and un-controllable nature of certain DERs cause voltage fluctuations that were not anticipated in the original design of feeders, especially radial distribution feeders. These fluctuations will have an impact on the frequency of operation of feeder voltage-regulating equipment. It is important to assess, monitor and manage the impact of varying DER output on distribution system operation performance.

The many unexplored features of DERs, such as but not limited to integration challenges, power quality issues, and safety considerations, require further investigation to minimize the risk and optimize the value to the distribution system.

As DER adoption continues to rise, Alectra Utilities expects that distributors will need to revise its approach to distribution system planning to maximize the benefits of DERs to the system, while maintaining reliability and reasonable costs for customers. The planned DER Integration investments are required for Alectra Utilities' to build capabilities and learnings to be prepared to plan and build a system that can safely integrate and optimize value from DERs.

Alectra Utilities will consider not only how DERs can be more fully integrated into the system to take advantage of DER benefits, but also how traditional distribution system planning and investment can account for DERs. Alectra Utilities will identify and communicate the hosting capacity considerations, utility needs and constraints to allow the adoption of DERs, and will increase access to certain types of system information to enable customers and DERs providers to help meet the grid needs. Alectra Utilities will have projections of DERs penetration in various parts of the system to ensure a thorough understanding of risks and opportunities, and will standardize interconnection requirements to maintain and enhance the reliability and flexibility of the grid with increased DER integration. Alectra Utilities needs to learn how to plan for, monitor, control and optimize the safe and reliable integration of DERs onto such a distribution system, as well as develop business processes on how to provide real-time transparency, tracking and management of DER participation in energy services. These are the drivers and objectives of the two DER Integration projects planned for the 2020-2024 period, as described in the following sections.

Project 1: DER Control Platform

The objective of the DER Control Platform project is to integrate DERs with Alectra Utilities' traditional distribution operation technology systems. It will enable Alectra Utilities to: build capabilities that could predict the grid operational impacts of DERs; help mitigate power quality issues associated with DERs; and reduce peak demand. These capabilities will be built as part of the overall DER Control Platform, also known as Distributed Energy Resource Management System ("DERMS"), further enabling a Virtual Power Plant ("VPP"), with integrated controls and real time signals in order to operationalize DERs as an aggregated source of capacity and storage.

The focus of Alectra Utilities' DER Control Platform project is to aggregate, integrate, control and optimize concentrated and dispersed DER, as a source of virtually aggregated deployment, in order to reduce system capacity demand necessary for system optimization and load balancing.

The expected benefits of the DER Control Platform project include:

- Enabling integration of DERMS with Alectra Utilities system control and operational systems, including Supervisory Control And Data Acquisition ("SCADA"), Geographical Information System ("GIS"), Outage Management System (OMS) and Network Simulation Software.
- Enabling system planning and business process development within Alectra Utilities to utilize DER deployment as a feasible non-wires solution to defer distribution and transmission infrastructure expansion;
- Establishing public and employee safety practices, protection settings and standards to facilitate safe and reliable operations of distribution system with high DER penetration;
- Understanding customers' preferred DER ownership structures and control features so that Alectra Utilities can determine the right balance of ownership and control that

Technology

Toronto Transit Commission launches first electric bus into service

Posted on June 7, 2019

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The Toronto Transit Commission (TTC) launched the first of its all-electric buses into service on the 35 Jane route.

The TTC will have 60 eBuses delivered by the end of Q1 2020.

TTC/New Flyer

The bus, manufactured by New Flyer Industries Inc., arrived in Toronto in April and has since undergone testing and commissioning as well as operator training. It is the first of 60 electric buses the TTC will have by the first quarter of 2020, making up one of the largest mini-fleets of electric buses in North America.

The TTC will have 60 eBuses delivered by the end of Q1 2020. In addition to New Flyer, the TTC is also procuring electric buses from Proterra Inc. and BYD, allowing the TTC to inform future procurement through a head-to-head evaluation.

RELATED: ***Toronto agencies team to study transit connections***

The TTC is working with partners at Toronto Hydro and Panasonic Eco Solutions Canada to prepare for the arrival of the new vehicles by performing hydro service upgrades, installing switchgear and transformers to lay the groundwork for the installation of chargers and retrofitting the garages to be all-electric. This also includes conducting electrical and civil construction upgrades, providing supporting infrastructure for the bus garage (e.g., substation, backup generator and related equipment).


In total, up to $1.8 billion is being invested in Toronto through PTIF, which was launched in August 2016. TTC/New Flyer

The electrification of vehicles is a key component of the City's TransformTO climate action strategy, which targets an 80% reduction in local greenhouse gas emissions by 2050. To meet that target, 100% of vehicles in Toronto must transition to low-carbon energy by 2050. The electrification of buses is an example of the City's commitment to lead by example. Vehicles generate about one-third of the emissions in Toronto today.

The TTC's new eBuses operate on truly green propulsion technology with zero tailpipe emissions. In Ontario, generation of electricity for overnight charging is 100% nuclear and completely free of GHG emissions.

The Government of Canada and the City of Toronto are investing $140 million in the electric buses as part of the federal Public Transit Infrastructure Fund (PTIF). This fund is helping keep Torontonians moving through investments in the repair, modernization, and expansion of the city's transit and active transportation networks. In total, up to $1.8 billion is being invested in Toronto through PTIF, which was launched in August 2016.

Tags: battery-electric buses BYD climate change electric buses New Flyer Proterra Toronto Transit Commission zero emissions

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SLEC lands largest vehicle lift contract in its history
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Port Authority of Alleghany continues partnership with Connectpoint
Comes after the Digital Bus Stop displays prove to be succesful in carrying out the mission to improve rider experience.

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CUSTOMER ENGAGEMENT

1. OVERVIEW

Toronto Hydro undertook extensive Customer Engagement in connection with and as part of the development of this CIR Application. Following the OEB's policy guidance, Toronto Hydro developed a genuine understanding of its customers' needs and preferences and analyzed and used the results of Engagement to inform its plans. Toronto Hydro relies on both "Planning-specific" and "Ongoing" Customer Engagement activities, as detailed in this Schedule.

2. CUSTOMER ENGAGEMENT: POLICY GUIDANCE

In conducting Customer Engagement, Toronto Hydro considered the Renewed Regulatory Framework for Electricity Distributors ("RRF"), Chapter 5 of the Filing Requirements for Electricity Distribution Rate Applications ("Filing Requirements"), the Handbook for Utility Rate Applications, the EB-2014-0116 decision in respect of Toronto Hydro's 2015-2019 rate application, and OEB decisions in other utilities' rate applications.[1] A key theme of the OEB's guidance is that a utility's business plan be informed by and responsive to customer needs and preferences. This requires an expectation that the utility develop a genuine understanding of its customers' needs and preferences, and is able to demonstrate how the development of its business plan was informed by the results of Customer Engagement.

3. PLANNING-SPECIFIC CUSTOMER ENGAGEMENT

Toronto Hydro's Planning-specific Customer Engagement process was a multi-phased, iterative process that equipped the utility with a genuine understanding of its

[1] For example, EB-2017-0024, Decision and Order.

is home to Canada's largest banks, stock exchange, major manufacturers, and other large organizations sensitive to service interruptions. There are dozens of hospital, healthcare and long-term care facilities and hundreds of schools, colleges, and universities. Toronto Hydro also delivers electricity to the Provincial Legislature, City Hall and a range of government offices and work centres. It also serves thousands of high-rise multi-residential condominium and apartment buildings, which serve many more customers behind a Toronto Hydro "bulk meter."

Over time, interactions with all customers through various channels inform the utility's plans in a number of ways including the continuous improvement of its customer services, as well as the development of its capital programs and execution of capital work.

3.2.3 Customer Services

Toronto Hydro's customer services continue to evolve with customer expectations, as detailed in the following examples.

As noted in the Customer Care Program (see Exhibit 4A, Tab 2, Schedule 14), an increasingly popular method of engagement continues to be Toronto Hydro's customized self-service portal (known as "MyTorontoHydro"). It offers automated move-in/move-out capability, eBill and pre-authorized payment enrolment, and the ability to view bill and payment histories. In addition, through the Independent Electricity System Operator's ("IESO") residential conservation program, Toronto Hydro expanded the functionality of its PowerLens portal to include a variety of electricity management tools and educational information such as usage breakdowns, kWh reduction goal setting, consumption and cost alerts, disaggregation charts, home assessments, and customized tips and recommendations to reduce consumption. The portal is available online or via mobile devices, further enhancing customer experience. Additional offerings will continue to be incorporated based on customer research and feedback to identify opportunities to bolster usage of the self-service portal. This includes offering MyTorontoHydro account management services to commercial customers, as well as expanding capabilities on PowerLens for electric vehicle usage.

Toronto Hydro's Contact Centre handles about 93,000 written inquiries and 527,000 telephone calls per year pertaining to inquiries about payment options, electricity consumptions, collections, and a range of other topics. The Contact Centre is responsible for many activities whose performance is tracked by the OEB in the Service Quality Requirements (see Exhibit 1B, Tab 2, Schedule 3).

Toronto Hydro's Customer Experience function manages research and work that provide insights to customers' views on current services, processes and communications, and opportunities for continuous improvement.

Escalations and Special Investigations resolves customer concerns that require more complex or lengthy analysis, and is closely connected to the Contact Centre, which initiates over 320 requests. Over 300 other requests are commenced through the Office of the President and the OEB. In 2017, Escalations and Special Investigations successfully resolved 98 percent of escalated customer inquiries within ten business days.

Communications and Public Relations is responsible for direct-to-customer and digital communications, such as bill inserts, website and social media, and corporate communications, such as news releases and reporting. Media are important conduits between Toronto Hydro and its customers that purvey accurate and timely information about power outages, electrical safety, consumer issues, and local investments. Media relations play a particularly critical role during emergency outage situations when customers are most likely to be looking for this information.

3.2.4 Individual Capital Projects

Feedback from customers received through Toronto Hydro's customer services can also influence individual capital projects within a given DSP program, as detailed in the following examples.

Through Community Relations and Customer Operations Communications ("COC"), Toronto Hydro maintains a comprehensive approach for communicating information to customers concerning planned capital work and planned outages, in order to provide a better understanding around the capital project and prepare customers for work at or near their properties. This engagement commonly takes the form of one-on-one contact with customers, community town hall meetings, special information sessions, and a variety of online content. A customer inquiry line and escalation process is available to customers and, when needed, staff are dispatched on-site to liaise directly with customers.

Engagement with Toronto Hydro customers is also a regular occurrence when work has the potential to disrupt local neighbourhoods and property. Typically, there are three rounds of notifications:[5]

[5] Toronto Hydro's Key Accounts function works directly with Key Account customers to minimize disruptions to large businesses and institutional customers.

- General notification of construction work is given to all residents in an affected area;
- Letters are provided to all customers that will have equipment, such as poles or transformers, located on or adjacent to their property; and
- A pre-construction letter is issued approximately one week prior to work commencing.

COC is responsible for providing these notifications and for addressing or escalating customer concerns. For example, if customers are not satisfied with the scope or nature of planned work, COC may investigate new design options or engage customers in-person or at Toronto Hydro-initiated community meetings.

More intensive and incremental engagement is used in relation to rear-lot projects, which can require significant work on Toronto Hydro's part to relocate electrical infrastructure and remove legacy assets from private property. Before work begins, Toronto Hydro proactively initiates an Open House in the community where work is expected to take place. At that forum, Toronto Hydro provides an overview of the scope and timelines of the work, an explanation of why the work is taking place and contact information for customers who wish to follow up for more information. The three-round notification process is then implemented. For more information about Toronto Hydro's rear-lot investments, see the Area Conversions program in the DSP (Exhibit 2B, Section E6.1).

In addition to COC, the Key Accounts function works proactively with large business and institutional customers on matters such as planned outage notification and coordination, Global Adjustment settlement notification, load profile and rates analysis

and power quality and energy management. It also responds to issues raised by Key Account customers and acts as a liaison to expedite workable solutions.
Municipal Government Relations and the Office of the President handle over 1,500 issues per year in response to City councillor requests on citizens inquiries, most commonly regarding street lighting, capital projects and power outage-related issues, and routinely meet with City councillors and staff on ongoing and emerging issues.

3.2.5 Capital Programs

Ongoing customer engagement can also influence Toronto Hydro's capital investment plans. Toronto Hydro's Worst Performing Feeder investment is an example of capital work that emerged from a customer-centric analysis of the utility's reliability performance that provided a better understanding of the customer experience as it relates to reliability.[6] This work is proposed to continue in 2020 to 2024 as part of the Reactive and Corrective Capital Program. More information on Worst Performing Feeders can be found in the DSP (Exhibit 2B, Sections D3, and E6.7).

Toronto Hydro's participation in Regional Planning is another channel of ongoing engagement that informs the development of the capital plan. The Regional Planning Process includes the Local Advisory Committee ("LAC"), led by the IESO. The IESO invited the City of Toronto, First Nations, and Metis communities, stakeholders, community groups, and the general public to provide input on the development of the Regional Plan. In all, the Toronto LAC has 18 members. For more information about the Regional Planning Process, see Section B of the DSP (Exhibit 2B). For more information about how Regional Planning considerations influence Toronto Hydro's plans, see Section E2.2.3.3 of the DSP.

[6] EB-2011-0144. Exhibit D1, Tab 10, Schedule 3. p. 1.

INNOVATIVE
RESEARCH GROUP

CUSTOMER ENGAGEMENT

2020 CIR Application

June 15, 2018

Prepared for:
Toronto Hydro
14 Carlton Street
Toronto, Ontario M5B 1K5

TORONTO HYDRO

Final Report | **PRIVILEGED AND CONFIDENTIAL**

Based on a review of the OEB handbook and previous decisions, the engagement focused on two types of questions: **needs** and **preferences.**

Needs	**Needs questions** focus on understanding the gap between the services and experience customers want and the services and experience customers are receiving.
Preferences	**Preferences questions** focus on customer views about the outcomes the utility should focus on, priorities among those outcomes, and trade-offs illustrated by choices on specific programs or the pacing and prioritization of investments.

As noted on the previous page, customer feedback related to THESL's proposed rate application was collected in two phases.

- **Phase I (2016-2017)** set out to identify customer needs and preferences as they relate to the outcomes that the utility should focus on and prioritize. While THESL has ongoing feedback on customer needs from its customer satisfaction work and had extensive input from customers on general trade-offs from both its IRRP and previous rate application consultations, it did not have any specific customer feedback on preferences related to outcomes. Given the priority placed on identifying customer preferences in the Handbook, the key priority for the first round was to develop a list of customer outcomes and to identify customer priorities among those outcomes for the THESL planning process. Customer feedback obtained in this phase helped inform Toronto Hydro's business planning, including the penultimate DSP.
- **Phase II (2017-18)** re-engaged with customers to confirm customer needs and preferences as they relate to outcomes in Phase I. With THESL planning now well advanced, this round of engagement was able to solicit customer feedback on THESL's proposed plans, and explore trade-offs in relation to specific programs and the associated bill impacts, as well as the pacing and prioritization of investments. Customers were able to look at the cumulative bill impact of their choices and adjust them as needed.

This report summarizes the findings from THESL's iterative CIR customer engagement program conducted over a two year period, between 2016 and 2018.

2.1.2 Customer Outcomes Priorities by Rate Class

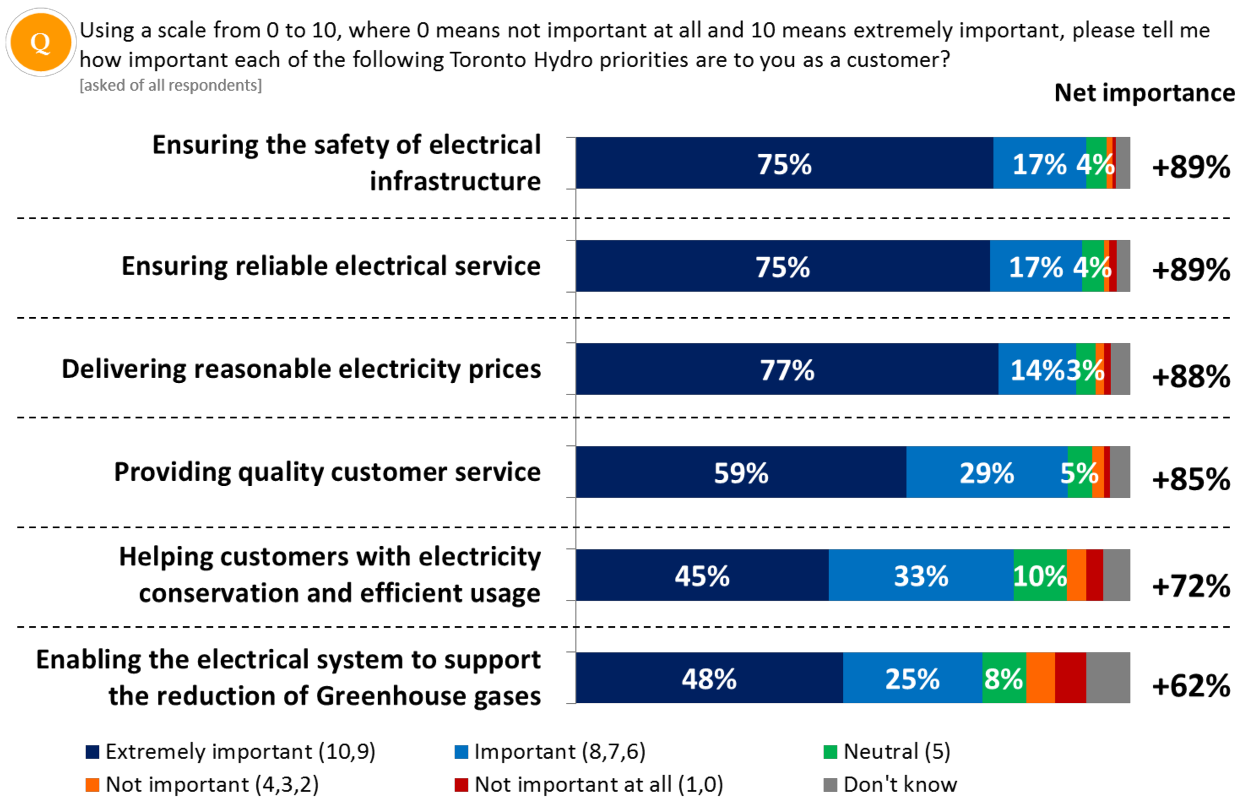
Low-Volume Customer Priorities

Through the focus groups with residential and GS < 50kW customers conducted on December 5 and 6, 2016, a list of six key customer outcomes were identified:

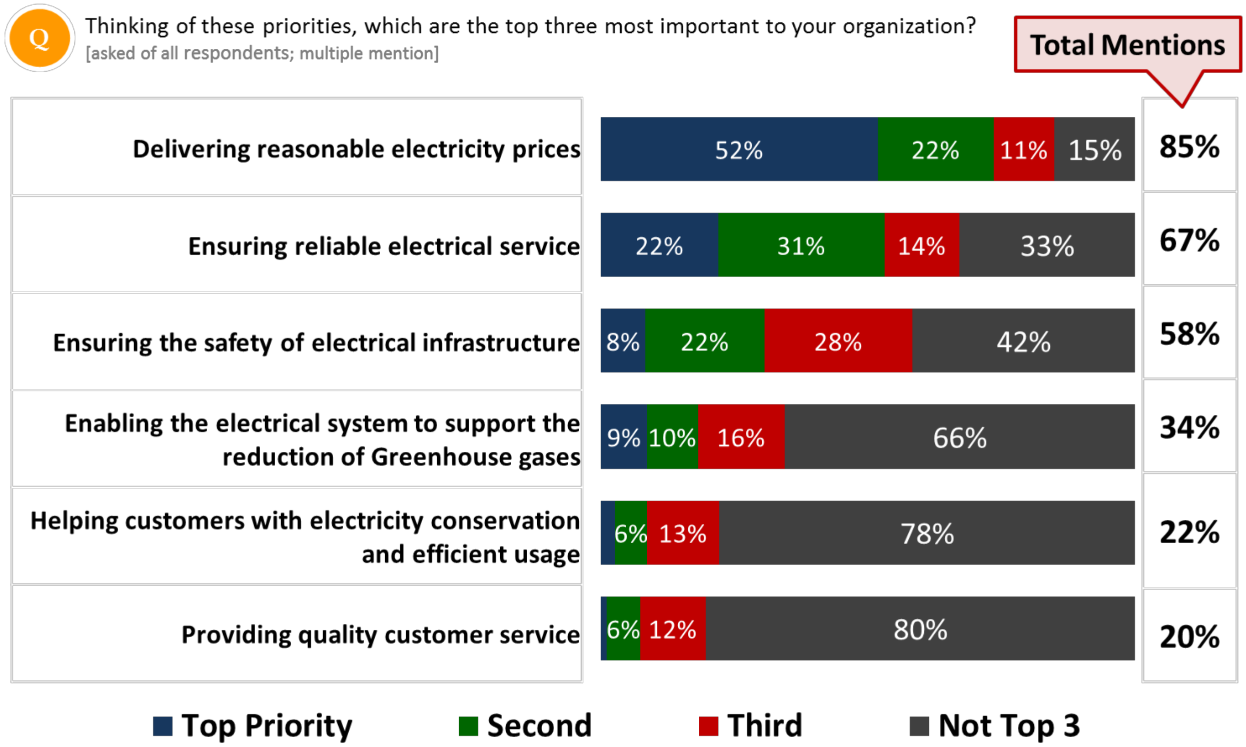
1. Delivering reasonable electricity prices
2. Ensuring reliable electrical service
3. Ensuring the safety of electrical infrastructure
4. Providing quality customer service
5. Helping customers with electricity conservation and efficient usage
6. Enabling the electrical system to support the reduction of Greenhouse gases

In a follow-up telephone survey of n=627 low-volume THESL customers (conducted December 7-14, 2016), respondents were asked to assess the importance of each priority.

Similar to what was observed in the previous focus group research, *safety*, *reliability,* and *price* are seen as equally important to low-volume customers.



Customers were then asked to rank outcomes in order to help THESL understand which of the most important outcomes to give priority to when those outcomes conflict. *Delivering reasonable electricity price* clearly emerges as the top priority valued by low-volume customers, followed by *reliability*, and then *safety.*



Mid-Market Customer Outcome Priorities

INNOVATIVE conducted a total of four focus groups over two nights, among GS > 50 kW customers on February 28 and March 1, 2017. All focus groups were held in North York. Respondents were randomly recruited from a THESL provided list of approximately 6,000 GS > 50 kW customers.

From the focus groups, the following common priorities were identified:

1. **Customer Service**: Overall, customer service is seen as excellent with the exception to specific incidents where base observations are noted. Generally, maintaining the current level of customer services was seen as a priority for THESL.
2. **Reliability and Outage Communications**: Power reliability is seen as good, but more importantly Toronto Hydro's responsiveness and communications were seen as key business needs. Maintaining the current level of reliability appears to be a priority among this rate class.
3. **Bill Impact**: Cost was an overarching concern, but not specifically directed at Toronto Hydro. The more participants learned about Toronto Hydro, its plans and its place in the electricity system, the less concern participants appeared to be regarding Toronto Hydro's impact on their bill.
4. **Future Rates**: While learning more about Toronto Hydro reduced concern about price, participants still give high priority to cost containment and short-term rate predictability. Even

with that concern about bill impacts, this rate class appears to be willing to accept "reasonable" rate increases based on a value proposition that included the following definitions:

a) Maintaining current reliability (not necessarily enhancing reliability);

b) Investing prudently, where long-term cost savings are realized (spend more now to save even more later);

c) No premature investing in unproven or untested technologies;

d) Enhanced customer service to match emerging technological capabilities and needs (e.g. allow customers to get bills by emails, create master accounts to manage multiple bills, live assistance chat features); and

e) Investing in education and promotion of CDM as a means for individual cost savings and also as a route to mitigating future demand and reliability challenges.

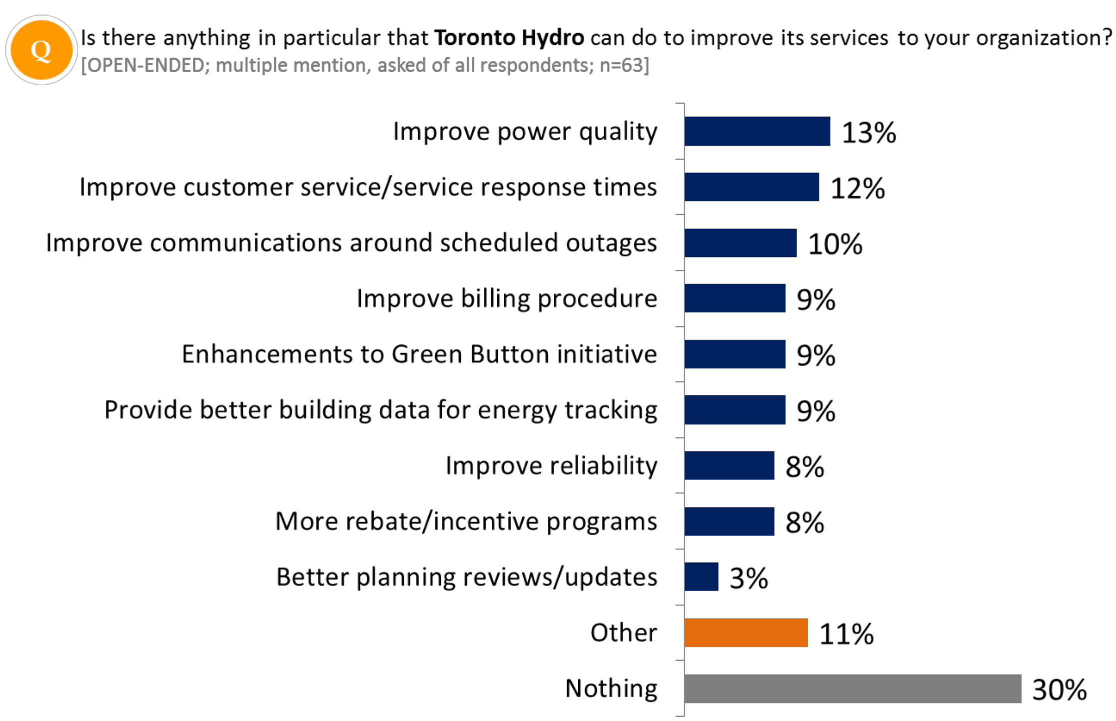
Key Account Customer Outcome Priorities

These are the findings from an INNOVATIVE online survey conducted among Key Account customers between February 23 and March 24, 2017.

Toronto Hydro provided INNOVATIVE with an email contact list consisting of the prime contact for each of its 275 Key Account customers. INNOVATIVE provided each Key Account contact with a unique URL via an email invitation so that only customers identified by Toronto Hydro were able to complete the survey and complete the survey only once.

The analysis of this survey is based on 63 eligible responses from Toronto Hydro's Key Account customers.

When asked what THESL could do to improve service, a plurality (30%) suggested nothing; followed by power quality and improved service response times.



As with lower volume customers, Key Accounts were asked to rate and rank a list of outcomes. Several categories were added to the Key Account list based on an initial review of previous Key Account engagements with THESL staff.

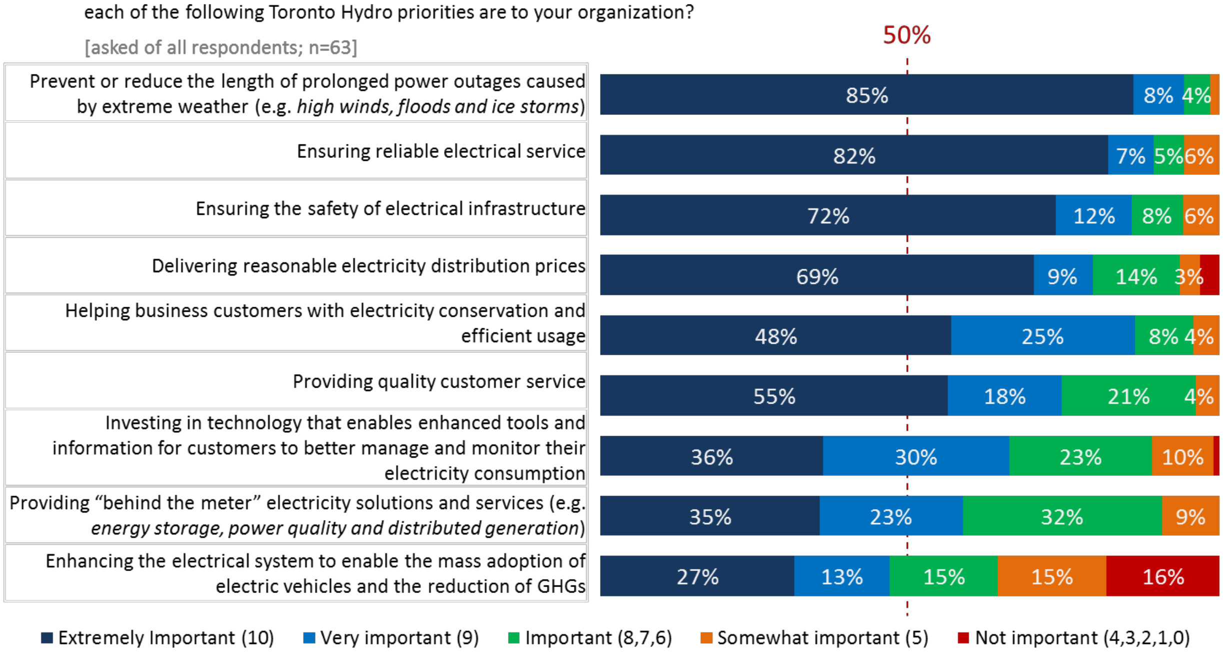
Similar to other rate classes, *safety*, *reliability,* and *price* are most important to customers. System hardening, an additional category unique to this survey, is the topped ranked priorities among Key Accounts (this priority did not come up in qualitative discussions with other rate classes).

Q

Toronto Hydro regularly holds discussions with its customers to better understand how it should set spending priorities with ratepayer dollars. In recent conversations with customers, a number of company goals were identified as priorities for Toronto Hydro.

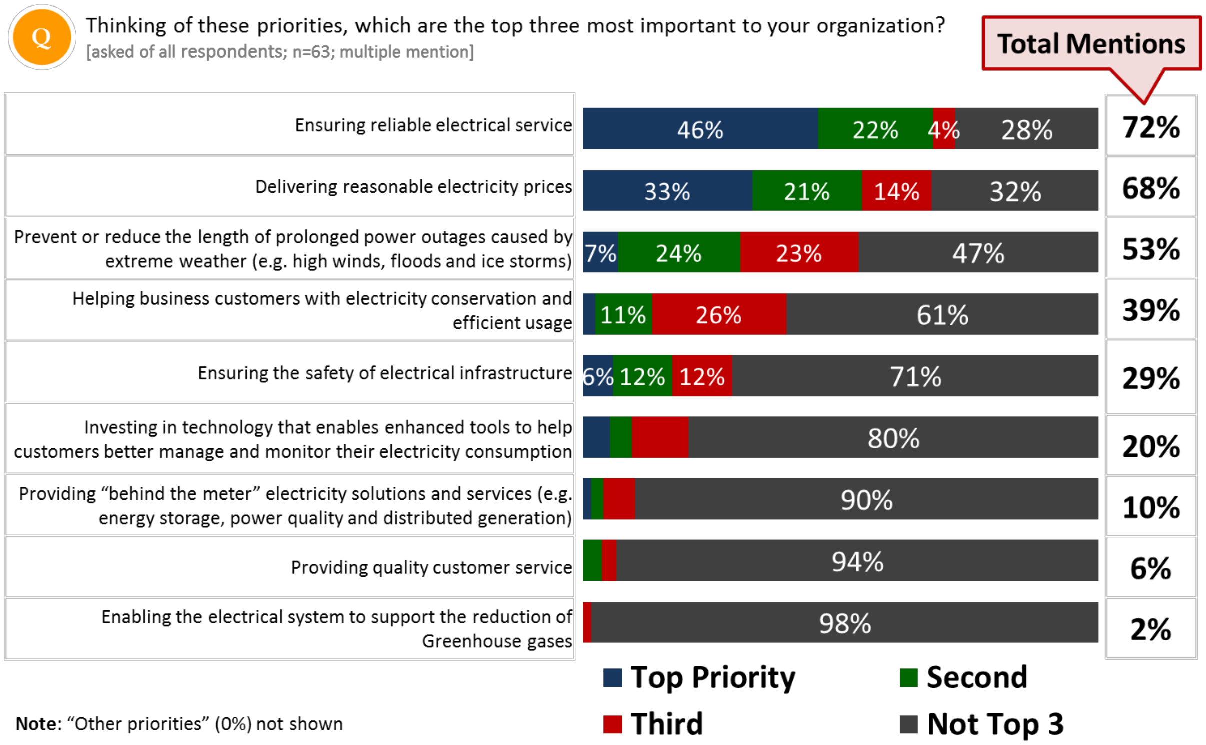
Using a scale from 0 to 10, where 0 means not important at all and 10 means extremely important, please indicate how important each of the following Toronto Hydro priorities are to your organization?

[asked of all respondents; n=63]



Looking at the top priority (first mention), *reliability* appears to be more important than *price* to this rate class (although price is a close second in priority rankings).

Q Thinking of these priorities, which are the top three most important to your organization?
[asked of all respondents; n=63; multiple mention]



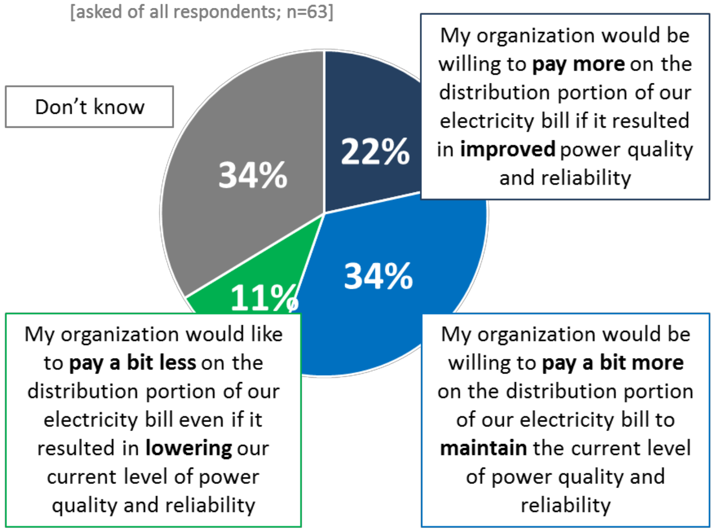
Note: "Other priorities" (0%) not shown

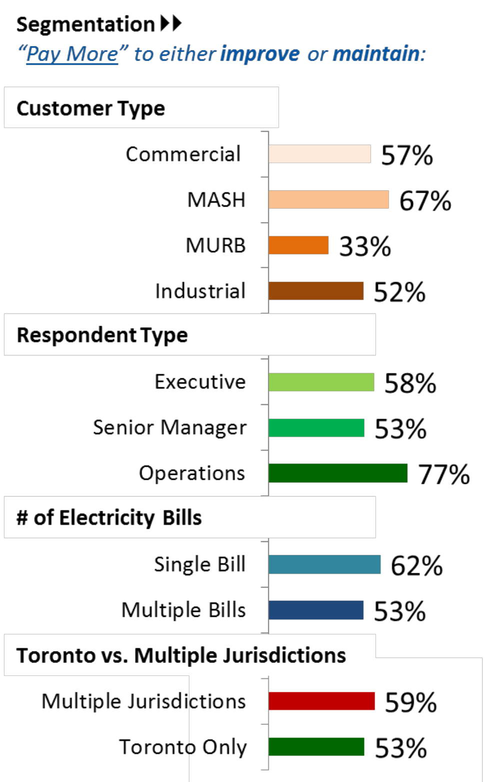
A majority of Key Account customers (56%) say they are willing to pay more to maintain or improve system reliability.

Q Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

Thinking about the trade-offs between reliability and the cost of your electricity bill, which of the following statements best represents your general point of view?

[asked of all respondents; n=63]





Stakeholder Outcomes Preferences

INNOVATIVE conducted nine in-depth interviews with industry and social stakeholders between June 12 and 30, 2017. Interviews and dyads were semi-structured based around key themes. Specific and topical probes were employed throughout. All interviews and dyads were held at participant organization offices across Toronto.

The in-depth stakeholder interviews revealed a number of common themes.

1) **Reliability**: Industry associations held reliability, by far, their overreaching top priority.
2) **Social Outcomes**: Social organizations also held reliability as top priority, but also held social outcomes as a key priority (e.g. community renewal, sustainable living).
3) **Price**: Mid-sized manufacturing association held price above all else, far above reliability. Specifically, this stakeholder was seeking a price reductions as opposed to price stabilization.
4) **Price Predictability**: Most industry and social organizations favour price stabilization and predictability over absolute reductions (e.g. reasonable price increase are accepted by this group of stakeholders). The biggest concern with the price of electricity is not distribution rates, but rather the global adjustment that has been unpredictable over the past decade.
5) **Risk Mitigation**: Resilience of infrastructure – defined as an ability of withstand adverse events which may be physical or virtual – appears to be a key priority for almost all stakeholder groups.
6) **Socio-economic Outcomes**: Every group, in varying ways, cited socio-economic outcomes as an increasing priority (e.g. impact poverty, employment, cost of living, quality of life, economic competitiveness, etc.).
7) **Incentive Programs**: Better target incentives where there is the greatest long-term benefits. Make it easier to access incentives.
8) **Other**: Specific one-off instances of interaction points of service friction with Toronto Hydro (e.g. vaults, sub-metering, inconsistent power quality, collaboration and communications on development projects, lampposts).

RATE FRAMEWORK

This schedule describes Toronto Hydro's rate framework for the 2020 to 2024 plan period. The utility's proposed rate framework continues the rate framework approved by the OEB in Toronto Hydro's 2015-2019 Rate Application.[1] The framework is aligned with OEB policy, and based on sound ratemaking principles. It has been structured in a way that includes productivity gains as part of the rate adjustment mechanism, constrains operational funding increases going forward at less than the rate of inflation, and reconciles a price-cap formula with funding requirements to address Toronto Hydro's significant, multi-year investment needs over the 2020 to 2024 period.

1. SUMMARY

Toronto Hydro's rate framework is a modification of the standard Fourth Generation Incentive Rate-Setting ("4th Generation IR") IR approach. The framework is comprehensive, covers the entirety of the application's term, and is informed by Toronto Hydro's forecasts. It is also informed by the OEB's current inflation and productivity analysis, and is aligned with Toronto Hydro's third party benchmarking of Toronto Hydro's costs. As noted, the framework is a continuation of the framework approved by the OEB in the utility's 2015-2019 Rate Application. As explained below, this includes the modifications required by the OEB in its 2015 decision, as related to the application of the stretch factor to capital and the inclusion of a growth variable to capture changes in revenue occurring due to changes in customers and loads.[2]
Year 1 is a traditional rebasing year, with costs allocated and rates set on the basis of a forecast Test Year.

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[1] EB-2014-0116 Decision and Order (December 29, 2015).
[2] Ibid.

Distribution rates in Years 2 through 5 are adjusted annually by a Custom Price Cap Index ("CPCI"), as follows:

CPCI = I – X + C - g

Where,

- "**I**" is the OEB's inflation factor, determined annually;
- "**X**" is the sum of:
    - The OEB's productivity factor, as of the date of filing; and
    - Toronto Hydro's custom stretch factor;
- "**C**" provides funds incremental to "I – X" that are necessary to reconcile Toronto Hydro's capital need within a PCI framework;
- "**g**" captures revenue growth occurring due to customer and/or load changes over the forecast period, based on Toronto Hydro's forecast of loads and customers for the 2021-2024 period;

2. YEAR 1: STANDARD REBASING

The first year of the proposed rate application is a standard rebasing year, consistent with the OEB's 4th Generation IR approach. Toronto Hydro developed and has submitted in this application a forecast of its base revenue requirement for 2020. The utility developed forecasts of its costs based on its capital and operational plans for 2020. The Distribution System Plan ("DSP") and Operations, Maintenance, and Administration ("OM&A") evidence contained in Exhibits 2B and 4A, respectively, provides the details supporting these projected costs. The calculated revenue requirement resulting from these projections is detailed in the Revenue Requirement evidence filed at Exhibit 6, Tab 1.

In the RRFE Report, the OEB offers alternative forms of rate making “to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant.”[4] The OEB notes that the CIR option in particular “will be most appropriate for distributors with significant large multi-year […] investment commitments that exceed historical levels,” whereas 4th Generation IR is more suitable for utilities with “some” incremental needs.[5] The evidence at Exhibit 1B, Tab 2, Schedule 4 and the DSP at Exhibit 2B discuss Toronto Hydro’s capital investment needs and, by extension, the appropriateness of the CIR option in greater detail.

A challenge for CIR applicants like Toronto Hydro is to reconcile their significantly large, multi-year investment commitments within a framework that aligns with RRFE guidance. To this end, Toronto Hydro proposes that these needs be reconciled within a CPCI framework that entrenches the OEB’s inflation and productivity factors within a formulaic approach to adjusting distribution rates, with customization as set out in this evidence. The following subsections set out the approach in more detail.

3.1 Inflation and Productivity Factors

In 2013, the OEB updated its standard rate adjustment parameters following a consultation process that explicitly considered:[6]

1) The development of a more Ontario-specific inflation factor;
2) The estimation of long-run Ontario electricity distribution total factor productivity (“TFP”); and
3) The development and implementation of total cost benchmarking.

[4] RRFE Report at page 9.
[5] RRFE Report at page 14.
[6] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario’s Electricity Distributors (December 4, 2013) [the “OEB Rate Setting Parameters Report”].

The OEB decided on a new methodology for the I-factor. The I-factor is based on a 30/70 weighting of labour and non-labour sub-indices and is updated annually. The labour sub-index is determined by changes in the average weekly earnings of Ontario workers, and the non-labour sub-index is determined by changes in the Canada Gross Domestic Product Implicit Price Index for final domestic demand.

Toronto Hydro proposes to use the OEB's I-factor in its CPCI. As the value for the I-factor is updated annually, Toronto Hydro will incorporate the updated value into its CPCI to appropriately adjust base distribution rates for the following year.

The productivity factor, one of the two X-factor components, was also updated. The productivity factor is intended to estimate the overall trend in the productivity of the electricity distribution industry in Ontario by measuring changes in TFP, defined by Pacific Economics Group ("PEG") as a "comprehensive measure of the extent to which firms convert inputs into outputs."[7]

In its report, PEG used an indexing method to estimate TFP for the Ontario distribution sector based on data from the 2002 to 2012 period.[8] This sample excluded the experience of both Toronto Hydro and Hydro One because, as a result of their large size relative to the rest of the industry, PEG determined that they were exerting a disproportionate impact on industry TFP.[9] Toronto Hydro presumes that this principle would have held if one or both had outperformed the sector on TFP.

[7] Pacific Economics Group (2013), Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario, (corrected January 24, 2014) at page 12 [the "PEG Report"].
[8] PEG suggests that a ten-year horizon is the minimum required for TFP Indexing.
[9] PEG Report, *supra* note 7 at page 4.

The result of PEG's analysis that excluded the two utilities suggested that industry TFP over that period changed at an average annual rate of -0.33 percent. That is, TFP for the sector actually declined over that period. In alignment with PEG's recommendation, the OEB ultimately adopted a zero productivity factor as a matter of policy, inclusive of an implicit stretch of 0.33 percent.

Toronto Hydro proposes to embed the OEB's productivity with its implicit incremental stretch factor unchanged within the proposed CPCI, fixed throughout the term of the ratemaking period.

3.2 Custom Stretch Factor

The second component of the X-factor is an explicit stretch factor. According to the OEB, "stretch factors promote, recognize, and reward distributors for efficiency improvements relative to the expected sector productivity trend."[10] Under the current methodology, which was updated most recently in 2013, utilities are assigned one of five stretch factors. This occurs on the basis of a comparison of the utility's total costs relative to their predicted total costs. The predicted total costs are determined using a total cost econometric model developed by PEG.[11]

As part of this application, Toronto Hydro is submitting alternative total cost benchmarking, the details of which can be found in the Power System Engineering's ("PSE") Econometric Benchmarking Report, at Exhibit 1B, Tab 4, Schedule 2 (the "PSE Report"). The alternative total cost benchmarking model prepared by PSE for Toronto Hydro is econometric in nature (similar to PEG's model) and includes an expanded data set. The results are statistically significant and relevant to the OEB's consideration of

[10] OEB Rate Setting Parameters Report, *supra* note 6 at page 18.
[11] OEB Rate Setting Parameters Report, *supra* note 6 at page 19.

Toronto Hydro's performance. The PSE Report also addresses the benchmarking comments set out in the OEB Decision in Toronto Hydro's 2015-2019 Rate Application.[12]

The PSE Report provides an appropriate and robust basis for setting Toronto Hydro's stretch factor. As noted in the PSE Report, Toronto Hydro's forecasts of its total costs are within 10 percent of its predicted total costs. Utilities within this demarcation point are assigned to Group III of the OEB's benchmarking cohorts, implying a stretch factor of 0.30 percent. Toronto Hydro therefore proposes that the stretch factor in the proposed CPCI framework be set at 0.30 percent, and fixed throughout the term of the ratemaking period.

Toronto Hydro's proposed plan and resulting revenue requirement in this CIR application reflects the results of a total cost econometric forecasting model, as envisioned in the Filing Requirements. A custom element of this CIR Application is using a PSE forecasting model in place of a PEG forecasting model.

3.3 Custom Capital Factor

The premise of the inclusion of a custom capital factor ("C-factor") is to reconcile the OEB's guidance that the CIR framework is best suited for utilities with significant, multi-year capital investment requirements as it is clear that the standard 4th Generation IR framework is not.

The proposed C-factor is designed as a rate adjustment mechanism that is directly proportional to the degree of capital investment required by Toronto Hydro, as detailed

[12] Supra note 1 at pp.16-17.

in its DSP (Exhibit 2B). It is comprised of two sub-components that serve two primary functions:

- Reconcile Toronto Hydro's capital investment need in a price cap framework; and
- Return to ratepayers the funding already provided for capital through the standard "I – X" increase.

The first sub-component, termed "C_n", is determined as the percent change in total revenue requirement that is attributable to changes in capital-related revenue requirement – that is, depreciation, return on equity, interest and PILs/taxes. Changes in capital-related revenue requirement are based on forecast changes in average annual rate base, associated depreciation, and taxes. Tax rates and the cost of capital are maintained at their 2020 levels, consistent with the standard 4th Generation IR treatment and the OEB approved treatment in Toronto Hydro's 2015-2019 Rate Application.

The OEB approved values of C_n from the 2015-2019 Rate Application are shown in Table 1 below.[13]

Table 1: OEB Approved C_n factors for 2016-2019

2016	2017	2018	2019
4.07	7.60	5.99	4.43

For the current application, Cn for 2021-2024 is be determined on the following basis:

[13] EB-2014-0116 Draft Rate Order Update (February 29, 2016) page 6.

Table 2: Calculation of C_n ($ Millions)

Revenue Requirement Component[14]	2020	2021	2022	2023	2024
Ratebase	4,615.3	4,829.0	5,081.6	5,374.5	5,650.0
Interest Expense	100.8	105.5	111.0	117.4	123.4
Return on Equity	162.8	170.4	179.3	189.6	199.3
Depreciation	268.7	281.9	293.1	310.9	325.4
PILs/Taxes	34.7	36.5	32.7	35.7	42.2
Capital-related RR (A)	567.0	594.3	616.0	653.6	690.3
OM&A	277.5	280.0	282.5	285.1	287.6
Revenue Offsets	-47.7	-48.1	-48.5	-49.0	-49.4
Total RR (B)	796.8	826.2	850.0	889.6	928.5
$Cn = (A_{yx} – A_{y(x-1)}) / B_{y(x-1)}$		3.43%	2.63%	4.42%	4.12%

For example, in the above table, the change in forecast capital related revenue requirement from 2020 to 2021 is $27.3 million ($594.3 million minus $567.0 million). The total revenue requirement in 2020 is $796.8 million. C_n for 2020 is therefore:

$$C_n = (594.3 – 567.0) / 796.8 = \mathbf{3.43\%}.$$

The values shown in Table 2 are filed as part of the OEB's Revenue Requirement Workforms, at Exhibit 6, Tab 1, Schedules 2-6. Capital-related revenue requirement, as noted, is determined on a forecast basis. By contrast, OM&A and Revenue Offsets are assumed to increase by "I – X".

The values of C_n represent the amount by which base rates would need to be increased to fund Toronto Hydro's capital needs over the course of the rate term.

[14] Each component can be found in the Revenue Requirement Workforms filed as Exhibit 6, Tab 1, Schedule 2-6.

With the inclusion of C_n in the CPCI, Toronto Hydro would receive sufficient funding for its capital needs as presented in the DSP. However, the "I – X" increase already included in the CPCI formula does provide some degree of incremental funding for capital. Absent adjustment, the CPCI formula with just C_n would risk over-funding relative to Toronto Hydro's capital needs. This risk is removed in the CPCI through a scaling of the C_n values. Termed S_{cap}, this scaling factor is calculated in the following fashion:

$$S_{cap} = \text{(capital-related revenue requirement) / (total revenue requirement)}$$

This scaling reduces the incremental funding for capital to capture just the capital component incremental to the "I – X" already included in the CPCI. Table 3 provides the information inputs for calculating S_{cap} for 2021-2024.

Table 3: Revenue Requirement Components for Determining S_{cap}

Revenue Requirement Component	2021	2022	2023	2024
Interest	105.5	111.0	117.4	123.4
ROE	170.4	179.3	189.6	199.3
Depreciation	281.9	293.1	310.9	325.4
PILs/Taxes	36.5	32.7	35.7	42.2
Capital-related RR (A)	**594.3**	**616.0**	**653.6**	**690.3**
OM&A	280.0	282.5	285.1	287.6
Revenue Offsets	-48.1	-48.5	-49.0	-49.4
Total RR (B)	**826.2**	**850.0**	**889.6**	**928.5**
S_{cap} = A / B	**71.9%**	**72.5%**	**73.5%**	**74.3%**

In Toronto Hydro's 2015-2019 Rate Application, the scaling factor was applied to a full "I – X". However, the OEB ruled that the scaling should only apply to "I", so that the stretch factor incentive remained a component of the capital funding.[15] Toronto Hydro's proposed CPCI conforms to this finding.

3.4 Growth Factor

In its 2015 Decision, the OEB found that the inclusion of a growth variable in the CPCI was warranted to capture the change in distribution revenue that would naturally occur (in the absence of any rate changes) due to changes in billing units (customer numbers and loads) over the forecast period.[16]

Toronto Hydro has accordingly included the growth term, "g", in the CPCI. The value of the growth term is determined based on Toronto Hydro's forecast of loads and customers for the 2021-2024 period,[17] applied to 2020 proposed rates. This methodology is consistent with the OEB's approved methodology in Toronto Hydro's 2015-2019 Rate Application, and results in a g-factor value of 0.2 percent. Calculation of the g factor is shown in Table 4, below.

Table 4: Forecast Revenue at 2020 Proposed Rates ($ Millions)

	2020	2021	2022	2023	2024	Annual Average
Revenue at 2020 Rates	796.8	797.8	799.8	801.6	804.8	
Annual Growth Rate		0.1%	0.2%	0.2%	0.4%	0.2%

The above discussion sets out the variables that constitute Toronto Hydro's proposed CPCI. The resulting CPCI value for a given year would, in keeping with IRM principles, be applied to all distribution rates from the previous year to determine the following year's distribution rates.

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[15] Supra note 1 at page 18.
[16] Supra note 1.
[17] See Exhibit 3, Tab 1, Schedule 1, for Toronto Hydro's forecast of loads and customers

To summarize, the CPCI is determined in the following fashion:

$$\mathbf{CPCI = I - X + C - g, or}$$

$$\mathbf{CPCI = I - X + C_n - (S_{cap} * I) - g}$$

Where,

- "**I**" is the OEB's inflation factor, determined annually;
- "**X**" is the sum of:
  - The OEB's productivity factor of 0.0 percent; and
  - Toronto Hydro's custom stretch factor, applied to both OM&A and capital expenditures;
- "**C**" is the difference between:
  - **C_n**, a reflection of Toronto Hydro's capital investment need, and
  - **S_{cap} * I**, an offsetting adjustment required to ensure that the C-factor provides funding only in excess of what is already provided for capital through the inflation factor I;
- **"g"** is the growth factor determined by growth in distribution revenue due to changes in load and customers over the CPCI period.

Table 5, below, shows the components of the CPCI based on an assumed I-factor of 1.2 percent, the current OEB approved inflation value, the proposed stretch factor, the forecast values of C_n and S_{cap}, and the g factor, shown in Tables 1 and 2, above.

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 1C
Tab 3
Schedule 10
ORIGINAL
(120 pages)

ENERGIZING GROWTH AND INNOVATION

2017 ANNUAL REPORT

TORONTO HYDRO®
Corporation

ENERGIZING GROWTH AND INNOVATION

AS TORONTO CONTINUES TO GROW, WE'RE WORKING HARD TO ENSURE THAT WE'RE PREPARED TO MEET OUR CITY'S EVOLVING NEEDS.

PROGRESSIVE AND SUSTAINABLE SOLUTIONS – To meet the challenge of growing electricity demand, we're focusing on innovative, integrated energy solutions to help us build the grid of the future. In 2017, we continued to monitor the world's first grid-scale pole-mounted energy storage system, which is showing promising results in the early stages of a pilot program. We also announced a collaboration with Metrolinx to build a battery energy storage system capable of providing backup and emergency power for the Eglinton Crosstown light rail transit (LRT) line.

We've been recognized as a Sustainable Electricity Company™ by the Canadian Electricity Association (CEA) since 2014, and we continue to pursue strategic projects to promote a sustainable future for Toronto. In order to encourage our employees to transition to electric vehicles (EVs), in 2017, we installed four charging stations at our location at 500 Commissioners Street. We also sponsored Plug'n Drive, a non-profit organization helping to accelerate the adoption of EVs, and powered two charging stations at the Plug'n Drive Electric Vehicle Discovery Centre in Toronto.

INVESTING IN INFRASTRUCTURE RENEWAL – We invested $552.9 million primarily to renew our aging infrastructure to address service reliability, safety and customer service requirements. In addition, we invested approximately $60 million in an upgrade to Hydro One's transmission grid serving the west end of the city, which is expected to benefit thousands of residents and businesses in Toronto. We also supported major capital investment projects across the city, including Metrolinx's Light Rail Transit (LRT) expansion and the City of Toronto's revitalization and relocation projects.

STRONG FINANCIAL RESULTS – Once again, Toronto Hydro had a highly successful year, resulting in a $156.5 million net income after net movements in regulatory balances. Our strong 2017 results were a reflection of our commitment to customer service and operational excellence. We also received a $250 million equity investment from the City of Toronto, and in connection with that investment, we declared the following dividends payable to the City and approved amendments to our Dividend Policy: an aggregate amount of $75 million in respect of fiscal 2017, and in respect of fiscal 2018 and subsequent fiscal years, 60% of Toronto Hydro's immediately previous year's annual consolidated net income after net movements in regulatory balances.

We're proud of the advancements we made in 2017, and encourage you to read more about our accomplishments in the Progress section of this report.

On behalf of the Board of Directors and the senior management team, we thank our customers and stakeholders for their continued support of Toronto Hydro. We would especially like to thank all of our employees for their hard work over the past year. Toronto Hydro's accomplishments are a result of your determination, perseverance and dedication to this organization.

David McFadden Chair	Anthony Haines President and Chief Executive Officer

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Toronto Hydro-Electric System Limited owns and operates $4.4 billion of capital assets comprised primarily of an electricity distribution system that delivers electricity to approximately 768,000 customers located in the city of Toronto. It serves the largest city in Canada and distributes approximately 19% of the electricity consumed in the province of Ontario.

Services

- Committed to delivering safe and reliable electrical power to approximately 768,000 residential, commercial and industrial customers in the City of Toronto, which has a population base of approximately 2.8 million
- Plans, maintains and aims to operate its electricity distribution infrastructure efficiently and in an environmentally responsible manner
- Strives to provide consistent, high-quality customer service
- Designs and delivers CDM programs

2017 Achievements

- Among the leading local distribution companies in the delivery of CDM programs to help customers conserve energy, save money and help the environment
- Recognized as a Sustainable Electricity Company™, a designation by the Canadian Electricity Association
- Continued work on Copeland transformer station, the first transformer station built in downtown Toronto since the 1960s, and the second underground transformer station in Canada
- Supported major capital investment projects across the city, including: Metrolinx's Light Rail Transit (LRT) expansion and GO Regional Electrification of Rail Program, Toronto Transit Commission's Scarborough Subway Extension project and Easier Access Program, the City of Toronto's revitalization and relocation projects and the Ministry of Transportation's Bridge Rehabilitation projects

ENERGIZING GROWTH AND INNOVATION

- Collaborated with Metrolinx on plans to build a battery energy storage system that will provide backup and emergency power for the Eglinton Crosstown LRT
- Invested approximately $60 million to upgrade electricity infrastructure in the city's west end
- Continued to monitor the world's first grid-scale pole-mounted energy storage system, which is showing promising results in the early stages of a pilot program
- Recognized again as one of Canada's safest employers, receiving Canada's Safest Employers Gold Safety Award in the Utilities and Electrical Category, and the 2017 Canadian Electricity Association President's Award of Excellence for Employee Safety
- Continued to improve digital communication channels with more enhancements to online tools, including the launch of the ***Power**Lens*® portal, a new platform that shows customers how their homes use electricity so they can take steps towards saving
- Deployed Mutual Aid resources to four American utilities following severe weather events
- Continued annual safety campaign to remind the public of electrical safety hazards on the street and at home
- Supported Georgian College's engineering facility to help train future electrical utility workers and fund curriculum development
- Participated in the Centre for Urban Energy at Ryerson University, an academic-industry collaboration that explores and develops sustainable solutions to urban energy challenges
- Sponsored Plug'n Drive, a non-profit organization committed to accelerating the adoption of electric vehicles, and powered two public charging stations at its Electric Vehicle Discovery Centre in northern Toronto

- In order to encourage our employees to transition to electric vehicles (EVs), we installed four charging stations at our 500 Commissions Street location in 2017, and there are plans to install charging stations at 71 Rexdale Boulevard and 715 Milner Avenue in 2018. We also initiated a project to replace small cars in our fleet with fully-electric vehicles
- We sponsored Plug'n Drive, a non-profit organization committed to accelerating the adoption of EVs. We also powered two charging stations in the test drive zone at the Plug'n Drive Electric Vehicle Discovery Centre in Toronto, the world's first experiential learning facility dedicated to EV education and awareness
- We contributed to advancing the transition to EVs through participation in various working groups and associations, including the City of Toronto's EV Working Group and the Canadian Urban Transit Research & Innovation Consortium
- We implemented the use of secure pull printing, which requires employees to use their access cards at our printers. This ensures that all printed documents are collected from the printer, thereby reducing wasted paper. We also implemented the use of tablets for issuing and completing facilities-related work orders. Previously, work orders were issued on paper and submitted for filing once completed. When combined with similar initiatives carried out in earlier years, we have reduced our annual paper consumption by approximately 3,073,000 sheets of paper, which equates to a savings of approximately 39 tCO_2e of associated GHG emissions in 2017, when compared to 2013
- For the fourth consecutive year, we hosted our annual charity golf tournament, raising $800,000 through our partners and sponsors for Sunnybrook's Ross Tilley Burn Centre – the largest, most advanced adult burn centre in Canada – for a total of $2.6 million raised in four years

Toronto Hydro – 71 Rexdale Boulevard

Value Through Performance: Additional 2018 Highlights

- In November 2018, we successfully completed an external audit to re-certify our Health and Safety Management System to the Occupational Health and Safety Assessment Series Standard for Occupational Health and Safety Management Systems (OHSAS 18001:2007). Additionally, the audit also confirmed that we've effectively maintained our Environmental Management System certification in accordance with the International Organization for Standardization's 2015 Environmental Management Systems Standard (ISO 14001:2015)
- We reduced the total GHG emissions from electricity use and natural gas use in our facilities by 20% and 14% respectively, compared to 2017
- Our total GHG emissions were 36,836 tCO_2e – a decrease of 2% relative to 2017
- We continued to work with residential, small business, industrial and commercial customers to implement energy-efficiency projects through our Conservation and Demand Management (CDM) programs. In 2018, our CDM programs led to an estimated energy savings of 321.2 GWh
- We received a CEA Sustainable Electricity award for Leadership in External Collaboration and Partnerships, in recognition of our work with Metrolinx on an innovative battery energy storage system that will provide backup and emergency power for the Eglinton Crosstown LRT
- We helped support renewable generation by enabling 245 microFIT interconnections (10 kW or less in capacity), totalling 2.1 MW of generation, and 59 FIT interconnections (greater than 10 kW capacity), totalling more than 9.6 MW of generation
- We enrolled an additional 37,000 customers for eBills, and continued to encourage our customers to switch to paperless billing as a way to exercise sustainability
- We achieved a corporate waste recycling rate of 92%, which accounts for a broad pool of waste streams, including metals from transformers and cables, wood poles removed from service, fluorescent lights, batteries and electronic waste
- We continued to use and install the Governor to Reduce Idle and Pollution (GRIP) technology on our vehicles. In addition, we undertook Phase II of our pilot project with Centennial College and eCamion to test the effectiveness of lithium ion batteries in vehicles, and trialed the use of electric power take-off for our bucket trucks. The cumulative 2018 savings, relative to 2014, associated with our fleet-related initiatives were: a 33% reduction in total fuel consumed; a 33% reduction in GHG emissions; and a 43% reduction in total non-PTO idling hours[1]
- We introduced eight fully-electric vehicles into our fleet to replace hybrid vehicles that were at the end of their useful life

[1] Some of our vehicles (e.g. bucket trucks) require engines to be kept on (idling) in order to charge and operate the vehicle hydraulics. This is referred to as PTO idling time.

COST OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

Section 2.2.2.7 of the OEB's Filing Requirements for Electricity Distributor Rate Applications[1] contemplates that a distributor will file for provincial rate protection associated with any costs incurred to make eligible investments.[2]

In accordance with the cost responsibility rules in the OEB's Distribution System Code ("DSC"), costs incurred by a distributor for the purpose of connecting or enabling the connection of a Renewable Energy Generation ("REG") facility to its distribution system are considered eligible investments for the purpose of provincial rate recovery under s. 79.1 of the *Ontario Energy Board Act, 1998*.[3]

1. REG CONNECTIONS

Significant renewable generation activity exists across Toronto Hydro's distribution system. As of December 31, 2017, Toronto Hydro connected 1,750 REG projects representing over 96 MW of capacity, and has undertaken approximately 540 MW of pre-assessment capacity reviews. Toronto Hydro anticipates 1,312 new REG connections during the 2018 through 2024 period, with a corresponding capacity of 116 MW. By the end of 2024, Toronto Hydro anticipates that approximately 212 MW of REG capacity will be connected to its distribution system.[4]

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (July 12, 2018).
[2] As described in section 79.1 of the *Ontario Energy Board Act, 1998* (the "Act") and O. Reg. 330/09 made under the Act.
[3] O. Reg. 330/09, at s. 1(2).
[4] For further information, please refer to Customer Connections (Exhibit 2B, Section E5.1).

Some REG projects are currently unable to connect to Toronto Hydro's system due to short-circuit limits on station equipment, feeder thermal limits, fault current, anti-islanding, and limited ability to transfer loads between feeders in the event of a contingency. The primary constraint at this time is short circuit capacity at the station bus.

2. ELIGIBLE INVESTMENTS SUMMARY

To address interconnection constraints at the distribution level, Toronto Hydro proposes to undertake a number of Renewable Enabling Improvement ("REI") investments as part of its 2020-2024 Distribution System Plan ("DSP"), which is filed at Exhibit 2B.

2.1 Generation Protection, Monitoring, and Control

Installation of Bus-Tie Reactors: Bus-tie reactors lower the short circuit current on the station bus and distribution system by insertion of an impedance at the bus-tie point. This method of fault mitigation has been successfully applied by PowerStream, Guelph Hydro, and Hydro One Networks Inc. ("Hydro One"). Toronto Hydro proposes to work with Hydro One to install bus-tie reactors at Ellesmere, Esplanade, Fairbank, Horner, and Sheppard TS to eliminate the existing fault current constraint, which will enable REG connections. For additional details, please refer to the Generation Protection, Monitoring, and Control Program (Exhibit 2B, Section E5.5).

Remote Monitoring and Control of Generation (SCADA): During the 2015-2019 plan period, Toronto Hydro has been installing monitoring and control systems for all new distributed generation ("DG") connections. This has provided system planners and operators with the visibility required to monitor generation to load ratios in real time to ensure all DG sites are de-energized in the event of a system fault. With the continued implementation of the Generation Protection, Monitoring, and Control program (Exhibit 2B, E5.5), Toronto Hydro will be able to actively monitor and control DGs in real time to ensure these ratios are within tolerable levels and the anti-islanding feature of DG facilities can properly operate in the event of a distribution system fault. These real-time monitoring and control systems communicate with REG resources via communication networks connected to the utility's supervisory control and data acquisition ("SCADA") system to enable safe operation of the distribution system and feeder management of bi-directional distribution grid flows. The system has the ability to forecast resources and coordinate with Toronto Hydro's distribution outage management system, thereby enabling greater REG penetration providing real-time visibility. Toronto Hydro's requirement for monitoring and control is modelled after requirements developed by the IESO. Consistent with the DSC, the costs associated with this investment program pertains only to renewable generation resources, as conventional generation projects bear the cost of monitoring and control requirements. For additional details, please refer to the Generation Protection, Monitoring, and Control program (Exhibit 2B, Section E5.5).

2.2 Energy Storage

Toronto Hydro plans to install five energy storage systems on three distribution feeders that are forecast to have high generator to minimum load ratios over the 2020-2024 period. These energy storage systems represent a total aggregated peak capacity of 2.5 MW and aggregated energy capacity of 10 MWh. Toronto Hydro's infrastructure was not designed to accommodate two-way, variable REG resources. These energy storage systems will balance energy flows in specific areas, allowing renewable generation connections to proceed and helping defer the need for conventional infrastructure upgrades. For additional details, please refer to the Energy Storage Systems program (Exhibit 2B, Section E7.2).

The IESO reviewed Toronto Hydro's plans for REG investments and found that: (i) the utility's plans are substantially consistent with that of IESO; and (ii) although specific REG investments are not included in the most recent Integrated Regional Resource Plan ("IRRP"), addressing barriers to connecting additional DG within Toronto Hydro's service area is consistent with regional planning principles. IESO concurs that removing technical barriers to new DG connections can provide lasting benefits. For more information, please refer to the IESO Comment Letter filed at Exhibit 2B, Section B, Appendix F.

3. ELIGIBLE INVESTMENTS COSTS

Table 1, below, summarizes the costs associated with Toronto Hydro's planned REI investments over the 2020 to 2024 plan period. Toronto Hydro is not proposing any specific Renewable Expansion[5] ("RE") investments during 2020-2024. However, certain demand response investments in the Station Expansion program (Exhibit 2B, Section E7.4) are expected to improve the utility's ability to connect REG facilities.

Table 1: Renewable Enabling Improvements ("REI") from 2020-2024 ($ Millions)

Capital Program	2020	2021	2022	2023	2024	Total
Generation, Protection, Monitoring, and Control	3.7	2.3	2.4	2.5	2.7	8.6
Energy Storage	1.0	1.0	1.0	1.0	1.0	5.0
Totals	**4.7**	**3.3**	**3.4**	**3.5**	**3.7**	**13.6**

[5] As defined in Section 3.2.30 of the Distribution System Code.

4. PROVINCIAL RATE PROTECTION

Toronto Hydro applied the six percent direct benefit percentage provided by the OEB with respect to REI investments to calculate the provincial rate protection amounts. The detailed breakdown is provided in the OEB Appendices 2-FA and 2-FB at Exhibit 2A, Tab 8, Schedules 2 and 3.[6]

Two versions of the OEB Appendices 2-FA and 2-FB are filed: one for Energy Storage and one for Generation, Protection, Monitoring, and Control systems. This is necessary as the life spans of these assets are different.

Further, the OEB Appendices reflect opening balances, which arise from the REI investments approved by the OEB in the utility’s 2015-2019 Rate Application.[7] The opening balances reflect the current forecast for those programs previously approved by the OEB.

[6] Appendix 2-FC provided in Schedule 4 is not applicable.
[7] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015).

E7.2 Energy Storage Systems

E7.2.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): $0.5 (Rate Base)	**2020-2024 Cost ($M):** $5.8 (Rate Base)
2015-2019 Cost ($M): $7.9 (Net Costs)	**2020-2024 Cost ($M):** $10.5 (Net Costs)
2015-2019 Cost ($M): $35.2 (Gross Costs)	**2020-2024 Cost ($M):** $52.8 (Gross Costs)
Segments: System Service	
Trigger Driver: Category 1- Power Quality; Category 2- Public Policy	
Outcomes: Customer Service, Reliability, Financial Sustainability, Public Policy	

The Energy Storage Systems ("ESS") program was developed to put batteries to use for the benefit of customers where this non-wires option is the best solution to enable or improve distribution service. As is stated in the 2017 Long-Term Energy Plan, "Energy storage can offer benefits throughout the grid, from large-scale facilities that can reduce the need to build new supply, import electricity or use GHG-emitting generation sources, to smaller-scale devices that can provide backup services to buildings."[1]

The Long-Term Energy Plan makes reference to two studies on energy storage that were completed at the request of the Ministry of Energy: (i) a 2016 IESO study on energy storage; and (ii) a 2017 study published by Essex Energy Corporation.

The IESO study, "IESO Report: Energy Storage," was produced in response to a request from the Ministry of Energy in April 2015. This study presents the many benefits of energy storage to the bulk electricity system. Among the benefits the report identifies is the deferral of system upgrades through the use of energy storage to reduce local system peaks.[2] The report states:

> *"Energy storage could also help improve the utilization of existing transmission and distribution assets by deferring some costs associated with their upgrades or refurbishments, as well as improve the quality of electricity supply in certain areas of the system by controlling local voltages."*[3]

[1] 2017 Long-Term Energy Plan, Ministry of Energy, 2017, p.60
[2] IESO Report: Energy Storage, Independent Electricty System Operator, 2016, p.5
[3] IESO Report: Energy Storage, Independent Electricty System Operator, 2016, p.35

ESS investments. The requesting customers will make capital contributions such that there will be a zero net effect on rate base in the 2020-2024 period.

The proposed Customer-Specific ESS projects are discussed below.

a. Metrolinx Finch West Light Rail Transit ("FWLRT") ESS

Metrolinx's Finch West Light Rail Transit ("FWLRT") is an 11-kilometre light rail transit line that will connect the TTC's Finch West subway station (on the Yonge-University Line) to Humber College westward along Finch Ave.

The FWLRT ESS will consist of a 8 MW/24 MWh battery system across four sites. The cost of this Customer-Specific ESS project is $16 million with a planned in-service date of 2022. The project is fully funded by the customer who is responsible for capital contributions. It will provide reliability improvement, enhanced resiliency, financial relief through peak-shaving, as well as emergency power to ensure service continuity and support underground station ventilation in a sustained grid outage. During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for the FWLRT, contributing to lower GHG emissions. The ESS will be located behind the meter, enabling peak-shaving by reducing coincident and non-coincident peak demand from the grid.

FWLRT will be supplied by feeders originating from the Finch TS BY Bus. According to Toronto Hydro's feeder reliability estimate (based on the ten feeders served by that bus), feeders on the Finch TS BY Bus averaged 5.1 sustained interruptions annually between 2014 through 2017. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

b. TTC Arrow Road Garage ESS

This large TTC public transit garage is located on Arrow Road near Finch Avenue and Highway 400 in the north end of Toronto. The TTC is investing in the facility such that it is expected to eventually support approximately 250-300 electric buses.

The TTC Arrow Road Garage ESS project will provide reliability improvements, resiliency, financial relief through peak-shaving, and emergency capacity. The cost of this Customer-Specific ESS project is $12.3 million with a planned in-service date of 2020. The project is fully funded by the customer through capital contributions. The ESS will be located behind the meter, enabling peak-shaving by reducing coincident and non-coincident peak demand from the grid.

The TTC Arrow Garage ESS will consist of a 5 MW/20 MWh battery system. The ESS will augment planned feeder upgrades at this site as part of the customer's project to deploy electric buses. During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for the TTC Arrow Garage.

Arrow Road Garage is supplied by a feeder (55-M29) originating from the Finch TS JQ Bus. During 2014-2017, 55-M29 averaged 4.5 sustained interruptions annually. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

3. Metrolinx Willowbrook Yard ESS

Metrolinx operates a large rail maintenance yard at Willowbrook in Etobicoke which services the busy regional rail lines on the lakeshore corridor.

The Willowbrook Yard ESS consists of a 8 MW/24 MWh battery system. The cost of this Customer-Specific ESS project is $14 million with a planned in-service date of 2022. The project is fully funded by the customer through capital contributions. It will provide reliability improvements, resiliency, financial relief through peak-shaving and emergency power.

During normal operation, the ESS will continuously condition the incoming supply and reduce peak demand for Willowbrook. The ESS will be located behind the meter and enable peak-shaving by reducing coincident and non-coincident peak demand from the grid.

Willowbrook Yard is supplied by a feeder (R30-M8) originating from the Horner TS BY Bus. During 2014-2017, R30-M8 averaged 5.1 sustained interruptions annually. The ESS is expected to reduce sustained interruptions, momentary interruptions, and voltage sags by over 50 percent.

E7.2.4.4 Options Analysis

This section examines other potential options for addressing the issues.

1. Option 1: On-Site Generation Options

Customers can consider on-site generation to provide some degree of reliability, financial benefits (i.e. behind the meter peak shaving), and emergency power. The on-site generator can be diesel or natural-gas fired and will operate either: (i) in parallel with the distribution grid and require emissions controls and protections or (ii) during an emergency only when the distribution grid is unavailable for extended periods (i.e. in an islanded configuration). On-site generation can address extended

LOAD, CUSTOMERS, AND REVENUE

Toronto Hydro's total load, customer, and distribution revenue forecast is summarized in Table 1. The revenue forecast is calculated based on proposed distribution rates, excluding commodity, rate riders, and all other non-distribution rates.

Table 1: Total Load, Revenues, and Customers

Year		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($M)	Total Customers
2013	Actual	25,245.1	42,737.5	531.9	724,144
2014	Actual	25,132.0	41,866.4	536.6	735,262
2015	Actual	25,031.1	41,320.7	628.0	747,811
2016	Actual	24,909.3	41,335.6	661.4	759,031
2017	Actual	24,427.6	40,731.3	693.6	765,559
2018	Bridge	24,378.2	40,925.0	740.7	771,079
2019	Bridge	24,123.8	40,761.1	771.5	776,786
2020	Forecast	24,036.0	40,408.1	796.9	784,330
2021	Forecast	23,818.0	40,275.5	824.2	790,944
2022	Forecast	23,651.8	40,200.6	846.8	798,591
2023	Forecast	23,475.3	40,104.6	885.2	806,238
2024	Forecast	23,396.7	40,166.6	924.2	813,886

Notes:

1. Total Normalized GWh are purchased GWh (before losses), and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer Allowance.
4. Total Customers are as of mid-year and exclude street lighting devices and unmetered load connections.

Table 3: Regression Variables by Rate Class

Residential	Competitive Sector Multi-unit Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000-4,999 kW	Large Use	Street Lighting	Unmetered Load
HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	Average use per device	Simple extrapolation
CDD per day	CDD per day	CDD per day	CDD per day	CDD per day	CDD per day		
Blackout dummy	Dew point temp.	Business days percent	Dew point temp.	Dew point temp.	Dew point temp.		
Time trend	Number of CSMUR customers	GDP	Business days percent	Business days percent	Business days percent		
Shoulder month	Intercept term	Black out dummy	GDP	GDP	GDP		
Intercept term		Time trend	Black out dummy	Toronto Unemployment Rate	Black out dummy		
		Shoulder month	Shoulder month	Black out dummy	Time trend		
		Number of GS<50 kW customers	Number of GS 50-999 kW customers	Time trend	Numbers of LU customers		
		Intercept term	Intercept term	Intercept term	Intercept term		

3.2 Electric Vehicles and Distributed Generation

The markets for Electric Vehicles (“EVs”) and widespread Distributed Generation (“DG”) are fairly new in Ontario. To date, any impacts on overall loads and demands on the Toronto Hydro system have not been determined to be material. Government policy in these areas has the potential to increase the amounts of loads associated with EVs and DG, including over the 2020-2024 forecast period.

Toronto Hydro does not have enough information about these markets to be able to confidently include any impacts on loads or demands at the time of filing. There has been no explicit incorporation of the potential load impacts into the load forecast, other than trends that would be part of measured loads to date, and would be captured in the multivariate regression models.

4. CLASS DEMAND (kVA) FORECAST

Toronto Hydro's forecast of monthly peak demand by customer class, which is used to determine revenue for those customers billed on a demand basis (GS 50-999 kW, GS 1000-4999 kW, Large User, and Street Lighting), is established using historical relationships between energy and demand. The utility uses the latest three-year average of this relationship for forecasting purposes. The resulting kW demand forecast is explicitly adjusted to reflect the impacts from the cumulative estimated CDM activities and subsequently converted based on the latest three-year average power factors to the peak kVA demand forecast (net of CDM). The cumulative CDM demand forecast consists of the incremental CDM forecast as well as persistence of historical CDM demand savings.

5. CDM FORECAST

Toronto Hydro confirms that it has explicitly included the impacts of CDM into its load forecast, consistent with the Board's CDM Guidelines (EB-2012-0003). The cumulative CDM forecast deducted from the gross load (step three of the three-step process described previously) includes the CDM savings for programs delivered in each year.

Toronto Hydro's actual and forecasted CDM savings for the 2006 to 2024 period can be separated into three separate components:

1) 2006 to 2016 verified historical savings;

CORPORATE TAXES (PILS)

1. INTRODUCTION

The Revenue Requirement filed at Exhibit 6, Tab 1, Schedule 1 of this application reflects amounts for Payments in Lieu of Taxes ("PILs") of $34.7 million (excluding investment tax credits of $1.9 million reallocated to OM&A), for the 2020 Test Year. The 2020 PILs tax models are filed at Exhibit 4B, Tab 2, Schedule 2.

Toronto Hydro used the OEB's PILs model for 2019 filers to prepare the 2020 PILs tax models. Other than the changes described below, no other changes to the OEB's PILs tax models have been made:

- All Tabs: The date in the header changed from "…2019 Filers" to "…2020 Filers".
- Tab "S. Summary":
  - Lines listed below have been added and linked to Tab "T0 PILs, Tax Provision" accordingly:
    - "Test Year – Grossed-up PILs before tax credits reclass to OM&A", and
    - "Test Year – Tax credits reclass to OM&A".
  - Description for "Test Year – Grossed-up PILs" changed to "Test Year – Grossed-up PILS after tax credits reclass to OM&A".
- Tab "B. Tax Rates & Exemptions": tax rates are updated for Toronto Hydro effective January 1, 2015 to January 1, 2020.
- Tabs "B0 PILs, Tax Provision Bridge" and "T0 PILs, Tax Provision" for bridge and test years: added adjustment for tax credits included in OM&A. The following lines have been added:

- Reconciliation of accounting income to net income for tax purposes agrees with the OM&A analysis for compensation and is reasonable when compared with the notes to the audited financial statements and the actuarial valuations; and
- The income tax rate used to calculate the tax expense is consistent with the current legislated rate.

16. TAX PAYABLE FILINGS

Details of actual taxes paid by Toronto Hydro from 2014 to 2016, as well as the forecasted taxes to be paid for 2017 and 2018, are outlined in the table below. Explanations of the variances for the forecast years are also provided. The tax return copy for the historical year 2016 is provided in Exhibit 4B, Tab 2, Schedule 3.[1]

Table 1: Summary of PILs by Year ($ Millions)

	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast	2019 Bridge	2020 Test
Income Taxes	10.5	3.2	18.8	29.4	30.8	20.4	34.7

The decrease/increase in PILs from year to year is mainly due to the change in net income before tax and the differences between tax and accounting treatments of various costs. These differences primarily stem from the variance between capital cost allowance and accounting depreciation, other post-employment benefit adjustments, investment tax credits and other costs.

[1] Toronto Hydro has provided its tax return for 2016, the latest completed tax return available at the time the application was being prepared.

Canada Revenue Agency Agence du revenu du Canada

Code 1501

Scientific Research and Experimental Development (SR&ED) Expenditures Claim

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 4B
Tab 2
Schedule 3
UPDATED: November 13, 2018
(185 pages)

Use this form:
- to provide technical information on your SR&ED projects;
- to calculate your SR&ED expenditures; and
- to calculate your qualified SR&ED expenditures for investment tax credits (ITC).

To claim an ITC, use either:
- Schedule T2SCH31, *Investment Tax Credit – Corporations*, or
- Form T2038(IND), *Investment Tax Credit (Individuals)*.

The information requested in this form and documents supporting your expenditures and project information (Part 2) are prescribed information.

Your SR&ED claim must be filed within 12 months of the filing due date of your income tax return.

To help you fill out this form, use the T4088, *Guide to Form T661*, which is available on our Web site: **www.cra.gc.ca/sred**.

Part 1 – General information

010 Name of claimant

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Enter one of the following:

[redacted]
Business number (BN)

Social insurance number (SIN)

Tax year
From: 2016-01-01 (Year Month Day)
To: 2016-12-31 (Year Month Day)

050 Total number of projects you are claiming this tax year: 10

100 Contact person for the financial information	**105** Telephone number/extension	**110** Fax number
[redacted]	[redacted]	[redacted]

115 Contact person for the technical information	**120** Telephone number/extension	**125** Fax number
[redacted]	[redacted]	

151 If this claim is filed for a partnership, was Form T5013 filed? . . . . 1 ☐ Yes 2 ☐ No

If you answered **no** to line 151, complete lines 153, 156 and 157.

153 Names of the partners	**156** %	**157** BN or SIN
1		
2		
3		
4		
5		

Part 2 - Project information

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A - Project identification

200 Project title (and identification code if applicable)

See schedule

Part 2 – Project information (continued)

Project number **1**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

P1: Electric Vehicle Program

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-02 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome?
(*Maximum 50 lines*)

The obstacles that TH had to overcome at the start of the claim project were: (1) Understanding what steps did TH have to take now and in future to be ready to accommodate the Provincial Government's target of 1 in 20 new vehicles in Ontario by 2020 being electric ones; how would we need to develop and prepare the assets and infrastructure; (2) Determining the electric vehicle makes, and technologies used, that would be selected for use in internal field trials; (3) Understanding and developing the design, operation, monitoring and reporting parameters that would need to be specified to ensure the data captured and analyzed from internal pilots, and from external participants through the EV Connections Program (CP), would lead to meaningful insights about all aspects of electric vehicle charging on its grid operations.

TH had made initial efforts in prior years to establish from modeling what the aggregate impacts on its grid might be. The EV pilot field trial continued in FY2016 from the previous fiscal year. The hope was that the trial results would be scalable and applicable to different degrees of EV penetration across its service area, and inform how EV charging could be integrated within its grid operations and control. Whether results from its internal trials and from the EV CP participants would be scalable and facilitate the integration of EV charging with grid operations remained to be explored.

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (*Maximum 100 lines*)

Data collected from the EV connections program was used to develop a model to understand what number and type of EVs could be connected to a distribution transformer before causing local infrastructure impacts. This model provided realistic representation of factors such as state of charge before charging, charging time and flow during various points in the charging time in addition to actual demand related to vehicle type. Few vehicles are needed to trigger a local infrastructure constraint. Together with the data on the location of actual EVs, local areas can be targeted for intervention.
Project for curb-side charging with the City of Toronto after being stalled for regulatory/legal issues. The focus is to understand the pattern of usage and the impact on downtown infrastructure. Focus will be to find solutions

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

that permit increased deployment while minimizing infrastructure impact and therefore cost.

Project was initiated to provide charging capability into neighbourhoods that have no private means of charging a vehicle. During 2016, customers were found to use extension cords over sidewalks which presents a safety issue. To prevent a safety concern, we worked to find/develop pole mounted solutions with manufacturers (such models do not currently exist in North America). We worked with Cross Chasm Technologies in the deployment of on-board and off-board vehicle charging controls to control over-night charging in a way that is beneficial to the grid and not user experience impactive to the driver. ("SmartCharging"). We worked with Cross Chasm to design the demand impact control, the data collection aspects to enable further technical insight as well as on the rewards program to encourage participation. Project was successful and objectives were achieved. Toronto Hydro will be participating in a larger Canada wide project using the same technology in 2017.
We also used the results of our work with Cross Chasm and retained ICF Consulting to develop models for use in Regulatory proceedings that would determine the cost benefit of SmartCharging program with rewards deployment given a variety of vehicle charging characteristics (captured through EV Connections program).
In late 2016 we initiated work on a workplace charging project at 500 Commissioners St. The aim of the project is to integrate electric vehicle charging with existing solar generation, battery storage and building demand management system to manage overall building electrical demand. This in turn would be a showcase for our customers.
The impact of the Ontario Climate Change Action Plan, particularly related to the electrification of transportation was assessed on a system wide basis to determine the infrastructure impact on a wide area basis
We also did work to modify our Conditions of Service technical requirements for metering in Multi-Unit Residential Buildings to achieve lower costs, less resource demand and increased deployment of electric vehicles.
Work would continue into FY2017 with: outreach programs, forecasting and projects (curbside EV charging stations, utilization of streetlight poles for charging capability, design of workplace charging systems, increasing the utilization of EV fleet, and condominium solutions to reduce cost of EV adoption.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

Scientific and technological advancements include:
Better models of the impact of the electric vehicle charging behaviour on a local area basis using data from the EV Connections program.
Understanding of the capabilities and implementability of "Smart Charging" (utility control of electric vehicle charging) to minimize local grid impacts as well as customer inconvenience.

Understanding of the impacts of Ontario's Climate Change Action Plan, specifically the electrification of transportation, on Toronto Hydro's peak demand at a system wide basis.
Understanding of the technical barriers that further need to be worked on to proceed with curb-side and workplace charging in 2017 in the context of minimizing infrastructure impacts.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	254 Name [redacted]
255 1 [ ] Other employee of the company	256 Name
257 1 [X] External consultant	258 Name Deloitte LLP — 259 Firm Deloitte LLP

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	261 Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	269 BN
1	

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents	276 1 [X] Progress reports, minutes of project meetings
271 1 [X] Records of resources allocated to the project, time sheets	277 1 [X] Test protocols, test data, analysis of test results, conclusions
272 1 [ ] Design of experiments	278 1 [X] Photographs and videos
273 1 [X] Project records, laboratory notebooks	279 1 [ ] Samples, prototypes, scrap or other artefacts
274 1 [ ] Design, system architecture and source code	280 1 [X] Contracts
275 1 [ ] Records of trial runs	281 1 [X] Others, specify 282 Invoices & emails.

Part 2 – Project information (continued)

Project number **4**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

P3: Electric Power System Capacity Planning & Improvement

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2007-03 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome? (*Maximum 50 lines*)

The technological objective of the project is to develop more accurate and flexible tools for peak demand forecasting and option development. The primary tool for input into subsequent tools is the load forecasting tool.

Challenges with current methods are: 1) they deal poorly with abrupt changes in underlying drivers of peak demand, 2) they are not flexible to include new factors (without previous history) that will increase electricity demand such as the electrification of transportation as proposed in the Ontario Climate Change Action Plan and 3 they do not provide understanding in the seasonality of peaks (as compared with a yearly peak) and further they are not designed to provide an hourly profile for peak conditions (which would be necessary in order to understand the feasibility of non-wires solution to deal with peak constraints).

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

Investigation into two key studies continued from the previous tax year.

In the first, new methods/techniques, beyond current practices, were developed. A subcontractor completed a long-term/25 year spatial peak demand forecast, including sensitivity analysis and a peak demand forecast process design, based on City forecasts of population & employment and IESO weather correction and extremes calculation, with the flexibility to handle multiple CDM and DG scenarios. Different CDM and DG scenarios were analyzed using the newly developed method. The Spatial Peak Demand Forecast from this study was contributed to the Central Toronto IRRP. THESL also continued to work with the OPA on developing contingencies for reliability and security analysis to identify mid- to long-term needs of the transmission system supplying downtown Toronto. Needs were examined on a probabilistic in addition to a deterministic approach traditionally used. A broader Metro Toronto Regional Infrastructure Report Plan (MTRI) extrapolating from the central IRRP was made and incorporated GO Line electrification and other potential future system additions. Through FY2016, a method to reduce work load in forecasting was pursued, and a new load forecasting approach conceived as a result of the

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

World Climate Change Action Plan (with extensive investigation planned for FY2017).

The second study took a broader approach to identify the root problems of supply unreliability covering the areas of asset condition, system design/operation/ maintenance, and contingency planning of supplies with a focus on bulk supply points to THESL and the distribution of power from these points of supply in an integrated manner. In addition, the study examined the reliability of supply and the investment planning process in other major cities and make improvement recommendations for both THESL and HONI. The study was completed in the tax year. A 2nd subcontractor contributed to this study's activities. A final report covered 3 major components, i.e. reliability of supply, the investment planning process, and key implementation considerations. Business plan and engineering feasibility would be subsequently pursued

After the release of the Ontario Climate Change Action Plan, an in-house study was performed of the impact of such a plan on Toronto's overall peak demand. The study included the adoption of electric vehicles, further electrification of mass transit, increased solar generation, conversion of natural gas heating to electric heat pumps, and conversion of natural gas water heaters to electricity.

Further internal study was undertaken to assess the impacts of the above factors on a seasonal basis rather than on a yearly basis as well as the impacts on an hourly load profile basis.

Contracted resources, listed below, worked as an integral part of the development teams.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

THESL sought in general terms, to gain more knowledge about how to plan for increasing its distribution system capacity and sources of power supplies in a cost effective manner in the face of severe physical constraints and changing circumstances. Electricity system planning in Ontario is conducted at 3 levels: bulk transmission system planning, regional system planning and distribution system planning. The OPA is responsible for the first level, and leads the effort in the second with the active participation of transmitters and distributors. The third level is led by distributors. More specifically the advances were to increase the knowledge and know-how behind the main options and key variables in the quest to increase bulk electricity supply to downtown Toronto, in a more reliable cost effective manner, and which examines the use of non-traditional contributions from distributed generation and demand management options and to improve long term planning techniques for supplies of different kinds and determining infrastructure needs. Furthermore, the impact of the Ontario Climate Change Action Plan are now known to increase winter peak demand in a way that would closely resemble summer peak demand and that on a system wide basis, it is now understood that peak demand will be shifted in time on a peak day to the interaction of decreased solar generation at the time of increased electric vehicle charging. These learnings on a system wide basis are guiding the development of a study for a small area forecast to be performed in 2017, closely aligned to the physical power system, the impact of the factors seen on a system wide basis due to the Ontario Climate Change Action Plan.

Section C – Additional project information

Who prepared the responses for Section B?

253 1 [X] Employee directly involved in the project	254 Name [redacted]		
255 1 [ ] Other employee of the company	256 Name		
257 1 [X] External consultant	258 Name Deloitte LLP	259 Firm Deloitte LLP	

List the key individuals directly involved in the project and indicate their qualifications/experience.

260 Names	261 Qualifications/experience and position title
1 [redacted]	[redacted]
2 [redacted]	[redacted]
3 [redacted]	[redacted]

265 Are you claiming any salary or wages for SR&ED performed outside Canada? . . . . . . 1 [ ] Yes 2 [X] No

266 Are you claiming expenditures for SR&ED carried out on behalf of another party? . . . . . . 1 [ ] Yes 2 [X] No

267 Are you claiming expenditures for SR&ED performed by people other than your employees? . . . . . . 1 [X] Yes 2 [ ] No

If you answered **yes** to line 267, complete lines 268 and 269.

268 Names of individuals or companies	269 BN
1 NAVIGANT CONSULTING LTD.	[redacted]

What evidence do you have to support your claim? (Check any that apply)
You do not need to submit these items with the claim. However, you are required to retain them in the event of a review.

270 1 [X] Project planning documents	276 1 [X] Progress reports, minutes of project meetings
271 1 [X] Records of resources allocated to the project, time sheets	277 1 [ ] Test protocols, test data, analysis of test results, conclusions
272 1 [ ] Design of experiments	278 1 [ ] Photographs and videos
273 1 [X] Project records, laboratory notebooks	279 1 [ ] Samples, prototypes, scrap or other artefacts
274 1 [ ] Design, system architecture and source code	280 1 [X] Contracts
275 1 [ ] Records of trial runs	281 1 [X] Others, specify 282 Invoices, emails, reports

Part 2 – Project information (continued)

Project number **6**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

P4: Improved Grid Solutions

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2010-03 (Year Month)	2017-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome?
(*Maximum 50 lines*)

The capability to deploy/implement a range of Smart Grid (SG) concepts/technologies across THESL's grid to transition it to one that has a fully intelligent infrastructure with: Compatible, durable and reliable equipment with built-in sensing and intelligent electronic devices for monitoring, fault diagnosis, and self-restoration; Fail-safe, robust, fast, high band-width, 2-way advanced communications from customers to the grid control centre; Centralized monitoring & control utilizing integrated databases for customer information, for asset records including their geographic locations, for the management of outages, for grid operations and for making physical changes to the grid infrastructure; Informed & intelligent operators & customers regarding electricity use and the assets for local generation, distribution & storage and initiatives to facilitate wise consumption for system-wide benefits; and unrestricted capability to accommodate, plug-in hybrid (PH) electric vehicles (EV), battery only EVs, distributed generation (DG), and energy storage devices. The obstacles faced in 2016 were:

-Meter-ready transformers failed tests leading to design changes. (In previous fiscal periods, outages from failures of pole top mounted units with ongoing TM were reviewed. However, in only one case had the unit been overloaded for a relatively long time prior to failure. TM data analytics work continued in FY16 to gain greater insight into transformer failures.

- Uncertainty of data analytics tools to extract and analyze information.

-The extent to which the benefits expected from the pilot field trial of PLMs were being realized. THESL wanted pilot implementation to lead to: (A) Better management of O/H assets and improved reliability, (B) Significant customer-minutes-out improvements by reporting outages to the control room (C) Reduction of momentary outages.

-Intelligent node implementation at Exhibition Place generation sites did not have telecommunications to meet utility grade cyber-security requirements or permit access and integration into utility SCADA system. In addition, significant technical challenges were encountered in implementing an intelligent node in the Strachan TS station. Using new secure routers and adapting THESL cellular private network for the purpose, secure communications were achieved. In addition, creative use of approved THESL intelligent electronic devices provided a means of installing the intelligent node at Strachan TS without having to modify the 13.8 kV buswork. Other uncertainties emerged in the course of development as a result of systematic challenges.

Part 2 – Project information (continued)

Project number **10**

CRA internal form identifier 060
Code 1501

Complete a separate Part 2 for each project claimed this year.

Section A – Project identification

200 Project title (and identification code if applicable)

P8: Distributed generation (DG) and Protection facilitation

202 Project start date	**204** Completion or expected completion date	**206** Field of science or technology code (See guide for list of codes)
2007-01 (Year Month)	2019-12 (Year Month)	2.02.01 Electrical and electronic engineering

Project claim history

208 1 [X] Continuation of a previously claimed project **210** 1 [ ] First claim for the project

218 Was any of the work done jointly or in collaboration with other businesses? . . . . 1 [ ] Yes 2 [X] No

If you answered **yes** to line 218, complete lines 220 and 221.

220 Names of the businesses	**221** BN
1	

Section B – Project descriptions

242 What scientific or technological uncertainties did you attempt to overcome?
(*Maximum 50 lines*)

For 2016, the uncertainties the project team had to address during the year were as follows:
(1) Developing and finalizing the standard for communication equipment that would maintain distribution system integrity and reliability and allow THESL to monitor/take appropriate corrective action during system contingencies;
(2) Continuing connection impact assessments (CIA) for all proposed DG projects to determine the suitability of connecting to the distribution system;
(3) Developing a forecast of near, medium and long term DG sites that will be connected to the THESL distribution system based on system technology, size and area of connection (station bus and feeder level);
(4) Identifying jurisdictions that operate a distribution system similar to THESL, which have implemented a centralized monitoring and control system for DG sites, and understanding how the similarities and differences could relate to the THESL distribution system;
(5) Identifying solutions that will allow for the integration of additional DG sites to the THESL distribution system (e.g. upgrading station protection systems and installing bus-tie reactors at transformer substations, installing remote communication equipment at DG sites for monitoring and control); and
(6) Developing and specifying a system tool that will enable power system simulation and which interfaces with Toronto Hydro's mapping system and enterprise systems to extract and build a network models for analyzing key parameters needed to assess system conditions.

Additional uncertainties that evolved over the course of development:
-Integrating a growing number and capacity of renewable energy and energy storage projects with the distribution grid
-Interconnecting large customer substations with rotating type generators and designs to improve interface and reliability with distributed generation
-Investigating and analyzing system disturbances impacting utility station protection systems and take corrective action to improve system reliability

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242?
(Summarize the systematic investigation or search) (*Maximum 100 lines*)

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

Ongoing in this fiscal period DG forecasting methods continued to be developed. To uphold the reliability/integrity of its distribution supply grid, analysis/simulation studies continued to be performed. Power system simulation and modeling studies had shown that distributed generation causes several challenges to the protection of distribution networks - development of a Gateway assessment tool continued with CYME.

The evolving practices and methodologies developed for DG would be tested on specific applications and would be subsequently modified and augmented to improve performance. New Conservation and Demand Management initiatives to reduce peak demand and energy were completed including projects such as the Campbell's Soup 3.8 MW combined heat and power generator, the Enwave 4MW steam generation and Humber Waste-Water Treatment Plant with 4.7MW biogas facility.

Large data centers and critical loads would be connected to the distribution grid with embedded generation. All data center activities considered complete toward the end of the fiscal period.

Protection and Control of Distribution Grid ongoing development continued - Investigated protection miscoordination and developed module with added flexibility to integrate large new customer capacity and load at Humber College.

Energy storage - Energy storage projects were developed to provide Toronto Hydro with strategic ancillary capabilities to address system efficiency, reliability and power quality, as well as Distributed Generation (DG) and Electric Vehicle (EV) enablement in targeted areas of the Toronto Hydro distribution system. By placing ancillary ESS strategically throughout the distribution system, localized issues can be addressed. This approach allows for a minor augmentation of the distribution system, rather than an expensive rebuild or major asset replacement. In this way, ESS deployments can be a creative and prudent approach to system risk mitigation. The Bulwer Battery Energy Storage System (BESS) project is a 2MW/8MWh and is located in the Downtown area of Toronto with ever increasing demands for electricity. The Community Energy Storage (CES) project includes a consortium partners eCAMION, Dow-Kokam, Toronto Hydro-Electric Systems Limited (THESL) and the University of Toronto with the first project installed at Roding Community Centre and the second installation at Toronto Hydro's Commissioners office is in progress and is slated for completion in 2017. Toronto Hydro is presently working with Green Power Labs Inc. on the deployment of Supervisory Predictive Control technology - The installation of a supervisory grid controller will provide real time analysis and control enabling the Battery Storage and Solar PV. Toronto Hydro, in collaboration with Ryerson University and eCAMION, successfully installed and commissioned the world's first grid-scale integrated pole mounted energy storage system (PMESS). Mounted on a Toronto Hydro pole in Toronto, Ontario, the unit employs lithium-ion batteries that charge during off-peak hours and discharge during peak hours. Toronto Hydro also initiated energy storage initiative with Metrolinx on the Eglinton Crosstown Transit for a 20MW/80MWh supply to power the traction power system. Technical specifications were developed to integrate the storage system with the Toronto Hydro feeder supplies from Runnymede TS and Bermondsey TS.

Ongoing:
Protection and coordination - models developed that enables analytic studies of the network to ensure adequacy of protection and loading capability.
Distribution Generation and Protection Methodologies - Developed the Generation Protection, Monitoring and Control program for the 2015-2019 forecast period -Future activities would include installing an advanced

244 What work did you perform **in the tax year** to overcome the scientific or technological uncertainties described in line 242? (Summarize the systematic investigation or search) (*Maximum 100 lines*)

protection systems at three stations with short-circuit capacity constraints; a bus-tie reactor at station bus tie to alleviate short-circuit capacity constraints; and a required monitoring and control systems at all DG facilities.

Network protectors: A revised criteria was developed to specifically address connecting DG onto network distribution system in order to avoid potential failure modes.

Arc Flash Studies: Labelling procedures developed to properly identify the arc flash level with the warning signs at the equipment.

We initiated the development of a power analysis tool for power systems simulation. CYME Gateway is an application that will be interfaced with Toronto Hydro's mapping system and enterprise systems in order to extract and build the network model as required to analyze loading, fault levels and assess Distributed Energy Resources connectivity with the distribution system.

246 What scientific or technological advancements did you achieve or attempt to achieve as a result of the work described in line 244? (*Maximum 50 lines*)

THESL system. DG sites 50kW and above were connected to THESL's Control Room using the utility wireless communication system and DG sites 500kW and above were connected using a private wired communication system. In both instances, THESL needed to know: (A) the nearest THESL network node in the area of the DG site, (B) For wireless: The signal strength in the area of the DG site, and (C) For wired: The shortest path to the network trunk line.

In addition to ensuring that THESL could enable DG sites in the near term (2016 - 2017), THESL began developing a technical plan to ensure it could connect the forecasted increase of DG sites for the medium and long term (2018 - 2025). The project teams focus was on (1) determining the technical roadblocks that would prevent THESL from connecting additional DG sites to the distribution system, (2) identifying solutions that can be implemented in the near term to meet the forecasted demand of generation connections, (3) identifying and quantifying the impact of the additional data coming into THESL existing Control Room systems from the additional DG sites, (4) identifying the necessary backend systems required to enable next-generation monitoring, forecasting, and control of DG sites, and (5) implementing the plan that will address DG connection issues as part of the 2015- 2019 Rate Application to the Ontario Energy Board (OEB).

Additional advancements realized over the course of development included:

Developing energy storage connection methodology:

- Developing technical requirement for the interconnection of Energy Storage Unit to help resolve localized system issues.
- Utilize CYME to create system study models for the connection impact on THESL's distribution system.

Developing Arc Flash hazard criteria and deployment approach:

- Existing arc flash hazard programs are suitable for Arc Flash Hazard (AFH) calculation in local or small distribution system.
- TH worked with CYME closely in developing the existing CYME AFH module to handle AFH calculation in large distribution system such as TH.

Developing System Protection methodology, analysis tools and criteria for modernizing station protection at TS and MS:

- Developed Protection Philosophy document to assist in the determination of feeder protection relay settings for Transformer and Municipal Stations.
- Numerous protection relay enhancements and supply station transformer replacements under way with feeder protection implications and settings required to be addressed.
- Protection Philosophy document prepared also serves as a technical guide

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 1:

Reference(s): **Exhibit 1B, Tab 3, Schedule 1**
Exhibit 1B, Tab 3, Schedule 1, Appendix A

<u>Preamble:</u>

THESL engaged Innovative Research Group (**Innovative**) to carry out the utility's planning-specific customer engagement. Innovative carried out two phases of work. Phase I sought to provide THESL with input on customer needs and preferences and Innovative conducted exploratory focus groups, a representative low-volume customer survey, and a survey of "key account" customers. Phase II sought to engage customers in order to align THESL's 2020 CIR DSP and operational programs with customer expectations.

a) Please provide a copy of all written instructions provided by THESL to Innovative in relation to Innovative's customer engagement mandate for the 2020 CIR Application and the report provided in Exhibit 1B, Tab 3, Schedule 1, Appendix A.

b) Innovative hosted focus groups for residential (December 5 and 6, 2016), small business (December 5 and 6, 2016), mid-market (February 28 and March 1, 2017), and stakeholders (June 12-30, 2017). Please describe all measures undertaken by THESL and Innovative to invite and ensure the participation of EV stakeholders and other distributed energy resource (**DER**) customers (including EV drivers, owners of DERs, EV associations, and DER industry associations) in the focus groups. In addition, please provide any and all notes from the focus groups relating to EVs/DERs that are supplementary to the reports provided in Appendix 1 to Exhibit

1B, Tab 3, Schedule 1, Appendix A.

c) Innovative conducted low-volume telephone surveys of residential and small business customers between December 7 and 14, 2016. Innovative also conducted an online survey of large use customers between February 23 and March 24, 2017. Please identify and list, in chart format, any and all questions used related to, and responses received pertaining to, EVs, batteries, EV charging, energy storage, and DERs generally.

RESPONSE:

a) Please see Toronto Hydro's response to interrogatory 1B-CCC-24 for the RFP and 1B-CCC-8 for the associated Retainer that established Innovative's mandate pursuant to which the customer engagement work was performed.

b) Residential, small business, and mid-market focus group participants were randomly recruited from complete Toronto Hydro customer lists. Therefore, each customer in these rate classes had an equally random opportunity of being contacted to participate in the groups. Toronto Hydro does not have a registry of all its customers who own EVs or DERs with which to target invitations, or to know if those who did participate were EV or DER owners.

There are no additional notes from the focus groups relating to EVs/DERs that are supplementary to the reports provided in Appendix 1 to Exhibit 1B, Tab 3, Schedule 1, Appendix A.

c) These dates correspond with Phase I of Toronto Hydro's Planning-specific Customer Engagement. During Phase I, no specific questions were asked of customers pertaining to EVs, batteries, EV charging, energy storage, or DERs generally. The objective of Phase I was to attain input on customer needs and preferences at the start of the planning process. At that time, the OEB had just released the Handbook for Utility Rate Applications with a clear focus on outcomes. Toronto Hydro's existing work had explored needs and a wide variety of trade-offs but had not explicitly addressed outcomes. Phase I focused on filling that gap by developing a list of outcomes important to customers and then establishing customer priorities among those outcomes.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 4:

Reference(s): Exhibit 1B, Tab 4, Schedule 1

Preamble:

THESL states that it's rate framework is comprehensive, covers the entirety of the application's term, and is informed by THESL's forecasts. Distribution rates in years 2 through 5 are adjusted annually by a Custom Price Cap Index (**CPCI**), as follows:

$$\mathbf{CPCI = I - X + C - g}$$

Where,

- "I" is the OEB's inflation factor, determined annually;
- "X" is the sum of"
    - The OEB's productivity factor, as of the date of filing; and
    - THESL's custom stretch factor;
- "C" provides funds incremental to "I – X" that are necessary to reconcile THESL's capital need within a PCI framework;
- "g" captures revenue growth occurring due to customer and/or load charges over the forecast period, based on THESL's forecast of loads and customers for the 2021-2024 period.

a) Please outline THESL's assumptions in the "C" term of the above CPCI equation regarding capacity, change of load, and leveraging due to EVs and other DERs in each of the years of the CIR.

b) Please outline THESL's assumptions in the "g" term of the above CPCI equation regarding capacity, change of load, and leveraging of EVs and other DERs in each of the years due to the CIR.

c) Please indicate whether THESL intends to include EV charging infrastructure as an eligible "C" term expense, and, if so, how? If not, how will it fit in the CPCI formula or otherwise be treated for rate-making purposes.

d) How were each of DERs, EVs, and EV charging infrastructure treated for the purpose of setting the "I" factor that at which THESL arrived. Please provide all related working papers.

RESPONSE:

a) Please see Exhibit 1B, Tab 4, Schedule 1, section 3.3. The ”C” factor in Toronto Hydro’s proposed CPCI is derived from the utility’s rates-funded capital spending as outlined in the Distribution System Plan (“DSP”). To the extent that these capital investments are considered to be DERs, they directly affect the C-Factor. One example of this is Energy Storage Systems Program in Exhibit 2B, Section E7.2.

EVs and other DERs may also indirectly affect the C-Factor. Toronto Hydro builds its infrastructure to meet its legal obligations (e.g. access to the grid) and the needs of the customers it serves (e.g. safety, reliability). Where capital spending is required to achieve these results for customers with EVs or DERs, Toronto Hydro makes those investments. Those investments affect the C-Factor.

b) As detailed in Exhibit 1B, Tab 4, Schedule 1, section 3.4, the "g" term in the proposed CPCI is derived based on the forecast of loads and customers over the 2021-2024 period. The load and customer forecast, which is detailed in Exhibit 3, Tab 1, Schedule 1, Section 3.2 does not include any specific additional loads associated with EVs or DERs due to uncertainty about the future, as noted in that evidence. However, the forecasting methodology will capture any historical load growth due to EV or DER in the load models.

c) Toronto Hydro has not incorporated any EV charging infrastructure in its Distribution System Plan, and therefore there is no component in the "C" factor. If in the future, Toronto Hydro seeks to recover costs in rate base related to EV charging infrastructure, Toronto Hydro will assess at the time the most appropriate mechanism to apply to recover these costs in rates.

d) As detailed in Exhibit 1B, Tab 4, Schedule 1, section 3.1, the "I" term in the CPCI is provided by the OEB, and reflects historical price increases based on a 30/70 weighting of labour and non-labour sub-indices provided by Statistics Canada. EVs, EV charging and DERs are not explicitly included in the value of I. However, to the extent that the Statistics Canada price indices used reflect any pricing for these services, they may be included implicitly.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 10:

Reference(s): **Exhibit 2B, Section E7.4**
Exhibit 3, Tab 1, Schedule 1, p. 10

Preamble:

THESL notes that impacts of EVs and distributed generation on overall loads and demands on the system have not been determined to be material. THESL states that it does not have enough information about these markets to be able to confidently include any impacts on loads or demands and there has been no explicit incorporation of the potential load impacts in\to the load forecast, other than trends that would be part of measured loads to date, and would be captured in the multivariate regression models.

THESL's Stations Expansion program addresses medium- to long-term system capacity needs. One of the segments of the program will expand the capacity of the Copeland TS located in Toronto's financial district, providing additional capacity of 144 MVA. The importance of the Copeland TS expansion is framed in the context of THESL's load forecasting for the area. However, THESL notes that the impact of EV deployment has not been accounted for in its forecast.

Further, THESL states that, following the release of the LTEP in the fall of 2017, THESL is working with regional planning stakeholders to develop a 25 year load forecast that includes an assessment of different EV deployment scenarios. Large-scale EV deployment may increase the peak load demand at certain stations, thus triggering the need for additional capacity.

a) Please provide the 25 year load forecast that includes an assessment of different EV deployment scenarios referenced at Exhibit 2B, Section E7.4, page 10. Please provide any and all EV-related data that THESL relied upon in support of the conclusions above and the load forecast. If the load forecast is not available, please provide an update as to its status and its expected date of completion.

b) Please provide, in the chart format below, an assessment of the impacts on loads and demands — including the load forecast for the 2020-2024 period — of your estimate of EVs and distributed generation in each of the years of the CIR and any supporting references.

	2020	2021	2022	2023	2024
EVs (number, kWh)					
EV infrastructure (number, kWh)					
DERs (number, type, kWh)					
etc.					

c) In the recently released *Made-in-Ontario Environment Plan* (the **Environment Plan**; see Attachment 1), the Ministry of Environment, Conservation and Parks estimates that 16% of targeted greenhouse gas emissions reductions will come from low carbon vehicles (i.e., primarily EV adoption. Please indicate:

i) whether THESL's assumptions regarding EVs are consistent with this;

ii) if not, what were THESL's assumptions;

iii) whether THESL has reconsidered the impact of EV adoption on load forecasts in light of the Environment Plan;

iv) whether THESL will update its EV assumptions in light of the Environment Plan;

v) what are the estimated total capital expenditures and operating expenditures regarding EV charging infrastructure that THESL has included in the application and for each year;

vi) what capital expenditure and operating expenditure funding (federal, provincial, or otherwise) is available to THESL specific to EVs and DERs.

d) Please explain whether THESL's load forecasts are consistent with and take into account EV adoption rates expected under the Environment Plan.

RESPONSE:

a) As set out in Exhibit 2B, Section B2.1, the planning process that produces the load forecast referred to in Exhibit 2B, Section E7.4 is ongoing and expected to conclude in the fall of 2019.

b) The forecasted generation connections in number and capacity for the period 2020-2024 can be found in Table 6 and Table 7 in Exhibit 2B, Section E5.1.

With respect to EVs, please refer to Toronto Hydro's response to interrogatory 1C-DRC-6.

c)

i) The Government's Environment Plan does not include an EV adoption forecast for the City of Toronto.

ii) Please see Toronto Hydro's response to part (a) with respect to regional planning. Please refer to Toronto Hydro's response to interrogatory 1C-DRC-6 with respect to more localized planning.

iii) Please see Toronto Hydro's response to part (c)(i).

iv) Please see Toronto Hydro's response to part (c)(i).

v) Please refer to Toronto Hydro's response to interrogatory 1C-EP-16 (c).

vi) As a distributor, Toronto Hydro is eligible to apply for a host of different federal, provincial, and other funding programs related to EVs. For example, Toronto Hydro received funding through the Workplace Electric Vehicle Charging Incentive Program through the Ministry of Transportation. With respect to DERs, Toronto Hydro is able to recover costs in accordance with O.Reg. 330/09 – Provincial Rate Protection.

d) Please see Toronto Hydro's response to part (c)(i).

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

UNDERTAKING NO. JTC4.23:

Reference(s): **2B-DRC-10(b)**
Exhibit 2B, Section E5.5., p. 10, line 13

To explain the relationship between the 800 megawatt number, the 225 megawatt number, and the 581 megawatt number, all of which are in Exhibit 2B at various places.

RESPONSE:

As of the end of 2017, Toronto Hydro had connected roughly 225.7 MW of distributed generation to its system. Based on its forecasts, Toronto Hydro anticipates an additional 581 MW of distributed generation to be connected to the grid over the 2018-2024 period, resulting in a total of 807 MW by the end of 2024. Please see Exhibit 2B, Section E.5.1, pages 9 to 13 for more details.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0165**	**Toronto Hydro Electric System Limited**

VOLUME: **Technical Conference**

DATE: **February 22, 2019**

position, you are not seeking approval of the specific measures?

MR. HIGGINS: Yes, it is.

MS. GRICE: Okay, thank you. Those are my questions, thank you.

MR. MILLAR: Thank you, Ms. Grice. Mr. McGillivray, are you prepared to go?

EXAMINATION BY MR. MCGILLIVRAY:

MR. McGILLIVRAY: Thank you, Mr. Millar. Good afternoon, panel. If I could take you to interrogatory 2B DRC 10, and maybe we can skip down to the question under part B.

And then this will probably lead us to somewhere in the evidence, but in part B you make reference, I think, to Exhibit 2B, section E8.1. So we may have to go there, and then there will be a few references here, which hopefully will become clear in a second.

So on page 8, line 20 there's reference made to the 800 megawatts by end of 2024. Do you see that?

MR. SEAL: I do.

MR. McGILLIVRAY: So it says:

> "The forecasted increase of distributed generation connections is expected to reach 800 megawatts by the end of 2024."

And then if we go down to page 12, roughly lines 5 through 8, that figure is repeated. And the evidence also states that Toronto Hydro has connected over 1,780 distributed generators of various sizes representing

approximately 225 megawatts; do you see that?
MR. SEAL: Yes, I do.
MR. McGILLIVRAY: And then if I can take you to Exhibit 2B, section E5.5, page 10, line 13. It says that there's forecasted 581 megawatts of additional distributed generation capacity anticipated by the year 2024. And I think that additional could also read incremental, but do you see that?
MR. SEAL: I see the reference.
MR. McGILLIVRAY: And then the actual forecasts are provided in section E5.1. We don't have to go there. My question basically is I am wondering if you can explain how this works a little bit, where are we now and where are we going, basically, and whether or not you can do the math for me between the 800 megawatt number and the 225 megawatt number.
MR. SEAL: I won't be able to help you with this particular exhibit, because I am not familiar with this particular piece of evidence, so I can't lead you between those.
MR. McGILLIVRAY: Okay. Could that be accomplished by way of undertaking? Because I think I have exhausted my panels at this point. And this interrogatory was under panel 3.
MR. SEAL: I can certainly speak to my load forecast, but not these particular numbers in this particular evidence.
MR. STERNBERG: We can respond by way of undertaking.

MR. McGILLIVRAY: Okay. I appreciate that. Thanks. And maybe we could -- well, you can see if you want to include these in the undertaking as well. My follow-up question was in relation to whether I would be right to say that the distributed generation forecast pertains to generation only and doesn't have any bearing on load or load forecasting, or maybe that could be answered by this panel?

MR. SEAL: Well, that would certainly be one of my considerations in doing my load forecast which I am doing for rate purposes, for billing purposes, as to whether any of this distributed generation would actually impact that load that I am using to set rates on or not. I would need to consider that exactly.

MR. McGILLIVRAY: Okay. And you haven't considered it to date, but you would?

MR. SEAL: To the extent that there was something, I had some information that led me to believe that there might be an impact on our load forecast I would. And I think in our evidence, in my evidence, and I will turn you to it, Exhibit 3, tab 1, schedule 1, page 10, so section 3.2 talks about electric vehicles and distributed generation and indicates it in my load forecast we haven't explicitly included any impacts other than trends that would have been part of historical data that we use in our multi-variant regression models.

MR. McGILLIVRAY: That's great, and I was actually going to go there next, so we can go there now. I think my question on that point that you just made was could you help me understand what potential load impacts from electric vehicles and distributed generation might already be reflected because of that multi-variant regression model, what kinds of things relating to distributed generation or -- and/or electric vehicles get captured in that model?

MR. SEAL: So our regression models use historical measured consumption as the basis for modelling against our various variables that drive that measured load. And so to the extent that there are any electric vehicles in our historical data or distributed energy that are impacting the measured loads, that would be captured within those models.

MR. McGILLIVRAY: Just like any other aspect of load, I guess?

MR. SEAL: Correct.

MR. McGILLIVRAY: Okay.

MR. MILLAR: Mr. McGillivray, I am sorry to interrupt. There had been an offer of an undertaking which we didn't mark, but I don't know if the question has been otherwise answered, so do you still require the undertaking?

MR. McGILLIVRAY: I think the first part would still be helpful to do by way of undertaking, so --

MR. MILLAR: And could you just repeat what that is so it's clear for the record?

MR. McGILLIVRAY: It's basically to explain the relationship between the 800 megawatt number, the 225 megawatt number, and the 581 megawatt number, all of which are in Exhibit 2B at various places, and I think the transcript will reflect where they are.

MR. McGILLIVRAY: Thank you.

MR. MILLAR: JTC4.23.

UNDERTAKING NO. JTC4.23: TO EXPLAIN THE RELATIONSHIP BETWEEN THE 800 MEGAWATT NUMBER, THE 225 MEGAWATT NUMBER, AND THE 581 MEGAWATT NUMBER, ALL OF WHICH ARE IN EXHIBIT 2B AT VARIOUS PLACES.

MR. McGILLIVRAY: Thank you. So in that reference that you just referred me to in section 3.2 around page 10 or 11, you indicated in a few places, I think, that the impacts are -- of electric vehicles and distributed generation may not be material or have determined not to be material and that you don't have enough information about those markets to be able to confidently include any impacts. And my question would be, would you be able to elaborate on what additional data or information you believe you might need in order to be able to confidently include those kinds of impacts on loads and demands?

MR. SEAL: So generally, in developing our load forecasts, as I said, we rely on our regression modelling to determine the forecasts. The regression modelling takes into account various economic drivers, various climate drivers, various other drivers of what would be explaining loads, and then uses forecasts of those to predict the consumption of the various -- of the different rate classes. So to the extent that -- generally, those models have a degree of variants within them, so they are a best estimate is what they are, but we recognize they are not going to be perfect.

To the extent that I would consider adjusting those models, I would -- I would need some confident forecasts that -- of loads that would be outside of what those models would be.

So I would want to have -- and especially for the purpose of developing the load forecast for rate-making treatment, which is what this is, I would want to have a high degree of confidence in the forecasts of those particular components, preferably with some kind of knowledge about where they have been historically.

Maybe one of the best examples of where I might make an adjustment to what my model forecast load would be, if I knew a particular large customer was going to be closing down business, I would probably reflect that in my load forecast for the large user class because I knew it was coming and I knew what kinds of loads were involved in it.

Those are the kinds of certainty and confidence that I would want before I would include anything in my load forecast beyond what my models are predicting.

MR. McGILLIVRAY: Thank you. So for, let's say electric vehicles, would that be things like the number of them out there, the type, the kilowatt hours, that sort of thing, or does it go beyond that?

MR. SEAL: I think it would go beyond that. It's not just numbers and kilowatts, it's somebody takes a usage by vehicle, but some confidence that the forecasted number of vehicles has some basis -- sound basis for it. And as I said, when we put together our forecast we didn't have that information to be able to include anything.

MR. McGILLIVRAY: Do you believe that information's out there but not collected or is it simply not available yet?

MR. SEAL: In my view, the electric vehicle industry is still in its infancy, and as I am sure you're aware, the climate is changing around some of those electric vehicle policies in Ontario. So, you know, I think that there's not enough information out there right now to confidently include anything in my load forecast.

MR. McGILLIVRAY: Okay, thank you. If I could take you to interrogatory 2B DRC 10; we have may have been there. I am now going to look at part A of that, the response to part A where it says Toronto Hydro is working -- oh, sorry. Could you scroll up to the questions?

Yes, I think part A is the right reference. Toronto Hydro is working with regional planning stakeholders to develop a 25-year load forecast that includes an assessment of different EV deployment scenarios. And this might be an in an exhibit that you can't speak to, but it's in, I think, Exhibit 2B, section E 7.4. And we don't have to go there, but there it says large scale EV deployment may increase the peak load demand at certain stations, thus triggering the need for additional capacity.

So I think maybe you can discuss the relationship between this sort of forecast, which I recognize is ongoing, and the ultimate load forecast for rate purposes that is developed and whether there is connection between this specific regional planning sort of level of 25-year load forecast and the load forecast for rates.

MR. SEAL: So I think you alluded to it in your question. I think the this particular exhibit, and the regional planning tends to be about peak demand -- peak demands on the system, peak demands on stations, peak demands on delivery points -- which is different than the load forecast that I am producing, which is all about billing units.

You know, one good example might be the difference -- the impact of electric vehicles on electric usage for the residential class. The residential class, starting in 2020, the distribution rates are fully fixed. So any electric vehicle usage behind the residential meter doesn't matter for the purposes of setting distribution rates. So there can be very different for different purposes.

MR. McGILLIVRAY: Okay, and just to confirm on this, this large scale peak load demand, I guess forecasting exercise going out 25 years, can you confirm that there are no interim reports or working papers in relation to this process?

MR. SEAL: I am not familiar -- I am not aware of what's going on with this regional plan.

MR. McGILLIVRAY: Could you undertake to provide an update on the status of it? I understand it's ongoing until fall 2019.

MR. STERNBERG: Yes, I'm pausing for a couple reasons, trying to understand what the specific request is first.

I am not sure what's being requested by way of update. Perhaps you can clarify that, and we might be able to take that away.

MR. McGILLIVRAY: Sure. I think there is an effort that's ongoing in respect of this 25-year load forecast including -- which includes an assessment of different EV deployment scenarios, and that goes back to the Exhibit 2B section E7.4 reference, page 10, lines 9 to 10. And I think in part A to interrogatory response 2B-DRC-10, Toronto Hydro indicated that the process is ongoing and expected to conclude in fall 2019, I think it says.

So my question would be what is the status of that and if there are any interim reports or working papers in relation to it, could they be produced.

MR. STERNBERG: We can certainly undertake to provide an update on the status of where that's at. I don't know whether there are documents or not. So in respect of the document request part, we will make an inquiry if there are any such documents and if so, consider them and whether they are probative. But we can certainly provide an update on the status.

MR. McGILLIVRAY: Great.

MR. MILLAR: JTC4.24.

UNDERTAKING NO. JTC4.24: TO PROVIDE A STATUS UPDATE TO THE 25-YEAR LOAD FORECAST INCLUDING ASSESSMENT OF

EV DEPLOYMENT SCNEARIOS; TO PROVIDE ANY RELATED REPORTS OR WORKING PAPERS, IF RELEVANT

MR. McGILLIVRAY: Thank you, those are my questions.

MR. MILLAR: Thank you, Mr. McGillivray. Dwayne, was that you just joining us?

MR. QUINN: Yes, it is, Michael.

MR. MILLAR: Very good timing on your behalf. You're up. Just to let you know, I think Bill may have actually asked some of your questions. But I think you were in another engagement so you didn't hear. So it's possible some of the responses you get may be to see what they said to Bill. But why don't you ask your questions, and we will see where we get.

EXAMINATION BY MR. QUINN:

MR. QUINN: Okay, thank you. I don't want to take people's time, so will just do this quickly. Was there an undertaking taken for Bill's inquiry?

MR. MILLAR: Yeah. Bill doesn't actually have your questions, and my notes on the undertakings are little more than the numbers, so I am not sure. You can review the transcript. But I suggest you just ask your questions and if they say they've already answered it, you'll know.

MR. QUINN: Okay, I will be quick then. So if I could ask Exhibit B -- sorry 1B, tab 5, schedule 1, page 5; if you can turn that up and let me know when you have it.

MR. SEAL: We see that.

MR. QUINN: Okay. So I am reading from that page, and it says: