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 1

DISTRIBUTED RESOURCE COALITION

July 2, 2019

TAB 1

TransformTO

City of Toronto

Electric Mobility Strategy Framework

July 2018

TORONTO

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City of Toronto Electric Mobility Strategy Framework

Framework purpose

The following Electric Mobility Strategy Framework can be understood as a roadmap toward the specific actions that Toronto will take to capture emissions reductions potential through the electrification of mobility. This framework serves as a guideline for the development of the forthcoming Electric Mobility Strategy, which will describe specific actions that the City can take to enable e-mobility and maximize the co-benefits identified by TransformTO.

TransformTO Guiding Principles

Based on the results of public engagement and a review of best practices, TransformTO identified the following principles to guide the development of its Short-term Strategies. Adhering to these principles helps to tie climate change mitigation efforts to other social benefits such as poverty reduction, and ensures that emission reduction efforts do not create unanticipated negative or disproportionate impacts for any of Toronto's residents or sectors. While presented here as a list, all of the Guiding Principles overlap and intersect to create the "big picture" of a transformed and resilient Toronto.

- Advance social equity
    - Improve affordability, particularly for vulnerable populations
    - Protect low-income residents
    - Contribute to poverty reduction
- Enhance and strengthen the local economy
- Maintain and create good quality local jobs
- Improve public health
- Create resilient communities and infrastructure

Electric Mobility Vision:

By 2050, GHG (greenhouse gas) emissions from the transportation sector will be reduced by 3,000 kt. The City of Toronto's Electric Mobility Strategy will guide this transformation by facilitating electric mobility alongside transit and active transportation transitions and establish Toronto as a global leader in clean transportation.

Electric Mobility Strategy Goals:

- To enable the city to achieve its GHG reduction potential through the electrification of transportation, as identified in Transform TO's Low-Carbon Scenario Model.
- To convert passenger, freight and transit vehicles from gasoline to electric or low-carbon renewable fuels, which would amount to near elimination of diesel and gasoline by 2050.
- In partnership with our local utilities, City divisions, and external stakeholders, ensure the City is well prepared and positioned to realize the benefits and address the challenges and risks associated with the electrification of transportation.

- To maximize the co-benefits associated with the electrification of transportation, including, the reduction of air pollutants that affect Toronto residents, as well as the strengthening of the local economy.
- To support and foster mutually beneficial collaborations between the City of Toronto and local innovators and entrepreneurs to catalyze equitable, low-carbon mobility.

Objectives:

City organization facing objectives:

- To understand and **address the barriers** for the anticipated adoption of EVs in the City of Toronto, with the aim of supporting the conversion of the city's vehicle stock.
- To establish a robust network of **EV charging infrastructure** that supports the City of Toronto's targets for the conversion of the City's vehicle stock and advances Transform TO's guiding principles.

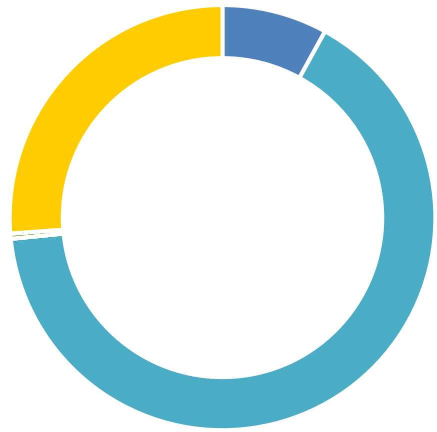
Public Facing Objectives:

- To identify the right mix of **policy and regulatory** signals to support the anticipated adoption of EVs for the city's transition to a low-carbon transportation system.
- To improve **access** to, and **affordability** of electric transportation options, including public transit, cycling and shared-use vehicle options, with a particular emphasis on the needs of vulnerable and underserved communities.
- To ensure that the implementation of the City of Toronto's EV Strategy results in an enhanced and **stronger local economy**.
- To ensure **alignment** with complementary City of Toronto low-carbon transportation system strategies and priorities for people and goods movement.
- To catalyze and support **local innovation** on electric mobility and other green transportation options, creating clean economic opportunities for Toronto.
- To create a **flexible and adaptive** Strategy that can be molded to align with future technologies, such as autonomous vehicles.
- To take a **multi-stakeholder** approach, identifying opportunities for collaboration and co-creation with stakeholders and the public.

TTO's Low-Carbon Scenario Model

As part of TransformTO, the City modelled one potential pathway to a low carbon future. In that model we found that the electrification of transportation could achieve 3,000 kt in annual GHG emissions by 2050. The potential reductions by vehicle category was:

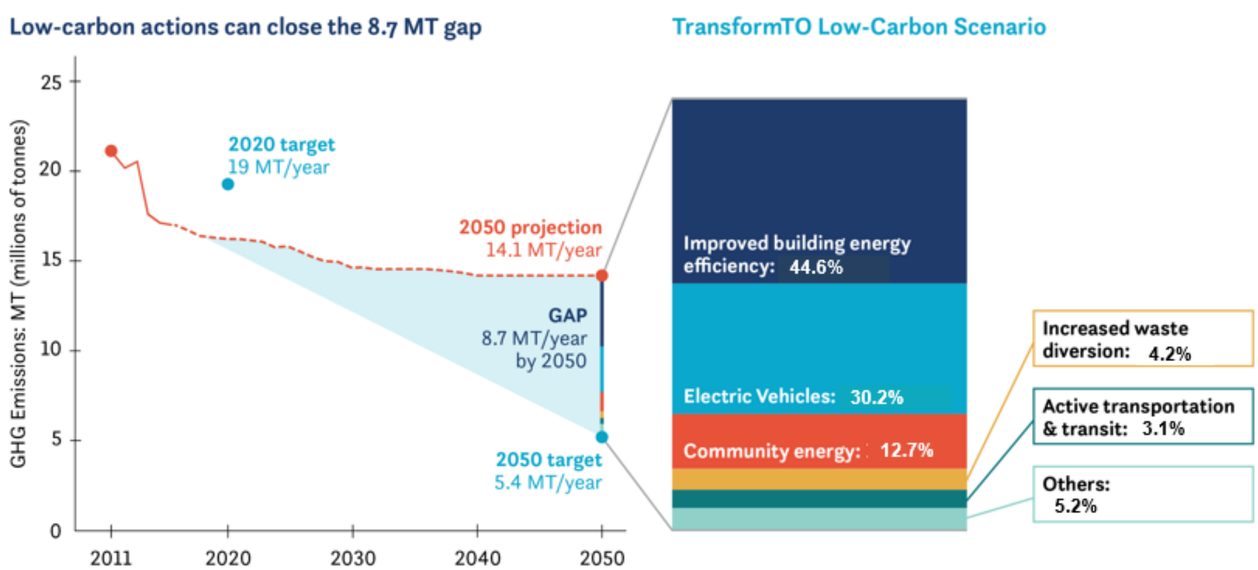
Reductions by category



- All electric buses by 2040 (239 kt - **8%**)
- All new personal and light duty vehicles are electric by 2030 (1,945 kt – **65.4%)**
- All city-owned vehicles are electric by 2042 (12 kt – **0.4%)**
- Zero emission vehicles for freight (780 kt – **26.2%**)

Transit and active transportation infrastructure expansion has an annual GHG potential reduction of 150 kt in 2050, described as follow:

- Build 25 lines of rapid transit across Toronto by 2050, including the Relief Line, Regional Express Rail including stops at Richmond Hill and Milton (CP freight line), and the development of a express bus network across the city.
- Reach 800,000 residents with personal transportation planning efforts
- Support active transportation for 75% trips less than 5 km through significant active transportation infrastructure investment.



A Foundation to Build Upon

City divisions, agencies and corporations are already working towards electrification of transportation in a number of ways. The EV Strategy will build upon and coordinate with these initiatives, which include:

- Downtown On-street EV Charge Station Pilot (Transportation Services & Toronto Hydro)
    - Includes the deployment of up to five Electric Vehicle Charge Stations at three public on-street downtown locations.
- Residential On-street EV Charge Station Pilot (Transportation Services & Toronto Hydro)
    - Installation of Electric Vehicle Charge Stations in two locations in each of Wards 19, 30 and 32, for up to 12 EVs, and at one location opposite Toronto Hydro's facilities at 500 Commissioners St (Ward 30) to serve 2 EVs.
- Potential installation of EVSE in several Toronto Parking Authority garages (Toronto Parking Authority - TPA & Toronto Hydro).
- Green Fleet Plan (Fleet Services)
    - Focuses on reducing emissions from nearly 10,000 on-and off- road vehicles and equipment owned and operated by the City. Initiatives undertaken in 2016 are expected to reduce over 5,650 cumulative tonnes of greenhouse gas emissions. The City recently received funding through the Provincial Municipal Challenge Fund that will support the transition of up to 220 vehicles to electric or plug-in electric systems.
- Green Bus Technology Plan (TTC)
    - TTC has endorsed the electrification of buses through procurement of only zero-emissions buses, starting in 2025 in line with the C40 Fossil Fuel Free Streets Declaration and a zero-emissions fleet by 2040. In 2019, with support of Federal and Provincial funding, the TTC will put 30 electric buses on the road and potentially 30 more by 2020.
- Toronto Hydro is in the process of finalizing their Electric Vehicle Strategy.

Areas of Alignment

The following are initiatives currently underway and addressed through other City strategies. The Electric Vehicle Strategy process will explore areas of intersection between the strategy and these initiatives, identify areas of improvement, and align with the goals that have already been developed by these initiatives.

Issue	Lead
Electrification and expansion of public transit	Toronto Transit Commission (TTC) – Green Bus Technology Plan; Ridership Growth Strategy
Expansion of active transportation infrastructure	City Planning – Official Plan Transportation Services – Cycling and Pedestrian Plans; Vision Zero strategy
Electrification of the City's fleet	Fleet Services – Green Fleet Plan
Electrification of goods and freight movement vehicles	Transportation Services – Goods Movement Strategy
Fuel standards	Federal Government City of Toronto already advocating for improvements
Fossil fuel pricing	Provincial Government City of Toronto already advocating for improvements
Hydrogen vehicles	Not captured in the Electric Mobility Strategy, but could be explored in TransformTO more broadly

Areas of Opportunity
In addition to the independent exploration of these opportunities, consideration of their interaction should be central to the evaluation of their potential effectiveness and impact.

1. **<u>Availability of Charging Infrastructure</u>**
   A proven enabler of EV adoption rates on a local scale. Increasing the availability of charging infrastructure is a key piece to be addressed by the strategy.
   Concerted action with Toronto Hydro, Ontario Power Generation (OPG), other levels of government and the private sector are crucial to increase charging capabilities in MURBs, residential areas that rely on on-street parking permits, in the workplaces, along major corridors on outskirts, underserved and vulnerable communities, parking facilities and public places.
   Potential actions to explore include new and enhanced EV-ready requirements for new construction, the development of policies and procedures that enable publically accessible EV charging infrastructure and ensure that charging infrastructure is made available strategically to address the mobility needs of all segments of the population, with a particular emphasis on vulnerable and underserved communities.

2. **<u>Policies and Regulations</u>**
   Identification and assessment of barriers and policy priorities, to ensure an appropriate mix of policy and regulatory signals that offer long-term certainty for the electrification of transportation.
   In addition to national and international best practices, consideration of lessons learned from existing City of Toronto initiatives will inform decision making in this area of opportunity.

3. **<u>Financial & Non-Financial Incentives</u>**
   Explore adoption of upstream and downstream and financial and non-financial incentives. Understand the potential impact of these mechanism in combination with other tools being explored, to offer a more integral approach. E.g. downstream financial incentives and policy directed at vehicles need to be considered and assessed in the context of those focused on charging infrastructure.

4. **<u>Research, Community Awareness & Behaviour change</u>**
   The strategy will consider and integrate the support of innovation and large scale EV adoption through community engagement, leveraging action from other levels of government & key stakeholders.
   Action will be supported by a clear understanding of the socio-economic factors that play a role in successful EV uptake, in order to guarantee that the City of Toronto's EV solutions will meet the mobility needs of the community, with a particular emphasis on underserved and vulnerable populations.

5. **<u>Understanding and Developing the EV Industry, Workforce and Training</u>**
   Creating an economic sector conducive to the transition from gasoline- and diesel-powered vehicles towards EV requires the development of the EV industry, with particular emphasis on job creation, workforce transition and local business development.

Acknowledgments

The City of Toronto Electric Mobility Strategy Framework is the result of a collaboration between the Environment and Energy Division (EED), the Electric Vehicle Work Group (EVWG) and feedback from an external stakeholder group. The City of Toronto thanks all of those who provided their time and expertise to develop the Strategy Framework which will be used as a guide for the development of the City of Toronto Electric Mobility Strategy.

Electric Vehicle Work Group (EVWG)

City Planning
Economic Development & Culture
Environment and Energy Division
Exhibition Place
Facilities Management Division
Fleet Services
Ministry of Economic Development and Trade
Ministry of Transportation
Parks, Forestry and Recreation
The Atmospheric Fund (TAF)
Toronto District School Board (TDSB)
Toronto Hydro
Toronto Parking Authority (TPA)
Toronto Transit Commission (TTC)
Toronto Zoo
Transportation Services (TS)
Waterfront Toronto

External Stakeholders Group

Electric Vehicle owners
Non-profit organizations
Academic experts

TAB 2

TTC Green Initiatives

While the TTC continues to modernize our service, introducing additional green initiatives are essential in the process. We have set goals to attain a zero emissions bus fleet that will continue to deliver safe and reliable service.

Hybrid buses and eBuses

The TTC's fleet by the end of 2019 will be comprised of 3 different propulsion technologies that would include clean diesel, hybrid electric and battery electric. The TTC wants to ensure that we move forward with the best vehicle model for our customers, the people of Toronto. This is part of our commitment to be 50% zero emissions by 2028-2032 and 100% zero emissions by 2040. This is just one way we are modernizing our service, innovating for the long term and planning for climate change. We will continue to deliver safe, reliable service to our customers with the new, more environmentally friendly fleet.

Fun fact! One bus at full capacity takes the place of 70 single occupancy cars. The clean-diesel bus produces less than 1/10 the emissions per passenger than a personal vehicle.

Electric Bus

Hide All

ElectricBus

The eBuses operate on truly green technology with the potential for zero emission. Zero emission buses have no tailpipe emissions, and in Ontario, generation of electricity for overnight charging is 100% nuclear and completely free of GHG emissions. The TTC will have 60 eBuses delivered by the end of 2019. The TTC will have one of the largest mini-fleets of electric buses in North America and this green initiative is part of the TTC's commitment to be 50% zero emissions by 2028-2032 and 100% zero emissions by 2040.

While the eBuses should be capable of 200km or more on one charge, they will be deployed initially on routes that are 75km or less. With time and confidence, they will be deployed on longer and longer routes. On Monday, June 3 the first bus will service the 35 Jane route, headed southbound.

Fun fact! During long-term hydro power outages, or in the event of an emergency, there is potential for these buses to serve as mobile power plants. A bus with a 440,000-watt battery on board can be plugged into a building, such as an emergency response center or hospital, to provide electricity.

Hybrid Bus

HybridBus

The hybrid buses incorporate series technology and run off power generated on-board. As opposed to an electric bus that is plugged in to charge, our hybrid buses use on-board generators that are powered by diesel engines.

Though these vehicles are still using fuel to produce energy, they use a lot less than the average vehicle. Hybrid buses also incorporate the recovery of braking energy, meaning that energy produced when descending a hill or during braking is fed back to the energy storage system to reuse for propulsion, resulting in approximately 25% fuel reduction and in turn, reduced tailpipe emissions. The TTC plans to have 55 hybrid buses delivered by the end of 2018 and 200 more hybrid buses delivered by the end of 2019.

Green and Cool Roofs

TTC Green

Green and Cool Roofs

- Downsview Park Station features sweeping lush vegetated green roofs at both the east and west entrance buildings.
- Finch West Station's design includes a cool roof over the main entrance and a green roof over the elevated substation box.
- York University and Highway 407 Stations feature metal cool roofs that have a high solar reflectance and absorb little heat.
- Pioneer Village Station includes cool roofs over the entrance buildings and green roofs over the TTC bus terminal and substation.
- Vaughan Metropolitan Centre station features a cool roof on the main entrance and a green roof on the south side of Highway 7 on the electrical substation.
- Leslie Barns' one-of-a-kind rooftop is low maintenance and can sustain sedums, grasses and other low herbaceous vegetation, while also providing a habitat for insects and birds. The large storm management pond collects water from the drainage system in the parking lot and is then used to water all of the plants on the green roof.
- The McNicoll Bus Garage features several green initiatives such as rooftop solar panels, a green roof and recycling system for bus wash water.
- The TTC's first green roof is located at Eglinton West Station with an 835-square-metre garden.
- Victoria Park Station was one of the first TTC stations to participate in the green roof pilot project. The design enhances the beauty of the station, while also diverting 300,000 gallons of storm water from the sewer system annually.

Hide All

TAB 3

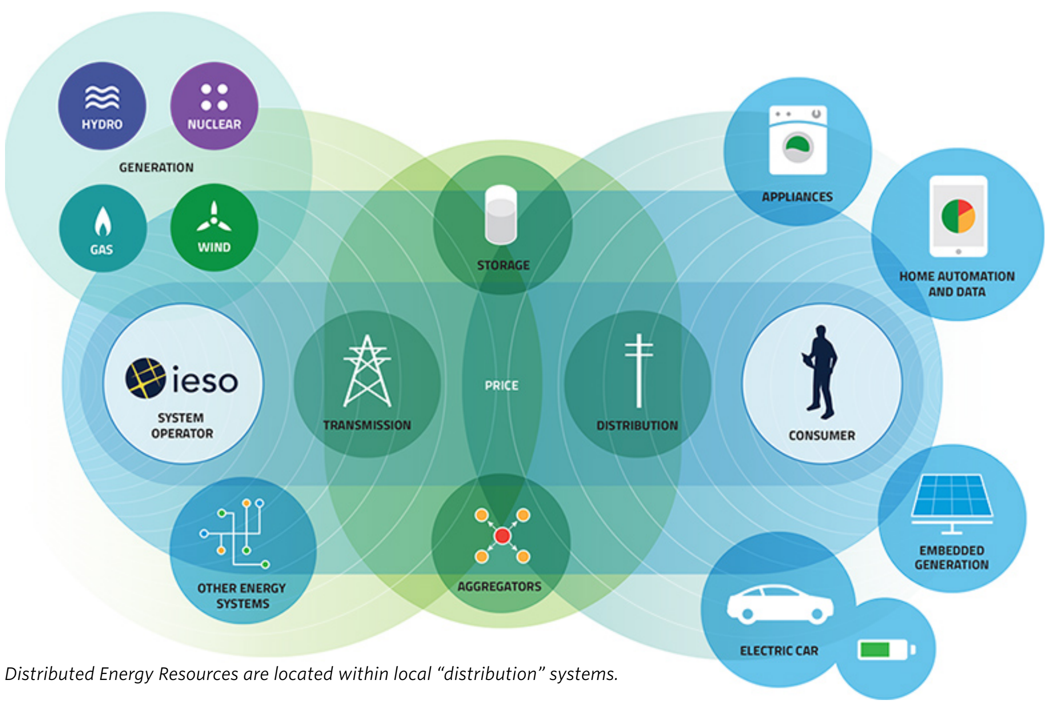
Ontario's Power System

Ontario's electricity system allows Ontarians to live, work and play safely and in comfort. Electricity is an inseparable and indispensable part of modern society. Learn how Ontario's power system delivers reliable, safe and sustainable electricity.

Distributed Energy Resources

Distributed energy resources (DERs) are electricity-producing resources or controllable loads that are directly connected to a local distribution system or connected to a host facility within the local distribution system.

DERs can include solar panels, combined heat and power plants, electricity storage, small natural gas-fuelled generators, electric vehicles and controllable loads, such as HVAC systems and electric water heaters. These resources are typically smaller in scale than the traditional generation facilities that serve most of Ontario demand.



Distributed Energy Resources are located within local "distribution" systems.

Growing Impact Leads to New Challenges and Opportunities

IN THIS SECTION...

Overview of Sector Roles

A Smarter Grid

Energy Transformation Network of Ontario

Electricity Market Today

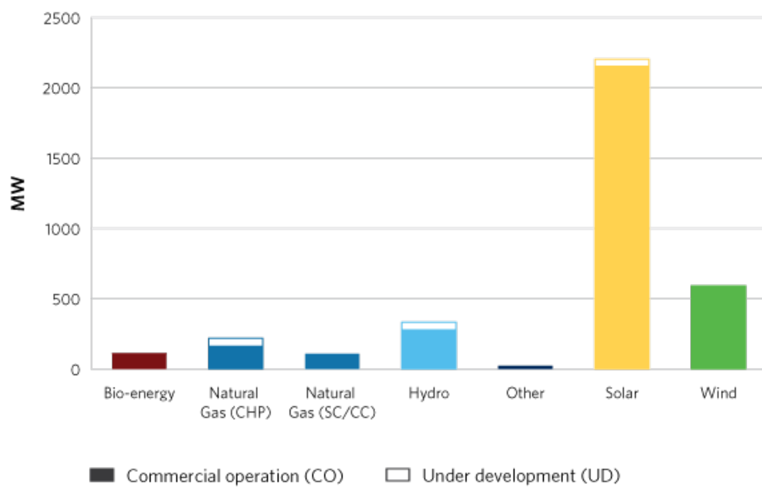
Creating the Electricity Market of Tomorrow

Ensuring A Reliable Grid

Planning and Forecasting

Technological advancements, climate change policies, and growing consumer opportunities are leading to an increase in DERs across North America. For example, more than 2,000 MW of distribution system solar generation has been installed in Ontario.

Distribution-connected Contracted Electricity Supply



Source: Progress Report on Contracted Electricity Supply, First Quarter 2019.

Output from DERs offsets the need for supply from the province-wide system. This is creating new opportunities and challenges for the electricity sector.

DERs can offer greater customer choice – the IESO has heard from some communities, through the regional planning process, a preference for DERs to address regional demand growth or to replace aging assets. DERs may also present opportunities to optimize overall system investments and provide a range of grid services.

However, increasing DERs creates a more decentralized electricity system and changes the traditional dynamic between local distribution systems and the province-wide transmission system. This creates a need to understand the impact on the transmission-distribution interface, which the IESO, local distribution companies, and other stakeholders are exploring through the Grid-LDC Interoperability Standing Committee. Collaboration is required to ensure the IESO can effectively forecast and have visibility of DER activity, benefit from the provision of reliability services, and explore opportunities to incorporate them into electricity markets.

Gaining Experiences With DERs

The IESO has initiated innovative pilot programs and procurements that are fostering innovation and leading to lessons learned regarding DERs, including:

- A local Demand Response (DR) Pilot in the Brant area aimed at better understanding the capabilities of DR to provide services as alternatives to transmission line solutions for meeting local-area capacity needs.
- The potential to aggregate residents who use solar and storage is being explored through PowerStream`s POWER.HOUSE project in the York region, which is funded, in part, by the IESO`s Conservation Fund.
- Two phases of an energy storage procurement that is exploring how batteries, flywheels and other storage technologies can offer ancillary services to support increased reliability and efficiency of the grid, and provide capacity value and price arbitrage through responding to market signals.
- A number of DER-related projects that are being supported through the IESO’s Conservation Fund.

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TAB 4

Technology

Toronto Transit Commission launches first electric bus into service

Posted on June 7, 2019

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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Setting up a multi-client electronic fare management (EFM) system in the Tampa Bay Area.

Bus warranty service   Driver seats

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Real-time info now available at all Sound Transit Link light rail stations
Digital signage informs riders of the anticipated arrival time for the next three trains.

REI launches new service to streamline data, asset management
ARMOR Cloud augments the list of features offered by REI's ARMOR Software Suite — an all-in-one wireless solution for fleet management.

SLEC lands largest vehicle lift contract in its history
The company recently announced that its lifts are now American-made, retaining many of the features of the former SEFAC lift.

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.

CTE to lead national advanced tech transit vehicle advisory panel
Group will streamline multiple advanced bus research and education resources into a cohesive FTA-led program.

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TAB 5

Advisory Committee on Innovation

Report to the Chair of the Ontario Energy Board

Actions the OEB can take to advance innovation in Ontario's energy sector

November, 2018

Recommendations

1. Provide a Transparent and Level Playing Field

Consistent rules of engagement provide predictability and transparency to parties about their rights and responsibilities when engaging in various activities. To facilitate growth in new service arrangements that will deliver greatest value for consumers these concepts must be extended to and embrace new players in the marketplace. The OEB should further promote innovation through the following actions:

A. Improve the transparency and consistency of the distribution system connection process and clarify cost responsibilities to reduce uncertainty for DER proponents, utilities and consumers

B. Establish clear rules for DER integration into distribution systems, addressing technical matters including information, visibility, management and control to, among other things, protect the reliable and safe operation of the distribution system, and optimize the planning and management of resources and assets

C. Establish guidelines for commercial arrangements governing performance of non-traditional resources so utilities and others can rely upon them as alternatives to traditional system investment

D. Reexamine regulatory restrictions on utility business activities and review the separation of regulated and competitive services in light of new technologies and service expectations

Recommendations

2. Remove Disincentives to Innovative Solutions

Putting nontraditional alternatives on an equal footing with traditional utility solutions can support pursuit of least-cost solutions with greatest value for consumers. To achieve this, the OEB should:

A. Remunerate utilities to make them indifferent to conventional or alternative solutions, including when other parties own and provide the alternative solution. Considerations will include, among other things, meaningful incentives and moving away from traditional rate base regulation

B. Establish an empirical evaluation methodology for cost-benefit comparison so all proposals are evaluated on a fair and consistent basis. Elements such as the value of optionality (i.e., the benefit of having options down the road), flexibility, location, time, resiliency, optimizing existing assets, and externalities as appropriate should be considered

C. Establish a way to ensure DERs can be compensated for their services commensurate with their value while paying their appropriate share of system costs. The approach should recognize new revenue streams which may be aggregated and allow shared cost recovery

D. Consider timely funding mechanisms to encourage utility innovation that provides near term customer benefits

Recommendations

3. Encourage Market-Based Solutions and Customer Choice

Information transparency is key to developing and deploying new market-based solutions. It expands the options for utilities to consider in their service offerings and enables informed consumer choice. In order to facilitate better access to information, the OEB should:

A. Require utilities to publish information about the characteristics and capabilities of their systems to enhance transparency of distribution system needs and capabilities within the market

B. Encourage cost-effective investment by utilities in monitoring and control capabilities to the extent that these enabling investments will help them efficiently manage a more dynamic distribution system

Recommendations

4. Embrace Simplified Regulation

Regulatory processes serve an important purpose but their complexity and pace is not conducive to deployment of innovation. Consumers, utilities and innovators in the sector need a simple and timely way of trying things out and learning from their experience. Regulatory simplicity will result in better pathways for innovation. In order to embrace simplified regulation, the OEB should:

A. Provide a means by which both utilities and unregulated entities are encouraged to discuss specific regulatory obstacles with the OEB, in order to allow near-term deployment of innovations while longer-term regulatory reforms are implemented

B. Review the information the OEB collects to ensure it is used to evaluate performance in the sector – specifically whether utilities, other service providers and regulation itself are benefitting customers

C. Explore the use of self-executing processes that use transparent, pre-approved criteria to allow streamlined regulatory review

D. Further examine OEB decision timelines to determine whether they can be shortened without compromising the effectiveness of stakeholder participation

TAB 6

Ontario Energy Board

Report of the Board

Supplemental Report on Smart Grid

EB-2011-0004

February 11, 2013

distributed generation, the Board notes that it has made a number of amendments to the Distribution System Code to facilitate the connection of distributed generation.

Another example of relevant investments would be using intelligent devices on the system such that network maintenance is enhanced. This investment can be targeted to where and when it is needed and operational efficiencies can be achieved, including improved power quality and outage management to increase reliability of service to customers.

The Board notes that some distributors have already undertaken, with Board approval, pilot and demonstration projects related to power system flexibility, including systems that facilitate real time communications with distributed generators and software solutions that enhance network intelligence (e.g., outage responsiveness).

As distributors plan for the modernization of their systems they must consider cost and the expectations for service from their customers and invest accordingly. The Board does not intend to prescribe specific investments and technological choices to be implemented. The Board recognizes that there is a diversity of circumstances among distributors. For example, an investment considered standard practice for one distributor may represent a significant modernization activity for a different distributor because of differences in size, geography, or evolution of customer preferences.

3.3 Adaptive Infrastructure

The Minister's Directive sets out the adaptive infrastructure objectives as follows:

> "For the purpose of 'accommodating the use of emerging, innovative and energy saving technologies and system control applications,' in accordance with subsection 2(1.3)(c) of the Electricity Act."

As noted in Section 2, the adaptive infrastructure objectives in the Minister's Directive align with the outcomes of Operational Effectiveness and Public Policy Responsiveness. The Board's expectations for this area are based on the renewed regulatory framework's goals of promoting ongoing productivity improvements and encouraging innovation.

Regulated entities must demonstrate in their investment plans that they have investigated opportunities for operational efficiencies and improved asset management, enabled by more and better data provided by smart grid technology. Investments that support and advance network operation and evolution (e.g., energy storage, interoperability, forward compatibility, and electric vehicles) are expected to be pursued when and where appropriate. As stated with respect to power system flexibility in Section 3.2, the Board does not intend to prescribe specific investments and technological choices for regulated entities.

Following Board approval, some distributors have already undertaken pilot and demonstration projects related to adaptive infrastructure, including electric vehicle charging, home energy management applications, and electricity storage options. The Board expects that distributors will report on the outcomes and learning from these pilots for the benefit all regulated entities. This expectation is consistent with the Board's policies (e.g., Filing Requirements: Distribution System Plans), which emphasize the need to avoid duplication of efforts in testing out and learning about new technologies.

The adaptive infrastructure objective in the Minister's Directive includes the following parameters: "Encourage Innovation" and "Maintain Pulse On Innovation." **When applicable and appropriate, capital and investment planning by regulated entities must demonstrate the consideration and/or adoption of innovative processes, services, business models, and technologies as well as an awareness of innovation and best practices.** As the Board identified in the RRFE Report, additional guidance from the Board regarding innovation is forthcoming. The Board intends to explore further opportunities to embed in the rate-setting framework for distributors (and eventually all regulated entities) the facilitation and recognition of technological innovation. Smart grid development and implementation activities will be a central focus of that effort.

TAB 7

2020-2024 Custom Incentive Rate-Setting Application

EXECUTIVE SUMMARY AND BUSINESS PLAN OVERVIEW

1. OVERVIEW

Toronto Hydro Electric-System Limited ("Toronto Hydro" or the "utility") distributes electricity in the City of Toronto. The utility and its predecessors have met the electricity needs of the residents, businesses, and institutions of the municipality (and its predecessors) for over 100 years, performing a critical role in the community. In planning and carrying out its work, the utility is guided by the needs, preferences, and priorities of its customers and other stakeholders. Meeting Toronto's electricity requirements remains central to Toronto Hydro's purpose.

This Application covers the 2020-2024 period. The proposed rates are necessary to fund the utility's business plan for that period. For a residential customer, the utility's 5-year proposal would result in an average annual increase of $0.77 (1.7 percent) on Toronto Hydro's distribution portion of the bill, or a $0.56 (0.4 percent) increase on the overall electricity bill. For the first year of the plan, 2020, residential customers will experience a decrease of $3.10 on the overall electricity bill.[1]

Toronto Hydro's plan was developed in consultation with its customers, having regard to how the utility's costs and performance compare with its peers (i.e. benchmarking), and with the objective of producing outcomes that customers value. These external inputs were combined with Toronto Hydro's knowledge and experience of the state of its distribution system infrastructure, and the other considerations that inform good utility practice and long-term performance. As part of its due diligence, and recognizing the

[1] All figures in this paragraph are for the monthly bill of a customer in the Residential rate class who uses 750 kWh of electricity. Bill impacts for other Residential customer profiles and other customer classes, and the only tariff (Wireline Attachment Rate) being updated in this Application, are explained in detail at Exhibit 1B, Tab 5, Schedule 1; and Exhibit 8, Tab 1, Schedule 1, and for quick reference, are included in a summary chart as Appendix "A" to this Exhibit.

value of third party perspective, Toronto Hydro engaged external experts to review significant parts of the plan and is filing their work product as part of the Application.

This is the second five-year plan filed by Toronto Hydro. The plan largely continues the methodology approved by the OEB for the 2015-2019 period. As with the 2015-2019 plan, the 2020-2024 plan reflects a Custom Incentive Rate-setting ("CIR") methodology that is aligned with OEB policy guidance.

This plan continues the utility's effort to renew a significant backlog of deteriorated and obsolete assets at risk of failure, and to adapt to the continuously evolving challenge of serving, and operating within a dense, mature, and growing major city. Efforts to date have resulted in gradual improvements to reliability, the overall age of the system, and other performance indicators.

Despite these indicators of progress, investing in the short-term performance and long-term viability of an aged, deteriorated, and highly utilized system remains an urgent priority for the utility (see Figure 1, below). Recent extreme weather events, accompanied by growing evidence of the impact of climate change on weather patterns in Toronto, have amplified this need, underscoring the challenge to build a resilient system for the long-term. At the same time, technology and innovation are driving a more dynamic system that is transitioning away from the usual patterns of supply and demand, adding additional complexity and urgency to the challenge of modernizing the grid, which in turn is driving investment needs in information technology and cyber security solutions.

Figure 1: Toronto Hydro at Work

The evidence that supports the Application is the utility's business plan. Organized according and in response to the OEB's Filing Requirements, Toronto Hydro's plan for 2020-2024 is the result of thorough business planning in which customers' needs and preferences were integrated from start to finish. The plan is expected to produce performance outcomes that customers value and are willing to financially support through their distribution rates. With the funding that these rates would provide, Toronto Hydro expects to continue to meet the needs of its customers.

Toronto Hydro is continuing the commitments made in its last application, while remaining responsive to challenges inherent in its operating environment. This performance-based plan is about ensuring Toronto Hydro is able to meet the needs and preferences of its customers today and in the future, including maintaining overall system performance and addressing specific areas requiring improvement.

2. ABOUT TORONTO HYDRO

Toronto Hydro is licensed by the OEB to serve the City of Toronto.[2] See Figure 2, below, for a map of Toronto Hydro's service territory. Toronto Hydro is the successor to the six former hydro-electric commissions of the municipalities which amalgamated on January 1, 1998 to form the City of Toronto. The utility is a wholly-owned subsidiary of Toronto Hydro Corporation, whose sole shareholder is the City of Toronto.[3]

Figure 2: Toronto Hydro's Service Territory

As of 2020, Toronto Hydro forecasts distributing electricity to 784,330 customers who are forecasted to consume over 24 TWh[4] of power that year.[5] Toronto Hydro serves them using approximately 30,000 kilometres of wire and cable, 180,000 poles, and over

[2] Electricity Distribution Licence ED-2002-0497.
[3] To learn more about Toronto Hydro's Corporate Structure and Governance, please refer to Exhibit 1C, Tab 2, Schedule 1.
[4] 24 TWh (terawatt hours) is equal to 24,000,000,000,000 watt hours of electricity. It is the equivalent of running 1 million 60 watt light bulbs non-stop for over 45 years.
[5] For more information about Toronto Hydro's load forecast, please refer to Exhibit 3, Tab 1, Schedule 1.

200 stations and substations. This is a 4.9 percent increase in customer count but a 4.0 percent decrease in power consumption over 2015.[6]

Toronto Hydro's customers range from residential consumers in single family dwellings and multi-unit buildings to large industrial and commercial businesses. These include the country's largest banks, stock exchanges and other large customers that are sensitive to service interruptions. The utility powers non-residential customers from a wide variety of sectors, including: dozens of accounts for hospitals and healthcare and long-term care facilities; hundreds of accounts for schools, colleges, and universities; data centres; and large industrial and manufacturing facilities. Toronto Hydro also supplies electricity to Ontario's Provincial Legislature and Ministries, as well as Toronto's municipal government. The utility also serves thousands of multi-unit residential condominium and apartment buildings, each of which can have dozens or hundreds of units.[7]

3. CUSTOMER ENGAGEMENT AND THE BUSINESS PLAN

Toronto Hydro began the process of developing its business plan by engaging its customers. Feedback from customers was that price, reliability, and safety were their top three priorities. Their other priorities related to customer service, environment, and public policy.[8] Considering this feedback and other inputs (as discussed below), Toronto Hydro established the following strategic parameters for its business plan:

1) **Price Limit:** Toronto Hydro set an upper limit of 3.5 percent as a cap on the average annual increase to base distribution rates.[9]

[6] For more information about Toronto Hydro's distribution system, please refer to Exhibit 1C, Tab 1, Schedules 1 and 2; and Exhibit 2B, Section D2.
[7] To learn more about the breadth and diversity of Toronto Hydro's customer base, please refer to Exhibit 1B, Tab 3.
[8] Please see Customer Engagement evidence at Exhibit 1B, Tab 3, Schedule 1.
[9] As calculated for the monthly bill of a Residential customer using 750 kWh.

resources on heavily loaded feeders in dense areas that serve customers sensitive to power quality. A dangerous example of that challenge is cyber threats.[18]

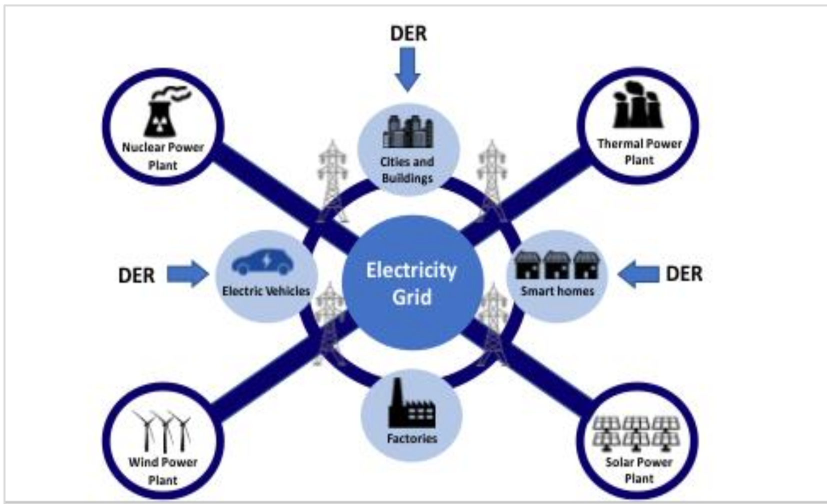

Figure 8: Distributed Energy Resources Interacting with the Electricity Grid[19]

Technology and innovation are driving a more dynamic system that is transitioning away from usual patterns of supply and demand towards more complex interactions and inputs in electricity generated and consumed (Figure 8, above). The role of the utility continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources, microgrids, electric vehicles, and growing interest in energy storage for power quality, off-peak storage, and grid resilience. See Figure 9, below, for an example of Toronto Hydro crews installing a pole-mounted

[18] Toronto Hydro works closely with the OEB on regulatory policy with respect to these challenges. In particular, on the OEB Chair's Advisory Committee on Innovation: < https://www.oeb.ca/sites/default/files/Advisory-Committee-on-Innovation-terms-of-reference.pdf> and the OEB Policy Steering Committee that helped develop the Ontario Cyber Security Framework (December 6, 2017): <https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.

[19] Exhibit 2B, Section 8.1, Appendix A.

The risk to the utility's deteriorating infrastructure is compounded by increases in the frequency and magnitude of extreme weather. Toronto Hydro continues to emphasize plans and programs that facilitate and improve its system resiliency, and ability to respond to these events.[41]

With more than 1,800 distributed energy resources connected to Toronto Hydro's system,[42] reducing risks to the grid requires Toronto Hydro to enhance its visibility of them and put in appropriate safety equipment and protocols. To this end, the utility plan includes a number of investments to assist in managing evolving system requirements and technological landscape.[43]

6.3 Operating, Maintenance & Administration ("OM&A" or "Operational") Plan

Toronto Hydro's operational plan is organized into 21 programs, each of which advances similar outcomes in similar ways. Some programs work directly with the distribution system, such as preventative maintenance, emergency response, and the control centre.[44] Other programs provide support to operations and customers, such as fleet, facilities, and supply chain,[45] customer service and support,[46] human resources, finance, and information technology.[47] All these programs are necessary to safely and reliably

[41] These programs include the Control Operations Reinforcement program (Exhibit 2B, Section E8.1), Area Conversions (Exhibit 2B, E6.1), System Enhancements (Exhibit 2B, E7.1), and Overhead System Renewal (Exhibit 2B, Section E6.5).
[42] There are likely dozens, perhaps even hundreds more of these micro-generation, storage, and other devices that are installed without notice to Toronto Hydro, the operation of which by the customer can affect the distribution system and other customers connected to it (e.g. power quality fluctuations, back-flow of power, spikes up and down in demand).
[43] See Exhibit 2B, Section E7.1 (System Enhancements); Exhibit 2B, Section E7.2 (Energy Storage Systems); Exhibit 2B, Section E7.3 (Network Condition Monitoring and Control); and Exhibit 2B, Section E8.1 (Control Operations Reinforcement program).
[44] See Exhibit 4A, Tab 2, Schedules 1-10.
[45] See Exhibit 4A, Tab 2, Schedules 11-13.
[46] See Exhibit 4A, Tab 2, Schedules 14 and 19.
[47] See Exhibit 4A, Tab 2, Schedules 15-18, 20-21.

TAB 8

ELECTRICITY DISTRIBUTOR SCORECARD AND 2015-2019 DISTRIBUTION SYSTEM PLAN PERFORMANCE MEASURES

In accordance with the OEB's *Renewed Regulatory Framework for Electricity Distributors* (the "RRF"), Toronto Hydro reports annually on its progress against measures aligned with the following core objectives: Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.[1] These results are reported as part of the OEB's Electricity Distributor Scorecard (the "EDS") and used to assess utility performance over time and in comparison to other utilities.

The first section of this Schedule discusses Toronto Hydro's performance for each of the EDS measures[2] for the last five years, i.e. 2013-2017, and is consistent with the approach Toronto Hydro undertakes in its annual reporting.[3] The second section of this Schedule discusses historical performance relating to the 12 Distribution System Plan ("DSP") measures introduced as part of the utility's 2015-2019 Rate Application.[4]

1. EDS PERFORMANCE

As illustrated in Table 1, Toronto Hydro's performance on the EDS has been strong over the 2013-2017 period, including notable improvements in Customer First Contact Resolution, Telephone Calls Answered on Time, New Residential and Small Business Services Completed on Time and Billing Accuracy. The following sections provide

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[1] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).

[2] The definitions of each of these performance measures is available at: <https://www.oeb.ca/sites/default/files/uploads/Scorecard_Performance_Measure_Descriptions.pdf>

[3] Toronto Hydro's Electricity Distributor Scorecard for 2016 is available at: <https://www.torontohydro.com/sites/electricsystem/residential/customercare/Documents/Scorecard%20-%20Toronto%20Hydro-Electric%20System%20Limited.pdf>

[4] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Section C.

additional detail on Toronto Hydro's EDS historical performance and targets, for each measure.

Table 1: Toronto Hydro EDS Performance 2013-2017

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017[a,b]	Target: Industry	Target: Distributor	Average
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		94.20%	91.50%	96.90%	97.70%	98.32%	90.00%		95.72%
		Scheduled Appointments Met On Time		99.60%	99.80%	99.90%	99.50%	99.37%	90.00%		99.63%
		Telephone Calls Answered On Time		82.00%	71.90%	76.80%	64.70%	77.92%	65.00%		74.66%
	Customer Satisfaction	First Contact Resolution		77%	81%	84%	86%	88%			83%
		Billing Accuracy			96.62%	97.54%	98.86%	99.24%	98.00%		98.07%
		Customer Satisfaction Survey Results			91%	91%	83%	83%			N/A
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				71.00%	71.00%	69.00%			70.33%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C		C	N/A
		Serious Electrical Incident Index	Number of General Public Incidents	2	3	0	0	1		2	1.2
			Rate per 10, 100, 1000 km of line	0.202	0.295	0	0	0.070		0.083	0.113
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.11	0.89	0.99	0.91	0.91		1.11	0.96
		Average Number of Times that Power to a Customer is Interrupted		1.34	1.18	1.31	1.28	1.18		1.36	1.26
	Asset Management	Distribution System Plan Implementation Progress[c]		105%	147%	100%	101%	99%			N/A
	Cost Control	Efficiency Assessment		5	5	5	5				5
		Total Cost per Customer		$924	$967	$1,000	$1,044				$984
		Total Cost per Km of Line		$66,793	$70,688	$73,309	$27,819				$59,652
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings				12.51%	34.58%	62.30%		1,576.05 GWh	N/A
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	97.12%	100.00%	100.00%	81.08%			95.64%
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	92.41%	90.00%		98.48%
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.80	0.68	0.67	0.61	0.64			0.68
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.34	1.65	1.57	1.45	1.34			1.47
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.58%	9.58%	9.30%	9.30%	9.30%			9.41%
			Achieved	7.10%	7.41%	10.71%	12.18%	9.08%			9.30%

a. Results to be finalized and submitted to the OEB via the annual Scorecard MD&A process
b. Certain results are issued by the OEB and were not available at the time of preperation.
c. The amount previously reported for 2016 has been adjusted from 113% to 101%

TAB 9

RELIABILITY PERFORMANCE

Toronto Hydro tracks reliability performance indicators System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") in several ways:[1]

1) All events;
2) Excluding events relating to Loss of Supply ("LoS");
3) Excluding events relating to Major Event Days ("MEDs");
4) Excluding MEDs and LoS; and
5) Excluding MEDs, LoS, and scheduled outages.

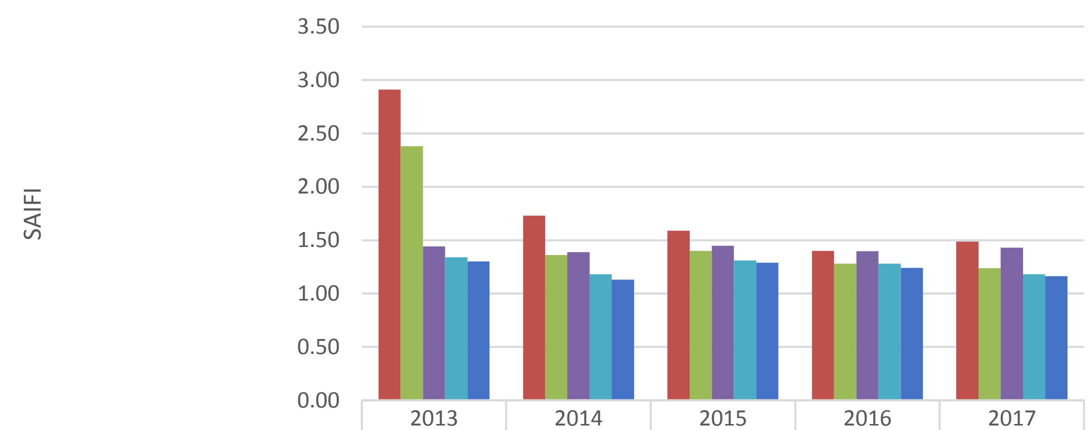
Scenarios 1, 2, and 3 provide SAIFI and SAIDI in the manner required by the OEB's prescribed Appendix 2-G, filed at Exhibit 1B, Tab 2, Schedule 5. Scenarios 4 and 5 provide SAIFI and SAIDI excluding: (i) outages related to MEDs and LoS (consistent with the OEB Electricity Distributor Scorecard and MD&A) discussed in Exhibit 1B, Tab 2, Schedule 2; and (ii) MEDs, LoS and scheduled outages, respectively, as a more normalized reflection of total system reliability performance. Each scenario provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

1. SYSTEM OVERVIEW

Figures 1 and 2 below show the system's total SAIFI and SAIDI between 2013 and 2017, respectively, under each of the five scenarios. The notably higher SAIFI and SAIDI in 2013 under Scenarios 1 and 2 can be attributed to the flooding of Manby TS in July and

[1] During the 2020-2024 plan period, Toronto Hydro will be tracking performance under FESI-7 (System) and FESI-6 (Large Customers) as part of its custom performance measures, please see Exhibit 2B, Section C for more information.

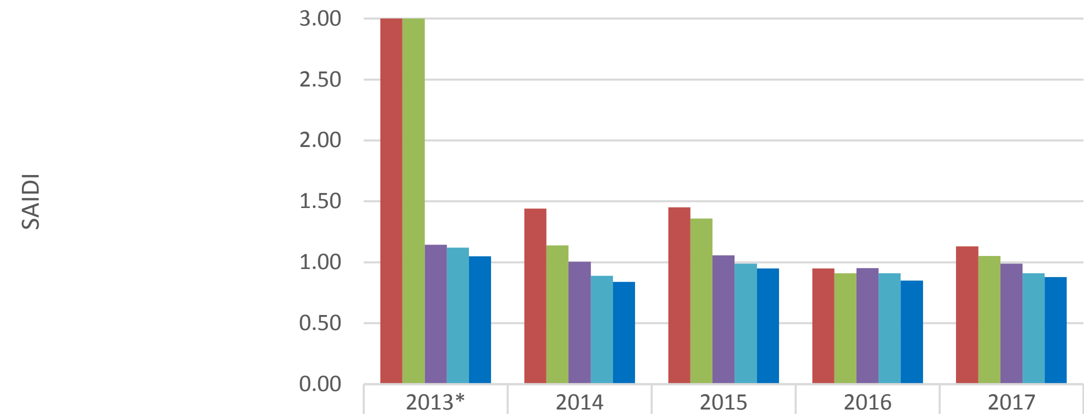
the ice storm in December of that year. Both of these occurrences were outside the utility's control and met the definition of MEDs as set out in the OEB's Electricity Reporting and Record Keeping Requirements ("RRR").[2] These MEDs caused the year-over-year fluctuations to be more drastic. In contrast, Scenarios 3 (excluding MEDs), Scenario 4 (excluding MEDs and LoS), and Scenario 5 (excluding MEDs, LoS, and scheduled outages) illustrate more normalized SAIFI and SAIDI values with less fluctuations. Toronto Hydro considers these latter scenarios to offer greater insight into system reliability as they provide a better indication of the performance trend of the system and the impact of recent investments, and are the more commonly used indicators across the industry for benchmarking against distribution system performance.



	2013	2014	2015	2016	2017
Total SAIFI	2.91	1.73	1.59	1.40	1.49
SAIFI Excluding LoS	2.38	1.36	1.40	1.28	1.24
SAIFI Excluding MED's	1.44	1.39	1.45	1.40	1.43
SAIFI Excluding MED's and LoS	1.34	1.18	1.31	1.28	1.18
SAIFI Excluding MED's, LoS and Scheduled Outages	1.30	1.13	1.29	1.24	1.16

Figure 1: System Level SAIFI

[2] OEB, Electricity Reporting and Record Keeping Requirements ("RRR"), Section 2.1.4.2(7).



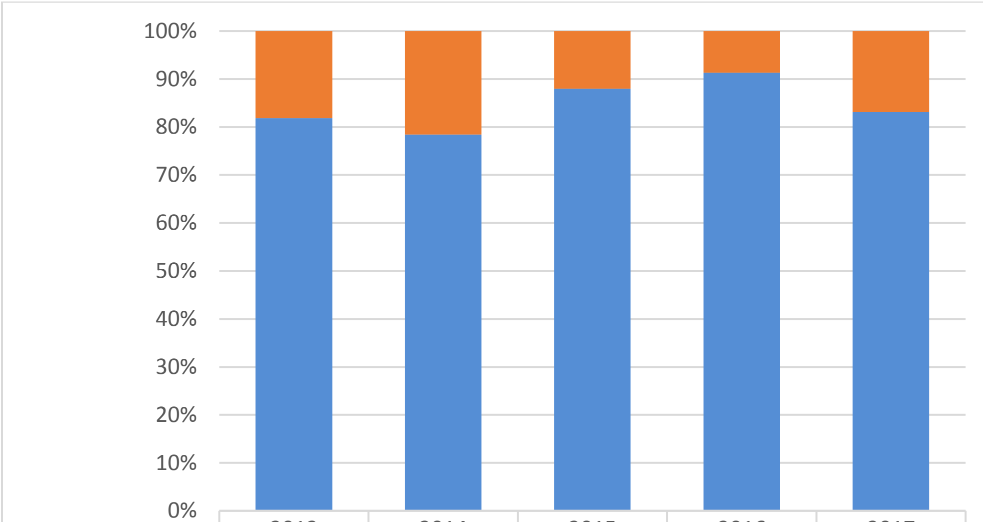
	2013*	2014	2015	2016	2017
Total SAIDI	21.07	1.44	1.45	0.95	1.13
SAIDI Excluding LoS	17.70	1.14	1.36	0.91	1.05
SAIDI Excluding MED's	1.14	1.00	1.06	0.95	0.99
SAIDI Excluding MED's and LoS	1.12	0.89	0.99	0.91	0.91
SAIDI Excluding MED's, LoS and Scheduled Outages	1.05	0.84	0.95	0.85	0.88

*2013 Values cut off above the chart due to the high SAIFI and SAIDI values prior to excluding MEDs.

Figure 2: System Level SAIDI

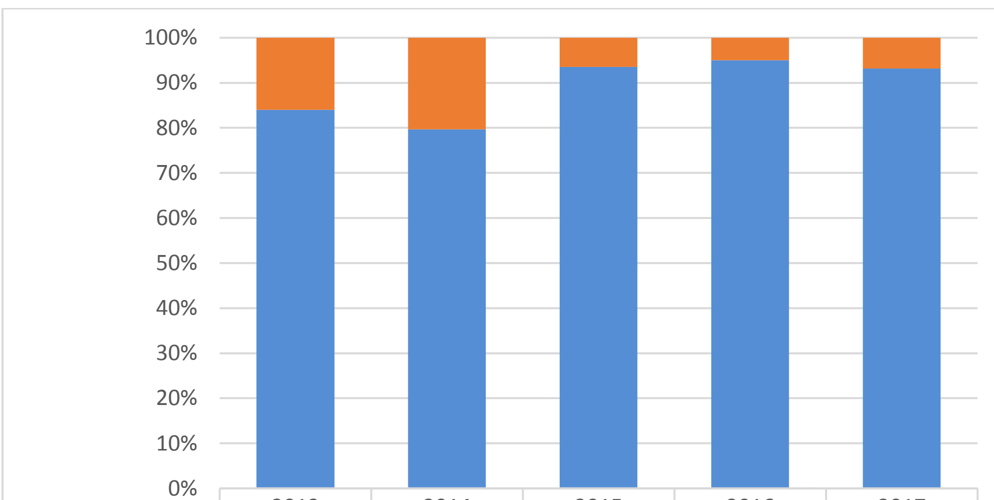
2. LOSS OF SUPPLY

Loss of Supply ("LoS") events have a significant impact on the overall reliability of Toronto Hydro's distribution system, and being external to Toronto Hydro's operations and control, are generally excluded from a system reliability analysis. On a system level, LoS events can contribute up to 22 percent of SAIFI and 20 percent of SAIDI (based on system reliability analysis beginning in 2013), although significant variations can occur year to year. There are also significant variations between individual LoS events, which makes it difficult to perform trend analyses and forecast future reliability performance. For instance, 23 LoS events occurred in 2015, whereas 20 LoS events occurred in 2017. Nevertheless, the fewer events in 2017 affected SAIFI and SAIDI to a greater extent due to the higher impacts of individual events in that year. Figures 3 and 4 below show the SAIFI and SAIDI system impact due to LoS.



	2013	2014	2015	2016	2017
Loss of Supply	18%	22%	12%	9%	17%
System	82%	78%	88%	91%	83%

Figure 3: Loss of Supply Impact on Total SAIFI



	2013	2014	2015	2016	2017
Loss of Supply	16%	20%	7%	5%	7%
System	84%	80%	93%	95%	93%

Figure 4: Loss of Supply Impact on Total SAIDI

TAB 10

3. MAJOR EVENT DAYS

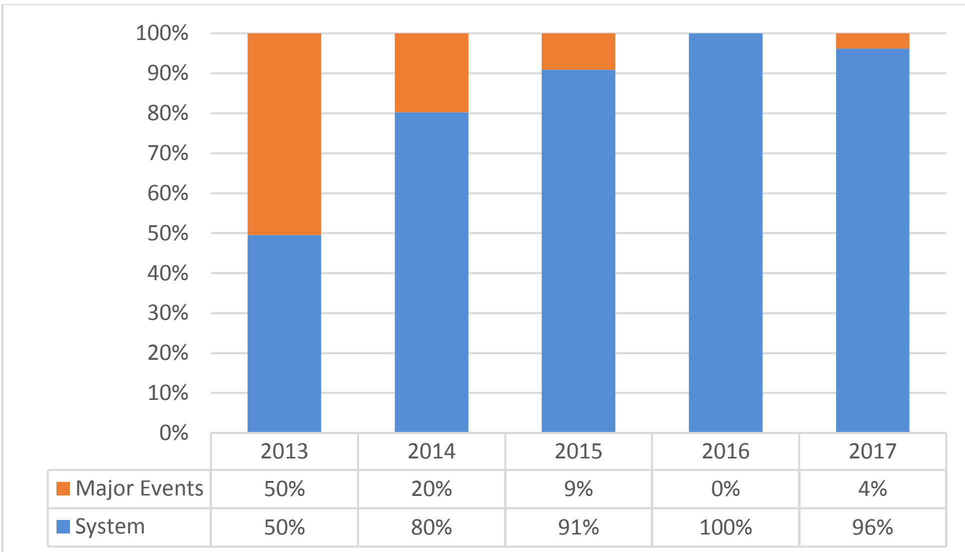
Major Event Days ("MEDs") are defined by the Institute of Electrical and Electronics Engineers ("IEEE") as "events that are beyond the design and/or operational limits of a utility."[3] Major Events are similarly defined by the OEB's RRR as "an event that is beyond the control of the distributor and is: unforeseeable, unpredictable, unpreventable, or unavoidable."[4] Similar to LoS events, MEDs are external to routine utility operation, and in addition, are highly volatile from year to year. The exclusion of MEDs and LoS events allows a utility to normalize its reliability data, making it possible to establish meaningful reliability performance trends and associated targets. MEDs experienced by Toronto Hydro since 2003 are shown in Table 1, below.

Table 1: Major Event Days

Dates	Description	Number of Outages	Total Customers Interrupted	Total Customer Hours Interrupted
July 8, 2013	Major Storm (Thunderstorm)	56	324,672	2,377,913
July 9, 2013	Major Storm (Thunderstorm)	44	41,502	91,646
December 21, 2013	Freezing Rain Ice Storm	42	175,928	3,204,481
December 22, 2013	Freezing Rain Ice Storm	208	441,547	8,295,093
December 23, 2013	Freezing Rain Ice Storm	25	29,530	196,633
December 24, 2013	Freezing Rain Ice Storm	23	13,983	149,337
December 25, 2013	Freezing Rain Ice Storm	18	20,225	92,924
December 26, 2013	Freezing Rain Ice Storm	20	19,147	91,458
April 15, 2014	Loss of Supply to Manby TS	27	113,035	129,479
June 17, 2014	Major Thunderstorm	38	55,442	88,496
November 24, 2014	Wind Storm	46	82,053	99,027
March 3, 2015	Freezing Rain	49	107,242	291,672
October 15, 2017	Wind Storm	31	43,175	107,846

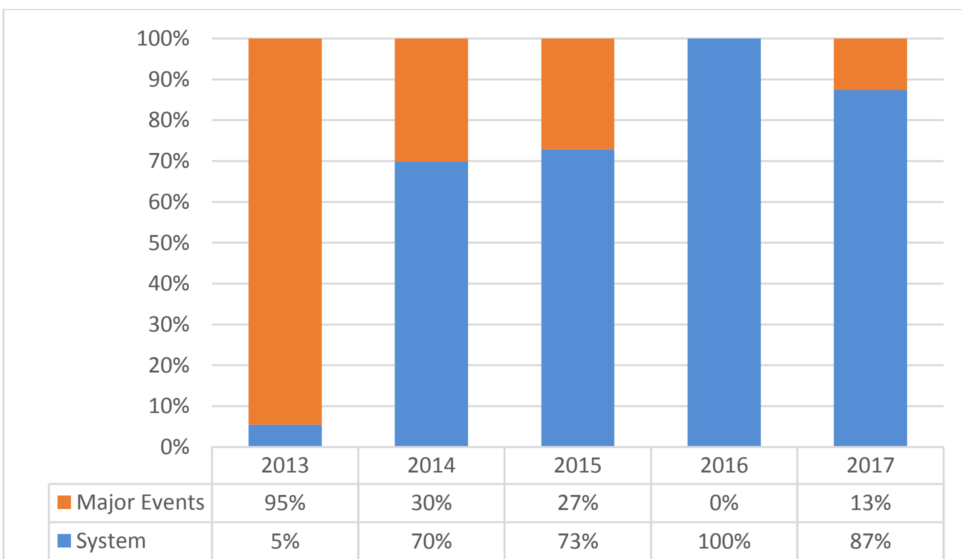
[3] IEEE 1366-2012 – IEEE Guide for Electric Power Distribution Reliability Indices.
[4] Ontario Energy Board, Electricity Reporting & Record Keeping Requirements (March 15, 2018) at p. 10.

Figures 5 and 6, below, demonstrate the SAIFI and SAIDI system impacts resulting from MEDs.



	2013	2014	2015	2016	2017
Major Events	50%	20%	9%	0%	4%
System	50%	80%	91%	100%	96%

Figure 5: Major Event Days Impact on Total SAIFI



	2013	2014	2015	2016	2017
Major Events	95%	30%	27%	0%	13%
System	5%	70%	73%	100%	87%

Figure 6: Major Event Days Impact on Total SAIDI

4. SCHEDULED OUTAGES

Scheduled outages are associated with construction and preventative maintenance activities. Assets that are at risk of failing in the near future may be taken out of service to be repaired or replaced. While this can lead to lengthy outages, the duration of the outage would generally be much shorter than those caused by the asset failing while in-service. These planned replacements are also often required to mitigate safety risks to Toronto Hydro's employees. Toronto Hydro provides customers advanced notification of any impeding work prior to engaging the project, which gives them the opportunity to plan their activities around the repair work. As planned outages do not reflect the inherent reliability performance of the distribution system, they are typically excluded from reliability analyses.

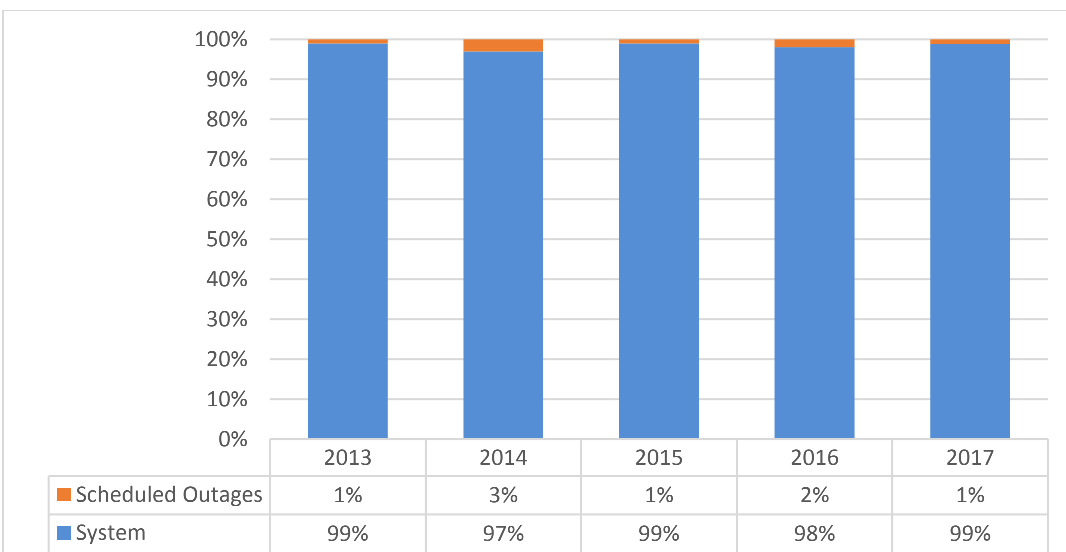


Figure 7: Scheduled Outages Impact on Total SAIFI

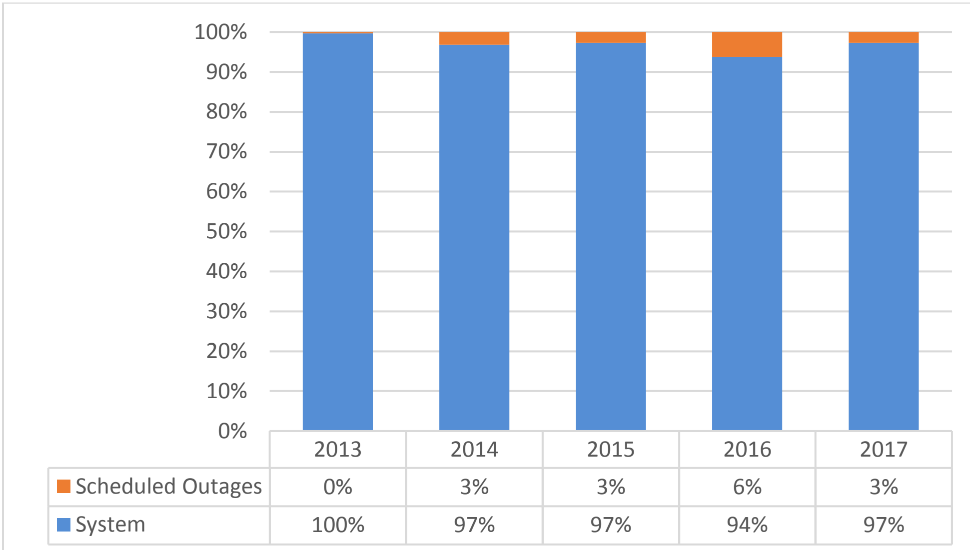


Figure 8: Scheduled Outages Impact on Total SAIDI

5. SYSTEM RELIABILITY EXCLUDING LOSS OF SUPPLY, MAJOR EVENT DAYS AND SCHEDULED OUTAGES

As noted above, MEDs and LoSs are outside the utility's control. As a result, these factors are typically excluded from analysis of the overall system performance. In addition, scheduled outages are required to allow certain work to be completed on the distribution system such as replacing assets that are at their end of life or in deteriorated condition to prevent a future outage. The inclusion of scheduled outages in reliability analysis would not provide a true reflection of distribution system performance. Figures 9 and 10, below, show the adjusted SAIFI and SAIDI (excluding LoS, MEDs, and scheduled outages).

The year-over-year adjusted values show that SAIFI and SAIDI have been generally stable, with a slight downward trend. A breakdown of system interruption causes is shown by the cause codes in Figures 11 and 12. The cumulative weather reliability impacts on the system are highlighted in Figures 13 and 14. SAIDI shows a steady improvement over the 2013-2017 period. This is in part a reflection of the utility's continued work to improve restoration times through the installation of remotely operated switches, which allow faster restoration of customers as well as reconfigurations to reduce assets in rear lot locations that typically have longer outage durations.

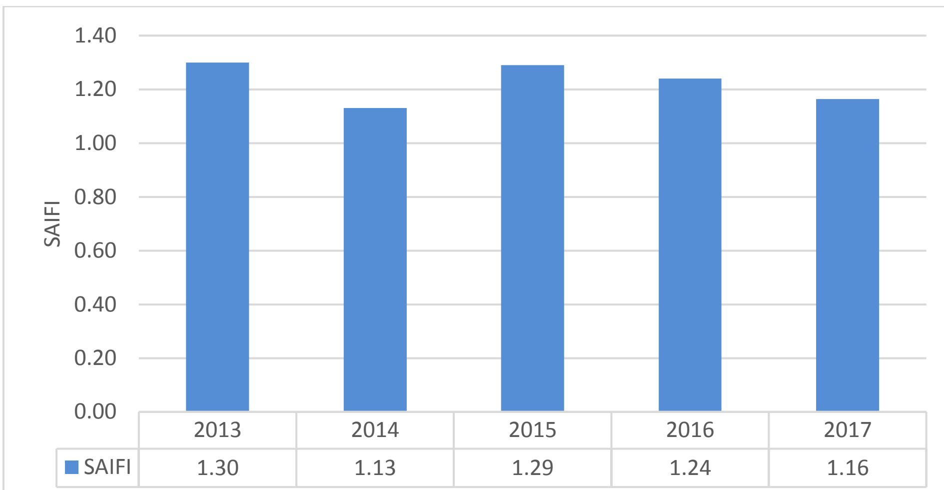


Figure 9: System SAIFI Excluding MEDs, Loss of Supply and Scheduled Outages

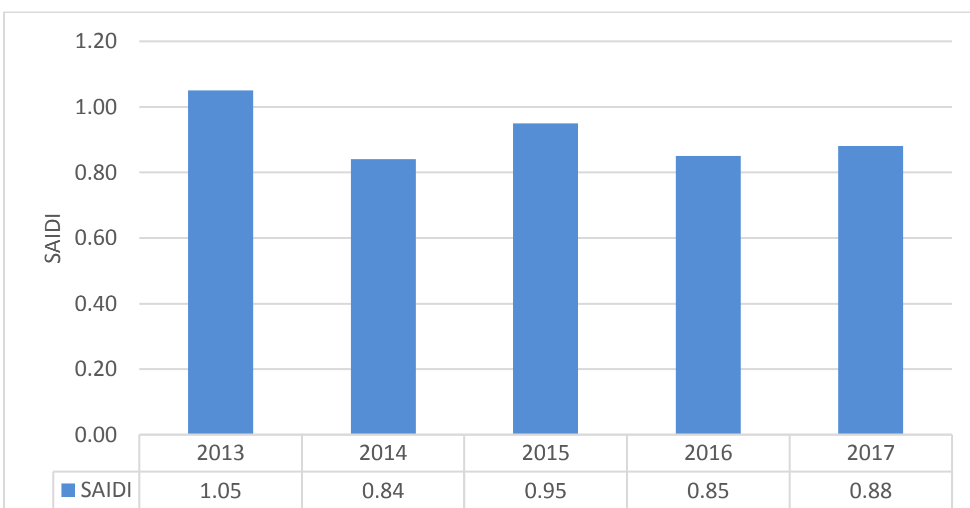
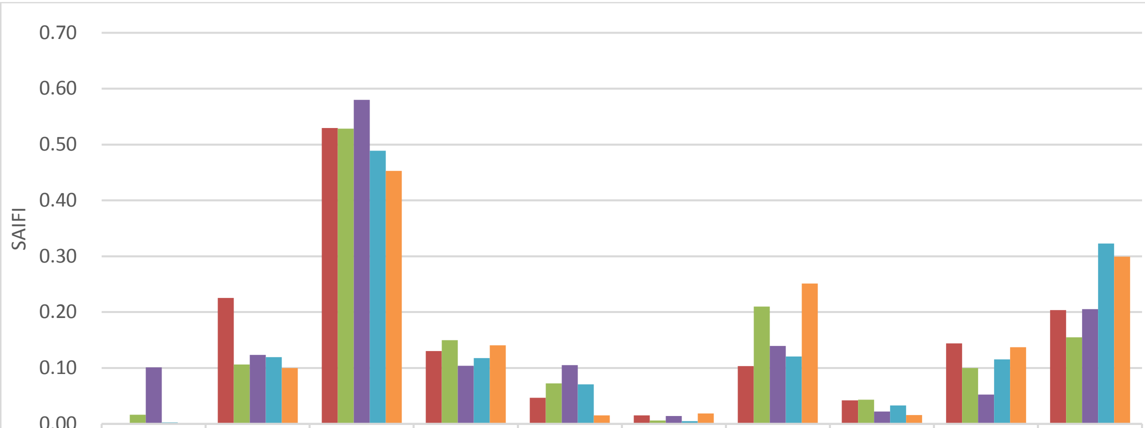


Figure 10: System SAIDI Excluding MEDs, Loss of Supply and Scheduled Outages

6. CAUSE CODE ANALYSIS

Toronto Hydro tracks causes of service interruptions using the ten primary cause codes as specified in the OEB's RRR.[5] Figures 11 and 12, below, show the utility's 2013-2017 SAIFI and SAIDI performance by cause code. Table 2, below, shows the percentage contribution of each cause code to overall system SAIFI and SAIDI.



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2013	0.00	0.23	0.53	0.13	0.05	0.02	0.10	0.04	0.14	0.20
2014	0.02	0.11	0.53	0.15	0.07	0.01	0.21	0.04	0.10	0.16
2015	0.10	0.12	0.58	0.10	0.10	0.01	0.14	0.02	0.05	0.21
2016	0.00	0.12	0.49	0.12	0.07	0.00	0.12	0.03	0.12	0.32
2017	0.00	0.10	0.45	0.14	0.02	0.02	0.25	0.02	0.14	0.30

Figure 11: SAIFI Cause Code Breakdown (Excluding MEDs)

[5] RRR, Section 2.1.4.2.5 - Reporting Cause Codes.

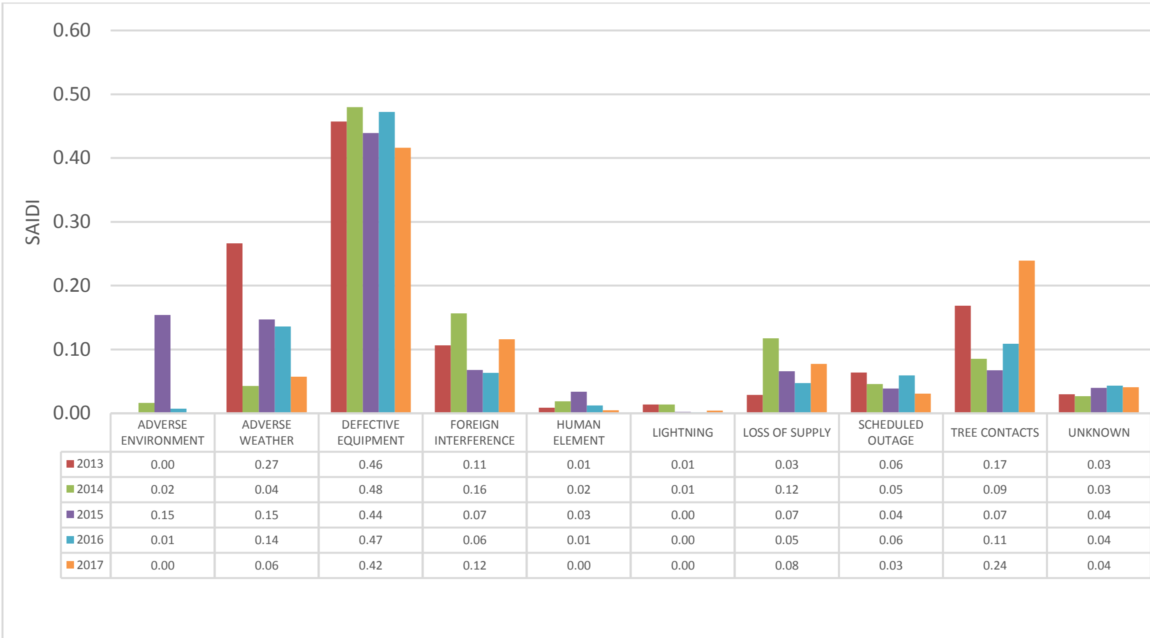


Figure 12: SAIDI Cause Code Breakdown (Excluding MEDs)

Table 2: Five-Year Average SAIFI and SAIDI Contribution by Cause Code

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
Defective Equipment	36.3	44.0
Unknown	16.7	3.5
Loss of Supply*	11.6	6.5
Foreign Interference	9.0	9.9
Adverse Weather	9.5	12.6
Tree Contacts	7.7	13.0
Human Element	4.4	1.5
Scheduled Outage*	2.2	4.6
Adverse Environment	1.7	3.5
Lightning	0.8	0.7

* Excluded from typical system analysis when evaluating Toronto Hydro's system reliability performance

Between 2013 and 2017, defective equipment was the main contributor to SAIFI and SAIDI, at 36.3 percent and 44.0 percent respectively. As shown in Figures 11 and 12, above, the majority of improvement in 2017 SAIFI and SAIDI results relative to prior years was in respect to Defective Equipment and Adverse Weather. Toronto Hydro views the Defective Equipment cause code as a primary indicator of the condition of its distribution system and tracks the cost code as a measure of continuous improvement in the execution of its capital expenditure and maintenance plans. To this end, Toronto Hydro has proposed two custom performance measures, SAIDI – Defective Equipment and SAIFI – Defective Equipment for the 2020-2024 plan period. Please refer to Exhibit 2B, Section C for more information. Additional analysis of certain cause codes is provided below.

7. WEATHER IMPACTS

The following three cause codes can generally be combined to provide a more accurate reflection of weather impacts on the system:

1) Adverse Weather,
2) Lightning, and
3) Tree Contacts.

Figures 13 and 14, below, illustrate the cumulative weather reliability impacts on the system.

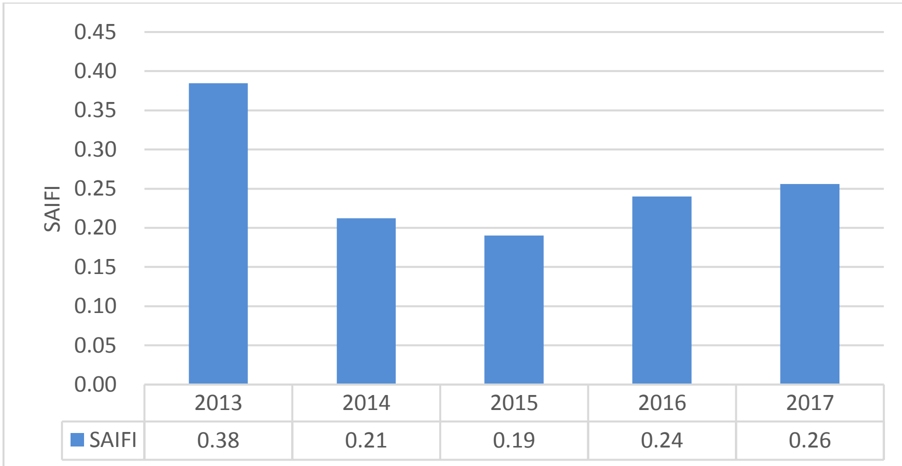


Figure 13: Weather Impacts to SAIFI

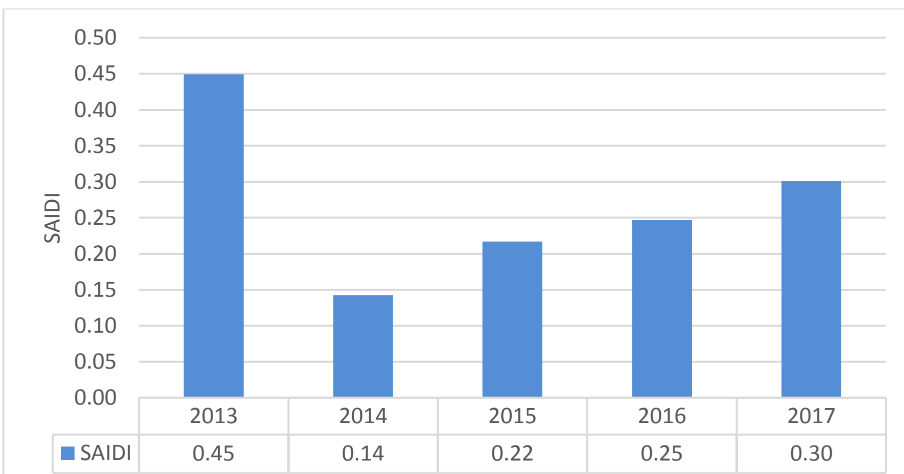


Figure 14: Weather Impacts to SAIDI

Weather impacts on the distribution system account for a significant portion of total system SAIFI and SAIDI. In 2017, weather related causes contributed 18 percent of the annual SAIFI and 30 percent of the annual SAIDI results. Figures 13 and 14, above, demonstrate that a large portion of the SAIFI and SAIDI improvements in 2014 can be attributed to relatively favorable weather conditions that year.

TAB 11

OEB Appendix 2-G
Service Reliability Indicators
2013 - 2017

Index	SAIDI					SAIFI				
	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
Including all events	21.07	1.44	1.45	0.95	1.13	2.91	1.73	1.59	1.40	1.49
Excl. LoS	17.70	1.14	1.36	0.91	1.05	2.38	1.36	1.40	1.28	1.24
Excl. MED's	1.14	1.00	1.06	0.95	0.99	1.44	1.39	1.45	1.40	1.43
Excl. LoS and MED's	1.12	0.89	0.99	0.91	0.91	1.34	1.18	1.31	1.28	1.18
Excl. LoS, MED's & Sch. Outages	1.05	0.84	0.95	0.85	0.88	1.30	1.13	1.29	1.24	1.16

	5 Year Historical Average SAIDI	5 Year Historical Average SAIFI
Including all events (1)	5.21	1.82
Excl. LoS (2)	4.43	1.53
Excl. MED's (3)	1.03	1.42
Excl. LoS and MED's (4)	0.96	1.26
Excl. LoS, MED's & Sch. Outages (5)	0.91	1.22

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index
(1) including all events
(2) excluding events related to Loss of Supply ("LoS")
(3) excluding events related to Major Event Days (MEDs)
(4) excluding Major Event Days ("MEDs") and LoS
(5) excluding MEDs, Loss of Supply, and Scheduled Outages

Indicator	OEB Minimum Standard	2013	2014	2015	2016	2017
Low Voltage Connections	90%	94.2	91.5	96.9	97.7	98.3
High Voltage Connections	90%	100.0	100.0	100.0	100.0	98.4
Micro-Embedded Generation Facilities	90%	100.0	100.0	100.0	100.0	92.4
Appointment Scheduling	90%	96.6	96.2	89.0	72.0	81.8
Appointments Met	90%	99.6	99.8	99.9	99.5	99.4
Rescheduling a Missed Appointment	100%	98.4	94.6	100.0	100.0	100.0
Telephone Accessibility	65%	82.0	71.9	76.8	64.7	77.9
Telephone Call Abandon Rate	10%	1.2	1.7	1.6	3.1	1.9
Written Response to Enquires	80%	98.9	85.8	97.5	93.1	99.0
Billing Accuracy	98%	n/a	96.6	97.5	98.9	99.2
Emergency Urban Response	80%	74.4	92.0	87.2	91.8	93.6
Emergency Rural Response	80%	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85%	100.0	100.0	100.0	99.7	99.4

TAB 12

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.

customers' needs, preferences, and priorities so as to inform the utility's business plan. The process spanned over 18 months, between late 2016 and mid-2018, and involved over 10,000 Toronto Hydro customers of all sizes.

Toronto Hydro engaged Innovative Research Group ("Innovative"), a national consulting firm with expertise in public opinion research (and experience in energy policy in particular), to execute the utility's Planning-specific Customer Engagement. The resulting final report (the "Innovative Report") can be found in Appendix A to this Schedule.

Innovative executed the Planning-specific Customer Engagement in two phases. Phase 1 provided input into the development of the business plan, including the penultimate Distribution System Plan ("DSP"). Phase 2 helped to refine the business plan, including the final DSP.

3.1 Phase 1

Phase 1 of the Planning-specific Customer Engagement focused on assessing customer needs and preferences in relation to outcomes relevant to Toronto Hydro's programs and services. Phase 1 was conducted to generate a comprehensive view of customers' priorities as a front-end input into Toronto Hydro's business plan.

Innovative used a range of techniques to assess customers' needs and preferences. Quantitative methods provided statistically valid results (e.g. surveys directed at residential and small business customers). Qualitative methods provided constructive context to supplement the statistical results (e.g. focus groups directed at residential, small business and mid-market customers).

The Innovative Report discusses in detail the Phase 1 process and results. For example, initial focus group engagement identified six key customer priorities:

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 the follow-up telephone survey, a majority of customers replied that each of these six priorities were either “important” or “extremely important.” When asked to rank them, low-volume customers prioritized “delivering reasonable electricity prices” first, followed by “ensuring reliable electrical service.” By comparison, large customers with average peak loads over 1 MW (“Key Accounts”) prioritized “ensuring electrical service”, ahead of “delivering reasonable electricity prices”.[2]

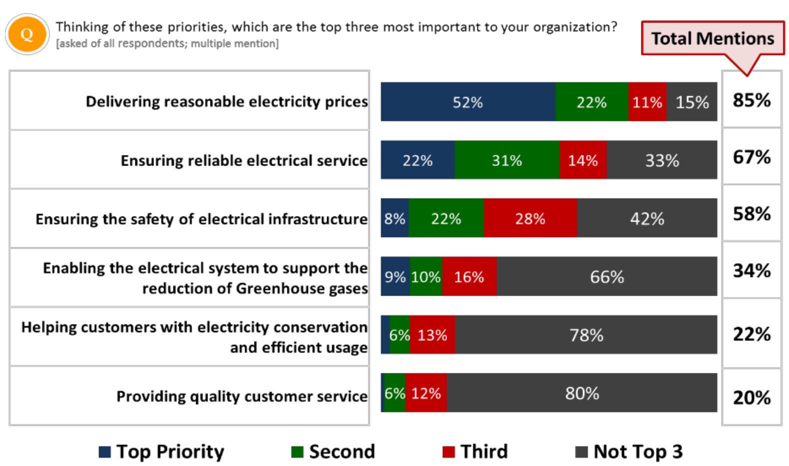


Figure 1: Low-volume Customer Priority Rankings, Phase 1.

[2] Innovative Report, Exhibit 1B, Tab 3, Schedule 1, Appendix A, Executive Summary pg. 11.

Considering the entirety of the Phase 1 results, Innovative concluded that "customer and stakeholder feedback from Phase 1 can be summarized by the following key points:

1) Keeping distribution price increases as low as possible;
2) Maintaining long-term performance for customers experiencing average or better service;
3) Improve service levels for customers experiencing below average service or who have special reliability needs (e.g. hospitals); and
4) Balancing other customer priorities (e.g. customer service) with the need to contain rate increases."[3]

The timing of Phase 1 allowed Toronto Hydro to leverage the results in a number of ways. It informed the development of the Outcomes Framework (see Exhibit 1B, Tab 2, Schedule 1), which became the lens through which the utility assessed the value to customers of its program expenditure proposals. It informed the strategic parameters established for the business plan, which included an upper limit of 3.5 percent as a cap on the average annual increase to base distribution rates (see Exhibit 1B, Tab 1, Schedule 1). Consequently, Phase 1 results informed the development of the penultimate business plan that was taken back to customers during Phase 2 (see Exhibit 1B, Tab 1, Schedule 1; Exhibit 2B, Section E2).

Innovative developed a high-level, two-page "Placemat" summary of the findings of its work in support of Toronto Hydro's Phase 1 Customer Engagement activities. The Customer Engagement Placemat provided an easily accessible version of the key results of Phase 1 Customer Engagement.

[3] Ibid., pg. 5

3.2 Phase 2

Phase 2 provided additional insight about customers' needs and preferences prior to the completion of the business plan. The purpose of Phase 2 was threefold:

- To confirm customer needs, preferences, and priorities identified in Phase 1;
- To solicit customer feedback on the content of Toronto Hydro's proposed plans and the subsequent rate impact including customer preferences toward particular capital programs where trade-offs on pacing existed; and
- To solicit customer feedback on Toronto Hydro's planning development process, including the customer engagement process.

The Phase 2 approach involved two different methods: a workbook and surveys. Innovative developed an online workbook to gather input from any interested residential, small business, or mid-market customer. Toronto Hydro took a number of steps to increase the visibility of the workbook, including: emailing over 200,000 residential and small business customers notifying them about the workbook; advertising the workbook in the utility's electronic newsletter delivered to nearly 200,000 customers; and promoting the workbook through social media posts, which made over 40,000 impressions (Twitter and Facebook).

Innovative developed surveys based on the feedback from the online workbook. A randomly recruited telephone survey was executed for residential, small business and mid-market customers, and an online survey was done to gather input from Key Account customers. All Key Account customers were notified by email about the survey and reminder emails were sent to encourage its completion. Details about both surveys are provided in the Innovative Report.

Based on the results, Innovative concluded that customers' needs and preferences identified in Phase 1 were consistent with customer feedback received in Phase 2. Customers were also strongly supportive of the customer engagement process used to collect and use customer needs and preferences.

Innovative further concluded that customers generally supported Toronto Hydro's proposed plan, and that "majorities of residential, small business, mid-mark and key account customers say [the utility] should stick with its proposed plan or do more."[4] Innovative also found a range of customer support for the various investment pacing trade-offs presented to customers. For example, a majority of customers favoured a more limited involvement by Toronto Hydro in support of microgrids, in contrast to strong support for increasing the pace of investments in monitoring and control equipment and network units.

In response to the conclusion that customers generally supported the plan, Toronto Hydro made only modest refinements to its plan. Given the particularly strong support across customer classes for programs that address the risk of network vault floods and fires (i.e. Network Unit Renewal and Network Condition Monitoring & Control), Toronto made minor adjustments to the pace of these programs to address these issues at an accelerated pace over the 2020-2024 period. Exhibit 2B, Section E2.3 discusses in detail how Customer Engagement results are reflected in the 2020-2024 Capital Expenditure Plan, including the final adjustments made in response to Phase 2 results.

[4] Ibid. pg. 3.

3.2.1 Continuous Improvement

The Planning-specific Customer Engagement described in this evidence represents an evolution in the process used in connection with Toronto Hydro's 2015 CIR Application in a number of important ways. Phase 1 was introduced as an entirely new process and purposefully sequenced to inform the development of the business plan.

The Phase 2 process was changed in a number of ways. Customers were provided specific information about Toronto Hydro's planning process, how it solicited feedback from customers, and information about Toronto Hydro's cost benchmarking performance. The results of the Phase 1 engagement were summarized and customers were again asked to rank priorities to evaluate if the needs and preferences that informed the business plan had changed. Program-specific information, including activities, outcomes, and bill impacts were shared in respect of trade-offs where customer input was sought. And customers participating in the online workbook were shown the estimated net bill impact of their trade-off choices and allowed to change their responses if desired.

3.2.2 Ongoing Customer Engagement

Ongoing Customer Engagement occurs and informs decision-making at Toronto Hydro through the range of interactions that are primarily intended to deliver valued customer services.

Toronto Hydro's customer services, outlined in the Customer Care program (Exhibit 4A, Tab 2, Schedule 14), respond to the needs of the utility's wide array of customers. The utility serves a large and diverse base of approximately 768,000 customers, ranging from individual residential consumers to large industrial and commercial businesses. Toronto 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.

Finally, Toronto Hydro's plans are responsive to the priorities of local government. An example is *TransformTO*, which identifies how the City of Toronto plans to reduce greenhouse gas emission and improve health, grow the economy and improve social equity. Toronto Hydro plans to partner with the Toronto Transit Commission ("TTC") to make improvements and additions to nearby distribution plant to support the conversion of the TTC's bus fleet from diesel hybrid to electric. For more information on Toronto Hydro's engagements with the City of Toronto, see Section D2.1 of the DSP.

TAB 13

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.

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

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.

TAB 14

A1 Introduction

Toronto Hydro's Distribution System Plan ("DSP") provides a detailed and comprehensive view of the utility's capital investment plans and supporting information for the 2020-2024 period. The capital programs described and justified in this plan address urgent and necessary work related to the distribution system assets that safely power the City of Toronto, as well as the general plant assets that keep the utility's "24/7" operations running and responsive to customer needs and requests.

This plan continues the utility's effort to renew a significant backlog of deteriorated and obsolete assets at risk of failure, and to adapt to the continuously evolving challenge of serving, and operating within a dense, mature, and growing major city. Toronto Hydro is on track to successfully complete its previous plan for 2015-2019, with adjustments for typical changes and evolving circumstances, including the final rates approved by the Ontario Energy Board ("OEB") for that period. Efforts to date have resulted in gradual improvements to reliability, the overall age of the system, and other performance indicators.

Despite these initial signs of progress, reinvesting in the short-term performance and long-term viability of an aged, deteriorated, and highly utilized system remains an urgent priority for the utility. Recent extreme weather events, accompanied by growing evidence of the impact of climate change on weather patterns in Toronto, have amplified this need, underscoring the challenge to build a resilient system for the long-term. At the same time, technology and innovation are driving a more dynamic system that is transitioning away from the usual patterns of supply and demand, adding additional complexity and urgency to the challenge of modernizing the grid, which in turn is driving investment needs in information technology and cyber security solutions.

The 2020-2024 DSP strikes a balance between these pressing needs and customer preferences for (i) keeping prices as low as possible, (ii) maintaining average reliability, (iii) improving reliability for customers experiencing below-average service, and (iv) balancing other priorities (e.g. customer service) with the need to contain rate increases. The resulting five-year capital expenditure plan represents the minimum level of investment needed to ensure this balance is achieved, while avoiding the accumulation of asset risk and associated declines in performance over the long-term.

Toronto Hydro developed the DSP in full accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, and in alignment with the principles and objectives of the OEB's *Renewed Regulatory Framework* ("RRF"), including the updated guidance in the OEB's aligned with the regional plans developed in coordination with the IESO and Hydro One as summarized in Section B, Coordinated Planning with Third Parties.

Another relevant aspect of economic growth in the City of Toronto is the number of large, third-party infrastructure renewal and expansion projects that require Toronto Hydro to relocate its existing infrastructure. Toronto Hydro is obligated by the *Public Service Works on Highways Act*[10] ("PSWHA") and section 3.4 of the Distribution System Code ("DSC") to accommodate these third-party requests in a fair and reasonable manner. For the 2020-2024 period, the utility is expecting greater needs in this area due to a larger number of committed relocation and expansion projects by Metrolinx, the Toronto Transit Commission, and the City of Toronto.

A4.1.4 System Challenges: Technology Advancement

Technology advancements are a major challenge in the electricity distribution sector globally. The challenge is in many ways greater for distributors in major urban centres. The most prominent example of that challenge may be the complexity of integrating distributed energy resources on heavily loaded feeders in dense built-out areas that serve customers sensitive to power quality.

Interest in generation projects within Toronto Hydro's service territory has been steady in recent years, and is anticipated to continue into the future. Toronto Hydro has connected approximately 1,800 distributed generation connections. The utility is regularly approached by its customers to discuss utility options for or capacity to facilitate net metering and battery energy storage. Inquiries regarding conventional generators have also increased as micro-turbine based installations become more economically viable and commercial and industrial customers attempt to increase site reliability and operational cost savings.

Toronto Hydro is obligated to facilitate the safe, timely, and cost-efficient connection of distributed energy resources to its grid, and the connection of renewable energy generation projections remains a key public policy-aligned objective. The utility's Generation Capacity and Capability Assessment (described in Section E3.3) has identified a number of potential barriers to connecting the forecasted 581 MW of incremental distributed generation anticipated by 2024, including short-circuit capacity constraints, islanding risks, and system thermal limits. Toronto Hydro's Customer Connections (E5.1), Generation Protection, Monitoring, and Control (E5.5), and Energy Storage Systems (E7.2) programs all contain necessary investments specifically targeted at connecting and facilitating distributed

[10] R.S.O. 1990, c. P-49.

TAB 15

E2 Capital Expenditure Planning Process Overview

Section E2 provides a comprehensive overview of how Toronto Hydro developed its 2020-2024 Capital Expenditure Plan, including the pacing and prioritization decisions that the utility made to support the delivery of outcomes that align with customer needs and preferences. This section is organized into the following three areas:

- **Section E2.1** describes the sequence of business planning activities that produced the Capital Expenditure Plan, and provides an overview of the utility's key considerations and decisions during this process.
- **Section E2.2** focuses on the outputs of Toronto Hydro's asset management and operational planning processes (described in Section D) and how they influenced the pacing and prioritization of the capital expenditure plan.
- **Section E2.3** describes the results of the utility's planning-specific Customer Engagement and how Toronto Hydro developed a plan that is aligned with and responsive to customer needs, preferences and priorities.

Fully detailed justifications and business cases for all of Toronto Hydro's planned capital expenditures can be found in the capital program sections in E5 through E8.

E2.1 Capital Planning in Business Planning

Toronto Hydro's 2020-2024 Capital Expenditure Plan was an output of its outcomes-oriented, customer-focused business planning activities. The plan was derived from the utility's distribution system asset management processes and other operational planning activities, including outputs from the Investment Planning & Portfolio Reporting ("IPPR") process described in Sections D1 and D3. A high-level view of business planning as it relates to the Capital Expenditure Plan is shown in Figure 1.

The following sections explain how each of the elements in this process contributed to the production of the 2020-2024 Capital Expenditure Plan for system-related investments.

E2.2.1 Asset Management Strategies and Outcomes for 2020-2024

As summarized in Section D1, Toronto Hydro integrated its customer-focused Outcomes Framework into planning for 2017 and refined the strategic parameters into specific outcome objectives for the 2020-2024 period as summarized in the table below.

Table 1: Asset Management Outcomes Objectives

Outcome	Objectives
Customer Service	• Continue connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers. • Comply with customer service regulations and standards over the 2020-2024 period.
Reliability & Safety	• Maintain and, where appropriate, reduce asset failure risk – as represented by leading indicators like asset condition – over the 2020-2024 period, supporting stable system reliability and safety outcomes for current and future customers. • Maintain system reliability at current levels over the 2020-2024 period while (1) improving the experience for customers with poor reliability and power quality, and (2) improving the resiliency of the distribution system. • Continue to reduce and eliminate public and employee safety risks, for example by removing higher-risk legacy assets from the system within a specific and reasonable timeframe. • Strive for zero public and employee safety incidents over the 2020-2024 period. • Comply with all safety regulations and standards over the 2020-2024 period.
Public Policy	• Respond effectively to public policy during the 2020-2024 period, including by enabling the timely connection of all forecasted renewable generation projects and implementing a Conservation First approach where appropriate.
Environment	• Endeavour to eliminate the risk of PCB-contaminated oil spills by 2025. • Reduce the system's impact on the environment caused by greenhouse gas emissions and oil leaks of all types. • Comply with all environmental regulations and standards over the 2020-2024 period.
Financial	• Minimize average rate increases over the 2020-2024 period while continuously improving the value delivered to current and future customers.

TAB 16

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

GTA North Region

Date: March 20, 2018

Prepared by: GTA North Region Study Team

In the previous RIP, the study team recommended to continue the assessment of wires and non-wires options to address the need for additional transformation capacity in the Markham-Richmond Hill area and to refine the need timing. During the RIP, Alectra advised that they were updating their load forecast and the need date may change (for more details, refer to section 7.1.4 of the RIP report). In April 2017, the IESO issued a letter of support to Hydro One Transmission and Alectra to proceed with wires planning for a new 230/27.6kV DESN and the associated distribution and/or transmission lines to connect the new transformer station. In the hand-off letter, the IESO concluded that it is not feasible to rely entirely on distributed energy resources to defer the near-term supply need in the area and that a new station and associated connection lines would be required by 2023 to meet the growth projections in the Markham-Richmond Hill area. Based on the current extreme summer weather non-coincident peak net load forecast, the need for additional transformation capacity is projected to be in the 2025-2026[3] timeframe. If CDM savings are not achieved as forecasted, then the need date can be as early as 2024.

The Study Team reaffirms this need and Hydro One and Alectra are currently in the process of selecting a preferred location to connect to 230 kV circuits P45/P46. Following this, Hydro One will proceed with development and estimate work to meet the need date. Further updates will be included in the next IRRP and RIP.

7.2.5 Station Service Supply to York Energy Centre

In the previous RIP, a need for addressing station service supply to York Energy Centre (currently supplied from Holland TS) in the event of a (i) low-voltage breaker failure at Holland TS or (ii) double circuit 230 kV contingency was identified (for more details, refer to section 7.2.1 of the RIP report). These events can result in an interruption to the station service supply to York Energy Centre and therefore the loss of all generation output until the station service can be restored from the alternate source.

Since the RIP, the IESO completed a System Impact Assessment (SIA) for the new 230 kV in-line breakers at Holland TS and it found that the use of load rejection will no longer be a suitable means to address (i) and (ii) in the near to medium term as the amount of load rejection required to address overloads and voltage collapse will exceed the permissible amount of 150 MW allowed by ORTAC load security criteria.

The Study Team reaffirms this need and recommends further assessment and regional coordination in the IRRP and RIP phase to review options and develop a preferred plan.

7.2.6 Northern York Area Transformation Capacity

In the previous RIP, the study team recommended that the need for additional transformation capacity in the Northern York Area, along with associated transmission capacity[4], be further assessed in the next regional planning cycle (for more details, refer to section 7.2.2 of the RIP report). Based on the current

[3] The need date will be further refined by Hydro One and Alectra through the project development process
[4] There are long-term transmission supply needs associated with new transformation capacity

TAB 17

CENTRAL TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN

Part of the Metro Toronto Planning Region | April 28, 2015

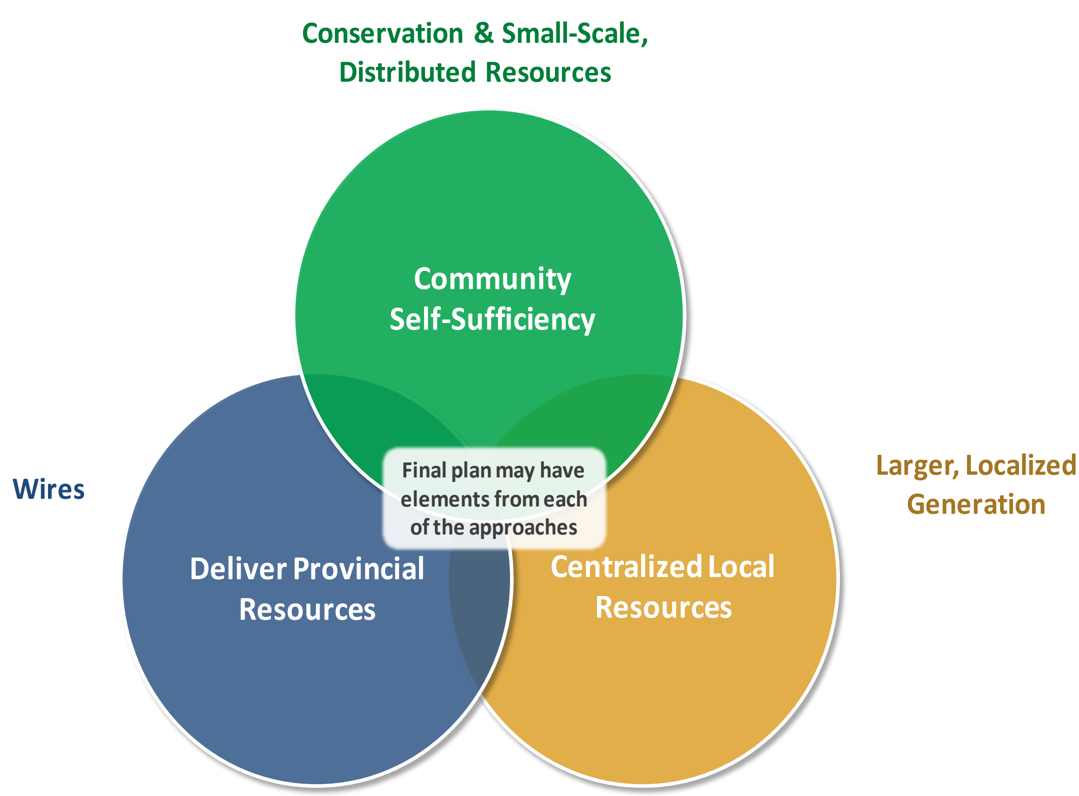
ieso
Independent Electricity System Operator

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increased community interest in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might envision its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (Figure 8-3). Based on regional planning experience across the province over the last ten years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by customers and the community in planning and developing local energy systems.

Figure 8-3: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional planning approach associated with the development of electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets, demand response, local renewable, DG and storage, smart grid technologies for managing distributed generation resources; integrated heat/power/process systems and electric vehicles ("EV"). While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test these options before commitment to specific projects is required. The success of this approach depends on early action to explore potential and develop options; it also requires the local community to take a lead role. This could be through a Community Energy Planning process, or a LDC or other local entity taking the initiative to pursue and develop options.

The intent of this discussion, going forward, is to identify which approach should be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches, and there will necessarily be some overlap between them. For example, provincially mandated conservation policies will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. As well, it is likely that all plans will contain some combination of conservation, local generation, transmission, and distribution elements. Once the preferences of the community are made clear, a plan can be developed around the approach that makes the most sense, which will affect the relative balance of conservation, generation, and wires in the plan. Details of how these three approaches could be developed to meet the specific long-term needs of Central Toronto are provided in the following sections.

The cost of the generation would depend on the size and technology of the units chosen, as well as the degree to which they can contribute to a provincial capacity or energy need.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Toronto under an approach that favours community self-sufficiency requires leadership from the community itself to identify opportunities and deploy solutions. As this approach relies to a great degree on new and emerging technologies, there will be a need to develop and test solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

In Toronto, there is strong community interest in this approach, as evidenced by the municipality taking the lead in identifying and developing energy-based opportunities within the city. Some of these initiatives are described below.

Community Energy Plans

A Community Energy Plan[27] ("CEP") is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas ("GHG") emissions. A number of municipalities across the province are undertaking Community Energy Plans to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans that better align energy, infrastructure and land use planning within the community.

The City of Toronto has completed a number of Community Energy Plans and others are in progress. While these plans may, more typically, be conducted at the level of the municipality, the size and character of the City of Toronto has resulted in a number of plans being done across the City. The CEPs completed and underway in the City of Toronto include:

- Etobicoke Centre (completed 2008)
- North York (completed 2010)
- Etobicoke – Mimico (completed 2012)
- Scarborough Centre (completed 2014)
- Downtown – Lower Yonge Precinct (in-progress)
- Etobicoke Centre – Six Points Interchange Reconfiguration (in-progress)
- North York – York University (in-progress)

[27] These plans are sometimes referred to as "Municipal Energy Plans."

Integrated energy planning at the community level provides an opportunity for broader consideration of land-use, development and growth, infrastructure requirements and technology solutions that include:

- Advanced fuel cell technologies
- Energy storage technologies
- Demand response programs – particularly residential and small commercial demand response programs enabled by aggregators
- Aggressive conservation programs targeted at residential consumers and enabled by next-generation home area networks
- Battery electric vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies
- Combined Heat and Power and district energy opportunities
- Renewed consideration of the Load Serving Entity/aggregator market model

The Working Group recognizes that there are risks associated with the community self-sufficiency approach, with the most crucial being the ability to successfully meet the electricity demand growth needs with new and unproven load management and storage technologies. Other key challenges include demonstrating consumer value, cost recovery certainty for innovative technologies and the risk of asset stranding, risk/reward incentives and technological obsolescence as a factor for asset replacement.

TAB 18

As explained in the System Renewal program justifications in Section E6, Toronto hydro is proposing a pace of renewal investment in a number of core programs that is the minimum required to prevent these age and condition-related risks from worsening over the 2020-2024 period. For instance, without the proposed proactive intervention in the overhead asset class, Toronto Hydro projects that the percentage of pole top transformers having reached or exceeded useful life will increase from 14 percent as of 2017 to approximately 40 percent by 2024, and the number of poles with material deterioration could nearly triple to over 30,000.

The utility also continues to face challenges related to higher-risk, obsolete, legacy assets, and asset configurations such as rear lot plant, box construction, non-submersible network equipment, and direct-buried cable. Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards, often featuring obsolete components with limited or no suppliers or skilled labour to support maintenance, repair, or replacement. Due to asset-specific defects or deficiencies, these assets typically carry elevated reliability, safety, or environmental risks. For example, direct-buried cable and non-submersible network protectors are highly susceptible to moisture-related damage and continue to be significant contributors to reliability and safety risk. Another example is transformers at risk of spilling PCB-contaminated oil. Toronto Hydro's pole-top and underground transformer replacement strategies for 2020-2024 are driven in part by the utility's efforts to effectively eliminate this critical environmental risk over the period.

Toronto Hydro has seen improvements in the frequency and duration of outages caused by defective equipment. However, defective equipment continues to be, by far, the largest contributor to outage frequency (i.e. SAIFI), at 36 percent, and outage duration (i.e. SAIDI), at 44 percent. In light of the age, condition, and legacy asset risks discussed above, Toronto Hydro concludes that a shift to a more reactive renewal approach would result in a decline in reliability over the short- and long-term, with potentially significant impacts for customers in areas served by legacy assets such as direct-buried cable and rear-lot plant. A reactive renewal approach would also be more costly over the long-term.

A4.1.2 System Challenges: Climate Change and Adverse Weather

On top of the reliability challenges posed by a backlog of deteriorating and obsolete equipment, Toronto Hydro anticipates that increasingly frequent adverse and extreme weather events will put additional reliability pressures on the system, making the resiliency of the system and the utility's operations a greater concern over the medium- to long-term than in past planning cycles.

Climate change is a significant factor influencing Toronto Hydro's planning and operations. By the year 2050, Toronto's climate is forecast to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures over 25°C are expected to occur 106 times per year as opposed to 66 times per year currently. Daily maximum temperatures over 40°C, which have historically been an anomaly, are projected to occur up to seven times per year by 2050.[3] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events such as ice storms and extreme rainfall events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, but trends from the past 20 years suggest that these changes are already affecting the system. Figure 4 below depicts cumulative rainfall and the number of high wind days in Toronto over the past 20 years. With respect to rainfall, seven of the 10 highest rain fall years have occurred in the last 10 years. Similarly, six of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have also occurred in the last 10 years.

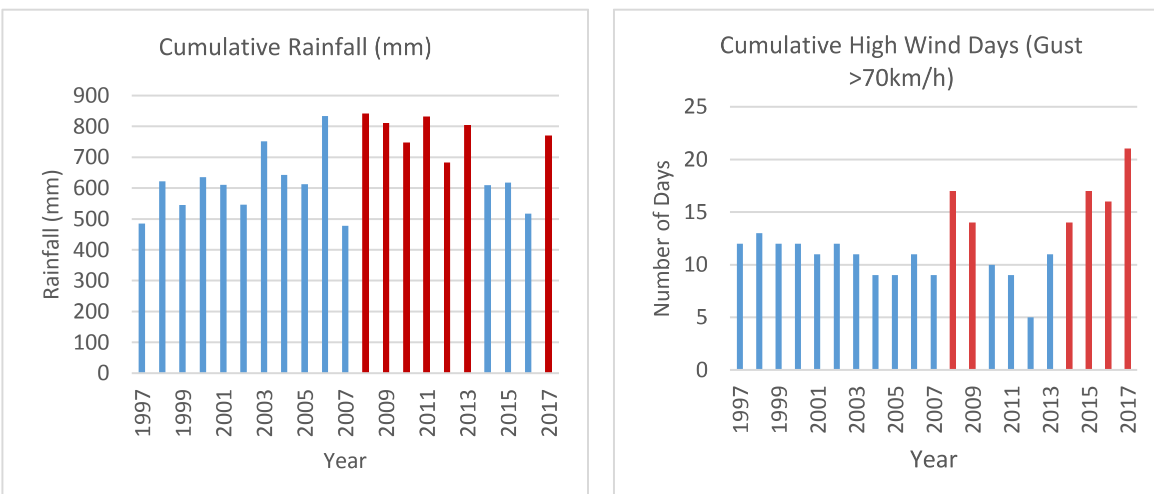


Figure 4: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[4]

[3] See Appendix D to Section D – Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment by AECOM (June 2015)

[4] Weather data compiled using Toronto Lester B. Pearson INTL A for January 1997 to June 2013 and Toronto INTL A for July 2013 to December 2017. Available from: Government of Canada, Weather, Climate and Hazard Historical Data online: <http://climate.weather.gc.ca/historical_data/search_historic_data_e.html>

Recent extreme weather events (see Table 4, below) have repeatedly and pervasively affected Toronto Hydro's customers. Extreme weather events in 2017 resulted in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years. Similarly, in 2018, Toronto Hydro experienced four extreme storms during the first half of the year.

These circumstances drive Toronto Hydro to continue emphasizing plans and programs that facilitate and improve its system resiliency and ability to respond to these events. This is reflected in the fact that all of the utility's investment categories include at least some investments that support this objective. System Renewal work – and especially the renewal of legacy asset types – will contribute to system hardening by improving asset health and introducing updated equipment design and construction standards that are better suited to the changing operating environment. Grid modernization efforts in the System Access,[5] System Renewal, [6] System Service,[7] and General Plant[8] categories will help the utility respond to major events more effectively. Neglecting to make these investments during the 2020-2024 period could leave the utility ill-prepared for the effects of climate change, leading to a potential decline in service and higher costs related to reactive and emergency scenarios.

Table 4: Extreme Weather Events since the Beginning of 2017

Event	Description
Freezing Rain (February 2017)	• Approximately 2-6 mm of freezing rain followed by additional heavy rain. • Estimated 9,200 customers out at peak; all customers restored within 24 hours of the start of the freezing rain event.
High-water/flooding (May - June 2017)	• Heavy rainfall in southern Ontario exceeded the yearly average for an entire summer. • Numerous incidents of high-water/flooding reported across Toronto. • No customers were directly impacted during this 55-day incident due to the utility's proactive damage assessment and DPM mitigation measures, including flood mitigation efforts.

[5] For example, replacing end-of-life meters with next-generation smart meters.
[6] For example, replacing end-of-life stations assets with assets equipped with modern SCADA-enabled remote monitoring and control capabilities.
[7] For example, installing remote sensing capabilities in network vaults to detect floods before they damage equipment.
[8] For example, creating a fully functional dual control centre (refer to Section E8.1).

Event	Description
Wind Storm (October 2017)	• Strong wind gusts approaching 100 km/h in some areas and lasting approximately 3 hours. • Estimated 43,000 customers out at peak. • 90 percent of customers restored within 11 hours of event; all customers restored within 48 hours of the end of the event.
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice Storm (April 2018)	• Approximately 10-20 mm of freezing rain, 20-25 mm rain, sustained winds of 70 km/h with gusts up to 110 km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind Storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120 km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event.
Flash Storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event.

A4.1.3 System Challenges: City Growth and Capacity Constraints

By 2020, Toronto Hydro expects to be distributing electricity to approximately 768,000 customers with a peak load of 4,316 MW. This continues a steady trajectory of customer growth and it is expected to continue. Despite this growth, overall system peak load (which is temperature-dependent) has remained relatively steady in recent years at approximately 5,000 MVA. Meanwhile, Toronto continues to experience concentrated load growth in certain areas of the City, primarily due to the high number of large condominium developments. Figure 5 illustrates how this type of growth continues to outpace nearly all North American cities. This concentrated growth is mainly observed in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue (and in the near future other corridors, such as Eglinton Avenue and Finch Avenue).

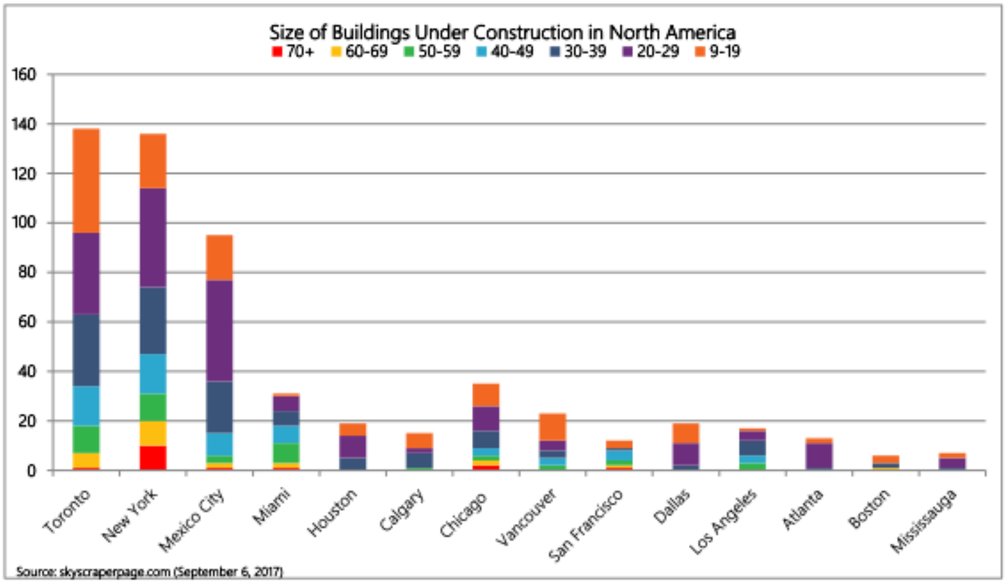


Figure 5: Number of Floors for High-Rise & Mid-Rise Buildings under Construction[9]

This growth is pushing certain distribution equipment to capacity. Infrastructure renewal and upgrades are urgently required to support that growth while maintaining reliability and safety outcomes. Investments in the System Access and System Service categories are driven by this projected level of demand. For example, Toronto Hydro projects increases in the costs associated with connecting customers and upgrading customer connections during the 2020-2024 period. Toronto Hydro must also continue investing proactively in its Load Demand (Section E5.3) and Stations Expansion (Section E7.4) programs to ensure adequate station bus capacity and feeder positions is available on the system. Failure to make these investments could have a detrimental effect on the utility's ability to connect future customers cost-effectively, without affecting reliability performance for existing customers. Furthermore, the failure to maintain and improve system operational flexibility will hamper the utility's ability to efficiently execute capital and maintenance work. Toronto Hydro's planned capacity-related investments for the 2020-2024 period are fully

[9] Toronto Economic Bulletin (September 26, 2017) : <https://www.toronto.ca/legdocs/mmis/2017/ed/bgrd/backgroundfile-107204.pdf>.

aligned with the regional plans developed in coordination with the IESO and Hydro One as summarized in Section B, Coordinated Planning with Third Parties.

Another relevant aspect of economic growth in the City of Toronto is the number of large, third-party infrastructure renewal and expansion projects that require Toronto Hydro to relocate its existing infrastructure. Toronto Hydro is obligated by the *Public Service Works on Highways Act*[10] ("PSWHA") and section 3.4 of the Distribution System Code ("DSC") to accommodate these third-party requests in a fair and reasonable manner. For the 2020-2024 period, the utility is expecting greater needs in this area due to a larger number of committed relocation and expansion projects by Metrolinx, the Toronto Transit Commission, and the City of Toronto.

A4.1.4 System Challenges: Technology Advancement

Technology advancements are a major challenge in the electricity distribution sector globally. The challenge is in many ways greater for distributors in major urban centres. The most prominent example of that challenge may be the complexity of integrating distributed energy resources on heavily loaded feeders in dense built-out areas that serve customers sensitive to power quality.

Interest in generation projects within Toronto Hydro's service territory has been steady in recent years, and is anticipated to continue into the future. Toronto Hydro has connected approximately 1,800 distributed generation connections. The utility is regularly approached by its customers to discuss utility options for or capacity to facilitate net metering and battery energy storage. Inquiries regarding conventional generators have also increased as micro-turbine based installations become more economically viable and commercial and industrial customers attempt to increase site reliability and operational cost savings.

Toronto Hydro is obligated to facilitate the safe, timely, and cost-efficient connection of distributed energy resources to its grid, and the connection of renewable energy generation projections remains a key public policy-aligned objective. The utility's Generation Capacity and Capability Assessment (described in Section E3.3) has identified a number of potential barriers to connecting the forecasted 581 MW of incremental distributed generation anticipated by 2024, including short-circuit capacity constraints, islanding risks, and system thermal limits. Toronto Hydro's Customer Connections (E5.1), Generation Protection, Monitoring, and Control (E5.5), and Energy Storage Systems (E7.2) programs all contain necessary investments specifically targeted at connecting and facilitating distributed

[10] R.S.O. 1990, c. P-49.

To keep pace with the growing city and ensure appropriate distribution system capacity, the utility plans to continue actively investing through the following programs, further described in Section E:

- Customer Connections (Section E5.1);
- Stations Expansion (Section E7.4);
- Load Demand (Section E5.3); and
- Generation Protection Monitoring & Control (Section E5.5).

D2.1.2 Climate and Weather

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. By the year 2050, Toronto's climate is forecasted to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures of 25°C are expected to occur 106 times per year as opposed to 66 times per year currently. Daily maximum temperatures over 40°C, which have historically been an anomaly, are projected to occur up to seven times per year by 2050.[1] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events such as ice storms and extreme rainfall events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Heat, high winds, heavy rainfall, freezing rain, and heavy snowfall have the potential to cause major system damage and extensive outages. Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, trends from the past 20 years suggest that these changes are already affecting the system. Figure 6 below contains two charts depicting cumulative rainfall and the number of high wind days (i.e. with wind gusts exceeding 70 kilometres per hour) in Toronto over the past 20 years. With respect to rainfall, seven of the 10 highest rain fall years have occurred in the last 10 years. Similarly, six of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have also occurred in the last 10 years (these years are highlighted in red).

[1] See Appendix D – Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment by AECOM (June 2015)

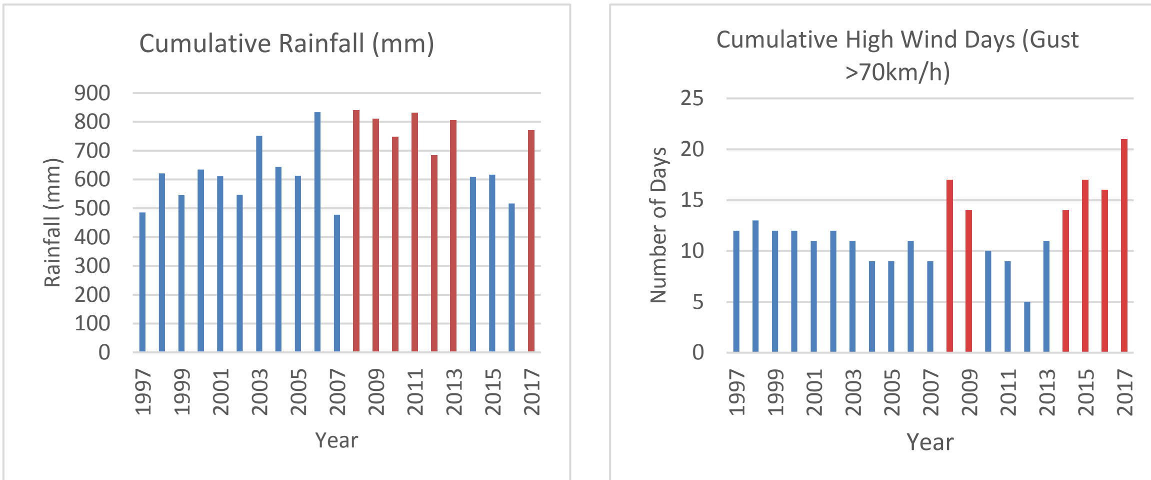


Figure 6: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[2]

These weather trends have increased reliability risks for Toronto Hydro's distribution system. Parts of the underground system are sensitive to significant rainfall, and in particular flooding, while the overhead system in general is sensitive to high winds, freezing rain and wet snow events resulting in damage and outages (e.g. from vegetation impact in proximity to overhead lines). In extreme cases, broken trees and the weight of ice and snow accretions bring lines, poles and associated equipment to the ground.

The aforementioned reliability risks are significant, as evidenced by examples of events that occurred in 2017. April and May of 2017 saw significant rainfall, causing a number of Toronto Hydro's vaults and cable chambers in the underground system to flood. From the perspective of the overhead system, high wind events in 2017 resulted in a 72 percent increase in the number of customer interruptions attributed to tree contacts compared to the average of the previous five years. Similarly, 2018 has seen significant storms and related damage, with four major events occurring during the first half of the year.

To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol.[3] The

[2] Weather data compiled using Toronto Lester B. Pearson INTL A for January 1997 to June 2013 and Toronto INTL A for July 2013 to December 2017. Available from: Government of Canada, Weather, Climate and Hazard Historical Data online: <http://climate.weather.gc.ca/historical_data/search_historic_data_e.html>

[3] See Appendix D to Section D.

assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model.

Existing codes, standards, and regulations were developed with regard to historical weather data and do not always account for ongoing and future changes to the climate. In efforts to close this gap, Toronto Hydro now utilizes climate data projections for temperature, rainfall, and freezing rain in its equipment specifications and station load forecasting. Further, Toronto Hydro reviewed and updated major equipment specifications in 2016 to adapt to climate change, including:

- Revisions to submersible transformer specifications to require stainless steel construction and testing of the equipment's ability to withstand fully flooded conditions;
- Replacement of air-vented, padmounted switches with new standard SF_6 sealed-type, padmounted switches to remove risk of failure due to ingress of dirt and road contaminants on the live (i.e. energized) surface;
- Initiation of trials of solid dielectric transformers that do not contain oil and are designed to withstand extreme environmental conditions underground; and
- Adoption of breakaway links in tree-covered areas for residential customers with overhead service connections, intended to facilitate faster restoration after extreme weather and prevent damage to customer-owned service masts.

As part of the climate change adaptation roadmap, Toronto Hydro conducted analyses between 2016 and 2017 to better understand how assets and operational practices could be impacted by climate change:

1) An asset impact review that looked at how each type of asset is affected by the different aspects of climate change. Resulting recommendations for each type of asset were used to alter maintenance and asset management programs.
2) An industry review of climate adaptation best practices that included an evaluation of other major utilities as well as published papers. Vegetation management practices, system hardening practices, design criteria, and maintenance practices were areas identified as being affected by climate change.
3) An emergency restoration analysis to evaluate various strategies in the event of a failure in the underground electrical distribution infrastructure when load switching or re-routing is

not feasible. Restoration methods that utilities, specialized companies, and manufacturers have developed in this field were reviewed in order to restore the network as quickly and efficiently as possible. Evaluations and trials of the proposed methods will be investigated and tested prior to being implemented as a standard practice.

The following 2020-2024 program activities will contribute to Toronto Hydro's ongoing efforts to renew and enhance its system to increase resiliency to changes in the weather and climate, thereby supporting the continued delivery of outcomes expected by existing and future customers:

- As assets are replaced in the Overhead System Renewal program (Exhibit 2B, Section E6.5), Toronto Hydro will install taller poles with armless construction and tree-proof wire to reduce vegetation contact risks.
- Stainless steel submersible transformers will replace existing units as the utility carries out its Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2).
- Underground System Renewal – Horseshoe program will also replace air-vented padmounted switches with SF_6 sealed-type padmounted switches to mitigate risk of failure due to ingress of dirt and road contaminants on the live surface.
- The Network System Renewal program (Exhibit 2B, Section E6.4) will replace non-submersible automatic transfer switches and remote power breakers with submersible equipment to tolerate flooding.
- The Network System Renewal program will also replace other end-of-life and deteriorated non-submersible protectors with submersible protectors to protect against flooding.
- The Network Condition Monitoring & Control program (Exhibit 2B, Section E7.3) will help the utility detect flooding in network vaults before it damages equipment.
- The Network Circuit Reconfiguration segment under the Network System Renewal program (Exhibit 2B, Section E6.4) will help the utility improve system restoration capabilities in the event of outages.
- Installation of flood mitigation systems at stations identified as being vulnerable to flooding will occur under the Stations Renewal program (Exhibit 2B, Section E6.6).
- New switchgear installed in the Stations Renewal or Station Expansion (Exhibit 2B, Section E6.6 and E7.4) programs will be specified to mitigate flood risk where appropriate (e.g. installing air-tight SF_6 switchgear or other engineered solutions).

- The Control Operations Reinforcement program (Exhibit 2B, Section E8.1) will improve Toronto Hydro's operational resiliency by developing a dual control centre at an existing work location.

Toronto Hydro is a partner of the City of Toronto in planning and preparing for the effects of climate change. The City's *ResilientTO* initiative includes a Resilient City Working Group that facilities collaboration between City divisions, agencies and corporations and external stakeholders on the topic of climate change resilience. Members share knowledge and technical information to facilitate the implementation of resilience actions within their operations.

D2.1.3 Economic Profile

The City of Toronto is Canada's economic and financial hub. It is home to the Toronto Stock Exchange, as well as the headquarters of five of the nation's largest banks. Toronto accounts for 10 percent of Canada's Gross Domestic Product ("GDP").[4] Its GDP growth has outperformed not only the national average, but also many of the most developed countries in the world in the past year, which is a trend that is expected to continue over the next year.[5]

Toronto also has a diverse industrial and commercial base comprised of 13 key sectors including aerospace, financial services, education, life sciences, technology, food, entertainment, and tourism.[6] The critical and growing importance of Toronto's economy underscores the necessity of continuing to invest sufficiently to ensure the delivery of value for current and future distribution customers and to prepare for technology driven change in this highly urbanized area.

D2.1.4 Toronto Hydro's Evolving Role in the City of Toronto

The role that Toronto Hydro plays in its service territory is evolving as new technologies emerge. In many cases, local and provincial policy imperatives aim to accelerate the uptake of new energy related technologies such as distributed generation and energy resources, and power quality, reliability and resiliency solutions.

[4] City of Toronto, Business and Economic Development facts, (2013), online: <http://www.toronto.ca/toronto_facts/business_econdev.html>. ["Toronto Business and Economic Development Facts"]
[5] City of Toronto, Toronto Economic Bulletin, Conference Board (December 2016 & September 2017) and OECD Economic Outlook – Interim Release, September 2017
[6] City of Toronto, Business & Economy, online: <https://www.toronto.ca/business-economy/industry-sector-support/>. ["Industry Sector Support"].

TAB 19

E6.1 Area Conversions

E6.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 185.7	**2020-2024 Cost ($M):** 220.8
Segments: Rear Lot Conversion, Box Construction Conversion	
Trigger Driver: Functional Obsolescence	
Outcomes: Reliability, Safety, Customer Service, Public Policy	

The Area Conversions program ("the Program") funds the replacement of functionally obsolete 4.16 kV distribution system designs with updated standard 13.8 kV and 27.6 kV lines; focusing mainly on two unique legacy 4.16 kV asset designs known as Rear Lot Construction and Box Construction. These assets serve residential customers in the Horseshoe region, and small commercial and residential customers along main streets in the downtown area of pre-amalgamation City of Toronto. The Program is designed to address below-average customer reliability outcomes, mitigate public and employee safety risks and other operational and customer service deficiencies posed by these legacy and aging assets.

The Program is grouped into the segments summarized below and is a continuation of the renewal activities described in Toronto Hydro's 2015-2019 Distribution System Plan.1

- **Rear Lot Conversion:** this segment continues the replacement of end-of-life overhead and underground assets installed in the backyard, or rear lot, with standard front lot underground supply. Typically installed over 40 years ago, these assets serving residential customers in the Horseshoe region of Toronto present significant safety and reliability risks in the event of failure. Toronto Hydro is on track to successfully upgrade approximately 2,400 rear lot customers to front lot 27.6 kV underground services during the 2015-2019 period. Toronto Hydro's overall objective for this segment is to mitigate and eventually eliminate rear lot equipment failure risk, as failures result in long duration outages and safety risks to customers and crews given the nature of the rear lot plant. To this end, Toronto Hydro plans to spend $109.3 million to convert an additional 2,350 customers over 2020-2024. This

[1] EB-2014-0116, Exhibit 2B, Section E6.6 and E6.7

Safety	• Contributes to improving Toronto Hydro's Box Construction Conversion Measure, public safety performance and employee safety by mitigating safety risks that are unique to obsolete rear lot and box construction designs. Specifically:
	  ○ Eliminate public safety risks to address compliance issues (i.e. relating to Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority) associated with legacy box construction feeders by replacing approximately three quarters of remaining box construction assets by 2024, with a target of 100 percent elimination by 2026.
	  ○ Maintain the pace of rear lot conversion in order to mitigate the risk of equipment failure and safety issues arising from potential crew and public exposure to rear lot access.

Customer Service	• Contributes to Toronto Hydro's customer service performance and customer satisfaction by:
	  ○ Minimizing the need for unplanned crew access of customer property by converting approximately 2,350 residential rear lot customers to front lot service.
	  ○ Improving the speed and cost-efficiency of customer grid access (including generation and electric vehicle access) in high-growth areas of downtown Toronto by converting approximately 2,600 poles (containing approximately 100 kilometres of low capacity and low clearance box construction feeders) to more efficient and flexible higher voltage standards.
	  ○ Reducing public traffic disruptions on main city streets from an operational and maintenance perspective (i.e. less frequent repairs and visits) once the box construction is converted.

Environment	• Contributes to improving Toronto Hydro's Spills of oil Containing PCBs measure by eliminating all PCB at-risk transformers on the box construction and rear lot plant by the end of 2024.

TAB 20

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

Essex Energy Corporation's 2017 study, "The Study of Energy Storage in Ontario's Distribution Systems," was requested by the Ministry of Energy in March 2016. The report describes a number of benefits of energy storage, including distribution system upgrade avoidance, new generation capacity avoidance, redundant power supply (reliability), and power quality improvement.[4] In one of its case studies, the report also identifies the enablement of renewable generation as another benefit of energy storage.[5]

The IESO's 2015 "Central Toronto Area Integrated Regional Resource Plan" also highlights the benefits of energy storage, particularly as a solution to "community level" energy planning, including opportunities to enable renewable generation.[6]

Battery-based Energy Storage Systems are typically comprised of two components: batteries and power electronics. Batteries absorb and supply energy in direct current ("DC"). Power electronics convert battery DC power to alternating current ("AC") (and vice versa) to enable connection to the distribution system. The power electronics also connect and disconnect the batteries from the distribution system. The ability of the ESS to deliver the expected benefits depends not only on the size of the batteries, but also on the capacity ratings, configuration, and switching capabilities of the associated power electronics.

Toronto Hydro's proposed ESS Program includes three investment segments:

1) Grid Performance ESS,
2) Renewable Enabling ESS, and
3) Customer-Specific ESS

Grid Performance ESS projects utilize battery energy storage as integrated components of the traditional distribution system. These projects benefit multiple customers, in the same way as other distribution infrastructure (e.g. poles, wires, and transformers), and can provide specific solutions to distribution problems. Toronto Hydro proposes to use ESS to achieved grid performance enhancements, including to remediate power quality problems (e.g. voltage sags), improve reliability by reducing the number or duration of outages, and increase capacity of a feeder at peak periods. During the 2020-2024 period, $5.5 million is proposed for this category of investment.

[4] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p12
[5] The Study of Energy Storage in Ontario's Distribution Systems, Essex Energy Corporation, 2017, p27
[6] Central Toronto Area Integrated Regional Resource Plan, Independent Electricity System Operatior, 2015, p90

ESS systems can provide other distribution benefits including local demand response (DR). A local DR solution is being implemented at Cecil TS in the 2015-2019 rate period and is proposed for expansion during the 2020-2024 rate period as described in Section E7.4.

Toronto Hydro is proposing to use ESS connected to the distribution system along the feeder segments where customers would benefit from enhanced grid performance. These needs are diagnosed on a feeder-by-feeder basis having regard to the performance of that part of the grid with respect to capacity, reliability, power quality, and other relevant measures. Where a traditional poles and wires approach is applicable, the solution might be to upgrade the feeder, re-orient feeders, install additional protection and control devices, or undertake other conventional investments. In other instances, a poles and wires option may not be available for a variety of technical or economic reasons. This program will enable Toronto Hydro to pursue ESS options, as may be optimal in a given situation.

A typical example of where a battery solution can be used to cost-effectively improve grid performance would be an area with a relatively high concentration of customers who are sensitive to power quality disturbances. Benefits of such a solution include the following:

- **Voltage Sags:** ESS can offset significant voltage sags and provide ride-through capability.
- **Voltage Support:** ESS can dynamically counteract voltage fluctuations through voltage regulation, thereby minimizing the voltage fluctuations that adversely affect customer equipment and processes.
- **Phase balancing/efficiency**: ESS can help rebalance feeders that exceed the threshold for single phase imbalances, thus decreasing the return current on the neutral conductor and reducing line losses.
- **Reliability and power quality improvements**: ESS can improve the overall power quality for customers by counteracting variations in voltage and harmonics, as well as the effects of switching.

Renewable Enabling ESS investments are distribution investments that support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investments to the benefit of all Ontario rate payers, and that also create environmental benefits. Distributed renewable generation has been supported in Ontario for over a decade through a series of programs offered through the Ontario Power Authority and IESO, including FIT, microFIT, and Net Metering. Customers who do not have contracts through these programs also install renewable generation. Those customers can receive payments according to hourly market prices or, more often, offset their monthly bill by generating their own electricity behind the meter.

As is the case with other renewable enabling improvements ("REI"), projects in this investment segment are funded 6 percent in the LDC rate base and 94 percent through the provincial REI revenue stream. Over the 2020-2024 period, $5 million is proposed for this segment, with $0.3 million (6 percent) allocated to Toronto Hydro's rate base. These investments are expected to enable the aggregate connection of 5 MW of renewable projects, which would otherwise not be possible due to technical limitations of the grid.

Similarly, ESS can cost-effectively enable electric vehicles ("EVs") to connect to the distribution system by addressing localized system constraints. Toronto Hydro is not proposing any EV ESS projects at this time.

Customer-Specific ESS projects would be installed at the request of the customer, typically behind the customer meter in order to maximize the benefits of the investment. These projects improve traditional distribution service outcomes such as power quality and reliability. By locating these distribution assets behind the meter, they also provide the customer with financial benefits, such as hourly peak-shaving and Industrial Conservation Initiative ("ICI") benefits (i.e. Global Adjustment relief for Class A customers who reduce their demand during provincial peak periods). Thus, the customer-specific behind the meter benefits "stack on top" of the distribution benefits, thereby creating a greater set of benefits associated with the ESS project.

Over the 2020-2024 period, $42.3 million is proposed for this segment. Investments in this segment are driven by the requesting customer's needs. In accordance with the "beneficiary pays" principle, Toronto Hydro will therefore hold these host site customers directly responsible for the costs of the projects that benefit them. As with other capital contributions, payments from the host site customers will offset the amounts that are added to rate base and charged through rates to all ratepayers. Presumptively, the result is that 100 percent of the $42.3 million of planned expenditures are offset by planned capital contributions, such that the net effect of this segment to the Toronto Hydro rate base is $0.

An example of this type of a Customer-Specific ESS project is the Metrolinx Eglinton Crosstown LRT ESS currently underway in 2018/2019. At its request, Metrolinx will receive reliability and emergency services in the event that distribution service from feeders becomes unavailable. The costs of the project are fully allocated to Metrolinx and recoverable through a capital contribution.

The general interconnection schematic for various ESS projects are illustrated in Figure 1 below.

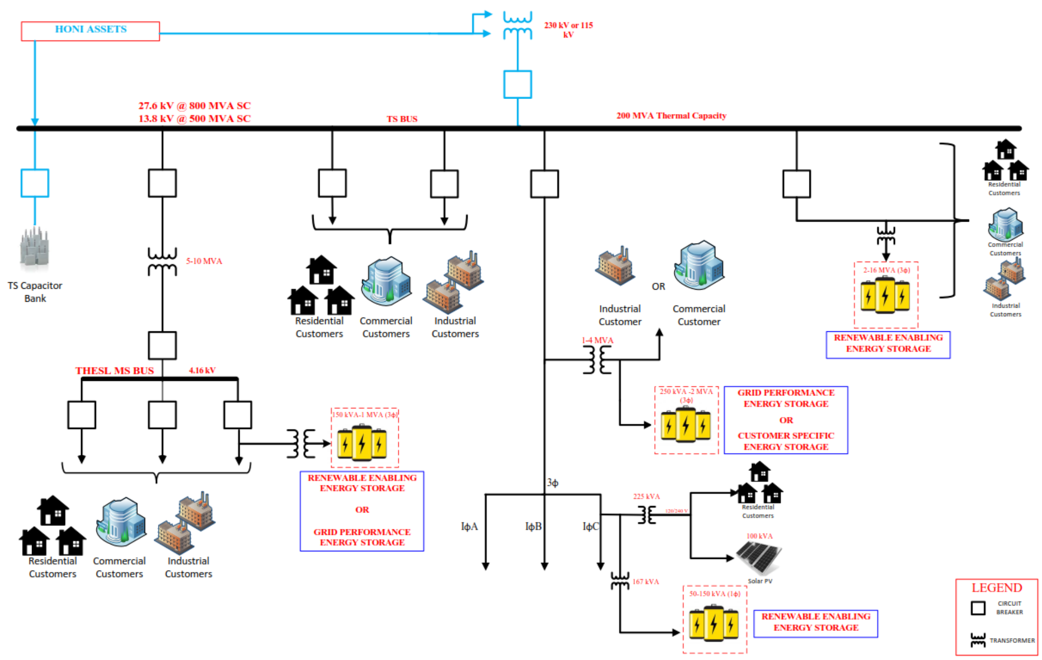


Figure 1: Typical Interconnection for ESS

E7.2.2 Grid Performance ESS

E7.2.2.1 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Service	• Contributes to the reduction of power outages and risk of costly asset failures by mitigating the effects of upstream line disturbances.
Reliability	• Contributes to increased reliability and power quality by mitigating the effects of voltage sags including customer interruptions • Contributes to reliable system performance by enabling dynamic voltage support and reduced harmonics through line voltage regulation.

Financial	• Contributes to Toronto Hydro's financial performance and objectives by: ○ Achieving local, targeted feeder performance improvements to defer the need for conventional infrastructure upgrades. ○ Enabling phase balancing to minimize neutral return currents and improve system efficiency.
Public Policy	• Contribute to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility battery storage projects that were recognized in the 2017 Long-Term Energy Plan. ○ Reducing greenhouse gas ("GHG") emissions by enabling the proliferation of energy storage, Distributed Energy Resources ("DERs"), and grid-modernization. ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.2.2 Drivers and Need

Table 3: Program Drivers – Grid Performance ESS

Trigger Driver	Reliability
Secondary Driver(s)	System Efficiency

E7.2.2.3 Reliability

Grid Performance ESS can eliminate voltage fluctuations and momentary interruptions, providing ride-through capability for customers and improving reliability of the grid. Grid Performance ESS can also provide the following benefits:

- Supply a feeder segment during an outage, reducing outage impact, improving SAIDI, and making the grid more resilient;
- Reduce peak demand on a feeder, thereby avoiding or deferring feeder or capacity upgrades; and
- Enable renewable generation.

The distribution system must be managed to balance supply and demand and ensure reliability for customers. "Reliability" is often viewed and measured through the lens of traditional factors such as peak capacity, outage avoidance, outage restoration, and grid resilience, which are priority outcomes particularly for customers averse to supply interruptions. At the same time, many customers on the modern distribution system not only value service continuity but also expect reliable supply in terms of high quality power that meets the operational needs of their voltage-sensitive equipment and processes. In this context, and due to an increasingly complex network of distribution assets and loads (including a growing population of DERs), utilities are increasingly having to manage bi-directional power flow, voltage regulation and power quality in addition to traditional reliability factors.

Poor power quality, most easily understood as lights flickering due to voltage fluctuations, can cause interruptions to customer owned equipment. Increasingly, critical customers (advanced manufacturing, information technology service providers, research institutions, hospitals, etc.) are installing sophisticated sensitive electronic equipment, including digital sensing and control equipment that cannot tolerate voltage dips, spikes and harmonics on Toronto Hydro's distribution system. Line disturbances and voltage fluctuations can originate from a number of sources, including traditional loads, switching devices used in the transmission and distribution systems, renewable generation and other distributed generation systems. As their operations evolve, customers, particularly those with loads over 1 MW, are demanding that the performance of the distribution grid keep up with their requirements. This means ensuring sufficient capacity and ride-through functionality to avoid outages and momentary events, regulate voltage within desired operating ranges and address transients generally caused by upstream transmission and distribution equipment. The reliability concerns of customers related to these types of disturbances can be mitigated with ESS.

As part of Toronto Hydro's customer engagement process, key account customers were asked a series of questions and to rank their priorities. Key account customers ranked reliable electrical service as their top priority. Further, in response to this open-ended question, "Is there anything else Toronto Hydro can do?", 13 percent of respondents cited improvements to power quality in their answers. Figure 2 below is a summary of their responses.

Customers other than industrial and institutional customers can also benefit from Grid Performance ESS to meet their reliability needs. Even homes and small businesses can suffer from the effects of voltage fluctuations and momentary outages. For example, overvoltages can damage household electronics and appliances. Elevators and HVAC equipment used in Toronto's extensive multi-unit residential buildings and large commercial buildings are increasingly sensitive to similar reliability disruptions.

During customer engagement, Toronto Hydro received feedback that customers support improving grid performance in parts of the city that experience lower reliability, particularly where it clearly has a disruptive effect on customers.

Given their experiences, sophistication, and insights, key account customers have made them important advisors to Toronto Hydro as the utility works to identify and better understand reliability issues and related customer needs, especially complex challenges such as poor power quality. As of May 2018, Toronto Hydro has 459 customers with loads above 1 MW, including 251 key account customers with ION meters, which are a special type of revenue meter with built-in power quality monitoring.

The approach and technology used to investigate and solve these reliability challenges have evolved over the years from installing mechanical chart recorders that could only identify gross attributes of power supply, to the current use of digital equipment capable of identifying harmonics, fast rising voltage, current fluctuations, and other line disturbances caused by modern switching equipment not previously available for use on the distribution system. Equipment in use today, along with advanced data and information available from upstream and downstream sources, is also able to identify the cause of the disturbance in most cases. Toronto Hydro has learned that some line disturbances can stem from upstream transmission and distribution equipment, and from disturbances on other feeders sharing a common bus.

Figures 2 and 3 below illustrate several types of voltage disturbances, and their respective contribution to the total disturbances across Toronto Hydro's system.

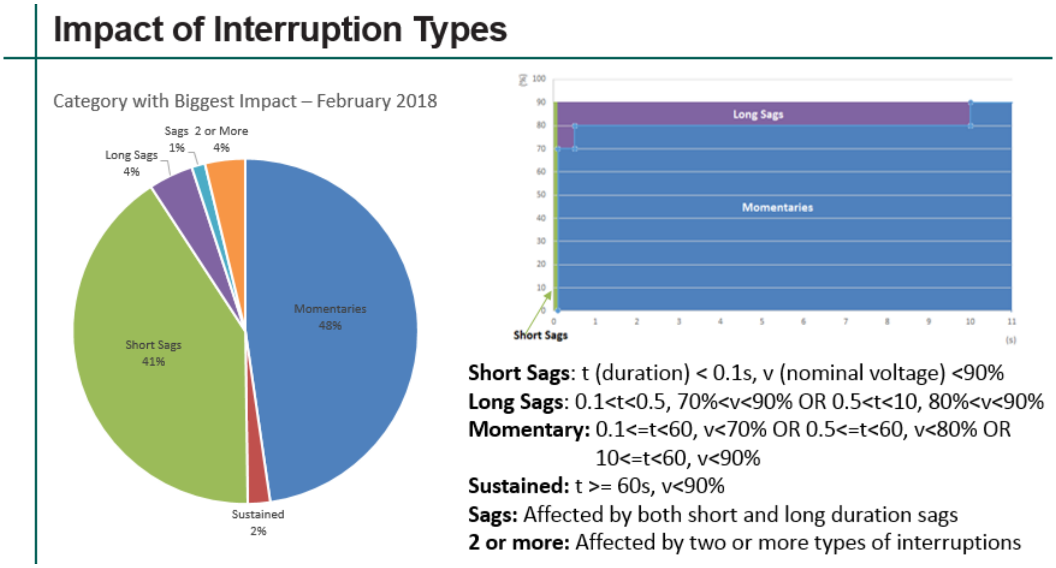


Figure 2: Categories of Line Disturbances

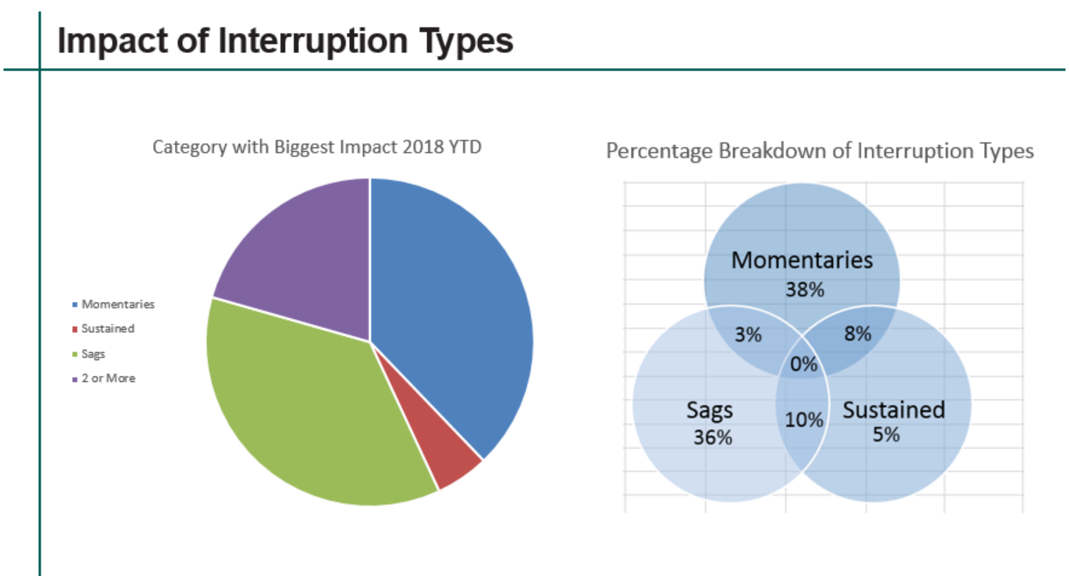


Figure 3: Contribution of Line Disturbances to System Total

Momentary interruptions and voltage sags constitute the vast majority of voltage disturbances on Toronto Hydro's system. These disturbances are typically associated with large current draws on the feeder or bus from large loads coming on line, tree contacts with overhead feeders, and other short duration events such as momentary feeder faults. Toronto Hydro uses an auto-reclose scheme to automatically reclose breakers when they operate due to a fault and then lock out if the fault is not cleared. This practice allows a momentary outage from temporary faults (which are mainly caused by tree contacts with overhead lines) in favour of increasing the frequency of sustained outages. While this practice does serve to minimize sustained outages, the resulting line disturbance can impact other feeders on the same bus and cause power quality problems and service interruption for customers on those feeders if they cannot ride through the line disturbances.

Table 4 below lists the momentary interruptions (excluding voltage sags) associated with transformer stations from 2013 to 2017. Since their duration do not exceed 60 seconds, these momentary events are not reflected in the sustained duration (SAIDI) or frequency (SAIFI) statistics. Voltage sags are tracked at the feeder level using ION meters at customer locations and are not shown in Table 4. However, voltage sags and momentary interruptions are generally closely linked and correlated. As such, the momentary interruption data shown in Table 4 is a useful screening tool for the purposes of addressing voltage sags for customers and prioritizing efforts on feeders associated with those stations.

1 **Table 4: Stations with Momentary Interruptions 2013-2017 (excluding Major Events)**

STATION NAME	2013	2014	2015	2016	2017	AVERAGE
AGINCOURT TS	24	36	27	20	13	24.0
BASIN TS	6	10	9	7	4	7.2
BATHURST I TS	34	24	25	25	24	26.4
BATHURST II TS	25	36	19	24	19	24.6
BERMONDSEY I TS	17	19	19	21	22	19.6
BERMONDSEY II TS	23	21	10	14	15	16.6
BRIDGMAN TS	2	0	4	8	3	3.4
CARLAW TS	8	14	12	22	18	14.8
CAVANAGH TS	38	51	53	48	26	43.2
CECIL TS	1	0	0	0	0	0.2
DUFFERIN TS	32	36	27	44	41	36.0
DUPLEX TS	7	10	8	20	3	9.6
ELLESMERE TS	37	39	46	44	33	39.8
ESPLANADE TS	0	1	0	0	0	0.2
FAIRBANKS I TS	20	18	25	22	21	21.2
FAIRBANKS II TS	15	19	18	11	23	17.2
FAIRCHILD I TS	17	32	37	36	29	30.2
FAIRCHILD II TS	19	13	17	15	16	16.0
FINCH I TS	20	20	21	11	24	19.2
FINCH II TS	24	25	27	30	22	25.6
GLENGROVE TS	9	8	9	11	7	8.8
HORNER TS	43	23	37	35	30	33.6
LEASIDE TS	23	27	16	21	16	20.6
LESLIE I TS	26	20	19	22	23	22.0
LESLIE II TS	32	59	48	29	21	37.8
MAIN TS	8	7	11	5	10	8.2
MALVERN TS	11	31	23	8	8	16.2
MANBY TS	29	42	38	18	31	31.6
REXDALE TS	33	46	25	46	33	36.6
RICHVIEW TS	44	49	59	42	66	52.0
RUNNYMEDE TS	42	37	50	30	29	37.6
SCARBOROUGH EAST TS	20	15	47	17	19	23.6
SCARBOROUGH WEST TS	27	36	32	27	29	30.2
SHEPPARD EAST TS	22	27	22	26	16	22.6
SHEPPARD WEST TS	32	40	34	24	15	29.0
STRACHAN TS	18	18	18	19	12	17.0
TERAULEY TS	0	1	0	0	0	0.2
WARDEN TS	48	46	46	46	51	47.4
WILTSHIRE TS	2	2	2	2	3	2.2
WOODBRIDGE TS	3	4	8	9	4	5.6

As part of Toronto Hydro's efforts to better understand the nature and cause of unacceptable line disturbances, the utility conducted a series of case studies with a number of large customers. Figure 4 and Figure 5 below summarily illustrate the results of these studies. Three of the four cases of poor power quality were traced to upstream anomalies on the transmission and distribution system.

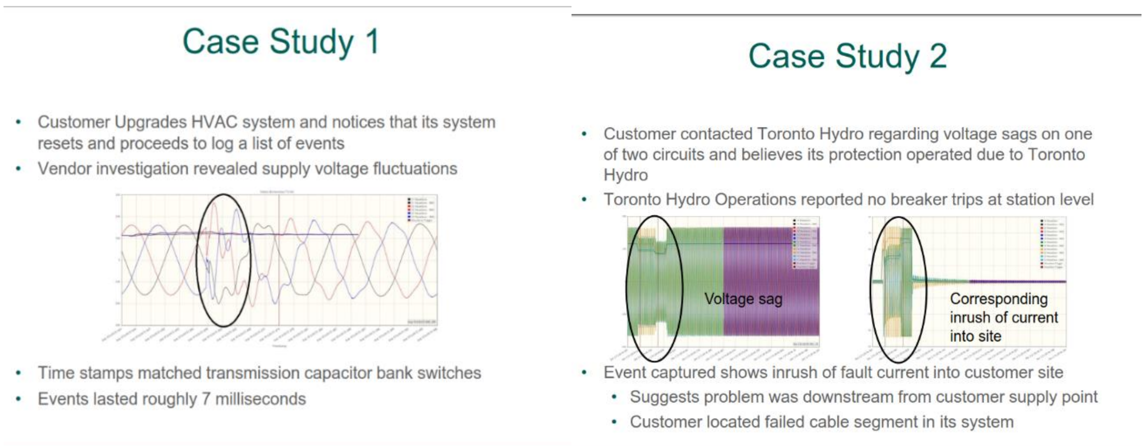


Figure 4: Power Quality Case Studies 1 and 2

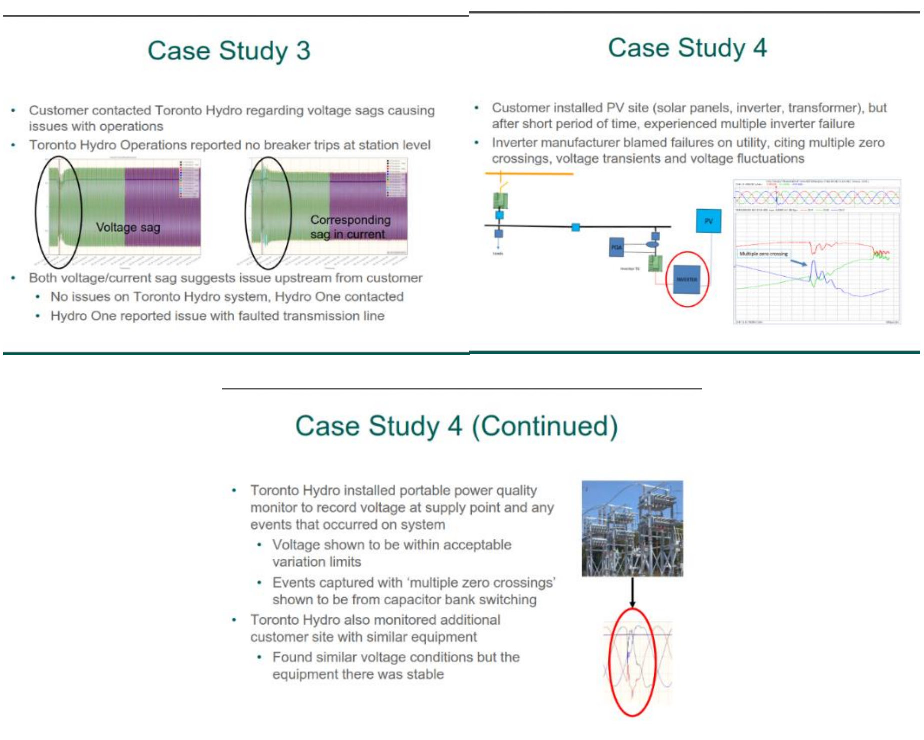


Figure 5: Power Quality Case Studies 3 and 4

In all four case studies, Toronto Hydro deployed power quality monitors to help the customer identify and investigate the disturbances they were experiencing. In particular, with respect to case study 3, power quality monitoring results indicated that voltage sag on the Hydro One transmission system was the root cause of the disturbance that manifested at the customer site. An ESS solution would have been effective in mitigating the impact of such upstream issue on customer operations.

E7.2.2.4 Expenditure Plan

Table 5: Forecast Program Costs- Grid Performance ESS Investments ($ Millions)

	2020	2021	2022	2023	2024
Grid Performance ESS Projects	-	2.7	2.8	-	-

Toronto Hydro proposes to install aggregate capacity of 8 MW/4 MWh of Grid Performance ESS over the forecast period, at a total cost of $5.5 million. These projects will be implemented in 2021 and 2022. Building on the consultations with key account customers and case studies performed to date, Toronto Hydro plans to identify and prioritize suitable sites for Grid Performance ESS investments based on the following screening factors:

1) Feeder has at least one customer with an ION meter (or soon to be installed) that can track the benefits of the Grid Performance ESS;
2) Load criticality, including benefit to vital services and comparative economic contribution;
3) Worst performing feeders; and
4) Benefits to other area customers

To support installations starting in 2021, the screening, customer engagement and selection of key account customers for Grid Performance ESS deployment is proposed to be completed during 2020 along with the required design and procurement. Similarly, the preparatory work necessary to support the 2022 installations is proposed be completed in 2021.

One of the projects considered in this segment involves the 88M43 feeder from Richview TS. As is shown in Table 6 below, between 2015 and 2017, this Richview TS feeder experienced on average 5 momentary interruptions per year (which is the highest out of all transmission stations in Toronto Hydro’s service territory) and 11 potential voltage sage events per year. Customers that would benefit from a Grid Performance ESS on this feeder include a manufacturing facility (1-2 MW peak) that has experienced poor reliability. In this example, Grid Performance ESS would eliminate voltage sags and momentary interruptions, reducing the average number of interruptions for this customer and other customers downstream of the ESS (from 17 to one interruption per year). An ESS could also provide benefits such as outage impact reduction, as described in section E7.2.2.3.

Table 6: Example Customer Reliability (88M43) Prior to Grid Performance ESS

Reliability Statistics	2015	2016	2017	Average
Momentary	5	6	8	**6.3**
Sustained	1	1	2	**1.3**
Hydro One Event	0	0	1	**0.3**
Potential Sag	7	14	22	**14.3**

E7.2.2.5 Options Analysis

1. Option 1: Do nothing

Toronto Hydro has been monitoring and working with key account customers to assess and understand the nature of power quality issues impacting their service and the associated system components. The majority of the feeder disturbances analyzed to date originated upstream of the impacted customers' service entrance equipment. Toronto Hydro has an obligation to address these system issues.

Commercial and industrial customers have informed Toronto Hydro that power quality and reliability are more important considerations than price due to the high cost of service interruptions caused by outages and feeder disturbances[7]. In some cases customers may choose to expand outside the city due to power quality issues, thereby adversely affecting economic growth and employment opportunities within the community.

Toronto Hydro continues to see a rapid pace of DER growth in its service territory, and expects that almost 60 feeders will be unable to support additional renewable generation by 2024. The role of storage in supporting renewable generation is well established. Although the ESS proposed for reliability improvement is not specifically targeted at feeders saturated with DERs, the screening criteria give credit to projects where these synergistic opportunities exist. The candidate feeders and distribution components will benefit from energy storage capacity, through improved reliability, increased efficiency, and expanded capacity for renewable generation.

[7] Exhibit 1B, Schedule 9, Appendix A

The do nothing option is not considered an acceptable solution, since it would not be responsive to customer expectations. Not addressing customer needs will result in continued adverse impact on customer operations (particularly those with sensitive power equipment) and potential economic loss for the customers, utility and local community over time.

2. Option 2: Conventional Wires Options

Conventional wires options can include new feeders, feeder rebuilds, placing lines underground, upgrading stations and building new stations. At the feeder level, a traditional approach is to establish regulated zones on feeders using capacitor banks and reactive power compensators (regulators). Additionally, under load tap changers are often used to increase and decrease line voltage in response to changes in line loading. These traditional approaches to regulation can solve certain power quality issues; however, the dynamic nature of the load along a feeder makes it impossible to achieve adequate regulation in response to load changes and high frequency transients. This technology is too slow to react to line disturbances and voltage can only be adjusted in fixed increments given the design of the tap changers.

Overhead feeders can be placed underground to substantially eliminate momentary interruptions, however such projects are in the order of tens of millions of dollars and cannot be justified based on tree and animal contact avoidance alone. In cases where line disturbances are associated with other feeders on the common bus, more than one overhead feeder may need to be converted to underground. This scale of intervention is inappropriate for solving power quality problems on a feeder segment affecting a relatively small number of customers.

Vegetation management practices, including aggressive cut back, can reduce (not eliminate) tree contacts but must be balanced with City policy and community acceptance given the importance of Toronto's tree canopy. Additionally, animal guards have been applied to reduce animal contacts and resulting feeder disturbances and outages. Different designs have been developed over many years to combat this problem with considerable success. Nevertheless, these designs and activities are insufficient to address the power quality problems these customers experience.

3. Option 3: Conventional Power Electronics Option

The conventional power electronics option involves using regulating devices to mitigate voltage drops (e.g. falling to 50 percent of nominal values for under 10 seconds). Conventional solutions include Static Synchronous Compensator ("STATCOM") and Static VAR Compensator ("SVC").

STATCOMs and SVCs employ power electronics and capacitors to absorb or supply reactive energy in order to regulate voltage. Since capacitors can store a very limited amount of energy, neither STATCOMs nor SVCs are intended to function as energy sources for the purpose of supplying load. As a result, they can provide limited benefit to customers. The differences between STATCOMs and SVCs include stability under varying voltage levels, response speed, and harmonic emissions.

Due to their limited capabilities and benefits, the deployment of STATCOMs and SVCs are not recommended as a solution.

4. Option 4: Do More and Accelerated Spend Options

Grid Performance ESS is an emerging segment based on evolving battery technology functionality, declining ESS costs, and changing customer needs and preferences. There is a risk that these drivers of adoption may prompt more customer interest in Grid Performance ESS than forecasted. There is also a risk that upon closer examination of Customer-Specific ESS projects, one or more of those projects may be reclassified as Grid Performance ESS.

5. Option 5 (Selected Option): Proposed Solution

The installation of appropriately sized Grid Performance ESS on the distribution system offers the best solution to address the upstream line disturbances impacting Toronto Hydro's customers. This solution offers targeted, local line regulation and ride-through capacity for significant reliability events, including voltage sags on feeders. Battery ESS is a "non-wires alternative" that has the ability to offer a lower cost alternative to conventional distribution infrastructure investment. It can also provide additional system and customer benefits that cannot be provided by conventional wires options. These benefits include outage reduction, peak shaving/shifting, and renewable generation enablement.

E7.2.2.6 Execution Risks and Mitigation

These are addressed for the entire ESS program in Section 7.2.5.

E7.2.3 Renewable Enabling ESS

E7.2.3.1 Outcomes and Measures

Table 7: Outcomes & Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by enabling customer investments in renewable energy and reducing energy costs.
Reliability	• Contributes to service reliability.
Financial	• Contributes to Toronto Hydro's financial objectives and performance by enabling the deferral of system generation, transmission, and distribution investments.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility ESS projects that were recognized in the 2017 Long-Term Energy Plan ("LTEP"); ○ Reducing GHG emissions by enabling the proliferation of energy storage, DERs, and grid-modernization; and ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.3.2 Drivers and Need

Table 8: Program Drivers

Trigger Driver	Public Policy
Secondary Driver(s)	System Efficiency

Applicable policy and economic conditions, together with the preferences of customers and consumers, have facilitated a steady interest in distributed renewable generation projects within Toronto Hydro's service territory. This trend is expected to continue into the foreseeable future. In addition, the decreasing costs of photovoltaic panels, coupled with the end of the IESO's FIT program, have generated growing interest in the net metering initiative, including continued customer investment in renewable energy resources in the distribution system.

Based on historical trends and given the end of the FIT program in 2018, Toronto Hydro anticipates the pace of renewable energy generation ("REG") connections will begin to slow by 2019. However, forecasted REG installations will be larger in size as compared to years past due to cost reductions in solar photovoltaic panels and net metering benefits. Between 2019 and 2024, Toronto Hydro forecasts that about 830 additional REG connections (totaling 69 MW) will be connected to its distribution system, as shown in Figures 6 and 7 below.

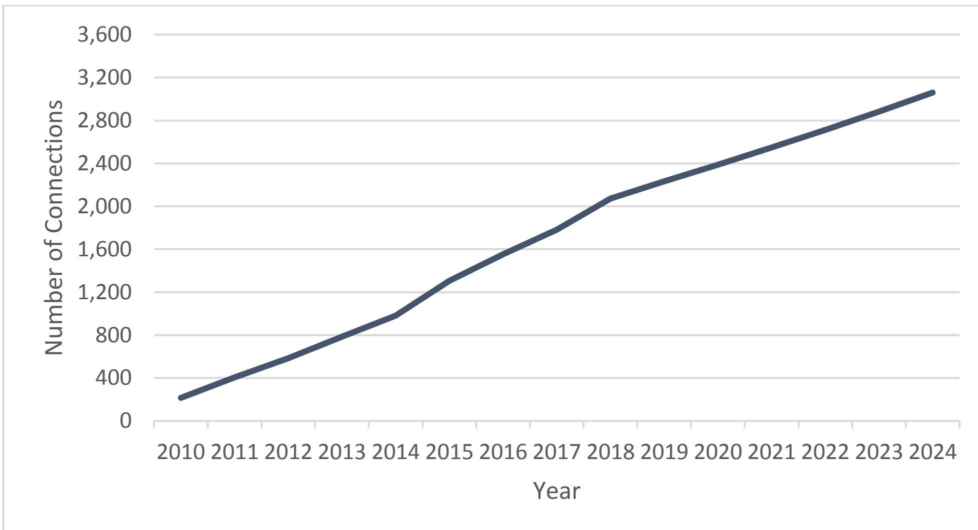


Figure 6: Forecast Renewable Generation Connections

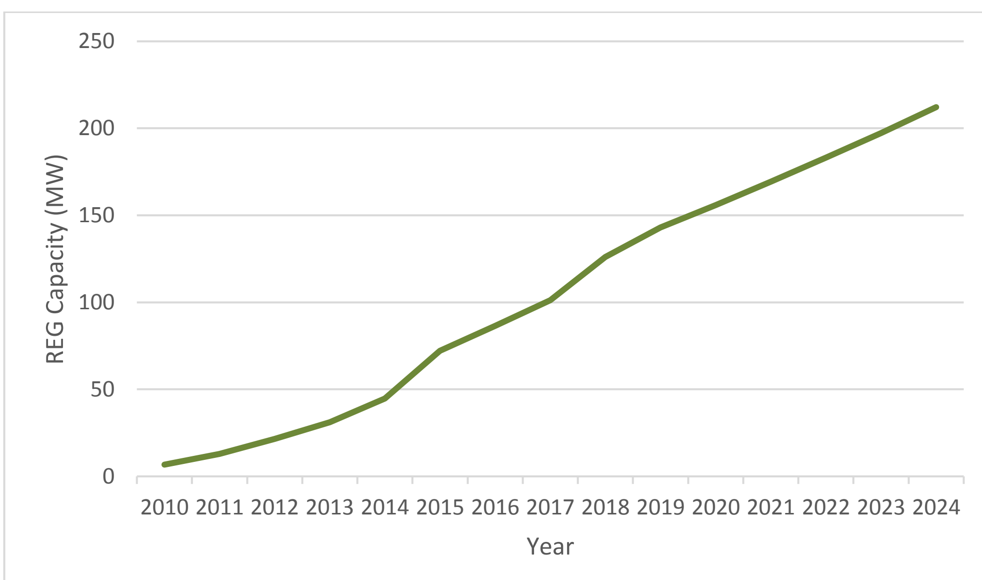
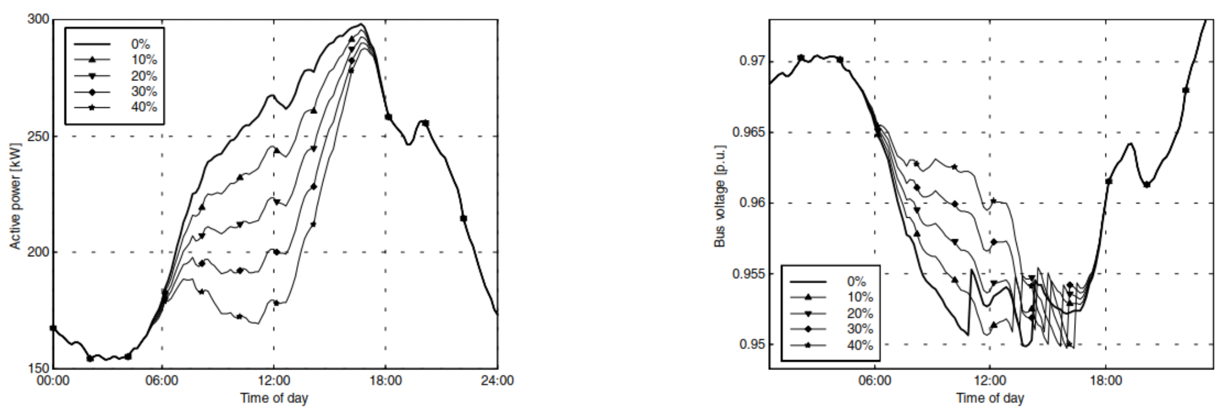


Figure 7: Forecasted Renewable Generation (MW)

Due to the expected demand for renewable generation at the distribution level, there has been a fundamental change in the power flow conditions of the distribution system, which has challenged the conventional radial nature of the grid to accommodate bi-directional power flow. Large scale deployment of REG (e.g. solar PV) causes issues in distribution system planning and operations such as reverse power flow, unintentional islanding and overvoltage on feeders. As a result, Toronto Hydro must proactively manage generation connections on feeders in order to accommodate future growth.

To illustrate the effect of REG on distribution line voltages, Figure 8 shows the load and voltage profiles at a system bus with various levels of REG on the bus.[8] As depicted, bus load begins to rise at the start of the workday at 6am. As generation comes online to support the local load demand, bus load is offset by this generation output and the bus voltage drops. As generation comes offline toward the end of the day, bus loads rise again and line voltages return to their nominal values. The higher the REG to load ratio, the more pronounced these effects become with a higher risk of potential islanding.



a) Active power at bus 53 **b) Voltage at bus 53**

Figure 8: Impacts of Renewable Generation on Bus Voltage

In the past few years, there have been numerous studies, standards and guidelines with respect to REG integration, such as IEEE Standard 1547 (Interconnecting Distributed Resources with Electric

[8] M. Begovic et. al., *Impact of Renewable Distributed Generation on Power Systems*, Proceedings of the 34th Hawaii International Conference on System Sciences (2001), available at <https://pserc.wisc.edu/ecow/get/publicatio/2000public/CSSAR01.PDF>.

Power Systems) and National Renewable Energy Laboratory's ("NREL")[9] High Penetration PV Integration Handbook for Distribution Engineers (NREL Handbook). These documents outline methods and practices to determine the maximum allowable generation on the distribution system (e.g. that DR aggregate capacity is less than one-third of the minimum load of the Local Electric Power System ("EPS")). As the ratio of generation capacity to minimum load[10] increases, the amount of time required by inverters to respond to anti-islanding scenarios increases and the likelihood of effective inverter response to anti-islanding scenarios decreases.

Toronto Hydro conducted an analysis for all feeders in its system to establish generation to minimum load ratios, stiffness factors[11], and fault ratio factors[12] in accordance with applicable guidance of the NREL. The study found that 13 feeders currently exceed the one third generation to minimum load screening ratio outlined by the NREL Handbook. It was also determined that if short circuit capacity constraints at the transformer station were ignored, given the forecast growth in REG, by 2024, an additional 45 feeders would exceed the generation to minimum load ratio.

These findings indicate a high penetration of REG in certain parts of Toronto Hydro's distribution system, which will increase the probability of serious issues such as unintentional islanding conditions. This will adversely affect the utility's ability to safely and reliably connect additional REG to the distribution system and, if not addressed by proactive investments, could ultimately lead to an increase in declined applications for connections in a region with a growing appetite for REG. An overview of these findings, as well as the ESS required to address expected exceedances of the generation-to-minimum load ratio, can be found in Table 9 below.

[9] The National Renewable Energy Laboratory (NREL) specializes in renewable energy and energy efficiency research and development and is a reputable authority on the level of penetration of renewables on electricity systems. It is a government-owned, contractor operated facility that is funded through the United States Department of Energy.
[10] Determined as the ratio of aggregate DG capacity on a particular power system section to the annual minimum load on that power system section.
[11] Determined as available utility fault current divided by DG rated output current in affected area.
[12] Determined as available utility fault current divided by DG fault contribution in affected area.

Table 9: Generation to Minimum Load Ratio Summary for Toronto Hydro Feeders

	Generation to Minimum Load Ratio					
	Existing – Dec 2017			Outlook by 2024		
Description	> 1/3	> 1/2	2/3	> 1/3	> 1/2	2/3
No. of Feeders Exceeding Applicable Ratio	13	0	0	58	51	31
ESS Required to Mitigate All Feeders to Applicable Ratio	5.8 MW/ 23.3 MWh	N/A	N/A	156 MW/ 624 MWh	62.5 MW/ 250 MWh	24.5 MW/ 98 MWh

Renewable Enabling ESS can be deployed on such feeders in order to lower the generation to minimum load ratio. At times during the day when the ratio is high, the ESS can function like a load by absorbing energy; whereas when the ratio is low, the ESS can act like a generator by supplying energy.

An overview of the analysis of seven representative feeders on Toronto Hydro's system can be found in Table 10 below.

Table 10: Generation Screening Ratio - 2024 Outlook Summary for Four Toronto Hydro Feeders

Feeder Name	TS Station - Bus	Region	Minimum Load (MW)	Existing DER (MW)	Gen to Load Ratio (Existing)	DER Outlook (MW)	Gen to Load Ratio (2024 Outlook)
51-M32	***Leslie – Q***	**North York**	**2.39**	**0.45**	**0.19**	**1.09**	**0.46**
51-M25	***Leslie – J***		**2.58**	**1.68**	**0.17**	**2.23**	**0.38**
80-M27	***Fairchild – J***		**2.01**	**0.01**	**0.00**	**1.03**	**0.51**
63-M6	***Agincourt – Y***	**Scarborough**	**6.88**	**2.93**	**0.43**	**4.10**	**0.60**
47-M1	***Sheppard – B***		**3.54**	**1.76**	**0.50**	**2.15**	**0.61**
R29-M36	***Rexdale – Q***	**Etobicoke**	**3.82**	**0.88**	**0.23**	**1.78**	**0.47**
11-M5	***Runnymede - B***	**Toronto**	**2.63**	**0.39**	**0.15**	**1.04**	**0.39**

Table 10 provides the NREL screening ratios for seven feeders in Etobicoke, North York, Scarborough and the former City of Toronto. The assessment indicates the following findings:

- **63-M6 & 47-M1 (Scarborough)**: already exceeds generation to minimum load ratio (in red);
- **51-M32 & 51-M32 (North York), R29-M36 (Etobicoke)**: currently have moderate generation to minimum load ratio for (orange); and
- **51-M32, 51-M25, 80-M27, R29-M36 & 11-M5**: exceeds generation to minimum load ratio for 2024 Outlook

In short, the screening ratios show that by 2024 all seven feeders will have a high penetration of PV generation and that they all will require grid investments or other solutions to ensure the safety of the grid and allow further REG connections.

As part of its DER process, Toronto Hydro offers a pre-application report for its customers, providing information about the proposed point of interconnection so the customer can determine if a DER system installation is worth pursuing. This process also allows Toronto Hydro the opportunity to gauge customer interest in DER and forecast potential DER growth on its distribution system. Pre-application reports help customers prepare successful applications while avoiding the need for Toronto Hydro to perform detailed studies on applications that are not likely to be proceed due to customer concerns.

The pre-application process also allows Toronto Hydro to discover potential distribution system issues that must be addressed to accommodate the proposed DER. In such instances, Toronto Hydro would work with the customer to find the best solution to move the DER installation forward, such as modifying the proposed system to satisfy the pre-application screening. Although Toronto Hydro has been able to manage DER customer expectations to date through this pre-application process, the distribution system is approaching its technical limits and Renewable Enabling ESS investments will be required to accommodate future DER growth.

When assessing the potential to connect a DG project, Toronto Hydro planning engineers determine if a feeder's phase current imbalance exceeds 10 percent of the total load on the feeder (at the station) when DG is added to the feeder. Phase imbalances in general result in a return current on the neutral conductor, causing line losses and, in cases of considerable imbalance, cable splice failures due to overheating. If the DG causes the current imbalance to exceed the 10 percent threshold, the imbalance must be corrected. One such correction method is to redistribute load among the other phases of the feeder, which is technically and operationally complex. Where load distribution is not possible, DG applications must be rejected. Renewable Enabling ESS can address this issue by dynamically balancing phases to respect the 10 percent threshold, without having to redistribute load to different phases. In both the short and long term, this approach is expected to resolve connection barriers for many projects seeking connection in a local area.

ESS is recognized as an effective distribution system solution to increase the PV connection capacity. [13] Not only does ESS present remarkable synergies with REG, Renewable Enabling ESS can also be used to improve system performance by reducing outage impact and shifting/shaving feeder peaks, as described in section 7.2.2.3.

E7.2.3.3 Expenditure Plan

Table 11 and Table 12 below summarize the REI ESS Program plan for 2015-2019.

Table 11: 2015-2019 CIR – Renewable Enabling Investments (Projects)

Assets (Units)	2015	2016	2017	2018	2019	Total (Units)
Local Support Energy Storage (LSES) System *(100 kW × 1 hr)*	1	2	3	3	3	12
Grid Support Energy Storage (GSES) System *(200 kW × 2.5 hrs)*	1	1	2	2	2	8
Municipal Station Energy Storage (MSES) System *(400 kW & 3 hrs)*	0	1	1	1	1	4

Table 12: 2015-2019 CIR – Renewable Enabling Investments ($ Millions)

	2015	2016	2017	2018	2019	Total
REI Investments	**$0.54**	**$1.09**	**$2.16**	**$3.24**	**$3.78**	**$10.8**

Table 13 below summarizes the actual and bridge year investments over the 2015-2019 period.

Table 13: Actual and Bridge Costs- Renewable Enabling Investments ($ Millions)

	Actual			Bridge	
	2015	2016	2017	2018	2019
REI Investments	-	-		**$5.9**	**$2.0**

[13] For example, see:
(i) J. Seuss, M. J. Reno, et al, "Improving distribution network PV hosting capacity via smart inverter reactive power support", Proc. IEEE PES General Meeting, July 2015, pp. 1–5.
(ii) Z. Waclawek, et al, "Sizing of photovoltaic power and storage system for optimized hosting capacity", Proc. IEEE International Conference on Environment and Electrical Engineering, June 2016, pp. 1–5.
(iii) B. P. Bhattarai, et al, "Overvoltage mitigation using coordinated control of demand response and grid-tied photovoltaics", Proc. IEEE SusTech, Jul 2015.
(iv) F. Capitanescu, et al, "Assessing the potential of network reconfiguration to improve distributed generation hosting capacity in active distribution systems", IEEE Transactions on Power Systems, Jan 2015, vol. 30, no. 1, pp. 346–356.
(v) Y. Takenobu, et al, "Maximizing hosting capacity of distributed generation by network reconfiguration in distribution system", Proc. Power Systems Computation Conference (PSCC), June 2016, pp. 1–7.

1. 2015-2019 CIR Energy Storage Systems ("ESS") Program

The 2015-2019 ESS program presented in the 2015-2019 CIR was designed to improve system efficiency, reliability and power quality, and to enable the connection of renewable generation and electric vehicles. Toronto Hydro's original plan involved $10.8 million to support 24 ESS installations. These were spread across 12 Local Support Energy Storage ("LSES") systems, eight Grid Support Energy Storage ("GSES") systems and four Municipal Station Energy Storage ("MSES") systems. The original plan was subsequently modified to reflect technology advancements and emerging customer needs. In the meantime, Toronto Hydro has been implementing various energy storage pilot/innovation projects and connecting customer storage projects. The data, experience and lessons learned from these projects have helped Toronto Hydro to:

- understand the benefits and requirements for safely integrating ESS into the distribution system;
- learn from the experiences of host customers regarding the benefits they derive from ESS;
- plan and design the 2020-2024 ESS projects;
- modernize the grid and prepare for future growth;
- satisfy customer desire to invest in innovative technologies; and
- explore new opportunities for both customers and Toronto Hydro to realize the benefits of DER.

By the end of 2019, Renewable Enabling ESS projects will be completed on two feeders with the highest generation to minimum load ratio, located at Sheppard TS and Agincourt TS, as further discussed below.

a. 2018- 2019 Forecast Expenditures

Based on applicable guidelines and supporting business cases, Toronto Hydro plans to install two Renewable Enabling ESS units totalling approximately $7.9 million with aggregate capacity of 3.75 MW/15 MWh to help mitigate existing generation to minimum load issues for two feeders over the 2018-2019 period. An overview of the candidate feeders, along with the sizing and cost of each ESS unit is detailed in the table below.

Table 14: Renewable ESS

No.	Feeder Name	Station	Bus	Gen to Min Load Ratio	ESS (MW)	ESS (MWh)	ESS Cost ($M)
1	***47-M1***	*Sheppard TS*	B	0.50	1.75	7.0	3.6
2	***63-M6***	*Agincourt TS*	Y	0.43	2.00	8.0	4.3
Total					**3.75**	**15**	**7.9**

2. 2020- 2024 Forecast Expenditures

During 2020-2024, Toronto Hydro plans to install three Renewable Enabling ESS units totalling approximately $5 million and 2.35 MW/9.5 MWh to help mitigate forecasted generation to minimum load levels at three feeders.

Table 15: Forecast Program Costs- Renewable Enabling ESS Investments ($ Millions)

	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**
REI Investments	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**

As mentioned earlier, due to forecasted DER growth by 2024, an additional 45 feeders on Toronto Hydro's distribution system will exceed the generation to minimum load ratio. Therefore, the necessary ESS required to mitigate these issues on all the feeders will range in size from 0.35 MW/1.4 MWh to 9 MW/36 MWh and range in cost from $0.8 million to $19 million. In order to mitigate all these feeders with ESS, it would cost roughly $217 million. As this cost figure indicates, ESS is not always the most economic REI option. Having regard to economics and other benefits, Toronto Hydro has planned wires solutions in most of these instances while proposing $5 million for Renewable Enabling ESS. The table below provides an overview of the proposed ESS projects for the feeders that are suitable for Renewable Enabling ESS investments.

Table 16: Feeders Proposed for Renewable Enabling ESS

No.	Feeder	Station	Bus	Gen to Min Load Ratio	ESS (MW)	ESS (MWh)	ESS Cost ($M)	ESS Start Year	ESS Completion Year
1	***51-M25***	*Leslie TS*	J	0.38	0.35	1.40	$0.8	2020	2020
2	***51-M32***	*Leslie TS*	Q	0.46	0.90	3.60	$1.9	2020	2022
3	***80-M27***	*Fairchild TS*	J	0.51	1.10	4.50	$2.3	2022	2024
TOTAL					**2.35**	**9.50**	**$5.0**	-	-

Toronto Hydro plans to pace the work uniformly in each year during 2020-2024. To accomplish this pacing, Toronto Hydro will commence work on the 51-M25 Leslie feeder in 2020, the 51-M32 Leslie feeder over three years (2020 to 2022), and the 80-M27 Fairchild feeder over three years (2022 to 2024).

Based on industry studies, Renewable Enabling ESS can be installed anywhere along a feeder in order to help mitigate concerns regarding generation to minimum load ratio. Therefore, to avoid additional costs, the proposed ESS units could potentially be connected to existing Toronto Hydro assets (i.e. padmounted transformers) that can accommodate the nameplate capacity and necessary footprint and layout. If such assets and locations cannot be established, then new assets (i.e. transformer) will be installed to accommodate the proposed ESS.

E7.2.3.4 Options Analysis

1. Option 1: Do nothing

Some feeders in Toronto Hydro's territory currently exceed the acceptable generation to minimum load ratios and more than 50 feeders are forecast to exceed acceptable ratios by 2024. If no action is taken, forecast demand for DG, including REG, cannot be safely accommodated in Toronto. This would put Toronto Hydro in non-compliance with its obligation to connect renewable generation (i.e. pursuant to Section 6.2.4 of the Distribution System Code). Further, customers willing to invest in modernizing the grid will be frustrated, and the associated grid and upstream benefits will not be realized, contrary to the opportunities identified in the Long-term Energy Plan.

2. Option 2: Traditional ”poles and wires” solutions

Traditional "poles and wires" solutions include upgrading or constructing additional primary distribution infrastructure (e.g. feeder lines, cables, transformers), modifying protection schemes, implementing direct transfer trip schemes and installing monitoring and control devices. Given the current state of technology and associated costs, traditional solutions are the best option to enable the connection of DER in most cases (but not in all cases). While Toronto Hydro has the Generation Protection Monitoring & Control program to address system-wide issues to enable DER, some localized areas would still experience issues involving generation to minimum load ratio and/or feeder phase imbalances, which can inhibit the connection of a DER project. These specific issues can be addressed with a targeted deployment of ESS.

Feeder re-configurations could also be performed to increase load on forecasted feeders where generation to minimum load ratios are high. However, this method may decrease reliability and may not always be feasible due to the existing network configuration.

3. Option 3: Production Curtailment and Decreasing Operational Margin

With better resource monitoring/forecasting and real-time estimation of the grid capacity, applicable operational margins can be reduced. This in turns allows the existing infrastructure to be used more efficiently and to a greater extent (i.e. with a higher capacity factor). For more detailed information regarding this option, please refer to the Generation Protection, Monitoring, and Control Program.[14]

Curtailment occurs when plants are required to reduce their generation output in order to maintain the operational limits of the grid. This may entail a small gradual decrease of the production (referred to as soft curtailment) or a complete stop to production through measures such as inter-tripping (referred to as hard curtailment). Soft curtailment requires a communication infrastructure and methods to assess the real-time performance of the grid and the appropriate production decrease. In a deregulated market without vertically integrated utilities, it requires willingness from grid users to participate and a legal framework enabling such participation. Moreover, economic arrangements are required to allocate the loss of income stemming from curtailed production.

As such, curtailment is not currently seen as a viable option.

4. Option 4: Do More and Accelerated Spend

Renewable Enabling ESS is customer driven. Spending more or spending more quickly than forecasted is a risk associated with any customer driven program. The proposed option is based on forecasted uptake of distributed renewable generation in the service area.

5. Option 5 (Selected Option): Proposed Solution

The proposed Renewable Enabling ESS program will provide Toronto Hydro with strategic capabilities to address specific issues relating to DG/REG enablement in targeted areas of its distribution system. It will allow Toronto Hydro to mitigate the problems described in sub-section 1 of Section 7.2.3.2 and fulfill its regulatory obligations to connect REG projects pursuant to the DSC. The proposed solution also best positions Toronto Hydro to support the goals of the Long-Term Energy Plan with respect to

[14] Exhibit 2B, Section E5.5

enabling renewable generation and deploying energy storage. It is expected that these investments will enable the aggregate connection of 5 MW of REG which would otherwise be constrained. The overall cost of this option is an estimated $5 million over the 2020 to 2024 period.

E7.2.3.5 Execution Risks and Mitigation

These are addressed for the entire ESS program in Section 7.2.5.

1 # E7.2.4 Customer Driven ESS

2 ## E7.2.4.1 Outcomes and Measures

3 **Table 17: Outcomes and Measures Summary**

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Reducing power outages and customer interruption costs. ○ Providing backup power during emergency situations for critical customers (e.g. emergency services, hospitals, government buildings etc.). ○ Enabling Global Adjustment relief for Class A customers. ○ Providing future opportunity to leverage DR and grid capacity relief, thereby avoiding or deferring the need for distribution infrastructure investments.
Reliability	• Contributes to Toronto Hydro's system reliability objectives and performance by enhancing power quality, and ensuring dynamic feeder voltage support, low harmonics and uninterrupted service.
Financial	• Contributes to Toronto Hydro's financial objectives and performance by supporting the satisfaction and retention of load customers and the deferral of conventional infrastructure upgrades.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Creating the stacked benefits of utility ESS projects that were recognized in the 2017 Long-Term Energy Plan (LTEP); ○ Reducing GHG emissions by supporting the proliferation of energy storage, DERs, and grid-modernization; and ○ More effectively utilizing surplus off-peak power, thereby optimizing distribution and infrastructure costs.

E7.2.4.2 Drivers and Need

Table 18: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Customer Economics

1. Evaluating Customer-Specific Need

As set out in section 7.2.2 (the Grid Performance ESS segment), ESS can be deployed to mitigate or resolve a number of issues for the benefit of customers. In the case of Grid Performance ESS, each project is expected to benefit multiple customers. In the Customer-Specific ESS segment, each project is expected to predominantly benefit a single customer.

Customer-Specific ESS allows Toronto Hydro to respond to customer-specific needs with a non-wires solution. This approach differs from the common industry practice of pursuing wires solutions (e.g. dedicated transformers, feeders, and transformer stations) to address customer-specific needs. Customer needs are typically made known to Toronto Hydro as part of a new or upgraded connection request or the ongoing dialogue between Toronto Hydro and customers. Customers' needs often involve increased capacity or reliability, which are driven as a function of changes in their operations. In collaboration with Toronto Hydro engineers and other professionals, customers and their advisors carry out options analysis, including cost forecasts. Given its improving functionality and decreasing costs, ESS is becoming an option that is attracting customer inquiry or being recommended by Toronto Hydro as an alternative for customer consideration. Working together with customers, Toronto Hydro ultimately arrives at a plan that will address their needs without adversely affecting grid reliability or other customers connected to the grid.

As options are reviewed with the customer driving the investment, Toronto Hydro examines whether that customer's need will be addressed through wires or non-wires investments already planned on that feeder (e.g. feeder capacity upgrades) or in the area more generally (e.g. feeder reconfigurations). If so, Toronto Hydro consults with the customer whether the timing of the investments and expected service improvements will meet relevant needs. Based on such feedback, adjustments can be made in some cases to the planned project to better address the needs of the customer.

Where a customer-specific investment closely aligns with work required to address the needs of other customers, the investment (whether in an ESS or wires solution) will proceed as a Grid

Performance project, and associated costs are considered part of the regular investment in the distribution system funded through rate base.

In other cases, customer-specific needs require an investment that only benefits that customer. While a wires solution (e.g. a dedicated feeder) is still appropriate in many situations, customers are increasingly interested in considering non-wires alternatives (e.g. Customer-Specific ESS) as part of the options analysis. Alternatives that entail individualized customer benefits result in costs that are outside of the utility's distribution system investment in the normal course. In accordance with the beneficiary pays principle, these costs are presumptively fully allocated to the customer who benefits. The customer pays for these costs through a capital contribution. As a result of the capital contribution, the asset enters rate base with a net $0 value. This is true for both wires and non-wires customer-driven investments.

2. Customer Need for Behind the Meter Investment

In addition to the above-noted customer needs, Toronto Hydro customers who are billed on a non-coincident demand basis have another need: reducing their peak demand in order to reduce their electricity bills. If these customers draw less electricity from the grid during their peak demand hour each month, they lower their electricity bill.

A subset of these customers (i.e. Class A customers) are also eligible for the Industrial Conservation Initiative ("ICI"), which creates a similar but unique need. If these customers can reduce their demand during the top five provincial peak hours of the year, their Global Adjustment charges can be reduced (potentially by a large amount) in the subsequent year. Since those five peak hours are not known until the end of the one year period, customers undertake demand reduction and peak-shaving activities multiple times per year in order to increase their chances of reducing their Global Adjustment charges.

In addition to benefiting specific customers, these load shifting investments could also have the aggregate effect of lowering the overall Ontario peak demand, thus alleviating costs throughout the electricity system for generation, transmission, and distribution. This is the intended result of the hourly price market, demand response programs, and the ICI.

Customer-Specific ESS can help Toronto Hydro customers achieve the desired peak shaving – whether as a stand-alone benefit or in tandem with other customer benefits. ESS can store electricity during non-peak hours and discharge it during peak hours. The same ESS can be used to improve customer-specific reliability, such as power quality enhancements, momentary outage avoidance, and increased resiliency. As such, the customer can derive both financial and reliability benefits from the same ESS asset. The costs of the investment are presumptively fully allocated to that customer, as discussed above.

Customer reliability needs can be met regardless of whether the ESS is located “in front of the meter” (i.e. traditionally thought of as “grid side”) or “behind the meter” (i.e. traditionally thought of as “customer side”). That is, the physics of ESS confers distribution service benefits to the customer in either scenario. For this reason, if reliability were the only customer need that Toronto Hydro needed to address, the distribution asset would typically be located in front of the meter.

However, to meet the customer’s financial need, Toronto Hydro has to site the ESS behind the meter, so that it can draw electricity during non-peak hours (for which the customer would incur the associated charges) and discharge during potential peak hours to achieve peak-shaving.

Customers generally prefer to meet both their reliability need and financial need through a single, economically efficient investment. In response, Toronto Hydro proposes to meet that need with Customer-Specific ESS projects that are located where customer benefits can be maximized.

E7.2.4.3 Expenditure Plan

Table 19 shows the gross capital expenditures for the Customer-Specific ESS segment, which is entirely funded by capital contributions from the beneficiary customers. The net impact to Toronto Hydro rate base is $0 over the 2015-2024 period.

Table 19: Bridge & Forecast Customer-Specific ESS ($ Millions)

	Bridge		Forecast					Total
	2018	2019	2020	2021	2022	2023	2024	
Metrolinx ECLRT	9.6	17.7						**27.3**
Metrolinx FWLRT			6.0	10.0				**16.0**
TTC Arrow Garage			12.3					**12.3**
Metrolinx Willowbrook Yard			6.0	2.1	5.9			**14.0**
Total	**9.6**	**17.7**	**24.3**	**12.1**	**5.9**	**0.0**	**0.0**	**69.6**

1. 2018-19 Forecast Expenditure Plan

Metrolinx Eglinton Crosstown Light Rail Transit ("ECLRT") ESS: Currently in construction, this Customer-Specific ESS project will provide emergency power, improve reliability, and reduce emissions for the ECLRT.

The ECLRT ESS is planned to be in-service in 2019, and will consist of a 10 MW/30 MWh battery system and a 100 kW PV system. The total cost of $27.3 million will be fully recovered through customer capital contribution. Located behind the meter, the ESS will enable peak-shaving by reducing coincident and non-coincident peak demand from the grid.

The ECLRT itself will span approximately 20 kilometres, starting at Mt. Dennis, located in the west-end of the city, and terminating at Kennedy station, located in the east-end of the city. The Eglinton Maintenance and Storage Facility Yard ("EMSF") will serve as a supply and charging station and will be fed by two Toronto Hydro feeders at the Mt. Dennis station.

In order to improve system reliability, resiliency and flexibility and to proactively manage power supply during peak demand periods, the ESS is designed to operate during both emergency and non-emergency scenarios. More specifically, it will provide backup power generation with the capability to deliver all the required electricity for the ECLRT traction power, including electricity required for the purposes of emergency ventilation.

ECLRT will be mainly supplied by new feeders originating from the new Runnymede TS bus that is currently in construction. From 2014 through 2017, feeders on the Runnymede TS BY Bus averaged 7.2 sustained interruptions annually. The ESS is expected to reduce the number of sustained interruptions by over 50 percent. Momentary interruptions ("MAIFI") are expected to be minimal with the new underground feeders supplying ECLRT.

2. 2020-24 Forecast Expenditure Plan

Three customers have requested that Toronto Hydro complete ESS projects from 2020-2024 to meet their distribution service needs. These projects will be designed to provide reliability improvements, peak-shaving financial relief and emergency resiliency capacity. Toronto Hydro has determined that satisfying these needs will require discrete projects, the benefits from which are only expected to accrue to each requesting customer. Accordingly, the projects are categorized as Customer-Specific

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 outages, but due to limited generator response and protection settings, does not generally address momentary interruptions or large voltage sags. As such, reliance on this solution generally involves a “bump” in supply until the generator can re-supply the load.

Further, the use of diesel or natural-gas fired generation will lead to an increase in local air/noise emissions. Cost for on-site generation (excluding cogeneration applications) is estimated at $10 million for a 10 MW facility, including interconnection and maintenance costs over the service life of the asset.

The customers driving the proposed Customer-Specific ESS projects have rejected this option.

2. Option 2: Conventional Wires Options

Conventional wires options can include new feeders, feeder rebuilds, placing lines underground, upgrading stations and building new stations. At a feeder level, a traditional approach is to establish regulated zones on feeders using capacitor banks and reactive power compensators (i.e. regulators). Additionally, under load tap changers are often used to increase and decrease line voltage in response to changes in line loading. These traditional approaches to regulation can solve certain issues associated with coarse power quality; however, the dynamic nature of the load along a feeder makes it impossible to achieve adequate regulation in reaction to changes in load and high frequency transients. This technology is too slow to react to line disturbances, and voltage can be adjusted only in fixed increments due to the design of the tap changer.

Overhead feeders can be placed underground to substantially eliminate momentary interruptions; however, the costs of such projects are in the order of millions of dollars and cannot be justified based on tree and animal contact avoidance alone. In cases where line disturbances are associated with other feeders on the common bus, more than one overhead feeder may need to be converted to underground. This scale of intervention is costly, takes a long time to build out, and is disruptive to the community.

Vegetation management practices, including aggressive cut backs, can reduce (not eliminate) tree contacts but must be balanced with City policy and community acceptance given the importance of Toronto’s tree canopy. Additionally, animal guards have been applied to help reduce animal contacts and resulting feeder disturbances and outages. Different designs have been developed over many years to combat this problem with considerable success. However, it remains difficult to eliminate animal contact.

None of the conventional wires options provide comprehensive protection (i.e. against momentaries, voltage sags and extended outages) or demand management and cost control, which are all benefits associated with on-site ESS.

The customers driving the proposed Customer-Specific ESS projects have rejected this option.

3. Option 3: Conventional Power Electronics

The conventional power electronics option involves using regulating devices to mitigate voltage drops (e.g. falling to 50 percent of nominal value for under 10 seconds). Conventional solutions include STATCOM and SVC, which employ power electronics and capacitors to absorb or supply reactive energy in order to regulate voltage . Since capacitors can store a very limited amount of energy, STATCOMs and SVCs are not intended to function as energy sources for the purpose of supplying load. As a result, they provide limited benefit to customers. The differences between STATCOMs and SVCs include stability under varying voltage levels, response speed, and harmonic emissions.

The installed cost for conventional power electronics ranges between $10 million to $15 million for a 10 MW facility.

Due to their limited capabilities and benefits, the deployment of STATCOMs and SVCs is not recommended in this case. Additionally, customers driving the proposed Customer-Specific ESS projects have rejected this option.

4. Option 4: Do More and Accelerated Spend Options

Customer-Specific ESS is customer driven. Spending more or spending more quickly than forecasted is a risk associated with any customer driven program. The proposed option is based on negotiation with several customers planning energy storage in the service area. This program can be expanded if necessary given the projects are funded with customer contributions.

5. Option 5 (Selected Option): Proposed Solution

Customer-Specific ESS provides Toronto Hydro with a more focused option for improving power quality and providing customers with emergency capacity. This non-wires solution can offer a lower cost alternative to conventional distribution infrastructure investment, can be executed quickly, and is less disruptive to the community than traditional wires solutions. Additionally, it can also provide additional system and customer benefits that are not available from conventional wires options or conventional on-site generation, including future control and capacity opportunities and deferral of traditional generation, transmission, and distribution upgrades.

Since the individual customers who benefit from these projects fund 100 percent of the cost through capital contributions, the size of the Customer-Specific ESS segment can scale-up relatively easily based on customer interest. That is, the proposed option also encompasses "Do More" and "Accelerated Spend" options.

E7.2.5 Execution Risks and Mitigation

Project execution risks may impact project design, project siting, approvals, construction, project schedule and commissioning.

Compared to traditional technologies, there are many fewer technical resources in the sector with knowledge on ESS are available to design, install and commission the systems, which can lead to a delay in program implementation and increased costs. Toronto Hydro will manage this risk by researching and applying relevant experiences from other jurisdictions and investing in training and staff development for engineering and skilled trades.

Project siting and approvals risk is generally limited because ESS involves electronics technology with minimal air/noise emissions and is therefore subject to standard building permit approvals (without extensive environmental assessment requirements) on utility or customer-hosted sites.

Construction cost variance is mitigated through a competitive procurement system for ESS projects and standard contract provisions which provide fixed price responsibility and liquidated damages for non-performance. Based on market projections, battery ESS technology will mature and prices fall providing some protection against year-over-year inflation and a degree of budget contingency. Battery costs represent approximately half the cost of ESS, while converters, switchgear, transformation, controls, conditioning, civil work and enclosures make up the balance. Costs for ESS continue to decline with average battery prices moving from US$300/kWh in 2015 to an expected US$110/kWh in 2024.[15] As such, over the 2020-2024 period, the cost/benefit value proposition of ESS will likely continue to improve, thereby facilitating increased use of this solution to address customer needs.

[15] Lithium-ion Battery Costs and Market, Bloomberg New Energy Finance, July 5, 2017.

Project schedule risk can be effectively managed by dedicated project teams that provide short-interval control and regular coordination between the utility and customers. Toronto Hydro will dedicate its efforts in the first year of the program to selecting suitable locations and obtaining lease/easement agreements for all feeder projects. Labour availability and project prioritization with other capital project and planned maintenance work will be managed to implement this program on-schedule.

ESS projects are complex due to bi-directional power flow and interface protections between project locations and their associated feeder/station supply point. Commissioning risk can be mitigated by using a standard requirements matrix and site acceptance testing protocol. Further, in-depth training in advance of actual field work is planned for crew members and operations staff who will take part in ESS installation and commissioning.

E7.2.6 Appendix A: EPRI Benefits of Energy Storage

Energy storage can provide a rich spectrum of economic, reliability, and environmental benefits to the electric grid, to electricity end-users and to society as a whole. Electric Power Research Institute (EPRI) studied benefits of energy storage using in their 2010 report: ***Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects***.

Table 21: EPRI Smart Grid Technology Benefits: Energy Storage

Benefit Category	Benefit Sub-Category	Benefit
Economic	*Improved Asset Utilization*	1) Optimized Generator Operation
		2) Deferred Generation Capacity Investments
		3) Reduced Ancillary Service Cost
		4) Reduced Congestion Cost
	T&D Capital Savings	5) Deferred Transmission Capacity Investments
		6) Deferred Distribution Capacity Investments
	Energy Efficiency	7) Reduced Electricity Losses
	Electricity Cost Savings	8) Reduced Electricity Costs
Reliability	*Power Interruptions*	9) Reduced Sustained Outages
	Power Quality	10) Reduced Momentary Outages
		11) Reduced Sags and Swells
Environmental	*Air Emissions*	12) Reduced CO_2 Emissions
		13) Reduced SOx, NOx, and PM-10 Emissions

1) **Optimized Generator Operation:** The ability to respond to changes in load would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost, including the cost associated with polluting emissions. Electricity storage can be used to absorb generator output as electrical load decreases, allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional, less efficient generation could be avoided. The storage can have the effect of smoothing the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs and (2) improved performance due to improved heat rate efficiency and load shaving.

2) **Deferred Generation Capacity Investments:** Electricity storage can be used to reduce the amount of central station generation required during peak times. This would tend to improve the overall load profile and allow a more efficient mix of generation resources to be dispatched. This can save utilities money on their generation costs.
3) **Reduced Ancillary Services Cost:** Ancillary services including spinning reserve and frequency regulation can be provided by energy storage resources. The reserve margin is a required capacity above the peak demand that must be available and is typically +15 percent of peak demand. If peak demand is reduced, reserve margin would be reduced.
4) **Reduced Congestion Cost:** Distributed energy resources provide energy closer to the end use, so less electricity must be passed through the transmission and distribution lines, which reduces congestion.
5) **Deferred Transmission Capacity Investments:** Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.
6) **Deferred Distribution Capacity Investments:** Electricity storage can also be used to relieve load on overloaded stations and feeders, potentially extending the time before upgrades or additions are required.
7) **Reduced Electricity Losses:** By managing peak feeder loads with electricity storage, peak feeder losses, which are higher than at non-peak times, would be reduced.
8) **Reduced Electricity Costs:** Electricity storage can be used to reduce the cost of electricity, particularly during times when the price of "grid power" is very high. A consumer or the owner of an enabled DER realizes savings on his electricity bill.
9) **Reduced Sustained Outages:** Electricity storage can be used as a backup power supply for one or more customers until normal electric service can be restored. However, the backup would only be possible for a limited time (a few hours) depending on the amount of energy stored.
10) **Reduced Momentary Outages:** When combined with the necessary control system, energy storage could act like an uninterruptible power supply (“UPS”), supporting end use load during a momentary outage.

11) **Reduced Sags and Swells**: The same UPS capability could be used to enable load to ride through voltage sags and swells.
12) **Reduced CO_2 Emissions**: Electricity storage can reduce electricity peak demand. This translates into a reduction in CO_2 emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall CO_2 emissions if fossil fuel generators are used for charging.
13) **Reduced SOx, NOx, and PM-10 Emissions**: Electricity storage can reduce electricity peak demand. This translates into a reduction in polluting emissions produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall emissions if fossil fuel generators are used for charging.

TAB 21

E7.4 Stations Expansion

E7.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 180.1	**2020-2024 Cost ($M):** 136.4
Segments: Copeland TS – Phase 2, Hydro One Contributions, Local Demand Response ("DR")	
Trigger Driver: Capacity Constraints	
Outcomes: Customer Service, Reliability, Public Policy, Environment, Financial	

Toronto Hydro's Stations Expansion program (the "Program") addresses medium- to long-term system capacity needs. The Program is driven by capacity constraints on the distribution system. Increased and continued densification and population growth are driving the need to relieve the loading on the distribution system and create additional capacity. If not dealt with proactively, this will impact Toronto Hydro's ability to connect customers to its distribution system. The primary focus of the work planned in the 2020-2024 period is on the downtown and south-west area of the system, where growth continues to be concentrated.

The Stations Expansion program consists of the three segments summarized below, and is a continuation of the expansion activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

- **Copeland TS – Phase 2**: this segment will expand the capacity of Toronto Hydro's Copeland Transformer Station ("TS"), located in the centre of Toronto's financial district. The project will provide additional capacity of 144 MVA. The additional capacity is needed to support forecasted growth and development in the City's Central Waterfront area while maintaining and enhancing system reliability and resiliency for outage-sensitive customers in the downtown core. Toronto Hydro's 2015-2019 Distribution System Plan included a high-level proposal to begin work on the Copeland TS – Phase 2 project in 2019. Toronto Hydro developed a more detailed plan in 2016 which included advancing some work into the 2017-2019 timeframe to account for expected project lead times. In total, Toronto Hydro expects the Copeland TS – Phase 2 project will cost an estimated $89 million, with $79 million of those expenditures occurring in the 2020-2024 period. The estimated in-service date is 2024.

[1] EB-2014-0116, Exhibit 2B, Section E7.9

- **Hydro One Contributions:** this segment covers Toronto Hydro's forecasted capital contributions to Hydro One for work related to:
  - Expansion of Horner TS, which will provide an additional capacity of 192 MVA in South-West Toronto to enable medium-to-long term load and customer growth as anticipated based on the Toronto Integrated Regional Resource Plan ("IRRP") process;
  - Cost-effective capacity upgrades of end-of-life ("EOL"), Hydro One-owned power transformers as anticipated based on the IRRP process;

  Toronto Hydro plans to invest an estimated $53 million in this segment in the 2020-2024 period compared to a forecasted $99 million in 2015-2019.
- **Local DR:** this segment includes cost-effective non-wires investments to manage local capacity constraints while deferring larger, traditional wires investments. Toronto Hydro is proposing targeted DR strategies to reduce peak demand by approximately 10 MW, supporting the deferral of approximately $135 million in capital investment at Cecil TS and Basin TS for 5 to 6 years. The capital budget for this Program in the 2020-2024 period consists of an estimated $4.6 million in 2023-2024 for a battery storage project in the Basin TS area. Under the Asset and Program Management program[2], Toronto Hydro plans to allocate operational expenditures associated with this segment.

The investments summarized above and in the remainder of this narrative are informed by, and fully aligned with, IRRP activities conducted in coordination with the IESO and Hydro One. The most recent planning document from this process is the Needs Assessment Report for the Toronto Region ("Needs Assessment"). A high level reconciliation of the Needs Assessment with Toronto Hydro's Stations Expansion program is found in Section E7.4.7 of this narrative.

The Stations Expansion program also responds to the need for maintained system reliability and increased grid resiliency to support Ontario public policy drivers. To this end, the Program focuses on Toronto Hydro's broad strategy of grid modernization within the context of an aging, dense urban infrastructure, aiming to support customers and load growth and both mitigating and adapting to climate change through grid resiliency and innovation.

[2] Exhibit 4A, Tab 2, Schedule 9, Section 7

In total, Toronto Hydro plans to invest an estimated $136.4 million in stations-level capacity expansion in the 2020-2024 timeframe compared to a forecasted $180.1 million in the 2015-2019 timeframe. The utility expects to add or free-up over 400 MVA in capacity on the system as a result.

E7.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Reducing the number of stations unable to connect new large customers in the downtown and Horseshoe areas by investing in 415 MVA in additional supply capacity by 2025; ○ Increasing supply capacity using DR measures; and ○ Alleviating feeder position limitations that prevent customer connections.
Reliability	• Contributes to maintaining Toronto Hydro's System Capacity Measure and system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Providing redundancy and operational flexibility by upgrading capacity at supply points to keep the number of highly loaded stations (with loads > 90 percent capacity) at a minimum for the downtown and Horseshoe areas; and ○ Managing peak loads and alleviating capacity constraints to reduce the risk of outages by maximizing the use of existing capacity through targeted DR initiatives, • Investing in climate-resilient station infrastructure and equipment, in particular at Copeland TS which has flood defenses, seismic protections (i.e. earthquake resistant), and is protected from exposure to storms.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Supporting the IRRP and the Ontario Long-Term Energy Plan ("LTEP") by meeting local needs through a mix of traditional infrastructure, energy storage, conservation and DR; ○ Enabling electrification by investing in additional capacity and operational flexibility; ○ Supporting Ontario's Conservation First Framework by investing in non-wires alternatives.

Environment	• Contributes to Toronto Hydro's environmental objectives by investing in capacity to support operational flexibility, enable electrification, and support the proliferation of distributed energy resources (DERs).
Financial	• Contributes to Toronto Hydro's financial objectives by deferring approximately $135 million in capital investment through the use of targeted DR strategies.

E7.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Capacity Constraints
Secondary Driver(s)	Reliability

The Stations Expansion program is driven by capacity constraints on the distribution system. Increased and continued densification and population growth are driving the need to relieve loading on the distribution system and create additional capacity. These conditions are only expected to intensify beyond 2024 as supported by the City of Toronto's long-term Precinct Plans[3] for both the downtown and the Horseshoe areas and by Toronto Hydro's 10-Year Station Load forecast (see Section D of the DSP). Toronto Hydro anticipates that the significant redevelopment and load growth associated with planned projects[3] in the downtown and central waterfront will result in 208 MVA of incremental load in the City's core over the 2020-2024 period or shortly thereafter. Similar to the downtown region, the Horseshoe area continues to experience concentrated load growth. The City of Toronto's "Precinct Plans" [4] for the region, including the South-West Toronto area, shows a load growth of 252 MVA, which includes all planned projects forecasted to materialize over the 2020-2024 period, or shortly thereafter. The Load Demand program[5] includes a more detailed discussion of the proposed Precinct Plans and how they factor into Toronto Hydro's capacity investment plans. Continued densification and population growth are expected to continue driving up system loading up to and beyond 2024. If not dealt with proactively, this trend will impact Toronto Hydro's ability to connect customers to the distribution system.

[3] City of Toronto, *How Does The City Grow?* (April 2017), available <https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf>.
[4] *Supra* note 4.
[5] Exhibit 2B, Section E5.3.

Addressing capacity constraints in the downtown core is crucial as stations primarily serve institutional, commercial, and large residential condominium customers experiencing rapid, large-scale growth, including electric transportation infrastructure (e.g. subways, streetcars). Given the importance of loads associated with essential services in all these station areas, resiliency and reliability are extremely important. The work under this Program responds to the need for resiliency and reliability in these areas by relieving highly loaded station buses and ensuring availability of feeder positions to connect new customers. This provides an overall benefit to all ratepayers by connecting new customers to their optimal supply point within the station service area and thus maintaining low connection costs. Ensuring reliable and resilient power supplies to these essential services is important to all Toronto Hydro customers, regardless of their rate class.

Toronto Hydro's 10-year Station Load forecast predicts an increase in load which will reduce capacity availability at the following stations: Carlaw, Esplanade, Windsor, Terauley, Cecil, Manby, Richview, Fairbank, Strachan, Duplex, Charles, Basin, and Horner. Most of these stations are highly loaded and have either limited or no spare feeder positions available to enable load transfers or enable additional capacity. As a result, this reduces Toronto Hydro's ability to connect customers and large DERs to the distribution system efficiently within the station service areas.

The work planned under the Stations Expansion program is aligned with system needs identified in the Needs Assessment and in the Regional Infrastructure Plan ("RIP") report.[6] Table 4, Table 5, and Table 6 below highlight the needs and how they are addressed through the Stations Expansion program.

Table 4: New Needs

New Needs	NA Report Section	Stations Expansion Narrative
End-of-Life Assets	*7.1.1*	See *Table 8*.

Table 5: Needs Identified in Previous RIP

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Narrative
South-West Toronto – Station Capacity	*7.2.1*	*7.2*	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.

[6] Exhibit 2B, Section B, Appendix A, B, C, D, and E

number of spare feeder positions at Cecil TS, Esplanade TS, Strachan TS, Terauley TS, Windsor TS and Copeland TS as well as the number of customers that could be affected by the failure of each bus.

Therefore, by introducing an additional 144 MVA capacity into the Toronto Hydro System, Copeland TS will help relieve the heavily loaded stations (as identified in Table 7), thus allowing new customers to be connected to their service areas, which would otherwise be difficult and expensive to connect.

It is important to note that the impact of electric vehicle ("EV") deployment has not been accounted for in this forecast. Following the release of the LTEP in the fall of 2017, Toronto Hydro 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.

E7.4.3.2 Hydro One Contributions

As a part of the IRRP process and Hydro One's long-term investment planning process, the Toronto Region needs are reviewed and agreed upon as a part of the Needs Assessment led by the IESO. The results of the most recent Needs Assessment highlight new emerging needs identified by Hydro One since the previous regional plan and reaffirm needs that were previously identified. These needs are summarized in Table 31, Table 32, and Table 33 in Section E7.4.7.

In response, Toronto Hydro is making capital contributions to Hydro One to carry out upgrades at Hydro One stations during the 2020-2024 period. This is done for large projects where a Toronto Hydro need requires Hydro One to perform a large capital project, such as the Horner expansion, or for projects where Toronto Hydro identifies an opportunity to enable incremental capacity upgrade in coordination with a Hydro One initiated project, such as the identified Hydro One EOL transformer upgrades. Contributing capital to Hydro One allows Toronto Hydro to alleviate capacity constraints on the distribution system by increasing bus firm capacity and increasing available load through transformer upgrades. This enables both customer connections to the system and load transfers which can reduce the risk and duration of outages. Table 8 below provides a summary of these Hydro One contribution projects included in the 2020-2024 filling:

of capital as medium-term investment options are considered. Local DR also supports the goals of the Toronto IRRP and the LTEP to meet local needs with DERs, conservation programs and DR strategies.

Local DR is most appropriate in service areas requiring non-urgent load relief to provide sufficient time to penetrate the market. Suitable candidate stations must have adequate lead-time (two to three years) for the implementation of a DR solution before a capacity constraint is expected to materialize. Toronto Hydro targets stations that exhibit physical or logistical barriers for pursuing conventional station expansion solutions, making the DR option significantly more cost-effective in the short-to-medium term. Further, DR works best at stations with load profiles that demonstrate short and infrequent system peaks. In Toronto Hydro's service area, these temporary "spikes" in customer demand typically occur during the hottest weekday afternoons in the summer when maximum cooling loads amplify the normal daily peaks that result from electrical building system and operational end-uses. Stations that serve a range of larger customers (greater than 3 MW average monthly peak demand) that have flexible operational profiles are best suited to DR solutions.

Local DR is needed to address capacity constraints that are forecast to start affecting the identified stations by as early as 2022**.** Implementing this program is expected to mitigate the risks of operating the system beyond its capacity and avoid the need to undertake complex and impractical load transfer projects to free up capacity for new customers. Failing to address capacity constraints can lead to operational and reliability risks by 2022, as shown in Table 14 below.

As can be seen in Table 14, Basin TS will reach 85 percent loading by 2020, and approach 90 percent by 2024. As such, Toronto Hydro has adequate lead-time to implement DR measures that can help defer the need for costly capital investments, while also providing sufficient buffer to allow for the implementation of wires solutions if needed. In the case of Cecil TS, which will reach 85 percent loading by 2024, there is no lead-time required as the proposal is to continue the current Local DR program, which was developed, implemented, and tested during the 2015-2019 period. Failure to implement Local DR could result in reduced reliability, costly short-term load transfer projects, reduced flexibility to schedule maintenance outages, inability to accommodate distributed generation (e.g. combined heat and power), increased risk of equipment failure, and inability to connect new loads. Operating station busses at high capacity puts the system at risk of violating design parameters, which could result in rotating blackouts and voltage reductions.

Over the 2015-2019 period, Toronto Hydro forecasts to spend $4.1 million in the Local DR segment for the purchase and installation of a battery for Cecil TS. The battery storage costs are estimated based on market costs for utility grade equipment, and installation estimates based on utility scale projects underway in Toronto over the 2015-2018 period.

Over the 2020-2024 period, Toronto Hydro forecasts to spend $4.6 million for the battery storage project in the Basin TS area. Similarly to the Local DR at Cecil TS, the capital cost of the battery and its installation is estimated based on the same assumptions regarding market costs and comparable projects.

The bulk of the total 2020-2024 Local DR program cost (e.g. incentives, labour) is not capitalized and therefore not included in Table 23. 60 percent of the $10.3 million total program cost is operating expenditures relating to program administration, customer incentives for DR activities, marketing and legal costs, and measurement and verification costs, as detailed in the Asset and Program Management program.[28]

E7.4.5 Options Analysis

Toronto Hydro has identified and evaluated various options based on current and future needs of the system.

E7.4.5.1 Options for Copeland TS

1. **Option 1: Do Nothing**

Do nothing is not a feasible option as it does not provide the necessary load relief and feeder positions required at downtown core stations (see Table 7 Columns D and E). This option would result in most busses being heavily loaded by 2024, including eight at 90 percent or above and two at more than 100 percent capacity. Toronto Hydro anticipates the remaining spare feeder positions will also be used up by 2024, which means that it will be very difficult, and in some cases impossible, for Toronto Hydro to connect new customers, including DERs, at these stations.

[28] See Exhibit 4A, Tab 2, Schedule 9 – Asset and Program Management

E7.4.7 Regional Planning Needs

The following tables, Table 31, Table 32, and Table 33 (from the IRRP Needs Assessment Report), highlights the emerging needs that have been identified in the Toronto Region since the previous regional planning cycle, and reaffirms the near, medium, and long-term needs already identified in the previous RIP.[30] The tables below also highlight how the Stations Expansion program is expected to address these needs.

Table 31: New Needs identified in the Needs Assessment

New Needs	NA Report Section	Stations Expansion Program
End-of-Life (EOL) Assets	*7.1.1*	See *Table 8*.
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	*7.1.2*	NA report identified this need by around 2025+. Therefore, no projects are included in this Program to address this need.
Load Restoration – C14L+C17L, C5E+C7E, K3W+K1W	*7.1.3*	Transmission network constraint. Not applicable to Toronto Hydro.

Table 32: Needs Identified in Previous RIP

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Program
South-West Toronto – Station Capacity	*7.2.1*	*7.2*	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	*7.2.2*	*7.3*	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.
230 kV Richview x Manby Corridor – Line Capacity	*7.2.3*	*7.4*	Transmission network constraint. Not applicable to Toronto Hydro.
Supply Security – Breaker Failure at Manby West & East TS	*7.2.4*	*7.6*	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Leaside Autotransformer – Transformation Capacity	*7.2.5*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.

[30] See Exhibit 2B, Section B, Appendix A, B, C, D, and E for Regional Planning Reports.

Needs Identified in Previous RIP	NA Report Section	RIP Report Section	Stations Expansion Program
Voltage Instability of 115 kV Leaside Subsystem	*7.2.5*	*Identified in Central Toronto Area IRRP report – Appendix E*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Leaside x Wiltshire Corridor – Line Capacity	*7.2.6*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Manby Autotransformers – Transformation Capacity	*4.2.7*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Manby West x Riverside Junction – Line Capacity	*7.2.8*	*7.10*	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Don Fleet JCT x Esplanade TS – Line Capacity	*7.2.9*	*Identified in Central Toronto Area IRRP report – Appendix E*	Transmission network constraint. Not applicable to Toronto Hydro.

1 **Table 33: End-of-Life Assets – Metro Toronto Region**

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Fairbank TS: T1/T3, T2/T4 Transformers	*2022-2023*	EOL transformers and other HV equipment are identified at these stations for replacement with similar type equipment of the same ratings (discussed further in Section 7.1.1.1 of NA report).	Current 50/83 MVA transformer is largest 115-27.6 kV standard size.
Fairchild TS: T1/T2 Transformers	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Leslie TS: T1 Transformer	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Runnymede TS: T3/T4 Transformers	*2021-2022*		Proposed 50/83 MVA transformer is largest 115-27.6 kV standard size.
Sheppard TS: T3/T4 Transformers	*2019-2020*		Toronto Hydro determined increase in capacity to larger 75/125 MVA transformer was not required.

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Bridgman TS: T11/T12/T13 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of NA report	Included in 2015-2019 Stations Expansion plan.
Charles TS T3/T4 Transformers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
Strachan TS: T12 Transformer	*2020-2021*		Included in 2015-2019 Stations Expansion plan.
Bermondsey TS: T3/T4 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of NA report.	Identified as consideration for downsizing, therefore Not Applicable to Toronto Hydro. See section 7.1.1.3 of NA report for details.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	*2021-2022*		Included in 2015-2019 Stations Expansion plan.
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230 kV yard	*2024-2025*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	*2024-2025*	EOL Line section is identified for replacement with similar type equipment, and is discussed further in Section 7.1.1.4 of NA report.	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV L9C/L12C: Leaside TS to Balfour JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.

TAB 22

E8.1 Control Operations Reinforcement

E8.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): N/A	**2020-2024 Cost ($M):** 40.2
Segments: Control Operations Reinforcement	
Trigger Driver: Operational Resilience	
Outcomes: Reliability, Safety, Customer Service, Public Policy	

The Control Operations Reinforcement program (the "Program") will increase Toronto Hydro's operational resiliency and improve the utility's ability to safely operate the distribution grid by creating a fully functional dual Control Centre at its [redacted] work centre. The dual Control Centre at Toronto Hydro will be designed to withstand evolving hazards and threats, deliver reliable electricity, and support the capability to restore electricity as efficiently as possible.

Toronto Hydro's existing Control Centre is a critical infrastructure that acts as a control authority and real-time operator of the distribution system within the City of Toronto. Control Centre operations are hosted from Toronto Hydro's 500 Commissioners work centre and include the following two primary responsibilities:

1) maintain real-time control of Toronto Hydro's distribution plant through telemetry and remote operation of station breakers and field devices; and
2) coordinate all activities involving field crew workers within the "safe limits of approach" to Toronto Hydro plant that is energized above 750 Volts, as prescribed by the Ontario Electrical Safety Code and Electrical Utility Safety Rules.

Failure of Toronto Hydro's existing Control Centre can have substantial financial and economic consequences for Toronto, the largest city in Canada, the fourth largest in North America, and the economic and financial centre of the country.

The proposed dual Control Centre at [redacted] will replace the existing back-up Control Centre at Toronto Hydro's [redacted] location and will be used to operate and control Toronto Hydro's distribution grid in parallel with the primary Control Centre. [redacted]

[redacted]

The development of a dual Control Centre will allow Toronto Hydro to more effectively safeguard, manage, and operate its distribution system, minimize potential safety hazards to the public and employees, and minimize business interruption impacts on its customers, should the primary Control Centre be compromised.

As energy policy changes, bringing innovation and new technology, the evolution of the smart grid is changing the value proposition of Control Centres. Control Centres are becoming more integrated with the technology, not only from a monitoring and control of energy delivery perspective but also from an energy management perspective, elevating their role and importance. The growth of distributed generation has also given distributors some of the reliability responsibilities traditionally reserved for transmission utilities.[1] [redacted] As such, as part of the Program, Toronto Hydro intends to build its dual Control Centre with the technology required to manage this growing system requirement.

In addition, over the last five years, Toronto Hydro's operations have been disrupted by several large-scale environmental and other hazard events. These large scale environmental and hazard events are becoming increasingly more common within Toronto Hydro's service territory and across the industry.[2] For instance, in 2018 alone, Toronto Hydro has experienced four severe weather-related events that caused wide-spread damage and outages.[3] Further, in addition to more frequent and severe weather events, there continues to be an escalation of terrorist attacks on people and property, cyber terrorist attacks, as well as system attacks from increasingly sophisticated hackers. The impact of these events on the distribution system has already been experienced in Ukraine, as demonstrated by the 2015 cyber-attack on three separate distribution companies where continuity

[1] London Economics International LLC, Jurisdictional Review and Economic Case for a Dual Distribution Control Center in Toronto Hydro Territory (June 22, 2018), at p. 15.
[2] AECOM Environment, Toronto Hydro-Electrical Systems Limited Climate Change Vulnerability Assessment filed in EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, E8.8, Appendix A (Filed July 31, 2014, Updated February 6, 2015).
[3] See Table 6 for examples of recent severe weather events in Toronto.

of service was disrupted for up to 225,000 customers.[4] Canada is not immune to such threats. Public Safety Canada issued a report titled "The 2017 Public Report on The Terrorist Threat to Canada" indicating that since 2014, Canada's terrorism threat level is Medium, meaning that a violent act of terrorism could occur.[5]

Toronto Hydro has examined its existing operational capabilities in light of these emerging challenges and needs. The plans contained in this Program address the shortcomings of Toronto Hydro's current back-up Control Centre. To assess Toronto Hydro's investment in a dual Control Centre, the utility retained London Economics International ("LEI") to undertake a review of comparator utilities with fully functional dual control centres as well as an economic analysis determining whether this investment is justifiable, see Appendix A.[6] LEI found that utilities expressed similar rationales for requiring a dual control centre, including supporting resiliency, increasing reliability, and ensuring quick recovery from terrorist threats and natural disasters, for example earthquakes, storms, and floods.[7] LEI also found that the growth in distributed energy resources, as is the case in Toronto, has caused distribution utility operations to be more complex and take on some of the traditional responsibilities associated with the Bulk Electricity System, including managing interconnected generation and greater responsibility over bulk system reliability.[8] The review concludes that based on the estimated cost of an outage, the investment in a dual control centre can be economically justified if it can reduce the duration of such an outage.[9]

[4] Electricity Information Sharing and Analysis Center, White Analysis of the Cyber Attack on the Ukrainian Power Grid (March 18, 2016) at p. 1, found at <https://www.nerc.com>.
[5] 2017 Public Report on the Terrorist Threat to Canada (December 17, 2017), found at <https://www.publicsafety.gc.ca/cnt/rsrcs/pblctns/pblc-rprt-trrrst-thrt-cnd-2017/index-en.aspx>.
[6] Supra note 1.
[7] Ibid at pp. 5-14.
[8] Ibid at p.16.
[9] Ibid at pp. 24-26.

1 ## E8.1.2 Outcomes and Measures

2 **Table 2: Outcomes and Measures Summary**

Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Reducing the likelihood of a complete or partial stand-down of field work and the likelihood of cascading outages resulting from interruption to visibility over the distribution system; and ○ Ensuring compliance with requirements relating to system restoration planning outlined in Chapter 5, Section 11 of the Market Rules.
Safety	• Contributes to Toronto Hydro's safety objectives as measured by Total Recordable Injury Frequency ("TRIF") by: ○ Providing seamless visibility over the distribution system, thereby reducing the likelihood of worker/public injury resulting from loading issues and inadvertent energizing of equipment; ○ Ensuring efficient administration and application of the Toronto Hydro Work Protection Code; and ○ Maintaining compliance with Ontario Regulation 22/04 (Electrical Distribution Safety) through timely reporting of serious electrical incidents involving Toronto Hydro plant.
Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Ensuring continued capability to receive and respond to trouble calls from customers and/or external stakeholders; ○ Maintaining the capability to effectively manage, prioritize and resolve multiple concurrent system issues impacting customers; and ○ Providing relevant and timely outage information to customers, such as estimated outage restoration times and other situational information relating to system outages.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by consistently meeting OEB-mandated service quality targets with respect to Emergency Response (Distribution System Code, s. 7.9).

E8.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Drivers	Operational Resilience
Secondary Driver(s)	Reliability, Safety

E8.1.3.1 Program Drivers

The primary driver for the Program is Operational Resilience and the secondary drivers are Reliability and Safety. As discussed below, the Control Centre is the control authority for Toronto Hydro and is the real-time operator of Toronto Hydro's distribution system. The Control Centre executes most of the critical functions required to successfully operate the distribution system. [redacted]

[redacted]

Table 4: Minimum Space Requirements for a Control Centre – [redacted]

	500 Commissioners	[redacted]	Gap (%)
Control Room Space Requirements (ft^2)	[redacted]	[redacted]	[redacted]

In November 2017, Toronto Hydro Power System Controllers executed a pilot whereby part of the distribution grid would be controlled entirely by the [redacted], as part of an effort to simulate the loss of the primary Control Centre. Within the scope of this pilot, key systems that are required to maintain full operational control of the system were identified as follows:

[redacted]

[redacted]

[redacted]

Table 5: Summary of Technological Restrictions at [redacted] Facility

	500 Commissioners	[redacted]	Gap (%)
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			
[redacted]			

[redacted] Orders to Operate ("OTO") are the final output of the system operation planning process to the field staff to receive step by step instructions on real time operation of equipment from Power System Controllers. These include orders which are executed in sequence to isolate, de-energize, and ground work areas to make them safe for work, change system state, test continuity, hipot test, and restore power. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] the primary Control Centre located at Toronto Hydro's 500 Commissioners site may be vulnerable to certain hazards, such as extreme weather events. Since the primary Control Centre is located within the flood plain, the most probable and consequential hazard or threat [redacted] The flooding is most likely to cause catastrophic damage to the building and various facilities that house the primary Control Centre, [redacted]

As discussed above, Canada's current terrorism threat level is "Medium," meaning that a violent act of terrorism could occur.[10] [redacted] Electrical hazards are, to a large extent, limited through constant system oversight via Control Centre operations.[11]

[redacted]

Moreover, with the introduction of renewable and other distributed energy resources, the nature of Control Centre operations continues to evolve. The growth of distributed energy resources has led to utilities being required to manage bi-directional flow of electricity, managing more complex operations and taking on increasing responsibility that has traditionally been reserved for transmission utilities.[12] This evolution changes the manner in which the power is managed and delivered throughout the grid. With the forecasted increase of distributed generation connections, which is expected to reach 800MW by the end of 2024, Toronto Hydro requires real-time monitoring and control in order to ensure distribution system safety and the adequate management of distributed energy connections.

Lastly, as part of its report, filed at Appendix A, LEI completed a review of various utilities in North America that have distribution operations with more than one Control Centre. These facilities were fully functional and were able to take over full operational functions from the primary Control Centre. The review confirms that utilities serving a critical load in North America invest in more than one fully functioning Control Centre to support resiliency, increase reliability, and ensure quick recovery

[10] Supra note 4.
[11] See Exhibit 4A, Tab 2, Schedule 7, for a discussion of the roles and responsibilities of Power System Controllers.
[12] Supra note 1 at p. 15.

from terrorist threats and natural disasters, for example earthquakes and floods. These same justifications are driving the need for Toronto Hydro's dual Control Centre.

E8.1.3.2 Control Centre Operations & Criticality

The Control Centre's Power System Controllers coordinate and monitor the safe distribution of electricity across Toronto Hydro's service territory and support most of its crtical functions. Power System Controllers maintain real-time control of Toronto Hydro's distribution plant and coordinate all activities involving field crew workers. This real-time control includes monitoring of grid operation, system loading, and response to system or asset failures.

[redacted]

Under normal operating conditions, Power System Controllers prepare and execute OTO (switching instructions), enabling planned capital, and operation and maintenance activities for Toronto Hydro's workforce. Control Centre personnel are involved in developing necessary OTO, dispatch of crews, and conducting isolation and switching functions for each capital construction project or maintenance task that is being performed in order to enable a safe work zone. Each OTO comprises a list of switching instructions which enable operations crews to safely transfer customer load and/or establish suitable work protection over a specified range of system devices, which, in turn, allows crews to work in accordance with applicable safety legislation and protects the security of supply to Toronto Hydro's customers. Work involved in the development of OTO is extremely detailed, drawing on multiple system records in conjunction with current system state/loading and is critical to crew and public safety. Where restoration is not possible, crews work directly with the Control Centre to switch equipment in order to restore power to the extent possible prior to continuing with the root cause.

During abnormal system conditions, which are typically caused by extreme weather events, defective equipment, or heat stress to distribution assets, Power System Controllers coordinate Toronto Hydro's response to these system contingencies. During the abnormal system conditions, the restoration efforts must be undertaken immediately as these conditions might pose a significant safety hazard. The emergency activities might include quick and safe restoration of the downed conductors, failed equipment, electrical/vault fires, environmental hazards and etc. Power System Controllers and Trouble Dispatchers direct the response efforts of Toronto Hydro's Grid Response (emergency maintenance) crews during system contingencies and abnormal conditions.

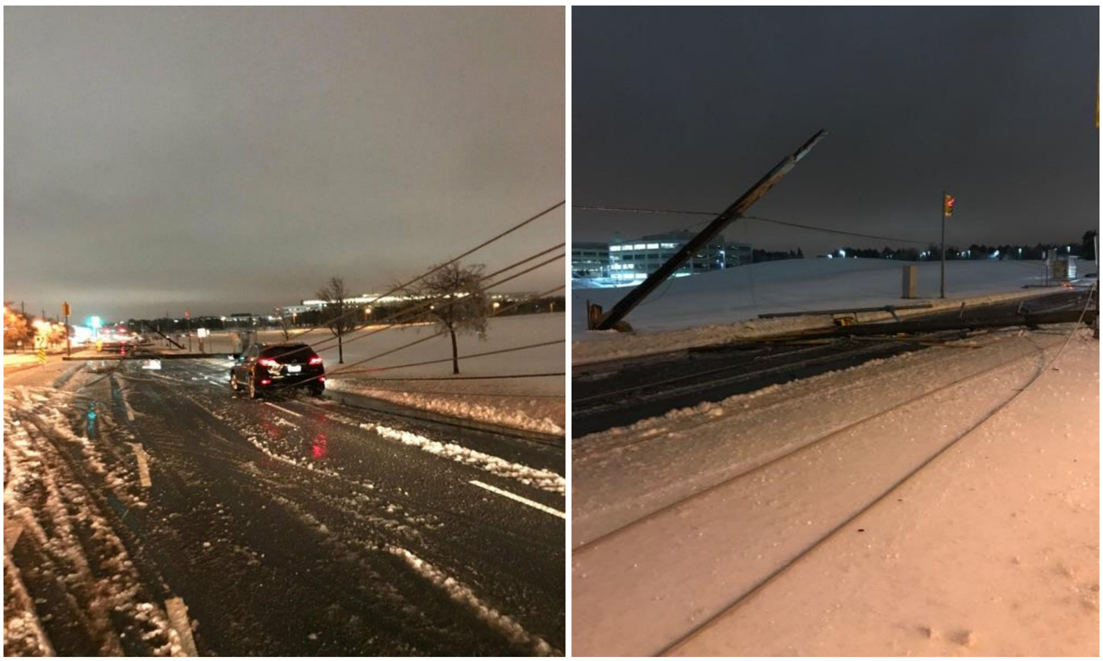


Figure 2: Damage from City of Toronto Ice Storm in April 2018

Toronto Hydro has defined a list of critical functions that are necessary for successful operation of the distribution system. A more detailed description of each these functions is provided in Appendix B. Notably, a number of these critical functions have a maximum tolerable downtime of zero hours.

The North American Electric Reliability Corporation ("NERC") have issued directives and rules concerning the "Loss of Control Room Functionality" which ensure continued reliable operation of the Bulk Electric System in the event that a Control Centre becomes inoperable.[13] NERC standards require the facility containing the Control Centre to be resilient enough to survive, to some extent, the hazards and threats it faces. With respect to criticality relative to their purpose or function, the assets that are subject to NERC requirements are similar in nature to Toronto Hydro's assets. Toronto Hydro serves the largest city in Canada and is also the Country's financial and business capital. As

[13] NERC, Reliability Standards for the Bulk Electric Systems of North America, Standard EOP-008-1 and EOP-008-2- Loss of Control Center Functionality (Updated February 15, 2018).

such, given the criticality of Toronto Hydro distribution system, NERC directives and rules are indicative of the measures that must be taken with respect to critical assets, such as the Control Centre.

E8.1.3.3 Continuity of Operations Capabilities

Control Centers_have become increasingly more sophisticated over the past 30 years from simple analogue tone-based telemetry and control based on electromechanical devices to digital electronic monitoring, data acquisition and control. Paper-based records have been replaced with geo-referenced graphical information systems and outage management systems and crew dispatch and coordination can be accomplished through tablets and crew resource management systems. Control Centers have always been considered critical infrastructure for the management of the distribution system mainly for monitoring and control of substations, transformers, and feeders. However, their purpose continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources, micro-grids, electric vehicles, and growing interest in energy storage on the system for power quality, off-peak storage, and grid resilience. As this new paradigm comes into focus, the manner in which power is managed and delivered evolves. Smart grid development requires a completely new concept of a smart grid Control Center, one which is not only critical to distribution system management, but also critical to energy management within the City, and ultimately the Bulk Electric System.

LEI, in its review, concludes that as distribution utilities evolve towards more complex operations and greater responsibility for reliability within the bulk electricity system, fully functioning dual Control Centres will become increasingly necessary.[14] See Figure 3, below, for LEI's depiction of industry trends such as distributed energy resources, smart grids, and electric vehicles that will inevitably challenge the traditional role of the distributor. The fundamental shift to managing bi-directional flow of electricity adds a layer of complexity to Control Centre operations necessitating more active involvement in forecasting intermittent generation, energy scheduling or dispatching generation to manage outages.[15]

14 Supra note 1 at p. 15.
15 Supra note 1 at p. 16.

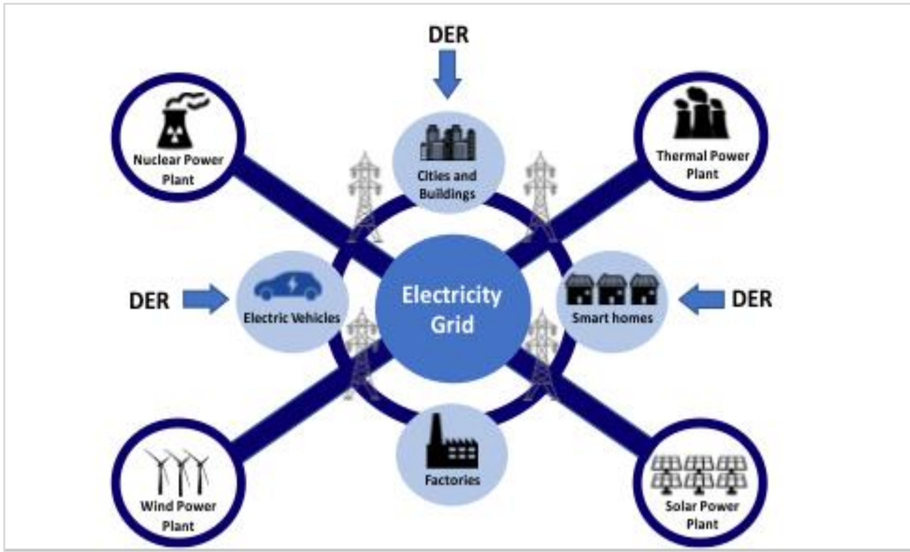


Figure 3: Distributed Energy Resources Interacting with the Electricity Grid[16]

In 2017, Toronto Hydro responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro has connected over 1,780 Distributed Generators of various sizes representing approximately 225MW. Based on internal forecasts, Distributed Generation connections in Toronto are expected to increase and to reach 800 MW by the end of 2024.[17]

[redacted] As such, as part of the Program, Toronto Hydro intends to build its dual Control Centre with the technology required to manage this growing system requirement. The dual Control Centre will have the capability to monitor and control distributed energy resources. In the event that primary control is lost, it is critical to understand which sources on the system have tripped off, and which have not, both for work protection, but also for power restoration efforts. In accordance with Rule 149 of the Electrical Utility Safety Rules, Toronto Hydro must identify backfeed hazards and eliminate where possible, or control using approved temporary grounding procedures. Although modern inverters

16 Supra note 1 at p. 15.
17 See Exhibit 2B, Section E5.1.

have anti-islanding capabilities, it has been known to fail, and, therefore, do not completely eliminate the back feed hazard, as required by the Electrical Utility Safety Rules.

E8.1.3.4 Risk Exposures

1. Extreme Weather Events

Toronto Hydro evaluates its state of operational preparedness for managing large-scale events on a periodic basis. As part of the evaluation, significant weather events are reviewed along with system resilience, system and customer impacts, and organizational response. Over the last five years, Toronto Hydro experienced several incidents, and some of the more extreme examples include:

- Hurricane Sandy (2012);
- Ice Storm (2013);
- City of Toronto Flooding Event (2013);
- Manby Station Flooding (2013);
- Freezing Rain Event (2017);
- City of Toronto High-water/flooding event (2017);
- Ice Storm (2018); and
- Wind Storm (2018).

Figure 4: Damage from City of Toronto Wind Storm in May 2018

Table 6, below, provides examples of extreme weather events occurring in the first half of 2018 in the City that exceeded Toronto Hydro's standard response practices and triggered the deployment of additional planning and response resources under the utility's Disaster Preparedness Management program.[18]

Table 6: Examples of Recent Severe Weather Events in the City of Toronto

Event	Description
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice storm (April 2018)	• Approximately 10-20mm of freezing rain, 20-25mm rain, sustained winds of 70km/h with gusts up to 110km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event
Flash storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100km/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event's occurrence

These events, some of which had significant impacts on Toronto Hydro operations, have highlighted a need for increased emergency preparedness and operational resilience of Toronto Hydro's distribution system. Toronto Hydro's distribution system and facilities continue to be exposed to ever-increasing hazards due to the increase in severe environmental events introduced as a result of

18 See Exhibit 4A, Tab 2, Schedule 6.

climate change.[19] It has been identified that global and regional climate has changed and will continue to change within the City of Toronto, including continued increases in average and extreme maximum temperatures, increases in total annual rainfall, and increases in the intensity of rainfall events.[20]

As illustrated in Figures 5 and 6 below, the 500 Commissioners work centre, which houses the primary Control Centre, is situated along the path of the Don flood plain and is adjacent to Lake Ontario. The last known major flooding disaster – brought on by Hurricane Hazel – occurred in 1953, affecting an extensive portion of Toronto and the Greater Toronto Area ("GTA"), and in particular introducing widespread flooding at the location where the 500 Commissioners facility currently exists. In recent years, including 2013 and 2017, there have been additional flooding events within the City of Toronto, brought on by ongoing climate changes. Global climate change is expected to continue to introduce observable impacts to the environment, including changes in precipitation patterns.[21] [redacted]

19 AECOM Environment, Toronto Hydro-Electrical Systems Limited Climate Change Vulnerability Assessment filed in EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, E8.8, Appendix A (Filed July 31, 2014, Updated February 6, 2015).
20 Ibid.
21 This is a consequences of climate change, see National Aeronautics and Space Administration (NASA), URL: https://climate.nasa.gov/effects/, 2018.

TAB 23

Jurisdictional review and economic case for a dual distribution control center in Toronto Hydro territory

prepared by London Economics International LLC

June 22nd, 2018

Distribution control centers ("DCC") support reliability, resiliency, and the ability to recover quickly from deliberate attacks and natural disasters. LEI has found that there is a precedent for utilities across North America to build fully functional backup control centers, at similar costs to those proposed by Toronto Hydro. Justifications included increasing reliability and resiliency, with certain utilities citing specific situations such as natural disasters or terrorism threats. Growth in distributed energy resources has also caused distribution utility operations to be more complex and take on some of the responsibilities traditionally required in the Bulk Electricity System, including dealing with interconnected generation and taking greater responsibility for bulk system reliability. LEI believes that the evolution of these responsibilities also support the need for Toronto Hydro's proposed dual DCC. Finally, LEI's analysis indicates that the proposed costs can be justified economically, given the significant costs of outages in the city of Toronto, and the potential for the dual control center to reduce the duration of high-impact outages.

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Figure 1. List of Acronyms

BEA	U.S. Bureau of Economic Analysis
BUCC	Backup Control Centers
CAD	Canadian Dollars
CECONY	Consolidated Edison Company of New York
DCC	Distribution Control Center
DER	Distributed Energy Resource
EIA	US Energy Information Administration
EMP	Electromagnetic Pulse
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPL	Florida Power & Light Company
GDP	Gross Domestic Product
HECO	Hawaiian Electric
HMCC	Hardened Mobile Control Center
HVAC	Heating, Ventilation, and Air Conditioning
IESO	Independent Electricity System Operator
ISO	Independent System Operator
ISOC	Integrated System Operations Center
IT	Information Technology
LDC	Local Distribution Company
LEI	London Economics International LLC
LTEP	Long Term Energy Plan
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
PG&E	Pacific Gas and Electric
RDGI	Renewable Distributed Generation Integration
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
TCC	Transmission Control Center
THESL	Toronto Hydro Electric System Limited
TS	Transformer Station
TSX	Toronto Stock Exchange
UPS	Uninterrupted Power Supply
US	United States
USD	US Dollars
VoLL	Value of Lost Load

1 Executive Summary

1.1 Scope of services

LEI was engaged by Toronto Hydro to undertake an independent study of comparator utilities with fully functional backup control centers ("BUCCs") in other jurisdictions. The utilities were reviewed and analyzed in terms of their functionality as well as cost. LEI also considered the proposed dual control center from an economic perspective by estimating economic costs of a high-impact outage on Toronto Hydro's service territory.

1.2 Summary of findings

LEI has identified five utilities that have built fully functional BUCCs— Hydro One, Consolidated Edison, Pacific Gas & Electric, Florida Light & Power, and San Diego Gas & Electric. These utilities identify various justifications for their investment, including supporting resiliency, increasing reliability, and ensuring quick recovery from terrorist threats and natural disasters, for example earthquakes and floods. Integration of Distributed Energy Resources ("DERs") was also cited.

All reviewed BUCCs were fully functional and were able to take over operations from the primary control center. However, different utilities varied in terms of their mode of operation: the number of backups, whether they were manned or unmanned, and whether they ran in parallel or not. Toronto Hydro's current BUCC has only [redacted] of the functionalities of the primary control center; the proposed dual control center is to be fully functional and run in parallel with the primary control center.

In its study of comparator utilities, LEI found that the cost of BUCCs built in the past 5 years are aligned with the cost of Toronto Hydro's proposed dual control center. Moreover, the justifications of costs, and challenges faced by comparator utilities are comparable. Compared to the utilities reviewed, Toronto Hydro serves a uniquely important load in terms of political and economic significance, as well as a large base of customers with significant population density.

LEI also reviewed the impact of DERs on the role of the distribution utility. The growth of distributed generation has given distributors some of the reliability responsibilities traditionally reserved for transmission utilities, such as forecasting and dispatching generation. In California, Texas and Hawaii, as well as Ontario, utilities, regulators and reliability authorities have recognized the threat of high DER penetration to the reliability of the bulk transmission system. Bulk system utilities are governed by NERC safety requirements, including the requirement for backup functionality of its control center. LEI believes as distribution utilities evolve towards more complex operations with greater responsibility for reliability, fully functional backup distribution control centers will become increasingly necessary.

Finally, LEI conducted a high-level review of the economic cost of a high-impact outage on Toronto Hydro's service territory, which covers the financial and economic capital of Canada. Extraordinary events such as natural disasters or terrorist attacks could cause the inability to operate Toronto Hydro's primary control center, resulting in delayed service recovery time following an outage. LEI's analysis shows that the proposed costs for the dual control center can be justified economically, given the significant costs of outages in the city of Toronto, and the dual control center's potential to reduce the duration of these outages.

2 Role of distribution control centers

Electricity distribution control centers ("DCCs") are used to control, coordinate, and monitor the distribution of electricity. Utilities in North America are upgrading their control centers to support reliability, resiliency, and to recover more quickly from natural disasters – and in order to further increase reliability, some utilities have built fully functional BUCCs.

DCCs provide real-time management of the grid. Supervisory Control and Data Acquisition ("SCADA") systems are used to obtain data about the distribution system via sensors and operate station breakers and field devices to manage the system. From the DCC, operators are able to monitor grid operation, manage planned and unplanned outages, manage system loading, as well as determine areas to improve grid performance and reliability. Key tasks at a DCC include clearance management and developing switching orders for planned maintenance.[1] Clearance management is the process by which the DCC determines periods that equipment can be taken out of service by asset management for planned work. Operators need to consider the outage length, system conditions and other clearance requests to determine when clearance can be taken. After clearance is approved, a switching order must be developed, which involves deenergizing equipment before any work is performed for safety, as well as reconfiguring the power system to perform reliably during this period. These responsibilities are critical to enable the reliable operation of the distribution system and ensure the safety of the public and utility employees.

Given their important role, DCCs are typically set up to run on a 24/7 basis with multiple levels of redundancy. Electrically they may be supported with an uninterrupted power supply ("UPS"), battery storage and/or a backup diesel generator, while SCADA systems will have multiple communication feeds, and technology systems will be designed to withstand application or hardware failures. BUCCs are used as a type of physical redundancy, where utilities have a separate facility that can take over the responsibilities of the primary DCC, if the primary DCC is inoperable or inaccessible.

Hot vs. Cold Backup Control Centers

Redundancy in BUCCs can be applied in various ways. Cold BUCCs are secondary backups that are only called upon when the primary system experiences a significant failure. Hot backups are a method of redundancy in which both primary and secondary systems are running, so that the secondary BUCC is receiving and processing the same information so that it can assume operations quickly and smoothly.

3 Control center operations in other jurisdictions

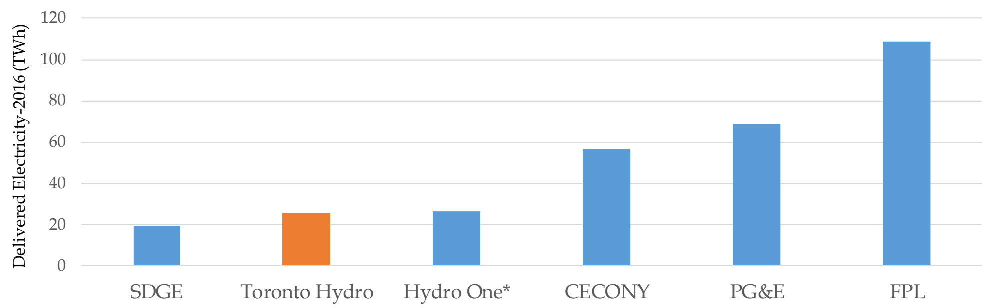
This section provides case studies of control centers in other jurisdictions, all of which are for utilities that have distribution operations. These utilities have sought to bolster their backup plans

[1] Vadari, Mani. *Electric System Operations: Evolving to the Modern Grid*. 2013.

to improve reliability and resiliency against severe weather events such as hurricanes and floods, as well as attacks including cyber-attacks.

LEI reviewed large Canadian and US utilities and identified four utilities that publicly disclose they utilize fully functional BUCCs to improve reliability in their distribution operations.[2] Hydro One has also been included, as they are developing a new 'dual primary' control center to replace their current BUCC, as discussed in its most recent distribution rate application.

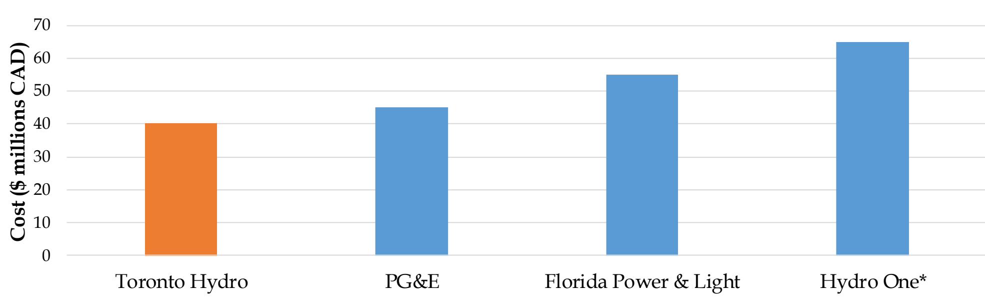
Figure 2. Electricity delivered by utilities



* Note: Electricity delivered to Hydro One distribution customers only
Source: Company reports and websites

In terms of the capabilities of the backup controls centers, all five case studies are fully functional and can completely take over operations from the primary control center. Toronto Hydro has estimated that the existing BUCC at [redacted] of the functionalities of the primary control center. Toronto Hydro's proposed dual control center at [redacted] would be fully functional, and costs are in line with (and slightly lower than) the identified utilities that had publicly available control center construction costs. A comparison of costs is shown below in Figure 3.

Figure 3. Control center construction costs



[2] LEI reviewed the 20 largest US utilities and 5 largest Canadian distribution utilities by number of customers. The excluded utilities may also use a backup control center, however were excluded from this review as no public information was found.

* Note: Budget of distribution portion of control center only, not the total cost

A comparative summary of the profiles and functionalities associated with the selected utilities is shown below in Figure 4. Toronto Hydro falls within the range of the selected utilities in terms of electricity delivered annually, as shown in Figure 2. Although certain selected utilities serve a larger load or area, Toronto Hydro serves a uniquely important load. Toronto Hydro serves the provincial capital as well as the economic and financial center of Canada; in fact, it serves the highest proportion of national economic activity out of all the identified utilities. In addition, Toronto Hydro has amongst the highest customer densities of the identified utilities and distributes approximately 19% of electricity consumed in Ontario.[3]

[3] Toronto Hydro. *About Us.* <https://www.torontohydro.com/sites/corporate/AboutUs/Pages/AboutUs.aspx>

Figure 4. Summary of identified utility distribution operations

	Metric	Toronto Hydro	Hydro One	FPL	PG&E	CECONY	SDGE
	Province/State of utility service territory	Ontario	Ontario	Florida, US	California, US	New York, US	California, US
Load Significance	**Delivered electricity (GWh, 2016)**	25,373	26,289*	108,871	68,820	45,745	19,200
	Number of customers ('000)	768	1,355	4,900	5,400	3,400	1,400
	Service area (km^2)	630	962,774	71,613	181,299	1,564	10,619
	Service area density (customers/km^2)	1,219	1	68	30	2,174	132
	Population of largest city served ('000)	2,732	<80	454	1,025	8,538	1,406
	Serving provincial/state capital?	✓	-	-	-	-	-
	Serving national financial center?	✓	-	-	-	✓	-
	% of national economic activity in utility's service territory**	10.0%	<6%***	3.3%	6.2%	4.0%	1.2%
Control center operations	**Qualitative Justification**	Withstand extreme weather events, climate adaptation, terror threat	Reduce financial risk, customer impacts and reputational harm	Increase reliability, reduce time required to recover from storms	Strengthen grid resiliency and reliability, particularly for natural disasters; DER integration	Withstand and rapidly recover from an EMP attack	Maintain reliability, DER related reliability concerns
	Mode of operation	One backup, Proposed: dual control centre	One backup, Proposed: dual primary control centre	Two backups	Parallel Three centers co-run	Parallel Four centers co-run + mobile backup	One backup
	Manned/Unmanned	Unmanned, Proposed: Manned	Manned	Unmanned	Manned	Manned	Unmanned
	Functionality	[redacted] proposed: [redacted]	Equivalent	Equivalent	Equivalent	Equivalent	Equivalent
	Cost (Canadian $ million)******	$40 (estimated cost of the proposed dual CC)	$65 (for proposed ISOC)	$55 (for one DCC)	$45 (average cost across three control centres)	n.a.	n.a.

* A total of 36,525 GWh were delivered through Hydro One distribution lines in 2016 - this includes electricity distributed to consumers who purchased power directly from the IESO

** Economic activity in Toronto Hydro service territory measured by comparing the 2016 annual GDP for the city of Toronto to Canada as a whole, using GDP estimates available from the city of Toronto's website. Economic activities in US utility's service territory was measured using county-level Personal Income data published by the US Bureau of Economic Analysis. Economic activity in counties the US utilities serve were then summed up and compared to total national Personal Income

*** Economic activity in Hydro One's distribution service territory is very difficult to estimate. Data available on Statistics Canada's website [CANSIM Table 381-5000] from 2009 provides GDP estimates for 15 metropolitan areas in Ontario, as well an estimate for 'non-census metropolitan areas' in Ontario. Assuming all economic activity in Ontario's 'non-census metropolitan areas' falls under Hydro One service territory, then this value divided by the total Canadian GDP estimate from the same data source indicates that 5.7% of Canada's economic activity falls within Hydro One's distribution service territory

**** Costs of US control rooms converted to Canadian dollars using an exchange rate of 1.3 CAD:1 USD (as of June 1st, 2018)

Sources: FERC, EIA, BEA, US Census Bureau, Statistics Canada, City of Toronto, Company reports and websites

3.1 Hydro One

Hydro One's primary power control center was opened in 2005 and cost $118 million.[4] The control center monitors both Hydro One's distribution and transmission networks in Ontario. Named the "Ontario Grid Control Centre", it consolidated monitoring and control functions under one roof, instead of the previously isolated regional control centers.

Hydro One also maintains a BUCC in Toronto originally commissioned in 1956 and is seeking to upgrade its control center capabilities (including both distribution and transmission) under its ongoing custom Incentive Rate-setting application for 2018-2022 electricity distribution rates [EB-2017-0049]. Hydro One has stated that its current BUCC requires upgrading due to an increased risk of facility failure. Hydro One has cited the main reasons to upgrade the facility as:

(i) regulatory compliance;
(ii) financial risk;
(iii) customer impacts; and
(iv) reputational harm.[5]

Hydro One presented a number of alternative approaches to replace/upgrade the existing BUCC operations, which are summarized in Figure 5 below (along with the costs associated with the distribution portion of these alternatives).

Figure 5. Alternative BUCC replacements initially presented by Hydro One

Alternative	Description	Distribution portion of costs ($ million)
1	Maintain status quo and use offsite leased space	$39
2	Build Network Operating Division ("NOD") BUCC and Data Centre ("DC") exclusively	$52
3	Build Integrated System Operations Center ("ISOC") as BUCC and Backup IT Management Center ("BUITMC"), with back office support areas and an integrated DC	$62
4	Acquire an existing facility for BUCC and BUITMC and integrated DC	N/A
5	Build Primary NOD Control Centre, primary SOC, and BUITMC	$71
6	Build ISOC capable of "dual primary" operations ***[Recommended by Hydro One]***	$65

Note: The above values represent only the distribution portion of costs. Total cost estimates for these listed alternatives are approximately double the values shown above.
Source: Hydro One exhibit B1-2 (OEB case EB-2017-0049) from April 4, 2017, pdf page 1314-1315

Of the approaches presented, Hydro One recommended the construction of a new Integrated System Operations Center ("ISOC"). Importantly, the ISOC would eventually allow Hydro One

[4] Hydro One. *Exhibit B1-2 from OEB case EB-2017-0049.* April 4, 2017 <http://www.rds.oeb.ca/HPECMWebDrawer/Record/569822/File/document>

[5] According to Hydro One's rate application for the 2015-2019 period

to operate a "dual primary" scenario, where both the current and new control centers can operate in parallel. Hydro One's distribution rate application is currently still ongoing.

3.2 Consolidated Edison

Consolidated Edison Company of New York ("CECONY") is a regulated utility which provides electric service to 3.4 million customers in New York City and Westchester County.[6] In addition to servicing a 604 square mile electric service territory, it also distributes natural gas and district energy steam. CECONY is divided into four different operating regions (Bronx/Westchester, Brooklyn/Queens, Manhattan, and Staten Island), each with an Electric Distribution Control Center which is responsible for coordinating switching operations and feeder processing for restoration of outages.[7] These DCCs are staffed 24/7. CECONY has highly concentrated underground distribution networks, which typically witness fewer interruptions in the face of weather events, in comparison to overhead systems common elsewhere.[8]

In recent years, CECONY has undertaken significant expense to upgrade its DCCs. A review of its reported annual capital expenditures from 2011-2016 shows total actual costs for "Electric Distribution Control Center Upgrades" of $23.7 million USD. [9,10,11,12,13,14] This work includes a project to upgrade the IT server, network, UPS infrastructure, and enhance the electrical and HVAC design of all DCCs. CECONY's justification for the project was that the DCCs are "vital to maintaining [their] ability to deliver safe and efficient services".[15] CECONY's

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6 ConEdison. *Company History and Statistical Information.* <https://www.coned.com/en/about-us/corporate-facts>

7 NYDPS. *ELECTRIC INFRASTRUCTURE AND OPERATIONS PANEL*. Jan 29, 2015. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B4BEE2FD7-6E49-40AE-B007-3B76085F31AC%7D>

8 NYDPS. Office of Electric, Gas, and Water. *2016 Electric Reliability Performance Report*. June 2017. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BBBCBF3C3-1812-4EEC-9E31-6901AED885D3%7D>

9 ConEdison. *Report on 2011 Capital Expenditures*. February 28, 2012.

10 ConEdison. *Report on 2012 Capital Expenditures*. February 28, 2013.

11 ConEdison. *Report on 2013 Capital Expenditures*. February 28, 2014.

12 ConEdison. *Report on 2014 Capital Expenditures and 2015-2019 Electric Capital Forecast*. March 2, 2015.

13 ConEdison. *Report on 2015 Capital Expenditures and 2016-2020 Electric Capital Forecast*. February 29, 2016.

14 ConEdison. *Report on 2016 Capital Expenditures and 2017-2021 Electric Capital Forecast*. February 28, 2017.

15 NYDPS. *Electric Infrastructure and Operations Panel*. Jan 29, 2015. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B4BEE2FD7-6E49-40AE-B007-3B76085F31AC%7D>

decision to invest in the project was to provide "a high level of availability to allow the operators, designers and engineers to make proper decisions during major distribution system events".[16] CECONY continues to invest in updating its distribution management; a multi-year outage management system integration project was initiated in 2018.[17]

In addition to multiple DCCs, CECONY is building the world's first utility Hardened Mobile Control Center ("HMCC") to enhance its ability to withstand and rapidly recover from an Electromagnetic Pulse ("EMP") attack. An EMP would potentially destroy many key control center systems and devices, leaving the utility operating with limited visibility, vulnerable to multiple contingencies, and possibly requiring reduced load and extended outages.[18] The HMCC is a modular backup system consisting of completely self-sufficient and self-contained elements that have their own power supplies. It would take over system operations in less than one day after an EMP attack, down from weeks or months. The system will be on a mobile platform consisting of three tractor trailers enclosures that can be deployed to one or several locations, that can support workstations for 16 operators in total. The contract to build the HMCC was awarded in December 2017.

As justification for the HMCC, CECONY cited growing tensions in world events and findings from a commission established by US Congress to assess threats of an EMP attack.[19] This commission concluded several potential adversaries would have the capability to attack the US with an EMP, even without a high level of sophistication, and that an "EMP is one of a small number of threats that can hold our society at risk of catastrophic consequences". CECONY describes the HMCC as a proactive and sensible approach to prepare for this threat.

3.3 Pacific Gas and Electric

Pacific Gas and Electric ("PG&E"), which serves around 5.4 million customers in California and has 140,000 miles of lines, operates three electric distribution control centers (Fresno, Rocklin, and Concord) over an entire service area exceeding 180,000 km^2. PG&E consolidated its 15 existing electric operations centers into these three centers in 2016, as part of its effort to create a "smart, more resilient grid". Each of the three centers monitor and control approximately one-third of PG&E's service region, also known as a parallel mode of operation. The centers provide the ability

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[16] ConEdison. Exhibit IIP-13. <https://legacyold.coned.com/documents/2013-rate-filings/Electric/Exhibits/076-IIP-13-ITCategory.pdf>

[17] GridBright. *ConEd Selects GridBright for Distribution Management Integration*. August 2017. <https://gridbright.com/coned-integration>

[18] Consolidated Edison. *Case 16-E-0060 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. Feb 28, 2018 <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B105D820F-4CE5-4E84-9E28-CC4F813E6158%7D>

[19] Ibid.

"to shift operations to the two other regional control centers if support is needed at one in the event of a major storm or natural disaster."[20] The centers were constructed with redundant data feeds and emergency back-up capabilities to be able enhance resiliency in the face of unforeseen events such as major storms or natural disasters.

PG&E's three DCCs cost a total of approximately $105 million USD. The first control center in Fresno opened in late 2014, at a total cost of $28.5 million USD. The second control center in Concord cost $40 million USD and was opened in August 2015. The third control center in Rocklin opened in February 2016, at a total cost of $36 million USD.[21]

According to PG&E, investment in these control centers will "strengthen resiliency of the grid, while enhancing electric reliability",[22] as well as advancing the integration of DERs into its distribution system. Smart grid technologies were also piloted and deployed alongside the control center consolidation.[23]

3.4 Florida Power & Light Company

FPL is one of the largest US electric utilities, serving approximately 4.9 million customers in Florida.[24] FPL operates three DCCs and maintains two backups near two of its control centers, and has "implemented multiple levels of resiliency and redundancy in both its transmission and distribution substations and control centers".[25] Not only is each facility equipped with redundant energy management systems, but each backup facility is geographically diverse, fully functional, and has dedicated and redundant communication links. This allows a BUCC to quickly and effectively take over if the primary control center loses functionality. The BUCCs closely replicate the main control centers and can also be accessed remotely from the nearby DCC. The BUCCs are

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[20] PG&E. *PG&E Opens New $40 Million State-Of-The-Art Electric Control Center in Concord.* August 20, 2015. <https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20150820_pge_opens_new_40_million_state-of-the-art_electric_control_center_in_concord>

[21] PG&E. With Opening of New Rocklin Facility, PG&E Completes Move to Industry-Leading, High-Tech Electric Distribution Control Centers. February 03, 2016. <https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160203_with_opening_of_new_rocklin_facility_pge_completes_move_to_industry-leading_high-tech_electric_distribution_control_centers>

[22] Ibid.

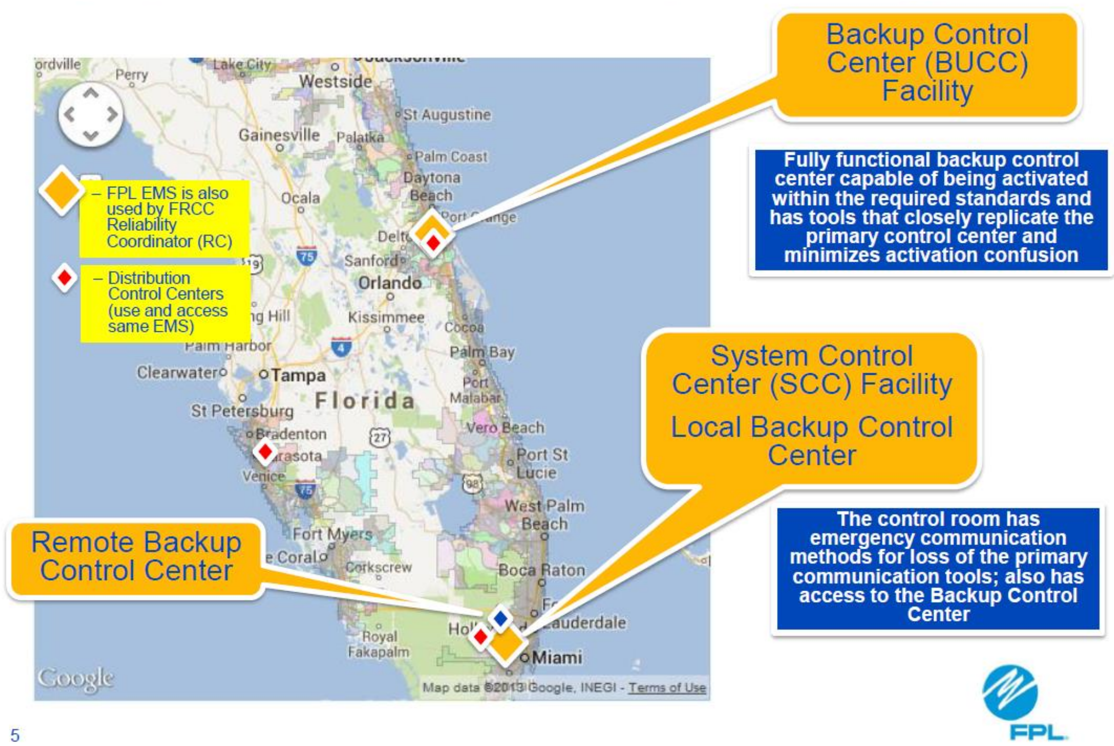
[23] PG&E. *Smart Grid Annual Report – 2017.* September 29, 2017. https://www.pge.com/pge_global/common/pdfs/safety/how-the-system-works/electric-systems/smart-grid/Annual-Report-2017.pdf>

[24] Florida Power & Light. *Company Profile*. <https://www.fpl.com/about/company-profile.html>

[25] State of Florida Public Service Commission. *Review of Physical Security Protection of Utility Substations And Control Centers*. December 2014. P. 29 <http://www.psc.state.fl.us/Files/PDF/Publications/Reports/General/Electricgas/Physical_Security_2014.pdf>

unmanned, so they do not run in parallel,[26] and can be considered "cold" backups. These DCCs support FPL's business continuity and recovery plans, and increase reliability and reduce time required to recover from storms.

Figure 6. FPL DCC locations



Source: NERC. *NERC Monitoring and Situational Awareness Conference: Loss of Control Center Procedures and Testing Practices*. September 19, 2013

In January 2017, FPL began construction on a $42 million USD DCC in West Palm Beach. It is located next to FPL's command center, a hub opened in 2012 that coordinates overall storm response.[27] The new center will be built to withstand Category 5 hurricanes, and will consolidate the two existing distribution control centers located in Miami and Sarasota. These enhancements come as part of FPL's $2 billion USD plan to harden its infrastructure against natural disasters.

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[26] NERC. *NERC Monitoring and Situational Awareness Conference: Loss of Control Center Procedures and Testing Practices*. September 19, 2013 <https://www.nerc.com/pa/rrm/Resources/MonitoringSituationalAwarenessDL/9.%20FPL_Loss_of_CC_Testing%20-%20Ed%20Batalla.pdf>

[27] Palm Beach Post. "*FPL breaks ground on distribution center to be Cat-5 storm ready*". January 18, 2017. <https://www.palmbeachpost.com/business/fpl-breaks-ground-distribution-center-cat-storm-ready/n5kRoKXSks4jcUpGRbz9SN/>

3.5 San Diego Gas & Electric

San Diego Gas & Electric ("SDGE") is a regulated utility which provides electric service to 1.4 million customers in San Diego County and a portion of Orange County, California, over a total area of around 10,600 km^2. SDGE owns 21,000 miles of distribution lines serving 25 communities and operates transmission lines as well as two generating stations. The monitoring, operation and dispatch for the entire SDGE electric network occurs from the Mission Control facility. A project to modernize these operations in terms of data infrastructure and workstations was forecast to cost $16.3 million USD;[28] justifications included "reducing time to identify abnormal or adverse system conditions" allowing for better and faster decisions.

SDGE also has a fully-functional backup DCC located 10 miles away from its primary control center which is used to continue to maintain reliability under emergency scenarios such as loss of the primary facility or any failure of computer or communications systems.[29] The "cold" backup center has redundant connectivity allowing for operators to virtually connect to the BUCC in the case of a failure of the primary energy management system, while physically remaining in the primary control center. The BUCC is also able to handle the situation where a total failure of connectivity means operators must relocate physically to the BUCC.

Note that SDGE is one of the leading utilities in incorporating DERs – in 2016 they were the first California utility to reach their net metering cap of 617 MW (though they continue to install solar capacity through the NEM 2.0 program).[30] In their control centers, SDGE has recognized that the high penetration of DER has contributed to greater risk of safety and reliability incidents.[31] Specific challenges identified include: reverse power flow, increased voltage variability, reduced switching flexibility, and a lack of visibility of actual circuit loads, among others.[32] For their operators, these challenges have added complexity to decision making and switching requirements.

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28 SDGE. *Direct Testimony of R. Dale Tattersall (Real Estate, Land Services and Facilities)*. October 6, 2017.

29 SDGE. *Prepared Direct Testimony of Don Akau on Behalf of San Diego Gas & Electric Company*. Sept 25, 2015. <https://www.sdge.com/sites/default/files/FINAL%2520Akau%2520Testimony.pdf >

30 Utility Dive. *As SDG&E edges closer to net metering cap, solar installations not expected to slow*. June 22, 2016 <https://www.utilitydive.com/news/as-sdge-edges-closer-to-net-metering-cap-solar-installations-not-expected/421312/>

31 SDGE. *Revised San Diego Gas & Electric Company Direct Testimony of William H. Speer (Electric Distribution O&M)*. December 2017. <https://www.sdge.com/sites/default/files/SDG%2526E-15-R%2520Speer%2520Revised%2520Prepared%2520Direct%2520Testimony.pdf>

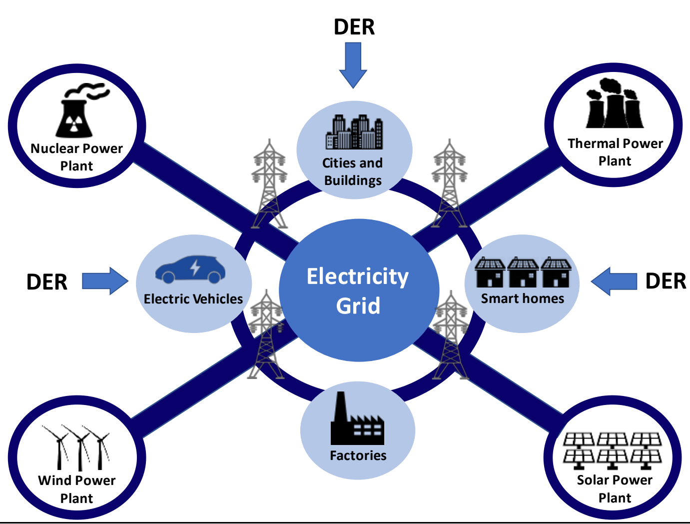
32 Utility Dive. *How SDG&E is dealing with high penetrations of rooftop solar*. July 25, 2014 <https://www.utilitydive.com/news/how-sdge-is-dealing-with-high-penetrations-of-rooftop-solar/290227/>

4 Impact of distributed energy resources on the role of distribution utilities

The following section discusses how the growth of DER has led distribution utilities to manage more complex operations. Ontario has seen significant DER growth, which has impacted distributor operations across the province in terms of monitoring and control of energy delivery as well as energy management. The growth of distributed generation has also given distributors some of the reliability responsibilities traditionally reserved for transmission utilities. Transmission utilities are part of the bulk electricity system and thus governed by NERC safety requirements, including the requirement for backup functionality of its control center. LEI believes as distribution utilities evolve towards more complex operations and greater responsibility for reliability, fully functional BUCCs will become increasingly necessary.

4.1 Changing role of the distribution utility

Figure 7. Distributed Energy Resource interaction with the electricity grid



Electricity distribution grids are undergoing fundamental changes with the advancement of industry trends such as DERs, smart grids, and integration of electric vehicles. These trends are challenging the traditional role of the distributor and the DCCs. The traditional power grid delivered power from large scale, centralized generation, through the transmission system and the distribution system to consumers. Therefore, DCCs only handled flows of electricity in a single direction: to electricity consumers. However, small scale generation and other DERs can now be found in the distribution side of the grid, as illustrated in Figure 7. Their growth means that distributors at times need to manage bi-directional flow of electricity between the utility and consumers. This fundamental change in utility operations adds a layer of complexity to control center operations, as they try to integrate, interpret, and act on this new information.[33] This evolution has caused DCCs to take on more operations which are more typically associated with TCCs, such as forecasting intermittent generation, energy scheduling, or dispatching generation to manage outages.

4.2 Growth of Distributed Energy Resources in Ontario

The definition for DERs can vary across jurisdictions, but generally they are decentralized, often modular, distribution grid-connected power supplying devices with smaller installed capacity. They often include power generation, storage, and demand response. In certain jurisdictions they may also have specific renewable, interconnection voltage or capacity requirements. The IESO definition of DERs is introduced in the textbox below.

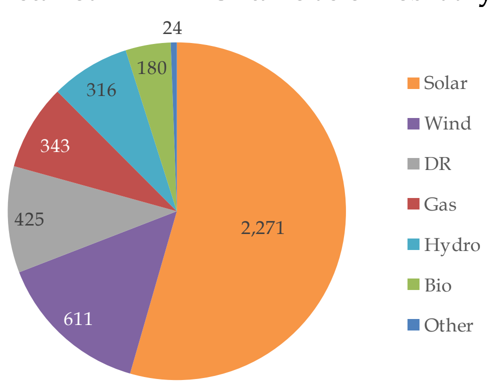
IESO definition of DERs

Distributed Energy Resources (DERs) are any electricity producing resources or controllable (dispatchable) loads connected to a distribution system that can serve electricity demand.

- DERs include, but are not limited to, generation, storage, and controllable load resources, but exclude persistent load reduction
- DERs may operate individually or be aggregated into virtual units
- DERs may connect directly to the distribution system or be integrated into a load

Source: IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26, 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/tp/2017/iesotp-20170926-6-grid-ldc-distributed-energy-resources-presentation.pdf?la=en&hash=50850B963ECB5B17141A7BB7F740444DE777F3EF>

Figure 8. Contracted and Installed DER in Ontario as of February 2017 (MW)



Source: IESO. Grid-LDC Coordination and Interoperability Initiatives. September 26, 2017.

[33] Stevens-Adams, Susan Marie, Cole, Kerstan Suzanne, Haass, Michael Joseph, Jeffers, Robert Fredric, Warrender, Christina E., Burnham, Laurie, and Forsythe, James C. *Situation awareness and automation in the electric grid control room*. United States: N. p., 2015. Web.

In Ontario, the growth of DER has been significant – as of 2017, there is 4,169 MW of contracted and installed DER capacity,[34] which is broken down in Figure 8. This includes over 2,000 MW of solar and 600 MW of wind connected to the distribution system. Solar and wind DER capacity is expected to grow to a total of over 3,000 MW by the early 2020s, and 34 MW of storage is also expected.[35] Between 2009 and 2016, Toronto Hydro has enabled approximately 81.9 MW of renewable generation, or over 1,572 interconnections.[36] Toronto's 2009 Sustainable Energy Strategy calls for an increase of 550 MW of renewable generation,[37] which is estimated to result in an additional 9,000 interconnections.[38] In the 2017 Long Term Energy Plan ("LTEP"), the Government of Ontario also refers to the future growth of DERs, including energy storage, microgrids, electric vehicles, in addition to renewable generation.[39] Although the 2017 LTEP does not explicitly state procurement targets, it has led to the development of the IESO's Renewable Distributed Generation Integration ("RDGI") Fund which will fund DER and smart-grid integration demonstration projects.[40]

The IESO has recognized impacts of DER to distributors and the broader bulk electric system. In 2017 it convened the Grid-LDC Inter-Operability Standing Committee, with the objectives of discussing issues and opportunities to coordinate management of the system.[41] Parties have discussed DER integration challenges, issues in forecasting, and data availability and sharing, with the goal of initiating pilot projects enabling greater coordination between LDCs and the IESO.[42]

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34 IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26, 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/tp/2017/iesotp-20170926-6-grid-ldc-distributed-energy-resources-presentation.pdf?la=en&hash=50850B963ECB5B17141A7BB7F740444DE777F3EF>

35 Ibid.

36 Toronto Hydro. *2016 Toronto Hydro Environmental Performance Report*. 3/3/2017. <https://www.torontohydro.com/sites/electricsystem/corporateresponsibility/Documents/2016%20Toronto%20Hydro%20Environmental%20Report%20-%202017-03-09.pdf>

37 City of Toronto. *The Power to Live Green: Toronto's Sustainable Energy Strategy*. October 19, 2009 <https://www.toronto.ca/legdocs/mmis/2009/ex/bgrd/backgroundfile-24583.pdf>

38 Assuming 2009-2016 average rate of 52 kW per interconnection.

39 Government of Ontario. *2017 Long-Term Energy Plan: Delivering fairness and choice*. <https://www.ontario.ca/document/2017-long-term-energy-plan>

40 IESO. *Renewable Distributed Generation Integration (RDGI) Fund*. March 29, 2018. http://www.ieso.ca/-/media/files/ieso/document-library/engage/rdgif/rdgif-20180329-presentation.pdf?la=en

41 IESO. *Grid-LDC Inter-Operability Standing Committee Terms of Reference*. March 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/standing-committee/gli/gldc-20170327-terms-of-reference.pdf?la=en>

42 IESO. *Where Do We Go From Here*. Feb 8, 2018. <http://www.ieso.ca/-/media/files/ieso/document-library/standing-committee/gli/gldc-20180208-planning-discussion.pdf?la=en>

4.3 Role of the Distribution System in Reliability

Potential DER impact to bulk system reliability

The bulk electricity system (including the transmission system) in the Continental US and Canada is under the regulatory authority of NERC, which develops and enforces reliability standards. NERC has studied the potential impacts to the bulk system from high levels of DER. NERC noted the operations at wholesale and retail, and transmission and distribution "may be increasingly blurred" and that additional communication and controls infrastructure will be required to handle the operational challenges associated with coordinating distribution and bulk data. Bulk system reliability impacts identified include:

- Non-dispatchable ramping/variability of certain DER
- Response to faults: lack of low voltage ride through, lack of frequency ride-through and coordination with the IEEE 1547 interconnection standards for distributed generation
- Potential system protection considerations
- Under Frequency Load Shedding (UFLS) and Under Voltage Load Shedding (UVLS) disconnecting generation and further reducing frequency and voltage support
- Visibility/controllability of DER
- Coordination of system restoration
- Scheduling/forecasting impacts on base load/cycling generation mix
- Reactive power and voltage control
- Impacts on forecast of apparent load seen by the transmission system

Source: NERC. *Potential Bulk System Reliability Impacts of Distributed Resources*. August 2011. https://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf

The growth of DERs has not only shifted the role and responsibilities of distributors and their DCCs, but the distribution system has also taken on greater importance from a bulk system reliability perspective. Traditionally, DCCs and TCCs have been managed separately and there has been minimal coordination between them. This is because the impact of the distribution system on the transmission system was previously assumed to be trivial.[43] This is generally true at lower DER penetration rates, as any impacts can be managed by bulk power system

[43] Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

resources.[44] However, a distribution system with significant DER integration can cause issues in transmission line loading, grid voltage, and system frequency,[45] and may change its operating state more often which can impact bulk system reliability.[46]

Utilities, Independent System Operators ("ISOs"), and their respective regulatory authorities also recognize issues caused by DERs. Utilities located within the Electric Reliability Council of Texas ("ERCOT") had interconnected nearly 900 MW of DERs in their service territories (at or below 60 kV) as of 2015. Although these resources do not pose an immediate concern at the transmission level, ERCOT noted several potential reliability issues for the bulk system with higher DER penetration. These include increased error in load forecasting resulting in excessive reliance on regulation and other ancillary services, and uncoordinated system restoration after a load shed event potentially causing large voltage or frequency swings.[47]

In Hawaii, over 10% of Hawaiian Electric's ("HECO") Oahu customers utilize rooftop solar. This high rate of DER penetration has resulted in distribution circuits exceeding 100% of daytime minimum load.[48] HECO implemented restrictions on PV interconnections, citing that additional PV may cause distribution circuits to become dangerous and unreliable due to overvoltage, voltage variations, and islanding issues. Impacts to the transmission system include magnifying transients, accelerating transients, degrading control measures and frequency instability.[49]

The distribution system was found to be one of the contributing factors in the Arizona-Southern California 2011 outages, where an 11-minute system disturbance in the Pacific Southwest caused cascading outages impacting an estimated 2.7 million customers.[50] A Federal Energy Regulatory Commission ("FERC")/ North American Electric Reliability Corporation ("NERC") study on this outage found that "the separate management over [transmission power subsystems] and

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44 NERC. *Distributed Energy Resources Connection Modeling and Reliability Considerations*. February 2017. <http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

45 Ibid.

46 Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

47 ERCOT. Distributed Energy Resources (DERs) Reliability Impacts and Recommended Changes. March 2017. <http://www.ercot.com/content/wcm/lists/121384/DERs_Reliability_Impacts_FINAL.pdf>

48 Greentech Media. *How Much Solar Can HECO and Oahu's Grid Really Handle?*. February 2014. <https://www.greentechmedia.com/articles/read/how-much-solar-can-heco-and-oahus-grid-really-handle#gs.1tYivlI>

49 HECO. *Renewables in Hawaii*. February 6, 2014. < https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_of_Trustees_Presentations-February_6_2014.pdf>

50 FERC. *Arizona-Southern California Outages on September 8, 2011*. April 2012. <https://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf>

[distribution power subsystems] is insufficient to ensure the operational security of an integrated T-D power system".[51] The NERC Distributed Energy Resources Task Force has also highlighted the importance of data sharing and coordination between distribution and transmission utilities.[52]

These examples, as well as the IESO's Grid-LDC Inter-Operability Standing Committee that was introduced in Section 4.2, show that the operation of the distribution system is becoming more important to bulk system reliability. Bulk system utilities are required by NERC to have backup functionality for their control center. LEI believes that the case for a fully functional backup distribution control center is further supported by the evolving challenges of integrating DERs, and the importance of coordination between the distribution and transmission utility.

[51] Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

[52] NERC. *Distributed Energy Resources Connection Modeling and Reliability Considerations*. Feb 2017. <https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf>

5 Economic case analysis for proposed control center

This section summarizes LEI's analysis of an economic case for the proposed dual control center, utilizing the concept of Value of Lost Load ("VoLL"). As demonstrated below, based on estimates of VoLL for Toronto, the proposed dual control center could pay for itself if it could reduce the duration of relatively short high impact outages; examples of the type and duration of such outages are presented in Figure 9. Given that the dual control center provides operational benefits beyond reducing outage durations, this suggests that the investment is economically justified.

Figure 9. Type & duration of outage event equivalent to $40.2 million dual control center cost

Extraordinary outage event	Duration of outage
System-wide outage at average 2016 peak load (3,961 MW)	**20 minutes**
System-wide outage at average 2016 load (2,913 MW)	**28 minutes**
Outage at Windsor Transformer Station (300 MW peak)	**4.5 hours**

Note: This figure summarizes analysis covered in Section 5.2.

Toronto Hydro's service area covers the city of Toronto. With a population of 2.9 million as of July 2017 and a GDP of $193 billion CAD in 2016, [53,54] Toronto is Canada's largest city; it is comparable to entire provinces in terms of population and economic activity. Toronto is also Canada's economic and financial center; the Toronto Stock Exchange ("TSX") is the 9th largest exchange in the world by market capitalization. The city's continued economic functionality is highly dependent on maintaining reliable and resilient grid operations and continuous electricity distribution by Toronto Hydro.

5.1 Value of Lost Load

LEI believes that analysis based on VoLL is an effective method to estimate the economic cost of outages in the city of Toronto. If the cost of outages can be estimated, we can determine whether a particular investment intended to avoid or reduce the duration of such outages is economically worthwhile. VoLL is a socio-economic monetary indicator of the economic consequences of a power outage; it is an indicator of the economic value of sustained electricity supply. As with any investment or consumption choice, if cost is less than value, the optimal investment has been chosen, and resources are available, the investment should be made, or the item consumed. In the case of a utility, if an investment is cost-effective and costs less to achieve than the Value of Lost Load, then the investment should be pursued.

[53] City of Toronto. <https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/>

[54] Toronto city GDP was $168 billion in 2016 measured in 2007 Canadian dollars. This value was inflated to 2016 dollars using inflation rate for Toronto based on StatsCan data [CANSIM Table 326-0021].

What is VoLL?

VoLL—usually measured in dollars per MWh—represents an indication of society's willingness to pay for electricity service (or to avoid curtailment). It is important to recognize that VoLL will vary depending on the type of outage considered. Generally, there are three broad classes of outages that can occur on an electricity grid:

- large-scale, long-term outages in which power is interrupted across a wide area for days or possibly even weeks due to a catastrophic event that causes a system-wide blackout and requires system restart and in some cases, extensive infrastructure repairs;
- more localized outages in which electricity service is unavailable for hours at a time (e.g., as a result of distribution service event or a more localized weather event, such as a tornado or a flood); and
- targeted, short-duration outages of select customers over more discrete timeframes. Long duration, system-wide outages will likely have the highest VoLL as the indirect and induced costs of the outage increase over time (loss of wages, loss of perishable goods, etc.).

Sources: adapted from London Economics International. *Estimating the Value of Lost Load*. June 17th, 2013; Schroder and Kuckshinrichs. *Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review*. December 24th, 2015

Accurately estimating VoLL for a given region and a specific type of outage depends on multiple factors such as the type of customer affected, regional economic conditions and demographics, time and duration of outage, and other specific traits of an outage. It is important to note that VoLL is a region-specific average representing what society as a whole would be willing to pay to avoid an outage; VoLL for specific customers may be higher or lower, and VoLL in specific hours of the day will be higher or lower than the overall reported average. VoLL is not a line item on any individual customer's bill. Instead, it is used for planning purposes to determine at what point society is better off to forgo the use of electricity rather than to make an investment that contributes to additional reliability.

Four key methodologies are used in the estimation of VoLL: (i) macroeconomic analysis; (ii) a survey of stated choices; (iii) a survey of revealed preferences; and (iv) case studies. Macroeconomic analysis and surveying stated choices are more common due to the relative ease of data acquisition.[55]

[55] Surveying revealed preferences is based on actual investments made by customers that install or procure back up power, meaning that a significant portion of customers will not be surveyed. Case studies depend on data obtained from an actual outage, which is difficult to obtain for a significant portion of customers; moreover, the available case studies may not be representative of forthcoming outages, particularly in other jurisdictions.

The macroeconomic approach involves the application of an electricity intensity ratio, such as GDP/kWh, based on the assumption that a power cut would result in a proportionate drop in economic activity. On the other hand, customers' perceived values can be surveyed to ask about the cost that a customer is willing to incur to avoid a power outage—or the amount of money a customer would need to be compensated to accept a power outage. Whether it is willingness to pay or willingness to accept payment, both approaches are used to estimate the direct cost that a customer would incur as a result of an outage.

LEI previously performed for Electric Reliability Council of Texas ("ERCOT") an extensive review of VoLL calculations in different jurisdictions; the studied jurisdictions all used one of the techniques discussed above.[56] LEI's study found that average VoLL for a developed, industrial economy ranges from approximately US$9,000/MWh to US$45,000/MWh, shown in Figure 10 below.[57]

Figure 10. Summary of VoLL by jurisdiction

Region/Market	Methodology	VoLL (CAD)	VoLL (USD)
New Zealand	Survey	$42,503	$41,269
Australia - Victoria	Survey	$45,767	$44,438
Australia	Survey	$47,075	$45,708
Republic of Ireland	Macroeconomic analysis	$9,823 - $16,751	$9,538 - $16,265
US - Northeast	Macroeconomic analysis	$9,561 - $14,341	$9,283 - $13,925

Sources: "Investigation into VOLL in New Zealand", "Assessment of the Value of Customer Reliability (VCR)", "Valuing Reliability in the National Electricity Market", "An Estimate of the Value of Lost Load for Ireland", "The Economic Cost of the Blackout"

Note: USD to CAD conversion rate is 1:1.0299, based on the 2013 average annual exchange rate

IESO utilized the concept of VoLL in its 2015 Central Toronto Integrated Regional Resource Plan. As part of this 25-year plan, IESO conducted a Probabilistic Reliability Assessment to estimate the economic impact of the risk of outages,[58] using a VoLL assumption of CAD$30,000/MWh.[59,60]

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[56] London Economics International. *Estimating the Value of Lost Load*. June 17, 2013. <http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf>

[57] Ibid.

[58] IESO. *Central Toronto Area Integrated Regional Resource Plan*. April 28, 2015. <http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/central-toronto/2015-central-toronto-irrp-report.pdf?la=en>

[59] Independent Electricity System Operator. *Central Toronto Area Integrated Regional Resource Plan – Appendices*. April 28, 2015. <http://www.ieso.ca/-/media/files/ieso/document-library/regional-planning/central-toronto/2015-central-toronto-irrp-report-appendices.pdf?la=en>

[60] This assumption is similar to a 2004 estimate of USD 22,600/MWh which used a survey-based methodology. (Bhavaraju, M., *Variable Resource Requirement*, PJM Stakeholder Meeting. 2004.)

As this assumption falls within LEI's previous study ranges for VoLL, LEI believes a $30,000/MWh is an appropriate VoLL assumption in Toronto Hydro's service territory.

5.2 Economic costs of an extraordinary event

Low-probability events such as terrorist attacks or extraordinary weather events can have significant system impacts – for example, flooding could cause outages and result in the inability to operate Toronto Hydro's primary control center. Note that extraordinary weather events are predicted to become more frequent due to climate change – for example, maximum daily rainfall in Toronto is expected to more than double by 2040, increasing the risk of flooding near critical components.[61] To the extent the primary control center cannot be used at the same time that significant system outages occur, Toronto Hydro's ability to restore service would be significantly delayed – the control center plays a vital role during recovery, including coordinating with field personnel, data analysis, switching, isolation, and facilitation of emergency reactive work.

The most beneficial case would be reducing the duration of a system wide outage. Toronto Hydro supplied a total of 25,588 GWh in 2016, which averages to about 2,913 MWh delivered per hour, and had an average peak load of 3,961 MW.[62] Taking Toronto Hydro's average load per hour of 2,913 MWh, and assuming a VoLL price of $30,000/MWh, the $40.2 million cost for the dual control center represents reducing the duration of a system-wide outage by 28 minutes at VoLL prices.[63] Assuming the outage occurs during an average peak load hour, the representative cost of the control center drops to reducing the duration a system-wide outage by 20 minutes. This shows that it would only take the reduction in duration of a single system-wide outage of these lengths over the lifetime of the control center investment to recover the construction costs.

To put these outage times in context, Toronto Hydro's System Average Interruption Duration Index ("SAIDI") has averaged 0.98 hours from 2012-2016, or 58.8 minutes; Figure 11 presents Toronto Hydro's historical SAIDI from 2012 to 2016.

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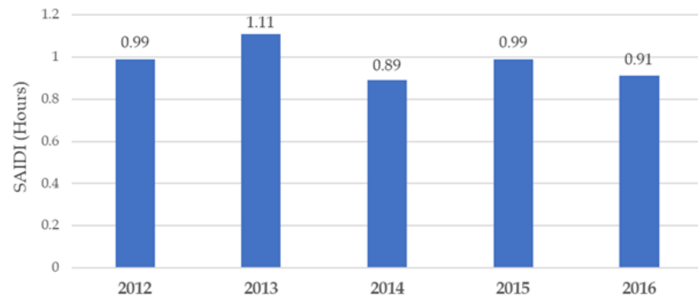
[61] City of Toronto. *TransformTO: Resilience and Adaptation to Extreme Weather.* < *https://www.toronto.ca/wp-content/uploads/2017/10/9801-TransformTO-Resilience-and-Adaption-to-Extreme-Weather-Workbook-Results-Summary-AODA-Compliant.pdf*>

[62] Data taken from the OEB's 2016 Yearbook on Electricity Distributors. Toronto Hydro's "average load per hour" estimated by dividing its 'Total kWh Supplied' from the OEB yearbook by the total number of hours in the year (8,784). Toronto Hydro's 'average peak load' taken from the OEB's yearbook (page 62, line 15). Source: Ontario Energy Board. *2016 Yearbook of Electricity Distributors*. August 17, 2017.

[63] Toronto Hydro delivered a total of 25,588 GWh in 2016, which is an average of about 49 MWh delivered per minute. At a VoLL of $30,000/MWh, each average minute of a Toronto Hydro outage would cost around $1.46 million CAD. Therefore, an outage of 28 minutes would cover the full value of the new control center ($40.2 million CAD).

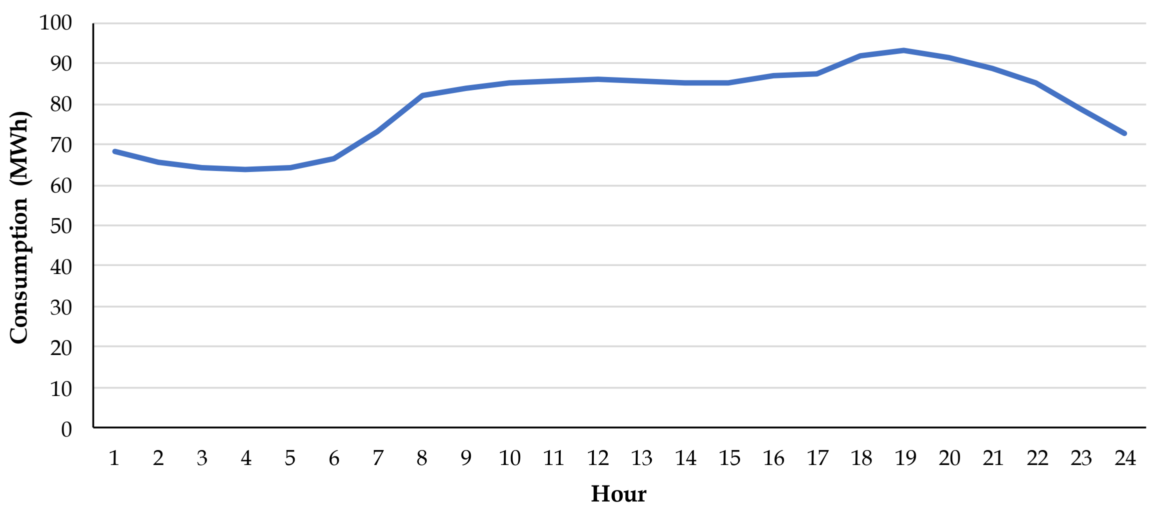
Figure 11. Toronto Hydro historical SAIDI (2012-2016)



Source: Toronto Hydro. *Scorecard - Toronto Hydro-Electric System Limited*. 9/24/2017.

More conservative cases involve the dual control center reducing the impact of losing a Transformer Station ("TS") at the same time as the primary control center, which could happen for example due to flooding which impacts both the control center and a TS. An example of the scale of TS losses occurred on January 15th, 2009, when the failure of the deluge system at the Dufferin TS caused an outage that lasted around 24 hours. Multiplying the $30,000/MWh VoLL assumption discussed previously, by an assumed customer demand profile over the 24-hour period as shown in Figure 12, the economic impact of such an outage is estimated to be $57.6 million, about 43% higher than the cost of the dual control center.

Figure 12. Assumed customer demand in Dufferin TS example

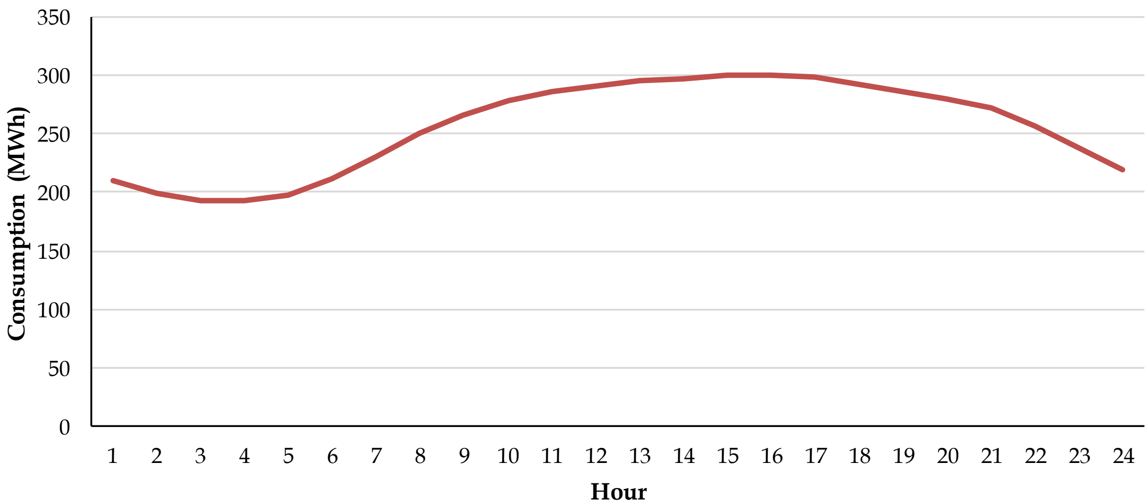


LEI estimated this demand shape in the outage location using the IESO's zonal demand for the Toronto Transmission Zone on January 15th, 2009. The outage to customers with an annual peak load of 113 MW was then fitted to the demand shape of the Toronto Transmission Zone on that day
Source: IESO 2009 zonal demand

Extended outages at larger Transformer Stations, such as the Windsor TS, are also possible and would have even greater effects including outages to Canada's economic and financial center. If a terrorist attack, fire, or flood causes the loss of the primary control center and the entire Windsor

TS, it could cause a loss of 300 MW at peak load. Assuming a VoLL of $30,000/MWh, a 300 MW peak load, and the demand profile shown in Figure 13 below, the $40.2 million cost for the control center represents in this example an outage duration of around 4.5 hours.[64]

Figure 13. Assumed customer demand in Windsor TS example



LEI estimated this demand shape in the outage location using the IESO's zonal demand for the Toronto Transmission Zone on its peak day for 2016, August 12th. The outage to customers with an annual peak load of 300 MW was then fitted to the demand shape of the Toronto Transmission Zone on that day

These examples show the potentially high economic impact of outages. LEI has estimated the loss of load possible during certain extraordinary events and using a VoLL of $30,000/MWh has estimated the economic cost of outages in the city of Toronto. The examples in this section show that relatively short duration outages would end up costing the equivalent of the $40.2 million cost of the dual control center. Therefore, if the dual control center could reduce the duration of potential outages or allow for a fully functional alternative in the event that the main control center needs to be evacuated, the avoided outage effects mean that the dual control center could essentially pay for itself.

[64] Duration reflects outage occurring at the highest demand hours (hours 13-17).

6 Concluding remarks

LEI believes there is a strong case to support a dual distribution control center for Toronto Hydro, based on the key points identified below:

- research in Section 3 shows a precedent for North American distribution utilities to build new fully functional backup distribution control centers to help alleviate reliability and resiliency concerns;
- observed construction costs for fully functional BUCCs are similar to those proposed by Toronto Hydro—see Figure 3;
- the importance of the load served by Toronto Hydro compares favourably to these examples;
- many of the justifications presented by other North American distribution utilities to add or enhance backup operations are equally applicable to Toronto Hydro—see Figure 4;
- an increase in adverse weather events, particularly maximum daily rainfall and flooding risks, further justify the need the need for a more capable alternative to the main control center in the case of a prolonged failure;
- the responsibilities of distribution utilities are evolving due to the proliferation of DERs, and with greater responsibility for reliability, alternate control centers will become increasingly necessary as discussed in Section 4; and
- from an economic perspective, the proposed cost of the dual control center can be justified given the significant costs associated with outages in the city of Toronto, and the potential for the dual control center to reduce the duration of high impact outages.

Appendix: List of Works Consulted

City of Orillia. *Hydro One Public Information Session*. September 29th, 2016.

City of Toronto. *TransformTO: Resilience and Adaptation to Extreme Weather.* September 2015.

FERC. *Arizona-Southern California Outages on September 8, 2011*. April 2012.

Hydro One Networks Inc. *Evidence, Exhibit B1-1-1. EB-2017-0049*. Received by the OEB on April 27th, 2014.

Hydro One Limited. *2017 Annual Report*. Released on February 13th, 2018.

IESO. *Central Toronto Area Integrated Regional Resource Plan – Appendices*. April 28th, 2015.

IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26th, 2017.

IESO. *Grid-LDC Inter-Operability Standing Committee Terms of Reference*. March 2017.

IESO. *Where Do We Go From Here*. February 8th, 2018.

Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24th, 2018. P. 1.

London Economics International. *Estimating the Value of Lost Load.* June 17th, 2013.

NERC. *Distributed Energy Resources Connection Modeling and Reliability Considerations*. February 2017.

NERC. *NERC Monitoring and Situational Awareness Conference: Loss of Control Center Procedures and Testing Practices*. September 19th, 2013.

New York Independent System Operator. *New Control Center Highlights 15th Year of Evolving Grid Operations and Markets.* January 2015.

New York Independent System Operator. *NYISO Control Center Project*. August 8th, 2011.

Ontario Energy Board. *2016 Yearbook of Electricity Distributors*. August 17th, 2017.

Ontario Energy Board. *Interrogatories. EB-2013*-0416. Exhibit I. Filed on July 4th, 2014.

Ontario Energy Board. OEB *Staff Report: Review of cost of capital for Ontario's regulated utilities*. January 14th, 2016.

Ontario Energy Board. *OEB cost of capital parameter updates for 2018 cost of service and custom Incentive-rate-setting application*. November 23rd, 2017.

PG&E. *Smart Grid Annual Report – 2017.* September 29th, 2017.

Schroder and Kuckshinrichs. *Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review*. December 24th, 2015.

State of Florida Public Service Commission. *Review of Physical Security Protection of Utility Substations And Control Centers*. December 2014. P. 29.

Stevens-Adams, Susan Marie, Cole, Kerstan Suzanne, Haass, Michael Joseph, Jeffers, Robert Fredric, Warrender, Christina E., Burnham, Laurie, and Forsythe, James C. *Situation awareness and automation in the electric grid control room*. United States: N. p., 2015.

Toronto Hydro. *Responses to Ontario Energy Board Staff Interrogatories on Issue 2.2*. [EB-2012-0064]. October 5th, 2012.

Vadari, Mani. *Electric System Operations: Evolving to the Modern Grid*. 2013.

TAB 24

E8.3 Fleet and Equipment Services

E8.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 19.1	**2020-2024 Cost ($M):** 42.5
Segments: Fleet and Equipment Services	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Reliability, Environment, Safety, Financial	

The Fleet and Equipment Services program (the "Program") is responsible for the procurement, maintenance, and disposal of vehicles and equipment that are needed to support Toronto Hydro's functional and operational needs. The Program's primary objective is to manage the Program's assets to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety. Capital investments within the Program are grouped into two categories: (1) vehicles: which includes, (a) heavy duty vehicles, used as a primary tool to perform distribution work, and to transport operators and equipment; and (b) light duty vehicles, which are fully equipped for employees to inform, manage and monitor distribution work; and (2) vehicle and employee equipment (e.g. forklifts, trailers, telematics systems, boom lifts, protective gear, etc.). The Program and its constituent segments are a continuation of the activities described in the Fleet and Equipment Services program in Toronto Hydro's 2015-2019 Rate Application.[1]

Toronto Hydro relies on its fleet of vehicles to support functional needs and performance requirements associated with executing a complex and dynamic capital and maintenance program. An insufficient or unreliable fleet can negatively impact utility performance, such as reliability and employee productivity. In addition, as vehicle fleets age, they incur higher operating expenses due to increasing levels of reactive repairs. Therefore, the Program ensures that capital investments are made at a level and pace that allow asset maintenance, repair and capital costs to be minimized. An optimally timed vehicle replacement strategy also ensures that the appropriate level of vehicles are available to support system maintenance and capital investment plans.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Schedule 8.1.

To ensure that the vehicles are replaced in a cost-effective manner, Toronto Hydro utilizes the Life Cycle Analysis ("LCA") approach to identify the capital investment candidates for future replacements and bases its decision to replace or dispose of the vehicle on the actual asset condition assessment. The LCA provides empirical justification to identify the best time to replace vehicles in terms of age, mileage or other pertinent factors. As the age of a vehicle increases, ownership costs decline and operating costs increase. As such, the optimal time to replace a vehicle is before the point where the operating costs begin to outweigh the decline in ownership costs. To assist with determining the LCA, Toronto Hydro retained a third party consultant to undertake a comprehensive study of Toronto Hydro on-road vehicle fleet and to provide recommendations regarding the optimal replacement age of the fleet vehicles. Toronto Hydro leverages the analysis to plan its future capital replacements during the 2020-2024 plan period.

Figure 1: Toronto Hydro Fleet

Although the LCA identifies the optimal age for vehicle replacements for the purposes of expenditure planning, Toronto Hydro replaces vehicles according to the results of vehicle condition assessments. Because a replacement cycle varies depending on the vehicle make, model year, equipment design, operating environment or even by how the operator uses the vehicle, some vehicles that are in poor condition or unsafe may require replacement before the criteria is met, and alternatively, some vehicles that exceed the criteria may be in good condition and not warrant replacement. As such, the vehicles forecasted for replacement in accordance with the LCA, also undergo condition assessments performed as part of the regular vehicle inspections. This forms the basis of Toronto Hydro's vehicle replacement and disposal decision-making.

Prioritization within the Program reflects the importance of the vehicle class to performing core distribution work, the lead time required to procure the asset, cost, and the level of customization required. As such, capital plans are created by first scheduling the heavy duty vehicle replacements in their recommended replacement year, followed by light duty vehicles. Equipment is scheduled on a more ad-hoc basis. It is more economical and efficient to procure vehicles in batches of approximately five to ten units, therefore asset replacements are shuffled between years within a five year plan to assist with balanced spending during the years.

Over the 2020-2024 plan period, Toronto Hydro will focus primarily on the replacement of heavy duty vehicles that are or will be due for replacement. Owing primarily to the fact that heavy duty vehicles are eight to ten times more expensive than light duty vehicles and due to the increase in foreign exchange rates that has led to an escalation in asset price, the requested Program funding over the 2020-2024 plan period is higher than the 2015-2019 period. Nevertheless, Toronto Hydro continues to implement various mitigation measures to minimize the impact of these costs. For instance, Toronto Hydro has taken steps to reduce its overall fleet size from 660 units[2] down to 588, thereby, reducing the operating costs of running a larger fleet.

In addition, the investments in Toronto Hydro vehicle fleet can produce the following benefits:

- Minimization of total vehicle costs;
- Minimization of fleet downtime due to repairs, and a corresponding increase in fleet reliability;
- Increase in vehicle efficiency, i.e. lower fuel consumption and idle reduction;
- Improvements in shop efficiency as less labour will be required to maintain new vehicles and focus can be on older vehicles;
- Reduction in environmental impacts such as reduction in greenhouse gases emitted as well as a reduction in the maintenance fluids used; and
- Increased employee and field safety as newer vehicles are equipped with new safety technology.

[2] I in EB-2014-0116, Toronto Hydro reported a fleet size of 660 units, including cars, pickups, bucket trucks, and other vehicles. See EB-2014-0116 Exhibit 2B, Section E8.1 at page 5.

TAB 25

E8.4 Information Technology and Operational Technology Systems

E8.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 231.2	**2020-2024 Cost ($M):** 281.4
Segments: IT Hardware, IT Software, and Communication Infrastructure	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Customer Service, Public Policy, and Financial	

The Information Technology and Operational Technology[1] Systems ("IT/OT") program (the "Program") proposes to invest in hardware, software, and communication assets that provide critical support to Toronto Hydro's customer and business-facing services. Toronto Hydro relies on IT/OT systems to execute capital and operational programs, including customer-facing and operationally-critical functions. The investments proposed in this Program were developed in accordance with Toronto Hydro's IT Asset Management Strategy,[2] which mitigates risks to reliability, cybersecurity, and the utility's business operations.

The Program's objective is to provide reliable technology solutions and services to support Toronto Hydro's business functions, including effective and reliable service to customers, safe and efficient management, and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability.

The Program consists of the following three segments:

- **IT Hardware**: includes the core back end infrastructure assets (e.g. servers, local area networks and data storage/centres) and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets) that support Toronto Hydro's day-to-day operations and core systems;
- **IT Software**: includes software applications that provide process improvements to a range of customer-facing and business functions; and,

[1] Operational Technology refers to hardware and software that detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise (https://www.gartner.com/it-glossary/operational-technology-ot/).
[2] Provided at Exhibit 2B, Section D5.

- **Communication Infrastructure**: includes assets that enable the monitoring and control of distribution communication infrastructure, including fibre-optic assets and wireless Supervisory Control and Data Acquisition ("SCADA") infrastructure.

E8.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Improving the customer experience of interacting with the utility through digital platform; and ○ Supporting accurate and timely communication with customers during prolonged power outages.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that support efficient distribution system management; ○ Supporting outage restoration efforts by ensuring that system operators have the necessary IT/OT tools to promptly identify incidents, develop effective resolution plans and communicate with operational teams; and ○ Enhancing IT/OT systems to enable remote equipment monitoring and operations capabilities.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Providing the technological infrastructure framework required to achieve conservation and demand management targets, enable grid-modernization, and support energy storage and distributed energy resources; and ○ Ensuring the effectiveness and availability of IT/OT systems that are required to support the utility's implementation of new policy initiatives and compliance with regulatory requirements, including those arising out of the OEB's Cyber Security Framework.

Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by: ○ Enabling the constant monitoring of substation and field assets; and ○ Maintaining the effectiveness and availability of IT/OT Systems that support the utility's safety performance (such as Intelex, Learning Management System, SCADA, Automated Vehicle Locator, Field Mobility System, Radio, and Network Management System).
Financial	• Contributes to Toronto Hydro's financial objectives by ensuring that the Tier 1 IT systems are available and reliable in support of efficient and accurate financial reporting.

E8.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Cyber Security Risks, Regulatory Compliance, and Functional Obsolescence

The Program supports Toronto Hydro's core operations and business processes, and enables the safe and efficient execution of the utility's capital and operational programs. The utility relies on its IT/OT systems to manage and operate the electricity distribution system, satisfy its obligations to customers, and comply with existing and emerging regulatory requirements.

E8.4.3.1 IT Hardware

Toronto Hydro's IT hardware must be renewed on a regular basis to ensure that systems that support customer-facing services, core distribution operations and other important processes continue to function reliably with a low risk of failure. Toronto Hydro employs many software applications to automate processes and efficiently execute required tasks such as preparing customers' bills and dispatching crews to respond to outages. These applications run on IT hardware, the building blocks of the overall IT System that must be reliable to ensure that the software applications it houses remain available.

TAB 26

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 2:

Reference(s): **Exhibit 1B, Tab 2, Schedule 2, Table 1**

a) Are batteries and EVs reflected in the "Performance Outcome" titled "Public Policy Responsiveness"? If not, where are they reflected?

b) If at all, how has THESL considered EVs and DERs to enhance electricity reliability generally and in any specific low-reliability areas of its service territory?

RESPONSE:

a) Batteries and EVs are not reflected in Public Policy Responsiveness outcome in Toronto Hydro's Electricity Distributor Scorecard. They are reflected in the Customer Service outcome of "connecting customers of all types (including distributed energy resources) on time and cost-effectively, without harming system performance for existing customers." Please refer to Exhibit 2B, Section E2.2.1 for further discussion of this outcome.

b) As noted in Exhibit 2B, Section E7.2 at pages 2-3, Toronto Hydro plans to invest $5.5 million in energy storage systems (ESS) to enhance grid performance, including to remediate power quality problems (e.g. voltage sags), improve reliability by reducing the number or duration of outages, and increase the capacity of feeders at peak periods.

Further, as detailed in the Expenditure Plan at Section E7.2.2.4, page 13, one of the projects considered in the Grid Performance ESS segment involves a feeder from Richview TS that has experienced poor reliability. Toronto Hydro expects that installing Grid Performance ESS on this feeder can reduce the average number of interruptions for customers in the area from 22 to one interruption per year.

With respect to EVs, Toronto Hydro continues to monitor the development of the technology and its effect on the safety and reliability of the distribution system. Given the evolving state of the technology and the need for further analysis, Toronto Hydro's plans in this Application do not include deploying EV technology for reliability enhancement purposes.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 3:

Reference(s): **Exhibit 1B, Tab 2, Schedule 4**
Exhibit 1B, Tab 2, Schedule 5

a) Are DERs and/or EVs used by THESL to improve SAIDI and/or SAIFI? If not, why not?

b) How would the weather impacts to SAIFI and SAIDI (Figures 13 and 14) be affected if 5 per cent, 10 per cent, and 25 per cent of load was provided through use of DERs?

c) In Exhibit 1B, Tab 2, Schedule 5, certain indictors are listed for "Low Voltage Connections", "High Voltage Connections", and "Micro-Embedded Generation Facilities". What percentage of these connections and facilities are EV chargers (please include type, e.g., Level I, Level II, DCFC), DERs, and energy storage facilities?

RESPONSE:

a) Please refer to Toronto Hydro's response to interrogatory 1B-DRC-2(b).

b) In Exhibit 2B, Section 7.2, Toronto Hydro has proposed Energy Storage System ("ESS") investments through which Toronto Hydro seeks to improve grid performance for customers and enable renewable energy generation, as well as evaluate the stacked benefits such as opportunities to leverage DERs to mitigate weather impacts to SAIFI and SAIDI.

c) The requested percentages are not available for EVs. Customers are not required to indicate to Toronto Hydro that they will be connecting an EV charger to their electrical system.

DERs and Energy Storage facilities are not included in the “Low Voltage Connections” or “High Voltage Connections” indicators.

DER and Energy Storage facilities are tracked as part of the "Micro-Embedded Generation Facilities". Table 1 below shows the breakdown by generation type.

Table 1: Micro-Embedded Generation Facilities by Type

Type	2013	2014	2015	2016	2017
EV Chargers	0%	0%	0%	0%	0%
DER	100%	100%	100%	100%	100%
Energy Storage	0%	0%	0%	0%	0%

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:

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 5:

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

a) Has THESL considered the rate, grid, and/or emissions impacts of offering extremely low-cost electricity distribution charges during the lowest-peak period (i.e., overnight) for EV charging? If so, please provide any and all working papers.

RESPONSE:

a) No, Toronto Hydro has not considered it.

TAB 27

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 6:

Reference(s): **Exhibit 1C, Tab 3, Schedule 5**

<u>Preamble:</u>

THESL's financial disclosure describes "asset integrity risk" as one of the risks to maintaining operations. An excerpt follows:

> [THESL-Electric System Limited (**LDC**)] estimates that approximately one-third of its electricity distribution assets have already exceeded or will reach the end of their expected useful lives within the next 5-year period. At the same time, Toronto is a growing city, and LDC must make system upgrades to expand its capacity to keep pace with urban intensification and electrification. In addition, as the City, Ontario and the Government of Canada implement policies and programs to respond to climate change, the pressures on the Corporation's system will only increase. Widespread adoption of electric vehicles, fuel switching and changing emissions standards make electricity the comparatively clean energy choice. This drives the need for significant capital expenditures for system upgrades so that the grid can handle such increased load. LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of the Corporation to fund additional infrastructure, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

a) Please provide any and all data and studies related to EVs and EV-related load relied upon in the above-quoted disclosure. Specifically, please provide the quantitative assessment of what "widespread adoption of electric vehicles" means in terms of number of vehicles and kilowatt-hours increase in load.

b) What capital expenditures has THESL identified to address the system upgrades so that the electricity grid can handle the increased load referenced above?

c) How, in THESL's assessment, may EV charging, batteries, and infrastructure assist and/or mitigate "asset integrity risk" and otherwise affect the nature and timing of both capital and operations and maintenance expenditures?

RESPONSE:

a) Toronto Hydro’s approach to incorporating EV-related load into its load forecast is set out at Exhibit 3, Tab 1, Schedule 1, Section 3.2, at page 10.

b) In the normal course, Toronto Hydro considers the load profile served by its infrastructure, including forecasted changes in load, when developing capital plans and designing corresponding infrastructure. Accordingly, capital expenditures throughout the Distribution System Plan (“DSP”) will be right-sized having regard to EV loading considerations. Please see, for example:
- Exhibit 2B, Section D3.3, which addresses Asset Utilization Policies and Practices.
- Exhibit 2B, Section 7.4, the Stations Expansion Program, which describes capital expenditures required to ensure Toronto Hydro’s distribution system can handle increased load such as that related to electrification.
- Exhibit 2B, Section E8.1, the Control Operations Reinforcement Program, which is necessary in part to address “more complex operations and greater

> responsibility for reliability," including on account of "industry trends such as distributed energy resources, smart grids, and electric vehicles… necessitating more active involvement in forecasting intermittent generation, energy scheduling or dispatching generation to manage outages."

c) The evidence at Exhibit 2B, Section E7.2 outlines the ways in which Toronto Hydro proposes to deploy Energy Storage System (ESS) technology over the plan to help address the asset integrity risk identified above. The evidence talks about making targeted ESS investments to enable the connection of renewable energy generation (REG), and installing ESS on feeders that are experiencing reliability issues such as momentary outages, voltage sags and sustained interruptions. These are both examples of how the ESS technology is being used as an alternative to traditional wires investments, where it is feasible and cost-effective to do so.

The Stations Expansion Program, in particular the Local Demand Response segment (Exhibit 2B, Section E7.4.3), also relies on ESS technology to defer capacity-related upgrades. The investments involve installing battery storage, and offering demand response incentives, to reduce peak demand by 10 MW, allowing the utility to defer an estimated $135 million of expansion investments at Cecil TS and Basin TS.

With respect to EVs, Toronto Hydro continues to monitor the technology and the effect of EVs on the safety and reliability of the distribution system. Toronto Hydro's plans in this Application do not include deploying EV technology in the operation and management of the distribution system.

TAB 28

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 7:

Reference(s): Exhibit 2B, Section D, Appendix D

a) Please identify any and all instances in which electrification, electric mobility, EVs, and electrified transportation charging were included or considered as mitigating or aggravating factors in THESL's Climate Change Vulnerability Assessment.

RESPONSE:

a) There were no such instances.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 8:

Reference(s): **Exhibit 2B, Section B**
Exhibit 2B, Section B, Appendix E

<u>Preamble:</u>

The Central Toronto Area Integrated Regional Resource Plan (the **IRRP**) prepared by the IESO on behalf of the Central Toronto Area Working Group (which includes THESL) identifies the following key considerations related to planning for long-term needs:

- Recent trends (including policy changes supporting distributed generation) are changing the landscape for regional electricity planning. "Traditional", wire-based approaches to electricity planning may not be the best fit for all communities (page 85).
- The "community self-sufficiency" approach to regional electricity planning places emphasis on meeting community needs largely with local, distributed resources, which include, *inter alia*, demand response, distributed generation and storage, smart grid technologies, and EVs (page 86).
- Integrated energy planning at the community level provides an opportunity for broader consideration of land-use, development and growth, infrastructure requirements, and technology solutions that include, *inter alia*, energy storage technologies, battery EV storage capabilities (especially for load intensification cluster applications), micro-grid and micro-generation capabilities (page 90).
- There is a strong community interest in the "community self-sufficiency" approach to planning (page 89).

THESL notes that its DSP has been informed by the results of the completed regional plans and continues to coordinate with the IESO and Hydro One Networks Inc. with respect to plans that are under development.

a) Please explain how THESL's DSP has been informed by the "community self-sufficiency" approach to regional electricity planning, as discussed in the IRRP, including the extent to which THESL has considered the capacity of EVs, "prosumers", and other DERs to meet integrated energy planning needs.

b) Please describe all measures that THESL is undertaking to facilitate the integration of EVs, "prosumers", and other DERs in its energy planning and business planning processes.

RESPONSE:

a) Toronto Hydro’s DSP includes a number of investments which are aligned with the “community sufficiency approach” discussed in the IRRP, and which support the Conservation First Framework, the connection of renewable energy generation (REG), and the use of distributed generation (DG) to meet long-term energy planning needs. These investments are summarized below. For more information, please refer to the evidence cited:
   - The Energy Storage program (Exhibit 2B, Section E7.2) includes plans to use energy storage systems (ESS), which are non-wires solutions, to enhance grid performance, remediate power quality problems (e.g. voltage sags), improve reliability in problem areas, increase the capacity of feeders at peak periods, and enable the connection of renewables.

- The investment in the Customer Connection (Exhibit 2B, Section E5.1) and Generation, Protection, Monitoring and Control (Exhibit 2B, Section E5.5) programs support the safe, timely and cost-efficient connection of distributed generation customers to the grid, including REG projects, in accordance with generation connection forecasts which show that Toronto Hydro expects over 581 MW of incremental DG by 2024.
- The Stations Expansion Program, in particular the Local Demand Response segment (Exhibit 2B, Section E7.4.3) includes non-wires alternatives to defer capacity-related upgrades at two stations in Central Toronto. The investments involve installing battery storage, and offering demand response incentives to reduce peak demand by 10 MW, allowing the utility to defer an estimated $135 million of expansion investments at Cecil TS and Basin TS.
- The Control Operations Reinforcement program (Exhibit 2B, Section 8.1) includes plans to invest in technology required to manage the growing system requirements to support the evolution of the smart grid (e.g. distributed energy resources), not only from a monitoring and control of energy delivery perspective but also from an energy management perspective.

b) Please refer to the response provided above, as well as Toronto Hydro's responses to interrogatories 1B-DRC-2(b) and 1C-DRC-6 which address the use of EVs and DERs in enhancing reliability and managing asset integrity risk, respectively.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 9:

Reference(s): Exhibit 2B, Section E7.2

Preamble:

THESL's proposed Energy Storage Systems (**ESS**) Program includes "renewable enabling" ESS investments, which are distribution investments that support the growth of distributed renewable generation on the system that in turn offset generation and transmission investments. THESL acknowledges that ESS can cost-effectively enable EVs to connect to the distribution system by addressing localized system constraints. However, THESL does not propose any EV ESS projects at this time.

a) Please indicate whether EV batteries are expressly and/or implicitly, included in THESL's definition of "Energy Storage Systems" and, if so, how?

b) Please explain how THESL proposes to optimize efficiencies from the many EV batteries and charging infrastructure in its systems?

c) Please itemize all of the benefits that an EV ESS may have and provide THESL's rationale for not pursuing any EV ESS projects at this time given the stated benefits.

RESPONSE:

a) EV batteries are not included in Toronto Hydro's definition of Energy Storage Systems.

b) Toronto Hydro does not currently have such a proposal. Toronto Hydro continues to monitor the development of EV technology and its effect on the safety and reliability of the distribution system.

c) Please see the response to part (b) above.

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).

Preserving and Protecting our Environment for Future Generations

A Made-in-Ontario Environment Plan

Ministry of the Environment,
Conservation and Parks

Ontario

Minister's Message

Rod Phillips
Minister of the Environment, Conservation and Parks

The people of Ontario are passionate about the great outdoors and the natural spaces our communities offer. We recognize the importance of a clean environment to our health, our wellbeing and our economic prosperity for future generations. We also recognize the important responsibility we all have to our environment.

Ontario boasts hundreds of thousands of parks, hiking trails and forests to explore with our families and friends. Ontarians can camp in protected areas like Quetico Provincial Park in Northern Ontario and see firsthand the magnificence of a moose. We can also enjoy a family picnic at Victoria Park in Kitchener and enjoy local fresh fruits, vegetables and dairy products that were grown and produced on nearby farms. Ontario is home to hundreds of thousands of lakes, rivers and waterways that are the lifeblood of our province, where people fish, kayak and swim. We also rely on our waters to transport goods, feed our crops, and have a safe, reliable source of drinking water.

These waterways are under increasing pressure as urban development expands along their shorelines, invasive species expand on land and in water, and climate change causes changing weather patterns that can bring heavier rains resulting in damage to homes, businesses and public infrastructure.

Preserving and protecting our environment begins with a new vision for Ontario. One where hardworking taxpayers are protected and respected, and where environmental stewardship connects with the people of this province.

I am pleased to present the following made-in-Ontario plan to keep our province beautiful by protecting our air, land and water, preventing and reducing litter and waste, supporting Ontarians to continue to do their share to reduce greenhouse gas emissions, and helping communities and families prepare for climate change.

This plan will ensure we balance a healthy environment with a healthy economy, and will be reviewed on a four-year basis.

This is a plan that represents a clean break from the status quo.

We understand the pressure Ontarians feel with rising costs of living as well as skyrocketing energy costs that have hurt our economy and our competitiveness. They are understandably frustrated to see their hard-earned tax-dollars being put towards policies and programs that don't deliver results.

That's why a cap-and-trade program or carbon tax that seeks to punish people for heating their home or driving their cars remains unacceptable to the people of Ontario.

When the government does invest in environmental programs, taxpayers should not have to watch their hard-earned dollars be diverted towards expensive, ineffective policies and programs that do not deliver results.

The people of Ontario deserve recognition for the sacrifices they have made and the ones they continue to pay for.

Our plan reflects our province's specific needs and opportunities, and it does not include a carbon tax. We will continue to do our share to reduce greenhouse gases and we will help communities and families prepare to address climate change. With hard work, innovation and commitment, we will ensure Ontario achieves emissions reductions in line with Canada's 2030 greenhouse gas reduction targets under the Paris Agreement.

We will tap into the resourcefulness and creativity of our diverse and thriving private sector by helping them invest in and develop clean solutions to today's environmental challenges.

We have consulted extensively with the public, receiving more than 8,000 ideas and recommendations through our online portal. These comments have been considered alongside submissions from stakeholders and information from Indigenous communities who provided feedback on fighting climate change and other areas of environmental focus. We will continue to consult and engage on the proposals contained within this plan in the coming weeks and months.

All of us have a role to play in protecting the environment, and there are many great ideas across our province and country. It will be important that we continue to have constructive dialogue with other jurisdictions to tackle these environmental challenges together. One thing that has become particularly clear over the past few months is the fact that no one solution fits all provinces, regions or communities.

Our plan describes the actions Ontario is proposing to take and the ways we will enable industry, business, communities and people to continue to do their part.

Ontario families understand that we have a personal responsibility to leave behind a province better off than the one we inherited; not just environmentally, but financially as well.

I invite you to read our plan and join with us today, and every day, to create a better future for Ontario.

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Our Province Today

Those of us who call Ontario home couldn't ask for a better place to live, work and raise a family. The quality of life in our communities and the success of our businesses depends to a great extent on the clean air we breathe, the safe water we drink, and the well-protected lands and parks we enjoy.

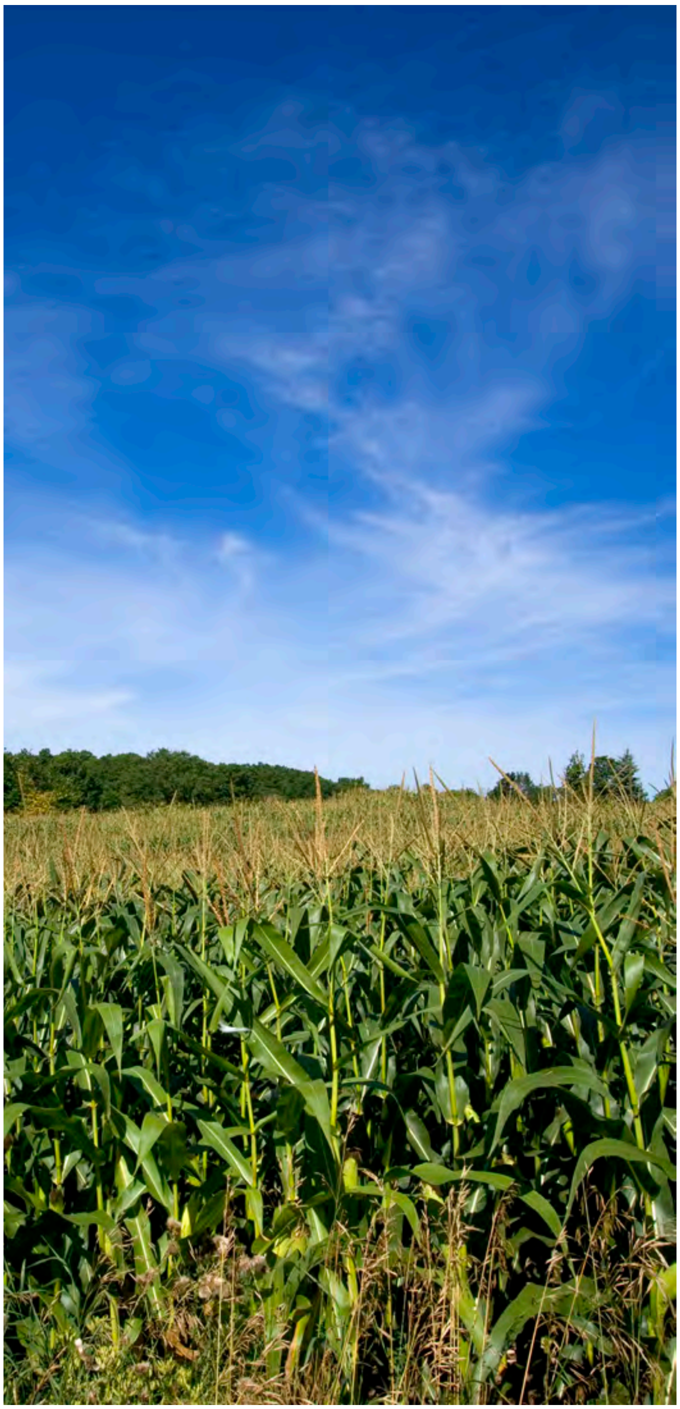
Today, the people of Ontario are breathing cleaner air with large reductions in levels of many harmful pollutants. In 2001, Ontario began the process of closing its coal plants and in the years since, we have significantly reduced pollutants such as nitrogen dioxide, sulphur dioxide, mercury and particulate matter.

Our Great Lakes attract millions of residents and visitors to waterfront communities around the province each year. These lakes provide safe drinking water to more than 70% of Ontarians and their watersheds are home to more than 4,000 species of fish, birds and other living things. They, along with all of our waterways and groundwater, underpin our province's economic prosperity and wellbeing – supporting Ontario's manufacturing, power generation, fisheries, tourism, agriculture and drinking water.

Parks and greenspace across our province provide individuals, families and tourists with opportunities to canoe in lakes, hike in forests and camp on protected lands.

THE CHALLENGE AHEAD

At the same time, climate change threatens these resources and our homes, communities and businesses, infrastructure, and our locally grown food and crops. It also threatens food security and road access for remote First Nations, as well as the health of ecosystems across our great province.



We can do more to protect ourselves from the extreme weather events that have flooded houses, buildings and roads, overwhelmed aging stormwater and wastewater systems, damaged crops, and brought heavy ice and wind storms that knocked out power for hundreds of thousands of people, including those who are most vulnerable.

Heat waves and recent drought conditions in some areas of the province, coupled with anticipated impacts of climate change and population growth, have intensified concerns related to water security for farmers, Indigenous communities, industry and municipalities.

We also recognize that there is much more that can still be done to keep our lands and waterways clean and free of litter. Nobody wants to see plastic and litter polluting our waterways, neighbourhoods and parks. No one wants sewage and wastewater overflowing into our lakes and rivers or salt making its way into our waterways. These issues are happening now and need to be addressed. There is also a need to address specific air quality concerns in communities that continue to face air quality challenges. True environmentalism begins with a sense of civic responsibility that we foster through meaningful action close to home.

Our environment plan reflects our government's commitment to addressing these pressing challenges. We will use the best science, real-time monitoring where available, and strong, transparent enforcement to protect our air, land and water, prevent and reduce litter and waste, support Ontarians to continue to do their share to reduce greenhouse gas emissions, and help communities and families prepare for climate change.

DOING OUR PART

In 2001, the government of the day announced the closure of the Lakeview Generating Station, setting the stage for the phase out of coal-fired electricity generation which remains the largest single greenhouse gas reduction in Canadian history. Ontario's low-emission combination of hydroelectric, nuclear, natural gas and non-hydro renewable generating capacity has enabled the province to avoid up to 30 megatonnes of annual greenhouse gas emissions, equivalent to taking up to seven million vehicles off our roads. In 2017, approximately 96% of the electricity generated in Ontario was emissions-free.

The combination of nuclear, hydro, other renewables and efficient natural gas has given Ontario one of the cleanest energy grids in North America. Ontario's supply of clean electricity is one of its unique strengths. Ontario is currently a net exporter of electricity, with our clean power offsetting a higher emitting mix of coal and natural gas generation in neighbouring states, such as Michigan and New York.

Measured against the same base year of Canada's target under the Paris Agreement (2005), the province's total greenhouse gas emissions have dropped by 22% – even while the rest of Canada saw emissions increase by 3% during that same time.

Doing Canada's heavy lifting on greenhouse gas emission reductions came at a cost that was too high for Ontario families and businesses. In 2017, prior to the introduction of the Fair Hydro Plan Act, 2017, the cost associated with transitioning to Ontario's low emission electricity system was an estimated $33 per month for a typical residential electricity consumer and about $435 per month for a small business, such as a restaurant. Since 2005, about $40 billion has been spent in capital investments to transition the province to an electricity system that is virtually emissions-free. Now is not the time to add further costs to the price of electricity that is already very clean.

We will continue to do our share to address climate change and protect our environment. We will do so in a way that protects our economy and respects the people.

We will hold polluters accountable by ensuring strong enforcement with real consequences and penalties, especially for repeat offenders.

We will also help our urban and rural communities and landscapes become more sustainable and resilient. We will help others do their part, whether it's leveraging private sector investments to drive environmental solutions or making it easier for people and companies to go the extra mile to reduce emissions, clean up their communities, protect waterways, conserve lands and restore habitats.

Ontario has a long history of working cooperatively with other provinces and territories, as well as with the federal government through formal agreements such as the Canada-Ontario Agreement on Great Lakes Water Quality and Ecosystem Health and through intergovernmental forums such as the Canadian Council of Ministers of the Environment. There are also global environmental issues on which Ontario will continue collaborating with the federal government and participating in international meetings and agreements.

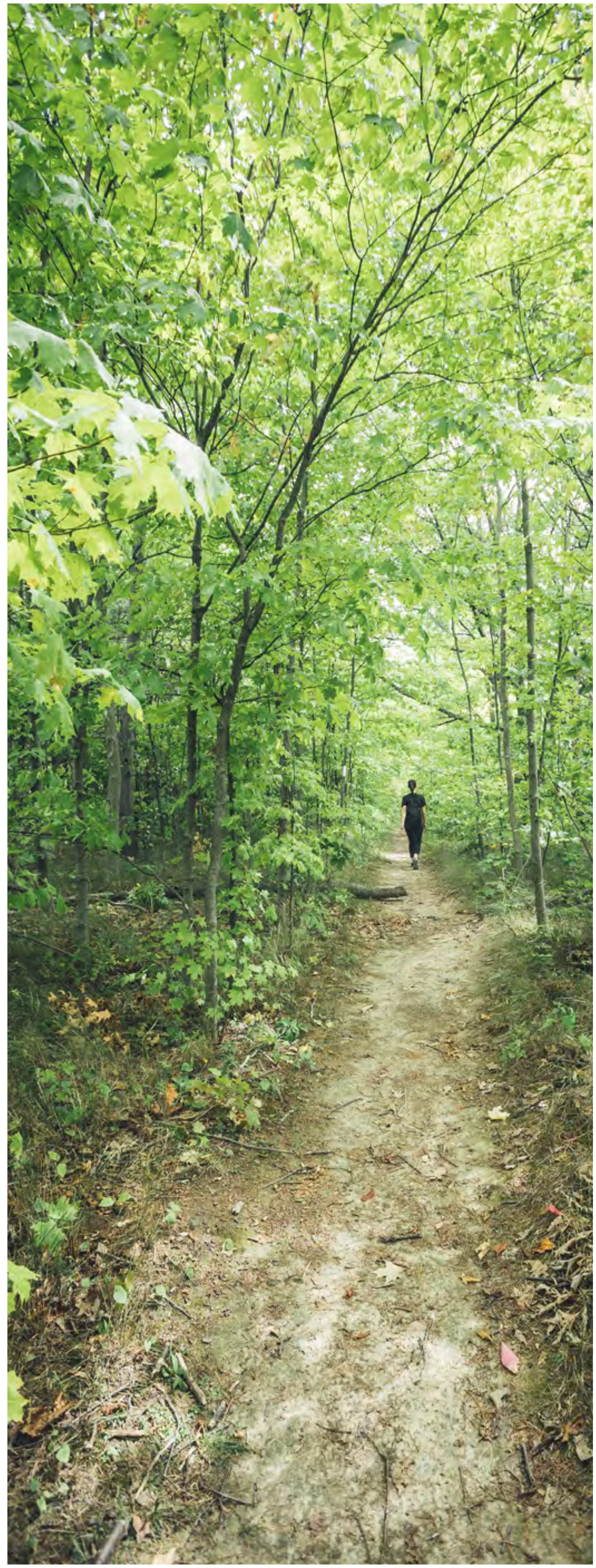
Protecting the environment is a responsibility of all of us who call Ontario home.

We will continue to work in partnership with other provinces, neighbouring jurisdictions, the federal government, municipalities, Indigenous communities, business and local partners to help protect our environment and ensure we pass on a cleaner environment to future generations.

GUIDING PRINCIPLES

Our guiding principles will help us address our most serious environmental challenges in a responsible, effective, measurable and balanced way.

- **Clear Rules and Strong Enforcement:** We will ensure that polluters are held accountable with tougher penalties, while reducing regulatory burden for responsible businesses.
- **Trust and Transparency:** We will provide Ontarians with the information and tools required – with a particular focus on real-time monitoring – to understand the current environmental challenges we face and how these challenges impact individuals, businesses and communities across the province.
- **Resilient Communities and Local Solutions:** We recognize that environmental impacts faced by communities across Ontario may be very different. We will work with these communities and use best scientific practices and other evidence-based methods to develop unique solutions to their challenges.



Protecting our Air, Lakes and Rivers

Ontario's water and air are life support systems for our province and our people. Pollution in our air and water increases healthcare costs, affects the enjoyment of our outdoors and contributes to lost economic opportunity. We will protect these critical systems by keeping our water and air clean while growing our economy.

Our plan will make it easier for people to report pollution that is impacting their lives by developing an online platform for reporting incidents that allows photos or video to be sent in, as well as reporting an incident by e-mail, phone or through an app.

Additionally, we will put in place an improved complaint response system that sets out the services Ontarians can expect from inspectors and investigators when they file a complaint, and new standards on the response time they can expect based on the type of incident they report. We will be transparent about pollution incidents and spills, and provide real-time information where it is available so that people can see if a spill or incident has already been reported, as well as the status of the ministry's response.

CLEAN AIR

Although Ontario's air quality has improved significantly, some areas of the province still experience poorer air quality due to pollution. We are committed to protecting our air, ensuring we have strong environmental standards that are protective of human health and the environment, and taking action to enforce local air quality standards.

Quick Fact: Ontario initiated the first closure of a coal plant in 2001. This action and the subsequent closure of 19 coal-fired units in five plants contributed to reducing the number of smog days in Ontario from a peak of 53 in 2005 to zero in 2017.

Actions

Improve air quality in communities by creating unique solutions to their individual challenges

- Focus on parts of the province that continue to experience air quality challenges due to pollution from transportation, industry and other sources.
- Work in partnership with municipalities, industry, public health units, other community stakeholders and Indigenous communities to address local air quality concerns and achieve clean air objectives.

Reduce emissions from heavy-duty vehicles

- Redesign the emissions testing program for heavy-duty vehicles (e.g. commercial transport trucks) and strengthen on-road enforcement of emissions standards.

Improve understanding of different sources of air pollution and their impact

- Monitor pollutants to evaluate long-term trends so we can gather the information we need to take action on air pollution.
- Increase road-side monitoring of traffic pollution and expand road-side monitoring of pollutants beyond the Greater Toronto Area to other heavily urbanized communities such as Sarnia, Sudbury and Hamilton.

Strengthen collaboration on addressing air pollution that comes from outside of Ontario's borders

- Call on the federal government to proactively address the impacts of air pollution from outside Ontario, including from the United States and international sources, and ensure continued cooperation and commitment to improve air quality.
- Expand collaboration with Michigan and Ohio to reduce the emission of contaminants of concern that impact southern Ontario, Michigan and Ohio airsheds.

Success story: Sarnia's air quality is improving

In partnership with industry, the Clean Air Sarnia and Area (CASA) advisory panel launched the website cleanairsarniaandarea.com so users could view contaminant levels from seven air monitoring stations in the Sarnia community. Air quality information is refreshed every hour on an interactive map so users can find out whether air quality is good, moderate or poor compared to provincial standards. While Ontario and industry have been monitoring air quality in the Sarnia area for decades, the CASA initiative marks the first time that data has been accessible to the public in real-time and in one location.

Ontario is also moving forward with a Sarnia Area Environmental Health Project to help address concerns about air pollution and other environmental stressors from local industries in the Sarnia area. The project will help enhance our understanding of the links between the environment and health in the community, with a focus on assessing exposures to air contaminants.

These projects are great examples of the collaborative efforts of local industry, the municipality, the Aamjiwnaang First Nation and interested community groups.

CLEAN WATER

Our lakes, waterways and groundwater are the foundation of Ontario's economic prosperity and wellbeing – supplying water to our communities, sustaining traditional activities of Indigenous peoples, supporting Ontario's economy, and providing healthy ecosystems for recreation and tourism.

Over past decades, Ontario has seen significant improvements in Great Lakes water quality due to efforts by governments and other partners. These partnerships have achieved a 90% reduction in releases of mercury, dioxins and polychlorinated biphenyls (PCBs), resulting in fish that are safer to eat, clean-up of polluted areas and the restoration of species.

Water resources in Ontario are facing many pressures. Population growth, rapid urban development, aging infrastructure and invasive species are threatening our waterways through pollution and loss of natural heritage. For example, excess road salt can damage roads, cause vehicle corrosion and be harmful to fish in our waterways. The changing climate is compounding these stresses with droughts, floods and extreme storms. Declining ice cover is causing shoreline erosion, warmer water is creating conditions for blooms of harmful algae, and shifting water conditions are changing when and where fish spawn.

Working together, we can help conserve and manage our water resources. Ontario's drinking water, for example, is among the best protected in the world as a result of the province's strong monitoring, reporting and enforcement activities and programs.

We will take strong enforcement action to protect our lakes, waterways and groundwater from pollution.

We will also work with municipalities and other partners to increase transparency through real-time monitoring of the sewage overflows from municipal wastewater systems, which too often flow into Ontario's lakes and rivers. We must step up efforts to ensure the public is aware and that proper monitoring occurs.

Quick Fact: 99.8% of more than 518,000 test results from municipal residential drinking water systems meet Ontario's strict drinking water quality standards.

Our plan focuses on key areas of action to protect our waters and keep our beaches clean for swimming, recreation, enjoyment and traditional use.

Actions

Continue work to restore and protect our Great Lakes

- Build on previous successes and continue efforts to protect water quality and ecosystems of the Great Lakes. This includes keeping coastlines and beaches clean, protecting native species and safeguarding against invasive species such as Asian carp or Phragmites, and reducing harmful algae by continuing partnerships and negotiations with the federal government under agreements and plans such as the Canada-Ontario Great Lakes Agreement (COA) and the Canada-Ontario Lake Erie Action Plan. Since signing the eighth COA in 2014, Ontario has directly invested $15.3 million per year in programs. This includes supporting the Lake Erie Action Plan and restoring geographic areas, known as areas of concern, where significant impairment or contamination has occurred as a result of human activities at the local level.
- Review and update Ontario's Great Lakes Strategy to continue to protect fish, parks, beaches, coastal wetlands and water by reducing plastic litter, excess algae and contaminants along our shorelines, and reducing salt entering waterways to protect our aquatic ecosystems.

Asian Carp:
A threat to the Great Lakes Fisheries and Economy

Asian carp typically weigh two to four kilograms but can weigh up to 50 kilograms and can grow to a length of more than one metre. They consume a significant amount of food and can eat up to 20% of their body weight each day, which harms the Great Lakes ecosystem. Asian carp were introduced to aquaculture facilities in the southern U.S. in the 1970s to remove algae and suspended solids from their ponds. They escaped when the Mississippi River flooded and have spread northward in the Mississippi watershed towards the Great Lakes.

Asian carp pose a significant threat to recreational and commercial fisheries in Ontario which are worth almost $2.5 billion combined. Ontario is working with many partners including the Asian Carp Regional Coordinating Committee, a committee including all Great Lakes states and provinces, U.S. federal agencies, and Fisheries and Oceans Canada to facilitate collaboration on prevention, early detection, response, and monitoring activities.

Quick Fact: Ontario's more than 250,000 lakes, including the Great Lakes, contain about one fifth of the world's fresh water.

Continue to protect and identify vulnerable waterways and inland waters

- Build on previous successes and continue to implement the Lake Simcoe Protection Plan to protect and restore important natural areas and features of the lake. Ontario has invested annually in the implementation of the Lake Simcoe Protection Plan.
- Protect the quality of the Lake of the Woods by continuing to work with partners on reducing phosphorus that, in excessive quantities, can cause toxic blue-green algae.
- Build on the ministry's monitoring and drinking water source protection activities to ensure that environmental impacts from road salt use are minimized. Work with municipalities, conservation authorities, the private sector and other partners to promote best management practices, certification and road salt alternatives.
- Work with Indigenous communities and stakeholders, including the public, on the remediation of mercury contaminated sediments in the St. Clair and English-Wabigoon Rivers, including efforts such as:
  - ensuring clean-up of the remaining mercury contaminated sediments located in three areas downstream of the former Dow Chemical site.
  - participating in the work of the English and Wabigoon Rivers Remediation Panel to fund remediation activities from a trust that was established with $85 million under the *English and Wabigoon Rivers Remediation Funding Act, 2017.*

Action in Progress:
Protecting the Muskoka watershed

Through the Muskoka Watershed Conservation and Management Initiative, the community and province will work together to protect this vital area by identifying the issues facing the region. Ontario will invest $5 million and commit up to an additional $5 million in matching contributions.

Effective watershed management is important to the people in our communities, especially at times when watersheds are facing stresses such as increased development and flooding caused by severe weather events.

This initiative will also help us develop a more comprehensive approach to watershed management, which can inform current actions and future development.

Success story: Celebrating recovery of freshwater fish in Lake Simcoe

Over the years, many organizations alongside the provincial and federal governments have worked hard to protect and restore the Lake Simcoe watershed against contaminants and excess nutrients like road salt and phosphorus that have had a negative effect on water quality. The Lake Simcoe ecosystem is showing encouraging signs of recovery and demonstrating that efforts to restore and protect the lake are having an impact. For example, populations of sensitive aquatic life such as lake trout, lake whitefish and cisco are trending upward.

Ensure sustainable water use and water security for future generations

- Thoroughly review the province's water taking policies, programs and science tools to ensure that vital water resources are adequately protected and sustainably used.
- Enhance how we manage water takings to ensure we have sustainable water resources in the face of a changing climate and continued population growth. We will do this by examining approaches to assessing and managing multiple water takings, establishing priorities for different water uses, and preparing and responding to drought conditions.
- Ensure the knowledge gained through the drinking water source protection program helps inform our water management programs.

Quick Fact: Thanks to local source protection committees and conservation authorities, Ontario has source protection plans being implemented across 38 watershed-based areas. These locally developed plans identify and protect areas where drinking water is vulnerable to contamination and depletion.

Help people conserve water and save money

- Promote the use of technologies and practices to ensure water is used more efficiently. This includes water conservation planning; water use tracking and reporting; improving standards for household fixtures and appliances, such as dishwashers or washing machines; and profiling provincial and broader public sector leadership in this area.

Improve municipal wastewater and stormwater management and reporting

- Increase transparency through real-time monitoring of sewage overflows from municipal wastewater systems into Ontario's lakes and rivers. Work with municipalities to ensure that proper monitoring occurs, and that the public is aware of overflow incidents.
- Update policies related to municipal wastewater and stormwater to make them easier to understand. We will consider how wastewater and stormwater financing could be updated to improve investment and support new and innovative technologies and practices.
- Encourage targeted investment and innovation in managing wastewater that overflows into our lakes and rivers.

Quick Fact: There were a total of 1,327 bypasses and/or overflows from all municipal wastewater sources in the 2017/18 fiscal year, as reported to the Ministry of the Environment, Conservation and Parks.

Success story:
City of Kingston shows environmental leadership

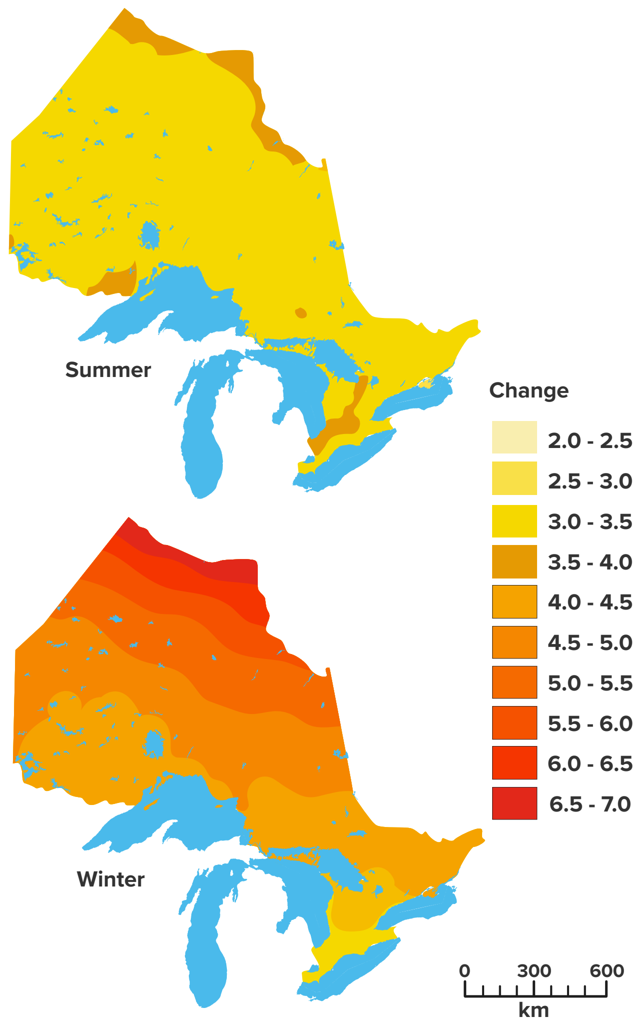
Utilities Kingston and the City of Kingston have shown leadership by providing real-time public reporting of sewage overflows, reducing pollution, and working with partners such as Swim Drink Fish Canada and the W. Garfield Weston Foundation to create the Gord Edgar Downie Pier at Breakwater Park, giving the community a new place to swim and enjoy a cleaner Lake Ontario waterfront.

Addressing Climate Change

Quick Fact: As of 2013, Canada is responsible for 1.6% of global emissions, with Ontario responsible for less than 0.4% of global emissions.

The climate is changing. Severe rain, ice and wind storms, prolonged heat waves and milder winters are much more common. Forests, waters and wildlife across the province are and will continue to be significantly impacted by these changes. People across the province – especially Northern communities – and all sectors of the economy are feeling the impacts of climate change and paying more and more for the costs associated with those impacts.

The following graph shows projected seasonal summer and winter temperature changes in Ontario by the 2050s.



Source: Ontario Climate Data Portal – http://lamps.math.yorku.ca/OntarioClimate/index_v18.htm.
Projected seasonal (summer and winter) temperature changes by the 2050s (relative to the average of 1986-2005), under the Inter-governmental Panel for Climate Change (IPCC) 5th assessment report (AR5) business as usual emission scenario (RCP8.5).

The people of Ontario have already made significant contributions to meaningful climate action. We have played an important role in fighting climate change and mitigating the threats to our prosperity and way of life, implementing significant changes to drastically reduce our greenhouse gas emissions.

The government of the day initiated the first closure of a coal plant in 2001. This action and the subsequent closure of 19 coal fired units in five plants by 2014 led to the largest single reduction of greenhouse gas emissions, not just in Ontario, but across Canada. It was also one of the largest actions to reduce emissions in North America.

Emission-free electricity generation also plays a significant role in Ontario. Nuclear power, along with our hydroelectric fleet, continues to generate the lion's share of our clean electricity.

Today, Ontario has one of North America's cleanest electricity grids. We also have effective natural gas conservation programs, helping homeowners, businesses and industry reduce their carbon footprint.

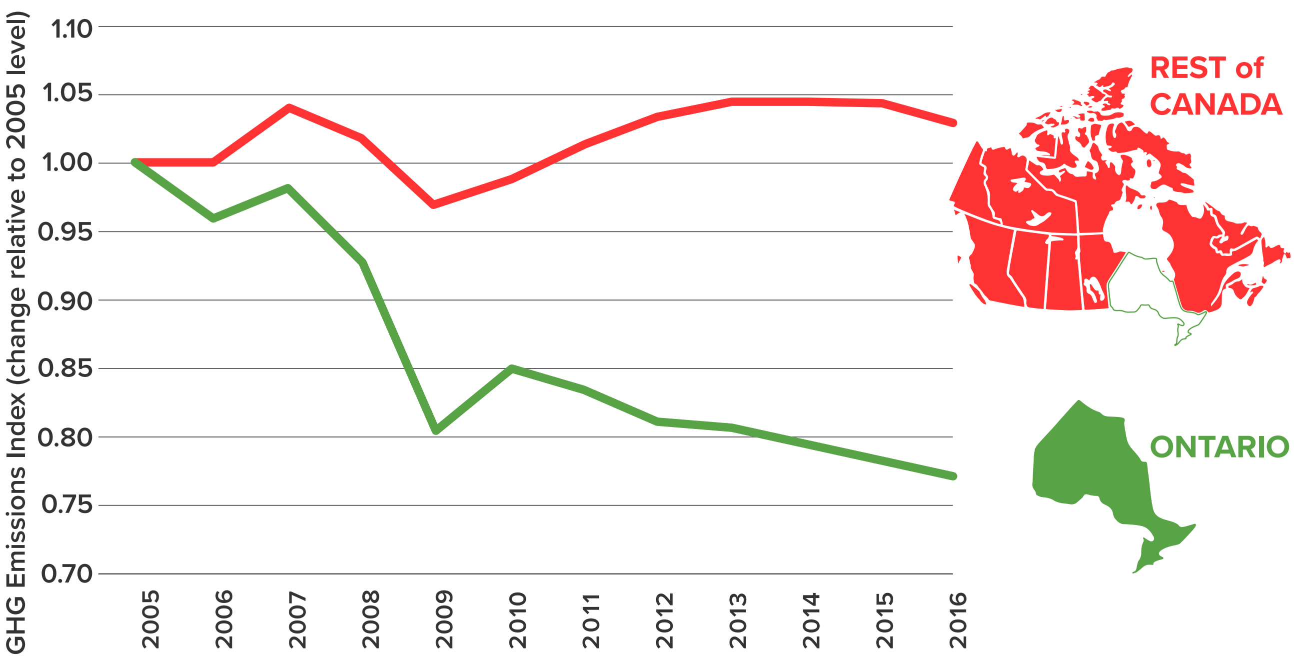
Quick Fact: Almost all of Canada's progress towards its 2030 Paris Agreement targets has been driven by Ontario.

But doing Canada's heavy lifting on greenhouse gas emission reductions has come at a cost to Ontario families. Our government understands the part that Ontarians have played and continue to play in reducing their emissions.

We have already been a leader when it comes to climate. **Indeed, we are on track to meet Canada's commitment under the Copenhagen Accord of 17% below 2005 levels by 2020.**

Now, we must look to find a balanced approach to reducing our emissions and prepare families for the impact of climate change in order to maintain both a healthy economy and healthy environment. This plan is our alternative to a carbon tax. It means finding effective and affordable ways to slow down climate change and build more resilient communities to prepare for its effects.

Ontario and the Rest of Canada's Greenhouse Gas Emissions from 2005 to 2016



We will work to unlock private capital to give Ontario businesses and residents new and more affordable ways to invest in energy efficiency, save money and reduce greenhouse gas emissions. One of the most effective ways we can combat climate change is encouraging innovation and reducing regulatory barriers to climate solutions. Through this plan, our government will focus on smart regulatory and policy approaches to facilitate and enable innovation rather than hindering it.

The following chapter of our environment plan acts as Ontario's climate change plan, which fulfills our commitment under the *Cap and Trade Cancellation Act, 2018*.

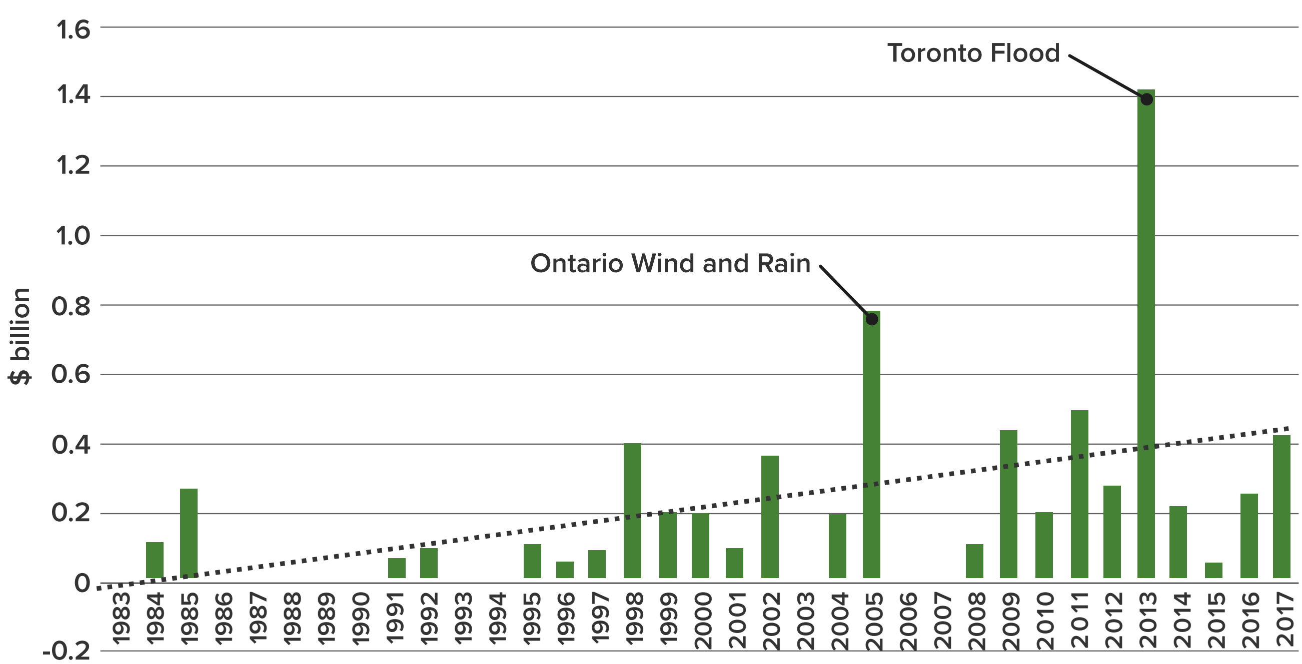
BUILDING RESILIENCE:
Helping Families and Communities Prepare

We are committed to preparing families and communities for the costs and impacts of climate change, and to protecting our natural environment, communities, businesses and municipalities.

While our actions are important in the global fight to reduce emissions, we all understand the need to strengthen our resilience to the impacts of climate change such as more frequent extreme weather events.

The following graph shows the rising costs of insured property damage in Ontario between 1983 and 2017, providing an indication of the costs of climate change. The financial costs associated with extreme weather events in Ontario have increased over this period. Chief among factors affecting the increasing costs to Ontarians is the phenomenon of flooding, and more specifically, residential basement flooding.

Costs of Insured Property Damage in Ontario Between 1983 and 2017



Source: Insurance Bureau of Canada.

Building resilience is about having the right information, tools and resources to adapt and respond to our changing climate. We will access the best science and information to better understand where the province is vulnerable and know which regions and economic sectors are most likely to be impacted. Through this enhanced understanding, the province, local communities, businesses, Indigenous communities and the public will be more prepared for the impacts of a changing climate.

Case study:
Climate change impact assessments

Ontario has never completed a provincial-level climate change impact assessment. Since 2008, the United Kingdom has conducted two assessments using best available data and an up-to-date understanding of climate science and future climate impacts. Each assessment provides detailed analysis of the risks, vulnerabilities and impacts of climate change on key economic sectors, infrastructure, the environment and societal health and well-being.

Each assessment gives the government a roadmap to "high" and "low" climate change risks now and in future years.

Actions

Improve our understanding of how climate change will impact Ontario

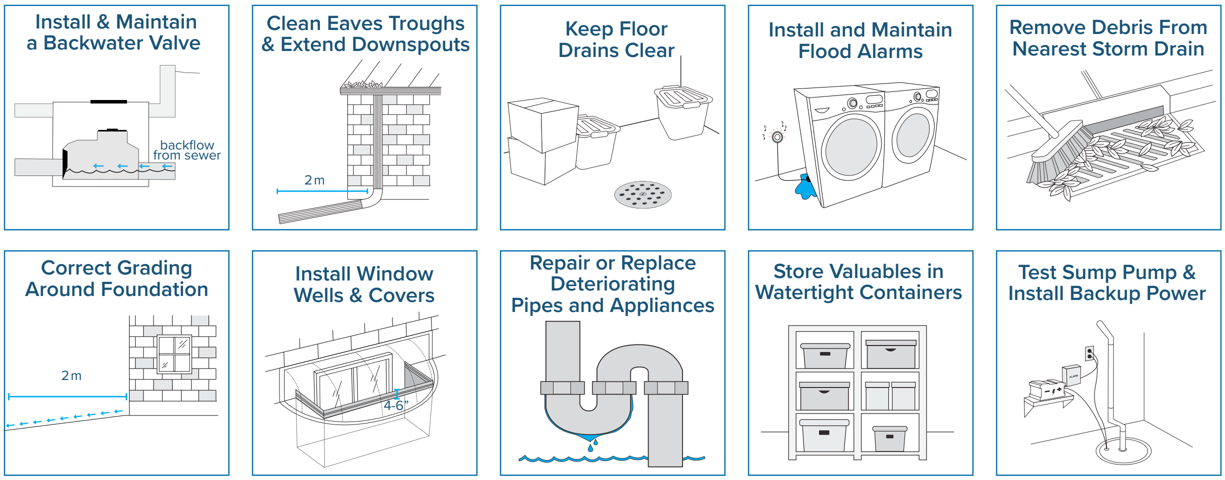
- Undertake a provincial impact assessment to identify where and how climate change is likely to impact Ontario's communities, critical infrastructure, economies and natural environment. The assessment would provide risk-based evidence to government, municipalities, businesses, Indigenous communities and Ontarians and guide future decision making.
- Undertake impact and vulnerability assessments for key sectors, such as transportation, water, agriculture and energy distribution.

Help Ontarians understand the impacts of climate change

- Develop a user-friendly online tool that makes practical climate change impact information available for the public and private sectors. This tool will help developers, planners, educators, homeowners and others understand the potential impacts of climate change in their communities.
- Work closely with climate science modelling experts, researchers, Indigenous communities, and existing climate service providers to identify and create adaptation solutions.
- Support communities by demonstrating how climate science can be applied in decision making to improve resilience.

The graphics below illustrate practical actions that homeowners can take – simply and affordably – to lower their risk of basement flooding. Home flood protection can include property level initiatives such as disconnecting downspouts from weeping tile systems, placing plastic covers over window wells, outfitting sump pumps with battery back-up supply, and installing back water valves on drain lines.

10 Ways to Prevent Home Basement Floods



Source: Home Flood Protection Program, Intact Centre on Climate Adaptation, University of Waterloo

Ontario will work with the real estate and insurance industries to raise awareness among homeowners about the increasing risk of flooding as we experience more frequent extreme weather events. Flooding damage is the leading cause of insured property damage in Ontario. The risk of home flooding is also increasingly the reason why homeowners are unable to adequately insure their homes.

Flood damages can cost homeowners tens of thousands of dollars to repair. According to the National Flood Insurance Program in the U.S., a 15-centimetre flood in a 2,000-square-foot home is likely to cause about USD $40,000 in flood damage. Once flooding occurs, securing insurance will become more difficult and may become unaffordable for individual homeowners.

However, simple steps, such as removing debris from nearby storm drains, ensuring correct grading around home foundations, clearing eaves troughs, and installing extended downspouts and window well covers can significantly mitigate basement flood risks.

Update government policies and build partnerships to improve local climate resilience

- Modernize the Building Code to better equip homes and buildings to be better able to withstand extreme weather events. This could include affordable adaptation measures such as requiring backwater valves in new homes that are at risk of backflow, which would significantly reduce the impacts of basement flooding.
- Review the Municipal Disaster Recovery Assistance program to encourage municipalities to incorporate climate resilience improvements when repairing or replacing damaged infrastructure after a natural disaster. Since the Municipal Disaster Recovery Assistance program was launched in 2016, over $2.6 million has been provided to 11 municipalities.
- Consult on tax policy options to support homeowners in adopting measures to protect their homes against extreme weather events, such as ice and wind storms and home flooding.

- Review land use planning policies and laws to update policy direction on climate resilience. This will help make the way our communities are planned and designed more responsive and adaptive to changing weather conditions, such as improving the way that stormwater is managed.
- Build resilience in the province's critical infrastructure, through better technology as well as back-up generation and energy storage options, so that our vital services and infrastructure, such as hospitals, can better withstand and remain operational during extreme weather events.
- Support improvements to existing winter roads where they may be required to replace roads that are deteriorating as a result of changing weather conditions and shortened winter seasons, and develop a strategy to enhance all-season road connections to northern communities.
- Continue to support programs and partnerships intended to make the agriculture and food sectors more resilient to current and future climate impacts. We will support on-farm soil and water quality programming and work with partners to improve agricultural management practices.

Lake Erie Action Plan and 4R Nutrient Stewardship

Ontario's farmers continue to demonstrate leadership in environmental stewardship, which is important to their livelihood. Farmers are also embracing and championing innovative farming practices, such as 4R Nutrient Stewardship (Right Source @ the Right Rate, Right Time, and Right Place®), and other initiatives under the Canada-Ontario Lake Erie Action Plan, that are designed to enhance environmental protection and improve sustainability.

CONTINUING TO DO OUR SHARE:

Achieving the Paris Agreement Target

One of the key ways we are defining our vision for climate action in Ontario is by setting an achievable greenhouse gas reduction target. This will help us focus our efforts and provide a benchmark for our province to assess its progress on the climate change mitigation components of our plan.

Ontario will reduce its emissions by 30% below 2005 levels by 2030.

This target aligns Ontario with Canada's 2030 target under the Paris Agreement.

This is Ontario's proposed target for the reduction of greenhouse gas emissions, which fulfills our commitment under the *Cap and Trade Cancellation Act, 2018*.

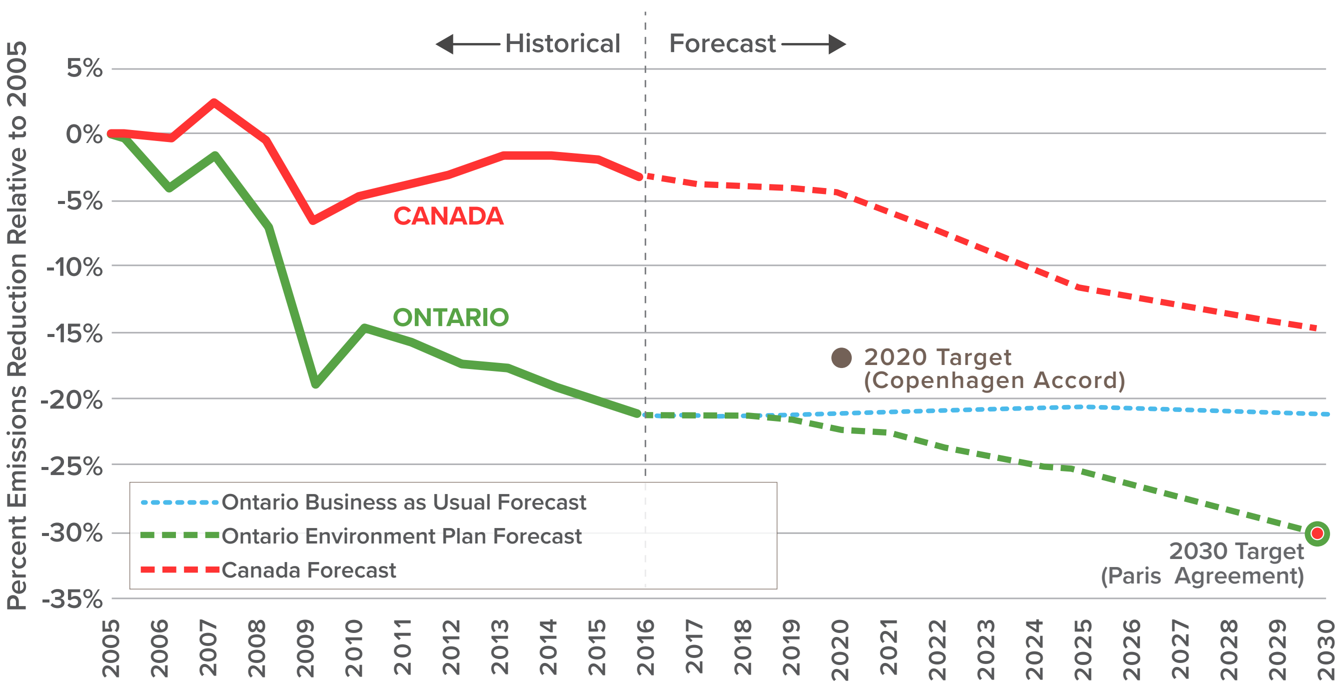
Quick Fact: The Paris Agreement is an agreement within the United Nations Framework Convention on Climate Change. Its goal is to keep the increase in global average temperature to well below 2 °C above pre-industrial levels, and pursue efforts to limit the increase even further to 1.5 °C, in order to reduce the risks and impacts of climate change.

This target takes into consideration the commitment the people of Ontario have already shown in reducing emissions, as well as our commitment to growing Ontario's economy while doing our part to tackle climate change.

There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation. As a result, we are on track to do better than the federal 2020 target set under the Copenhagen Accord in 2010.

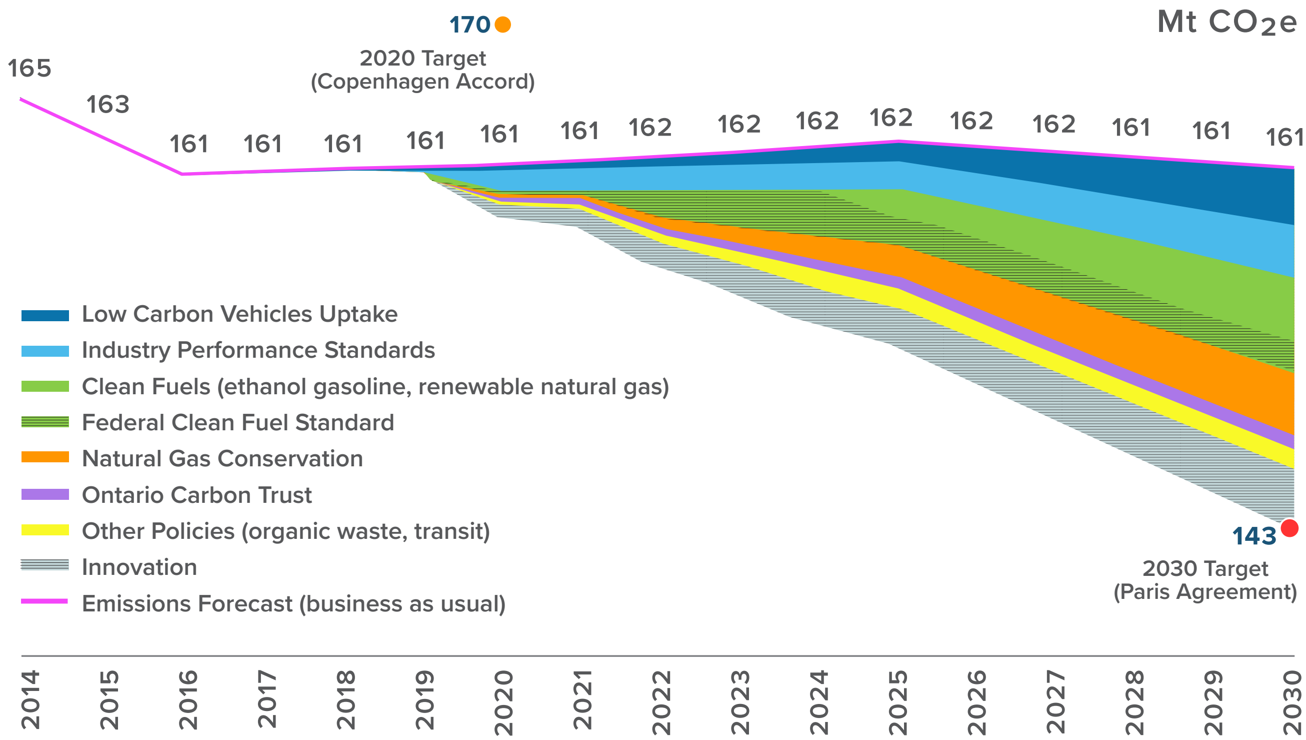
The following graph shows our 2030 target is achievable. The policies within this plan will put us on the path to meet our 2030 target, and we will continue to develop and improve them over the next 12 years. This plan will be reviewed and revised on a four-year basis.

Past and Projected Greenhouse Gas Emission Reductions for Canada and Ontario



Source: Environment and Climate Change Canada (2018) National Inventory Report 1990-2016: Greenhouse Gas Sources and Sinks in Canada. Canada 2017 Biennial Report and internal Ontario modelling.

Path to Meeting Ontario's 2030 Emission Reduction Target



The chart above shows where we expect Ontario's emissions to be if we take no action (161 megatonnes) compared to where we expect our emissions to go if we take actions in specific sectors. Our target is equivalent to 143 megatonnes in 2030 and we will need reductions in key sectors identified in the graph to get there.

The coloured portions of the chart above refer to emissions reductions we expect to see from actions in this plan and the shaded portions represent the potential we have to enhance some of those actions.

The actual reductions achieved will depend on how actions identified in our plan are finalized based on feedback we get from businesses and communities. The estimated reductions are explained in more detail below.

The **Low Carbon Vehicles** uptake portion refers primarily to electric vehicle adoption in Ontario and in small part to the expansion of compressed natural gas in trucking.

Industry Performance Standards refer to our proposed approach to regulate large emitters of greenhouse gas emissions, as described later in this plan. The final impact of this approach will depend on consultation with industry partners.

Clean Fuels refer to increasing the ethanol content of gasoline to 15% as early as 2025, and encouraging uptake of renewable natural gas and the use of lower carbon fuels.

The Federal **Clean Fuel Standard** is an estimate of the additional impact of the proposed federal standards, which could expand the use of a broad range of low-carbon fuels, energy sources and technologies, such as ethanol, renewable natural gas, greener diesel, electricity, and renewable hydrogen.

The Natural Gas Conservation action reflects programs that are well established in Ontario to conserve energy and save people money. This case assumes a gradual expansion of programs delivered by utilities, which would be subject to discussions with the Ontario Energy Board.

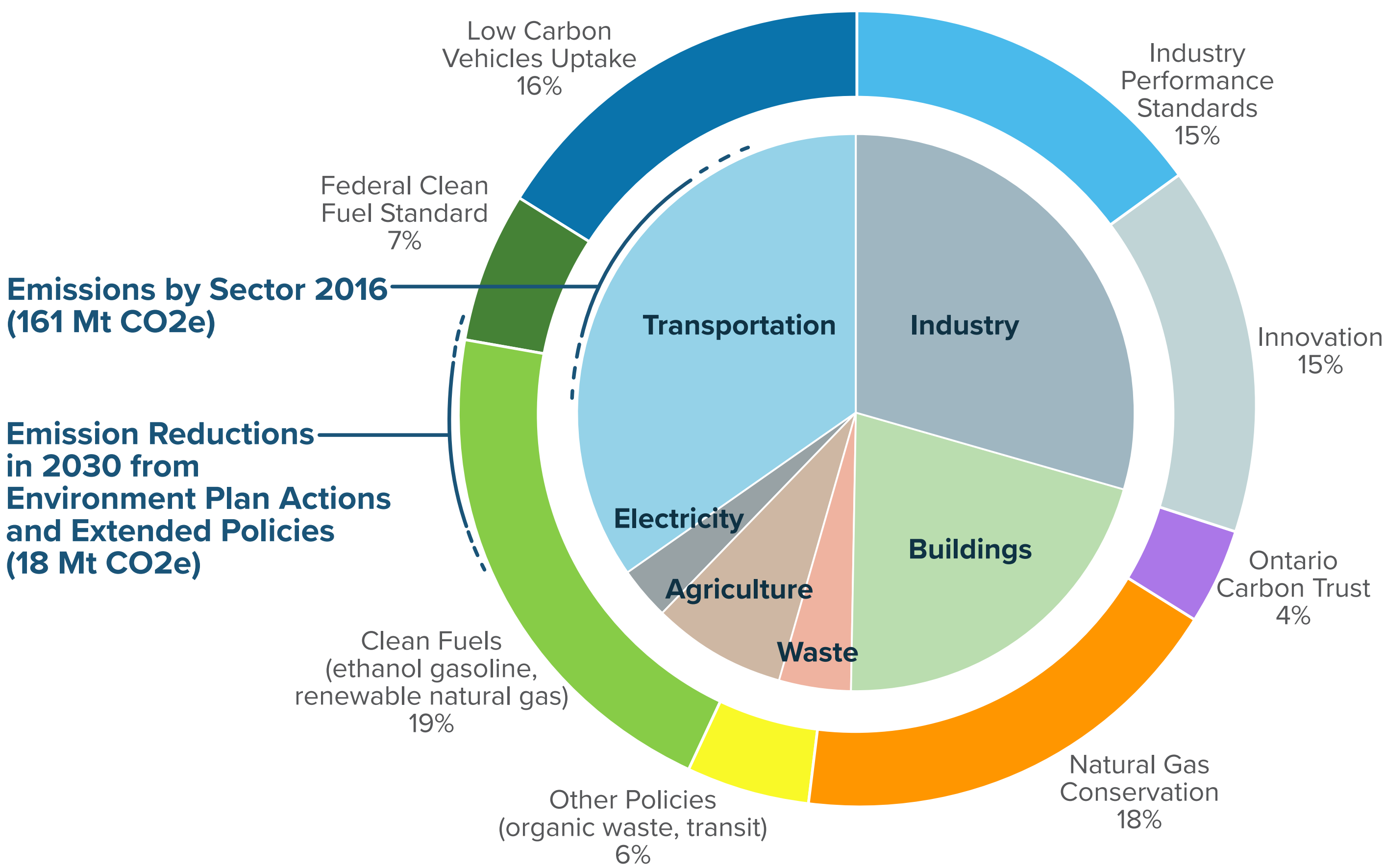
The **Ontario Carbon Trust** is an emission reduction fund that will use public funds to leverage private investment in clean technologies that are commercially viable. For this action we estimate a fund of $350 million will be used to leverage private capital at a 4:1 ratio. Estimates will depend on the final design and mandate of the trust. The estimates also include the potential emission reductions associated with a $50 million Ontario Reverse Auction designed to attract lowest-cost greenhouse gas emission reduction projects.

Other policies include the emission reductions associated with investments in public transit, and our commitment to improve diversion of food and organic waste from landfills, as described later in this plan.

Innovation includes potential advancements in energy storage and cost-effective fuel switching from high intensive fuels in buildings to electricity and lower carbon fuels.

As part of our commitment to transparency, the government is committed to updating and reporting on these estimates once program details are finalized to ensure we are making progress to the 2030 targets.

Planned Emission Reductions in 2030 by Sector



The chart above shows how the plan is tailored to address Ontario's greenhouse gas emissions. The inner pie shows the breakdown of Ontario's 2016 greenhouse gas emissions by sector. The outer ring colours show the policies from the environment plan that are targeted at reducing emissions in each sector.

The government is committed to balancing emissions reductions and economic growth. Ontario's economy has been growing, even as emissions are declining.

Tracking this improvement is an important part of Ontario's climate change plan. In coming months we will consult on the development of an economy wide carbon intensity target as a complementary metric to our absolute emissions target and to ensure that our climate change plan helps us to continue this positive trend.

The below areas are where we will focus our initiatives and actions to tackle and be more resilient to climate change and to meet our balanced target.

MAKE POLLUTERS ACCOUNTABLE

We know job creators in this province have made great strides to reduce greenhouse gas emissions, some leading their industry globally. We will ensure polluters pay their fair share for their greenhouse gas emissions, while also ensuring industry continues to make advances to help Ontario achieve its share of reductions.

Greenhouse gas emissions from the industrial sector, including smaller industrial facilities, accounted for 29% of Ontario's total emissions in 2016. We plan to regulate large emitters with a system that is tough but fair, cost-effective and flexible to the needs and circumstances of our province and its job creators. We will also ensure strong enforcement of these rules.

This system will recognize the unique situation of Canada's manufacturing and industrial heartland. Ontario depends on many industries that compete internationally. Our made-in-Ontario standards will consider factors such as trade-exposure, competitiveness and process-emissions, and allow the province to grant across-the-board exemptions for industries of particular concern, like the auto sector, as needed.

Actions

Implement emission performance standards for large emitters

We will create and establish emission performance standards to achieve greenhouse gas emissions reductions from large emitters. Each large industrial emitter will be required to demonstrate compliance on a regular basis. The program may include compliance flexibility mechanisms such as offset credits and/or payment of an amount to achieve compliance.

An emissions performance standard establishes emission levels that industrial facilities are required to meet and is tied to their level of output or production. This approach does not enforce a blanket cap on emissions across Ontario and takes into consideration specific industry and facility conditions while allowing for economic growth. It also recognizes industries in Ontario that are best-in-class while requiring improvements from sectors that have room to improve.

Case study: Saskatchewan's output-based performance standards (OBPS) system

In December 2017, Saskatchewan introduced a comprehensive Prairie Resilience climate change strategy, which included a plan to implement an OBPS system in 2019. The OBPS will apply to facilities in regulated sectors that emit more than 25,000 tonnes of greenhouse gas emissions per year. The OBPS is expected to be implemented by January 1, 2019, and the Government of Saskatchewan estimates it will cut annual emissions of covered sectors by 10% by 2030.

In addition, Saskatchewan is regulating emissions from electricity generation to achieve a 40% reduction in electricity emissions, and is regulating flared and vented methane emissions in the upstream oil and gas sector, which will lead to additional annual reductions of 40 to 45% in that sector by 2025.

ACTIVATE THE PRIVATE SECTOR

Ontario is home to the hub of the Canadian financial industry – banks, investment firms, pension funds and insurance companies. Ontario hosts the head offices of Canada's five largest banks, three of which rank among the world's largest 25 banks by market capitalization.

We recognize that our private sector has the capital, capability and know-how to transform clean technology markets and transition Ontario to a low-carbon economy. This is why we intend to help facilitate the private sector's best projects and ideas to drive emission reductions at the lowest cost to taxpayers. Our plan will ensure the prudent and responsible use of public resources to drive private sector investment.

We also want to enable consistent disclosure about financial risks associated with climate change so that companies can provide information to investors, lenders, insurers and other stakeholders.

Together, these actions will help improve the capacity of the sustainable finance sector in Ontario and position us as a global leader in this area.

Actions

Launch an emission reduction fund – The Ontario Carbon Trust – and a reverse auction to encourage private investment in clean technology solutions

Ontario will commit to ensuring funding of $400 million over four years. These funds will complement penalties paid into The Ontario Carbon Trust by polluters. This will ensure that over the next four years, The Ontario Carbon Trust should be able to leverage over $400 million to unlock over $1 billion of private capital.

If Canada's federal government returns to the Pan-Canadian Framework agreement with the people of Ontario, The Ontario Carbon Trust could be increased by $420 million through the Low Carbon Economy Leadership Fund. This would increase the fund to $820 million and unlock more than $2 billion of private capital. It would also ensure that the people of Ontario are provided the most cost-effective approach to reducing greenhouse gas emissions. Canada's commitment to partner with the people of Ontario through supporting The Ontario Carbon Trust would allow Ontario to reduce emissions beyond what is forecasted in this plan, and help Canada meet its Paris target.

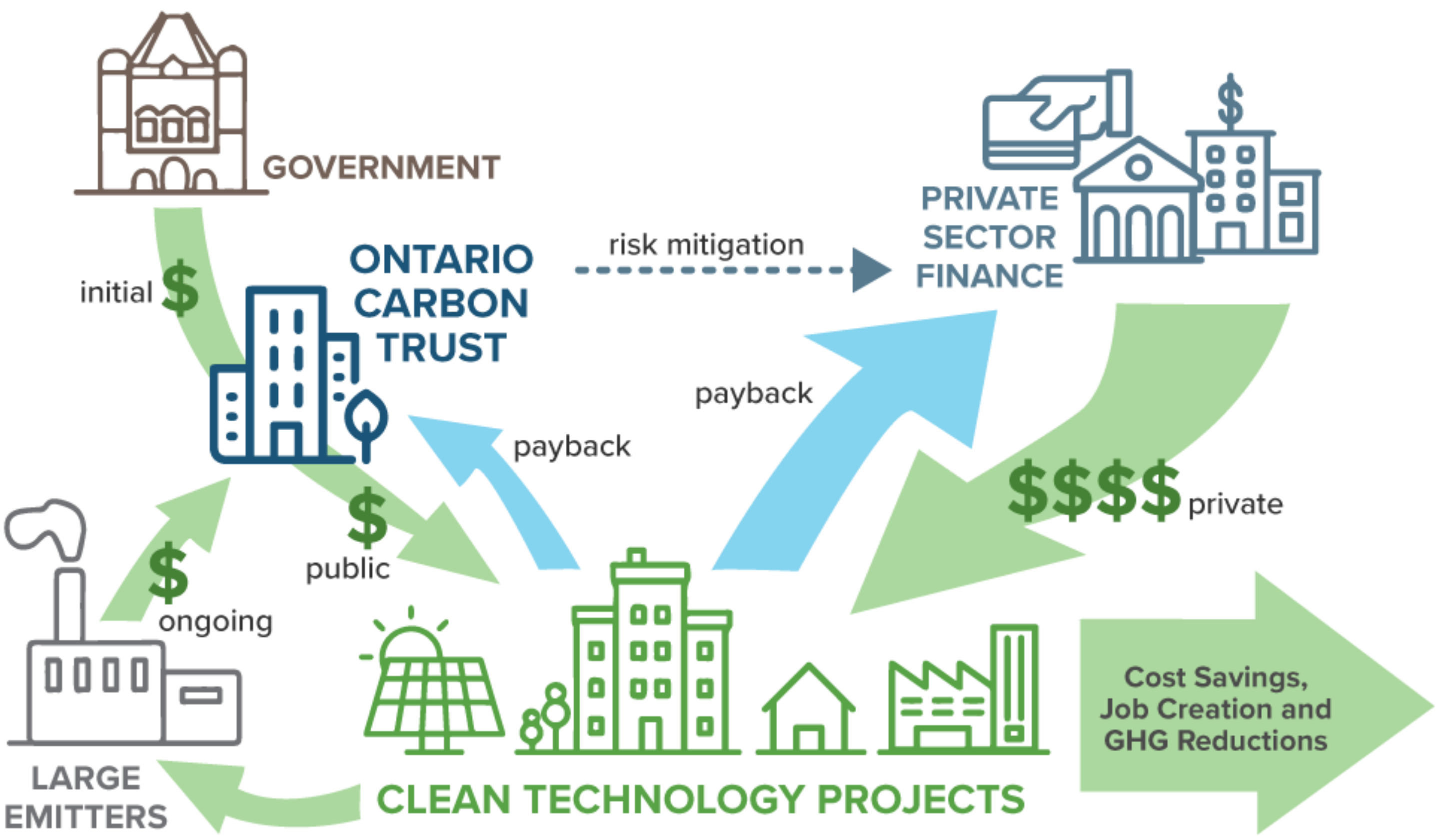
The Ontario Carbon Trust will use innovative financing techniques and market development tools in partnership with the private sector to speed up the deployment of low-carbon solutions. It will use public funds to leverage private investment in clean technologies that are commercially viable and will have a widespread presence. It will also seek to reduce energy costs for ratepayers, stimulate private sector investment and economic activity, and accelerate the transition to a low-carbon economy.

The Ontario Carbon Trust could consider investing in cost-effective projects from various sectors, such as transportation, industry, residential, business and municipal.

We will establish an independent board with the appropriate expertise, with a mandate to form The Ontario Carbon Trust, which will be tasked with working with the private sector to identify projects that will reduce emissions and deliver cost savings. We will:

- Create an emission reduction fund to support and encourage investments across the province for initiatives that reduce greenhouse gas emissions. The fund will leverage an initial investment from the government ($350 million) to attract funds from the private sector in order to drive investment in clean technologies.
- Launch an Ontario Reverse Auction ($50 million), allowing bidders to send proposals for emissions reduction projects and compete for contracts based on the lowest-cost greenhouse gas emission reductions.

The Ontario Carbon Trust



Source: Adapted from Coalition for Green Capital, Growing Clean Energy Markets with Green Bank Financing: White Paper, page 2, http://coalitionforgreencapital.com/wp-content/uploads/2015/08/CGC-Green-Bank-White-Paper.pdf.

Case study:
NY Green Bank

Created as a division of the New York State Energy Research and Development Authority, NY Green Bank is a state-sponsored, specialized financial entity that works with the private sector to increase investments in clean energy markets.

NY Green Bank's flexible approach to clean energy financing helps reduce the need for government support and increase investments into New York's clean energy markets, creating a more efficient, reliable and sustainable energy system.

By investing funds at market rates, NY Green Bank is able to cover its own costs and keep its funding base for future projects. As of September 30, 2018, NY Green Bank has committed $580.1 million to support clean energy projects with a total cost of between $1.44 and $1.68 billion.

What is a reverse auction? The buyer, in this case government, sends out a request for proposals, services or contracts. Bids are assessed and chosen based on the lowest cost, which in this case is the lowest cost per tonne of greenhouse gas emission reductions. The "bidders" in the auction compete to win the project or contract, often underbidding each other, resulting in lower costs for the buyer.

Enhance corporate disclosure and information sharing

- Work with the financial sector to promote climate-related disclosures in Ontario.
- Encourage the Ontario Securities Commission to improve guidance on climate-related disclosures.

Globally, many financial institutions are adopting the recommendations of the Task Force on Climate-Related Financial Disclosures. Ontario's financial sector is also working to improve disclosures.

Encourage private investments in clean technologies and green infrastructure

- Ontario will parallel federal changes to the Accelerated Capital Cost Allowance, which will make technology investments in clean energy generation and energy conservation equipment more attractive.
- Work with the Ontario Financing Authority to issue Green Bonds by the end of the fiscal year, after realigning the Green Bond program to support our approach to addressing environmental challenges. This action was included in the Fall Economic Statement.
- Consider tax policy options to encourage the creation of clean technology manufacturing jobs in Ontario.

Green Bonds serve as an important tool to help finance projects that will help us address our environmental challenges. Project categories include transit initiatives, extreme-weather resistant infrastructure, and energy conservation and efficiency projects (including health and education-related projects). By capitalizing on low interest rates, Ontario's Green Bonds enable the Province to raise funds while respecting the taxpayers of Ontario and without adversely impacting businesses.

Success story:
Algae carbon capture

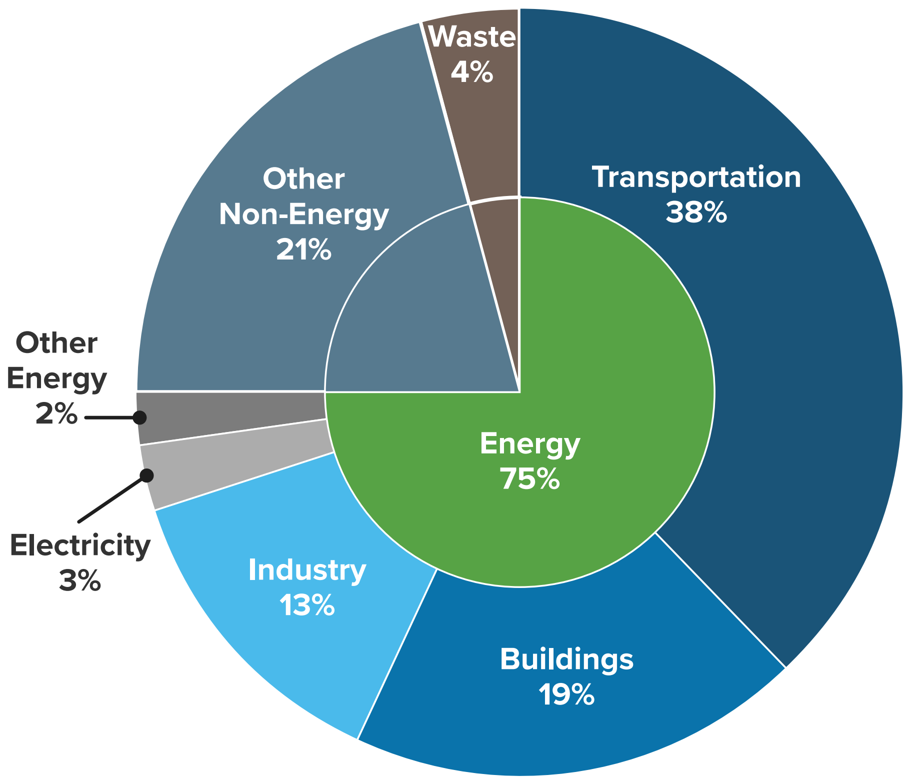
In 2012, Pond Technologies, an Ontario technology company, partnered with St. Marys Cement to run a pilot using CO2 generated by its cement plant to grow algae. Like plants, algae absorb carbon as they grow. Revenue generated from the sale of algae-derived bioproducts provide the economic basis for the adoption of this technology. Pond's pilot proved that reducing greenhouse gas emissions can generate revenue.

USE ENERGY AND RESOURCES WISELY

We will develop climate solutions that will save energy, resources and money.

About 75% of Ontario's greenhouse gas emissions come from using energy in our homes, buildings, vehicles and industry while 4% comes from waste.

Ontario's Energy Use by Sector



Source: Data from Environment and Climate Change Canada, 2018 National Inventory Report

We use gasoline and diesel fuel almost exclusively for transportation, while our main energy source for space and water heating is natural gas. Even though Ontario's vehicles have become more efficient, the number of vehicles on the road has increased.

Today, the transportation sector remains our largest source of emissions. That means we need to focus on using energy more efficiently, including in transportation, on expanding access to cleaner energy.

Our government will ensure the Ontario Energy Board keeps pace with consumer demands and the adoption of innovative energy solutions in this time of unprecedented technological change.

We also know that just over 60% of Ontario's food and organic waste is sent to landfills. In a landfill, it breaks down to create methane, a potent greenhouse gas that contributes to climate change. In fact, methane is 25 times more potent as a greenhouse gas than carbon dioxide. When food and organic waste is sent to landfill, opportunities are lost to preserve valuable resources that could be used to heat our homes, support healthy soils and reduce greenhouse gas emissions.

We will work with partners on ways to make it easier for residents and businesses to waste less food or reuse it for beneficial purposes such as compost.

Quick Fact: About 60% of Ontario's food and organic waste is sent to landfills which emits methane – a potent greenhouse gas – when it decomposes. Efficient diversion of household waste from landfills is an important tool in the fight against climate change. To read more about our plan to fight litter and waste, see page 40.

Actions

Conserve energy in homes and buildings to cut costs and reduce emissions

- Increase the availability and accessibility of information on energy and water consumption so that households, businesses and governments understand their energy use (e.g. collection of data related to electric vehicles, household-level energy and water consumption data). For example, provide customers with access to their energy data by working with electricity and natural gas utilities to implement the Green Button data standard. We will support water utilities to implement Green Button on a voluntary basis.
- Work with the Ontario Real Estate Association to encourage the voluntary display of home energy efficiency information on real estate listings to better inform buyers and encourage energy-efficiency measures.
- Review the Building Code and support the adoption of cost effective energy efficiency measures that can lower the cost of electricity and natural gas needed to operate buildings. Ontario is currently a leading jurisdiction in Canada when it comes to energy efficiency standards in its Building Code. Today, Ontario's Building Code ensures new homes built after 2017 use 50% less energy to heat and cool than houses built before 2005, resulting in a much lower carbon footprint than older homes.
- Work with the Ontario Energy Board and natural gas utilities to increase the cost-effective conservation of natural gas to simultaneously reduce emissions and lower energy bills.
- Ensure Ontario's energy-efficiency standards for appliances and equipment continue to be among the highest in North America.

Quick Fact: Enbridge Gas Distribution and Union Gas offer gas conservation programs that offer incentives for homeowners to complete upgrades that make their homes more energy efficient. Each dollar spent results in up to $2.67 in reduced energy bills for program participants.

Increase access to clean and affordable energy for families

- Continue to support connecting Indigenous communities in Northern Ontario to Ontario's clean electricity grid, to replace local diesel and other types of electricity generation.
- Increase the renewable content requirement (e.g. ethanol) in gasoline to 15% as early as 2025 through the Greener Gasoline regulation, and reduce emissions without increasing the price at the pump, based on current ethanol and gasoline prices.
- Encourage the use of heat pumps for space and water heating where it makes sense, as well as innovative community-based systems like district energy.
- Require natural gas utilities to implement a voluntary renewable natural gas option for customers. We will also consult on the appropriateness of clean content requirements in this space.
- Consult on tax policy options to make it easier for homeowners to increase energy efficiency and save money.
- Streamline and prioritize environmental approvals for businesses that use low-carbon technology, while maintaining high standards for environmental protection.
- Support the integration of emerging smart grid technologies and distributed resources – including energy storage – to harness and make best use of Ontario's clean electricity.
- Improve rules and remove regulatory barriers that block private investors from deploying low-carbon refueling infrastructure that will help increase the uptake of electric, hydrogen, propane, autonomous and other low-carbon vehicles without government subsidies.
- Collaborate with the private sector to remove barriers to expanding 24/7 compressed natural gas refueling stations for trucks along the 400-series highways, and maintain the existing tax exemption (gasoline and fuel tax) on natural gas as a transportation fuel. This will provide heavy-duty vehicles (such as transport trucks) with a cost-effective path to lower on-road transportation emissions.

Quick Fact: Natural gas is exempt from the fuel tax in Ontario, and natural gas trucks have a smaller carbon footprint compared to diesel trucks.

Success story:
Niagara Falls pump generating station produces zero-emissions power

Ontario Power Generation's Sir Adam Beck Pump Generating Station is an important source of flexible zero-emissions power for Ontarians. The station fills a 750-acre reservoir when demand for power is low, storing the equivalent amount of energy as 100,000 electric car batteries. The filled reservoir can then be used to generate hydroelectric power when needed, displacing 600 megawatts of fossil fuel generation for up to eight hours.

Success story:
Partnering to fuel lower-carbon heavy-duty transportation

In April 2018, Union Energy Solutions Limited Partnership, an unregulated affiliate of Union Gas Limited (an Enbridge Company), announced a partnership with Clean Energy to build three compressed natural gas fueling stations along Ontario's Highway 401. The initiative will enable heavy-duty vehicles (such as transport trucks) that use natural gas as a transportation fuel to travel and refuel along the 401, leading to lower on-road transportation emissions.

Case study:
Electrify Canada building an electric vehicle charging network

Electrify Canada is a new company that will build ultra-fast charging networks for electric vehicles across Canada, which are anticipated to be operational starting in 2019. This includes the installation of 32 electric vehicle charging sites near major highways and in major metro areas in British Columbia, Alberta, Ontario and Quebec.

DOING OUR PART: Government Leadership

Ontario is committed to doing its part to address climate change. This includes leading by example. We will encourage local leadership on climate change, including municipal governments, the broader public sector, business associations, community groups, Indigenous communities and voluntary organizations to develop and promote climate solutions for their members and communities. We will continue to engage on international climate issues by providing Ontario's perspective to Canada's international climate negotiations.

As part of the government's commitment to curriculum renewal we will explore changes that embed learning about the environment in the classroom. Learning about protecting our air, land and water, addressing climate change, and reducing the amount of litter and waste in our communities will not only raise awareness in schools, it will also enable students to pass on this knowledge to their families.

Partnering with and enabling people, businesses, municipalities and schools will help us find ways to address local issues and needs, save energy and costs, and minimize climate risks to our schools, hospitals, highways and critical infrastructure.

Actions

Make climate change a cross-government priority

- Improve our ability to consider climate change when we make decisions about government policies and operations by developing a Climate Change Governance Framework that will:
  - Establish clear responsibilities and requirements for ministries to track and report on climate change measures.
  - Consider climate change when we purchase goods and services across government, where it is cost-effective (i.e. low-carbon intensity steel and cement).
  - Explore opportunities to enhance coordination and guidance for municipalities to help them consider climate change in their decision-making.
  - Update Statements of Environmental Values to reflect Ontario's environmental plan.

- Continue to execute a high-performance building automation strategy for government buildings. This strategy uses advanced automation and integration to measure, monitor, and control operations and maintenance at the lowest cost, also reducing greenhouse gas emissions during day-to-day building operations. The strategy includes, but is not limited to, HVAC and lighting controls, security, elevators, fire protection, and life safety systems in order to improve performance and to reduce energy consumption.
- Ensure investments in future renovations of government buildings maximize energy cost savings. For instance, Ontario is building new correctional facilities to meet LEED standards, which ensures high environmental performance and will improve efficiency while saving money.
- Undertake a review of government office space, with an eye to optimizing our physical and carbon footprint. Ontario will reduce its per employee real estate footprint to reduce energy costs and emissions, as recommended in the Auditor General's 2017 Report.
- Support the adoption of low-carbon technologies and climate resilience measures by working to reduce costly and time-consuming regulatory and operational barriers.
- Encourage the federal government to ensure that climate negotiations under Article 6 of the Paris Agreement improve our cleantech sector's access to emerging global markets for low-carbon technologies. Ontario is a leader in clean technology and more access to global markets will help our local companies create new green jobs in Ontario.
- Develop tools to help decision makers understand the climate impacts of government activities. For example, we will identify and report on emissions reductions from school capital investments and enable school boards to access energy efficiency data to inform their investment decisions.
- Provide guidance to public property owners of heritage buildings to help them reduce their energy use and save on operating costs while continuing to conserve these important cultural heritage resources for future generations.
- Continue to support the purchase of electric ferries which will be in service in 2020 and 2021 connecting Wolfe and Amherst Islands to the mainland.

Quick fact: The government's annual procurement budget to purchase goods and services is $6 billion.

Success story: Ontario's private sector leads the country in cleantech

Ontario has the largest and fastest-growing cleantech sector in Canada, with $19.8 billion in annual revenues and over 5,000 companies employing 130,000 people.

Ontario is home to 35% of Canada's innovative cleantech companies.

Ontario is a leading hub for water technologies with over 900 companies and 22,000 employees.

Success story: Government building renovations to save energy and money

The Queen's Park Reconstruction Project is an eight-year initiative that involves the extensive reconstruction of the Macdonald Block Complex, which is located in downtown Toronto and includes the Macdonald Block Podium, Hearst, Hepburn, Mowat and Ferguson Towers.

The 47-year-old Macdonald Block Complex is home to the largest concentration of political and public service individuals in the province. It has never undergone a major renovation and the building's core systems, including electrical, water, cooling and heating, have reached the end of their useful life.

Following advice from an independent third-party expert panel, the government's Macdonald Block Complex is undergoing extensive reconstruction to achieve significant long-term cost and energy savings for the province over the next 50 years. Those savings will be achieved through reduced operating costs, lower energy and capital maintenance expenditures, and the reduction of costly third-party leases across the downtown Toronto core. The reconstructed Macdonald Block Complex will meet LEED silver certification.

Success story: City of Toronto Green Fleet

The City of Toronto's Green Fleet Plan focuses on reducing emissions from almost 10,000 vehicles as well as by equipment owned and operated by the city. The consolidated plan, led by the Fleet Services Division, brings together all five major City of Toronto fleets – City of Toronto Fleet Services Division, Emergency Medical Services, Toronto Fire Services, Toronto Police Service, and Toronto Transit Commission – under one plan.

As of 2017, the city had 2,091 green vehicles and pieces of equipment in its fleet, representing 24% of the total number of vehicles in the city's fleet.

Empower effective local leadership on climate change

- Work with municipalities to develop climate and energy plans and initiatives to support building climate resilience and transformation to the low-carbon future.
- Support the efforts of Indigenous communities to integrate climate action into local plans and initiatives for community power, economic development, health and sustainability.
- Encourage local leadership by forming stronger partnerships and sharing best practices with community groups and business associations.

Improve public transportation to expand commuter choices and support communities

Commit $5 billion more for subways and relief lines. Ontario will also invest in a two-way GO transit service to Niagara Falls, as part of the existing plan to build a regional transportation system.

- Establish a public education and awareness program to make people more aware of the environmental, financial and health impacts of their transportation choices.
- Develop a plan to upload the responsibility for Toronto Transit Commission (TTC) subway infrastructure from the City of Toronto to Ontario. An upload would enable the province to implement a more efficient regional transit system, and build transit faster. Moreover, this would allow the province to fund and deliver new transit projects sooner.

Support green infrastructure projects

We're also greening the government's fleet of vehicles. The Ontario Public Service currently has 1,632 hybrid, plug-in hybrid and full battery electric vehicles, which represent 70% of its entire passenger vehicle fleet.

Work with federal and municipal governments through the green stream of the Investing in Canada Infrastructure Program to invest up to $7 billion in federal, provincial and municipal funding over the next 10 years. Funding could be for projects that lower greenhouse gas emissions, reduce pollution, and help make community infrastructure more resilient. Example investments could include improvements to transit and transportation infrastructure and improved local water, wastewater and stormwater systems.

Early actions: GO Train Service Increase

This government is expanding GO service and making it easier for commuters and members of the community to move around the GTHA. More riders in seats relieves congestion on the roads. We're providing more reliable, predictable journeys across the region – greatly improving the daily transit experience. These improvements bring us a step closer to our vision to deliver two-way, all-day GO service.

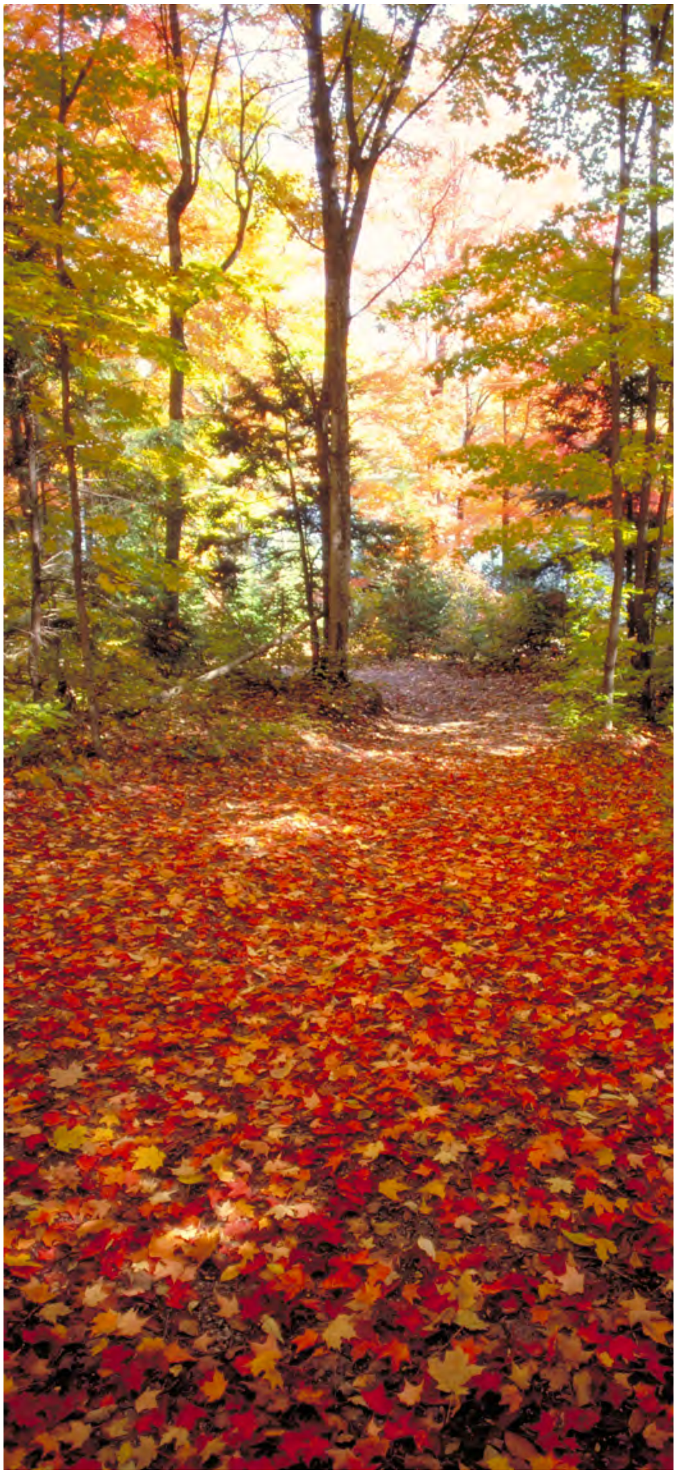
Reducing Litter and Waste in Our Communities & Keeping our Land and Soil Clean

Currently, Ontario generates nearly a tonne of waste per person every year and our overall diversion rate has stalled below 30% over the last 15 years. Ontario needs to reduce the amount of waste we generate and divert more waste from landfill through proven methods like Ontario's curbside Blue Box Program, existing and emerging municipal green bin programs and other waste recovery options. Existing and emerging technologies are increasingly allowing us to recover and recycle materials back into our economy rather than sending them to landfills. This is helping us to better protect our communities and keep our air, land and water clean and healthy.

To keep our land and water clean, we will take strong enforcement action to ensure waste, including hazardous waste, is properly stored, transported, recycled, recovered or disposed.

We are looking at proposed ways to:

- Reduce the amount of waste going to landfills or becoming litter
- Increase opportunities for Ontarians to participate in efforts to reduce waste
- Increase opportunities to use technologies, such as thermal treatment, to recover valuable resources in waste
- Manage excess soil and hauled sewage
- Redevelop brownfield sites to better protect human health and the environment



REDUCE LITTER AND WASTE

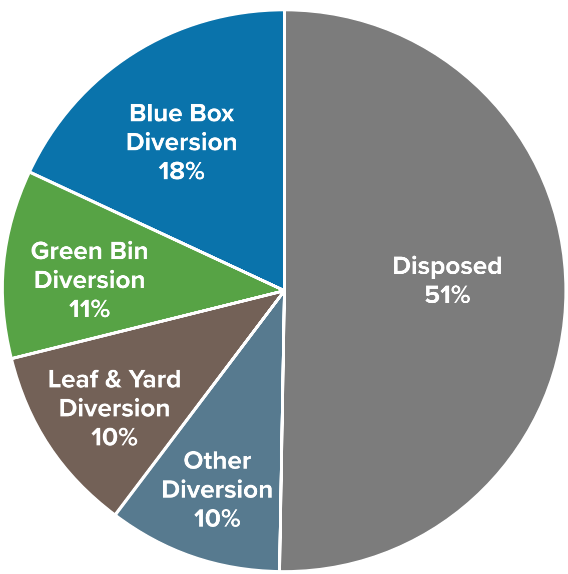
Today, some of the highest waste diversion rates in the province are in our homes. Ontarians divert almost 50% of their own household waste, through sorting what they throw away into their blue bin and, increasingly, their green bin.

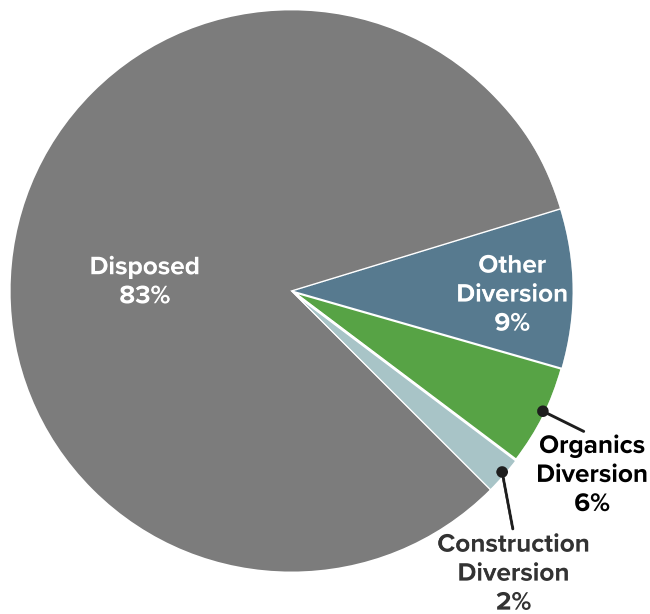
However, Ontario's general waste diversion rate (residential, commercial and industrial) has been stalled at below 30% over the past 15 years – meaning that over 70% of our waste materials continue to end up in landfills. Such heavy reliance on landfills will require the province to either focus on siting new landfills or look for new ways to reduce what we send to them.

While some individual municipalities and businesses have shown leadership, Ontarians know there is still a lot more that can be done to reduce the amount of waste we produce, recover valuable resources from our waste and better manage organics.

We believe that producers should be responsible for managing the waste they produce. Placing responsibility squarely on those who produce the waste will help unleash the creative talents and energies of the private sector. Making producers responsible for the full life-cycle of their products and the waste they produce will help companies to consider what materials they use in and to package their products, and find new and innovative cost-effective ways to recycle them and lower costs for consumers. It can also make recycling easier and more accessible right across the province, keeping it clean and beautiful.

Ontario's Residential and Industrial, Commercial and Institutional Waste Management





Residential Waste: Managed by municipalities. Includes waste generated by residents in single-family homes, some apartments and some small businesses. Mix of mandatory and voluntary diversion programs.

Business Waste: Managed by the private sector. Includes food processing sites, manufacturing facilities, schools, hospitals, offices, restaurants, retail sites and some apartments. Largely voluntary diversion programs.

Sources: Statistics Canada, Waste Management Industry Survey 2016 for non-residential data; Resource Productivity and Recovery Authority, Datacall data and residential diversion rates for residential data. Data on organic waste from 2018 study prepared for MECP by 2cg.

Actions

Reduce and divert food and organic waste from households and businesses

- Expand green bin or similar collection systems in large cities and to relevant businesses.
- Develop a proposal to ban food waste from landfill and consult with key partners such as municipalities, businesses and the waste industry.
- Educate the public and business about reducing and diverting food and organic waste.
- Develop best practices for safe food donation.

Success story: Farmers receive support for food donations

The rescue of surplus food helps ensure food does not go to waste. Ontario supports these efforts through the following mechanisms:

- The Ontario Community Food Program Donation Tax Credit for Farmers provides tax credits up to 25% to farmers who recover and donate agricultural products to eligible programs.
- The Ontario Donation of Food Act, 1994, encourages donations, with certain limitations, and protects food donors from liability as a result of injuries caused by the consumption of donated food.

Success story: City of Stratford turning organic waste into natural gas

Stratford, Ontario, is improving its wastewater treatment infrastructure to produce renewable natural gas from organic waste and feed it back into the local gas distribution system. Renewable natural gas is a clean, carbon-neutral energy source.

Reduce plastic waste

- Work with other provinces, territories and the federal government to develop a plastics strategy to reduce plastic waste and limit micro-plastics that can end up in our lakes and rivers.
- Seek federal commitment to implement national standards that address recyclability and labelling for plastic products and packaging to reduce the cost of recycling in Ontario.
- Work to ensure the Great Lakes and other inland waters are included in national and international agreements, charters and strategies that deal with plastic waste in the environment.

Reduce litter in our neighbourhoods and parks

Our environment plan reflects our government's commitment to keep our neighbourhoods, parks and waterways clean and free of litter and waste. When Ontarians walk their dog or take their children to the park they expect their time outdoors to be litter-free.

Ontario will establish an official day focused on cleanup of litter in Ontario, coordinated with schools, municipalities and businesses, to raise awareness about the impacts of waste in our neighbourhoods, in our waterways and in our green spaces.

- Work with municipal partners to take strong action against those who illegally dump waste or litter in our neighbourhoods, parks and coastal areas.

- Develop future conservation leaders through supporting programs that will actively clean up litter in Ontario's green spaces, including provincial parks, conservation areas and municipalities.
- Connect students with recognized organizations that encourage environmental stewardship so they could earn volunteer hours by cleaning up parks, planting trees and participating in other conservation initiatives.

Increase opportunities for Ontarians to participate in waste reduction efforts

- Work with municipalities and producers to provide more consistency across the province regarding what can and cannot be accepted in the Blue Box program.
- Explore additional opportunities to reduce and recycle waste in our businesses and institutions.

Make producers responsible for the waste generated from their products and packaging

- Move Ontario's existing waste diversion programs to the producer responsibility model. This will provide relief for taxpayers and make producers of packaging and products more efficient by better connecting them with the markets that recycle what they produce.

Explore opportunities to recover the value of resources in waste

- Investigate options to recover resources from waste, such as chemical recycling or thermal treatment, which have an important role – along with reduction, reuse and recycling – in ensuring that the valuable resources in waste do not end up in landfills.
- Encourage increased recycling and new projects or technologies that recover the value of waste (such as hard to recycle materials).

Provide clear rules for compostable products and packaging

- Ensure new compostable packaging materials in Ontario are accepted by existing and emerging green bin programs across the province, by working with municipalities and private composting facilities to build a consensus around requirements for emerging compostable materials.
- Consider making producers responsible for the end of life management of their products and packaging.

Success story: Making products compostable to reduce waste

Club Coffee makes a compostable coffee pod used by brands including Loblaw Companies Limited (President's Choice), Ethical Bean, Muskoka Roastery, Melitta Canada and Jumping Bean. Club Coffee works with municipalities so coffee drinkers can put these pods in their green bins; however they are not yet accepted in every program. We will work to support businesses that are trying to do the right thing and with leading municipalities that are working to reduce waste going to landfills. This will include working with industry and municipal partners to help ensure contamination of the Blue Box and green bin programs is minimized and that the public is provided with accurate information on how to properly manage compostable products and packaging.

Support competitive and sustainable end-markets for Ontario's waste

- Cut regulatory red tape and modernize environmental approvals to support sustainable end markets for waste and new waste processing infrastructure.
- Provide municipalities and the communities they represent with a say in landfill siting approvals. While we work to reduce the amount of waste we produce, it is recognized that there will be a need for landfills in the future. The province will look for opportunities to enhance municipal say while continuing to ensure that proposals for new and expanded landfills are subject to rigorous assessment processes and strict requirements for design, operation, closure, post-closure care and financial assurance.

CLEAN SOIL

Rural and urban communities benefit from healthy soil and land. Soils with contaminants need to be cleaned up to ensure new home owners or property users are safe, and contaminated soils are not relocated to farms where our food is grown. Having clear rules and standards around how extra soil from construction projects is managed, relocated and reused makes it easier for construction businesses to know what soils they can reuse and what soils need to be disposed of or treated before reusing.

Proper management of excess soil can reduce construction costs and unnecessary landfilling while ensuring soil from construction projects is safe for the environment and human health. By clarifying what soil can be reused locally, we can also reduce greenhouse gas emissions generated by trucking soil from place to place unnecessarily.

Redevelopment of underused, often contaminated sites (brownfields) also provides an opportunity to clean up historical contamination and put vacant prime land back into good use.

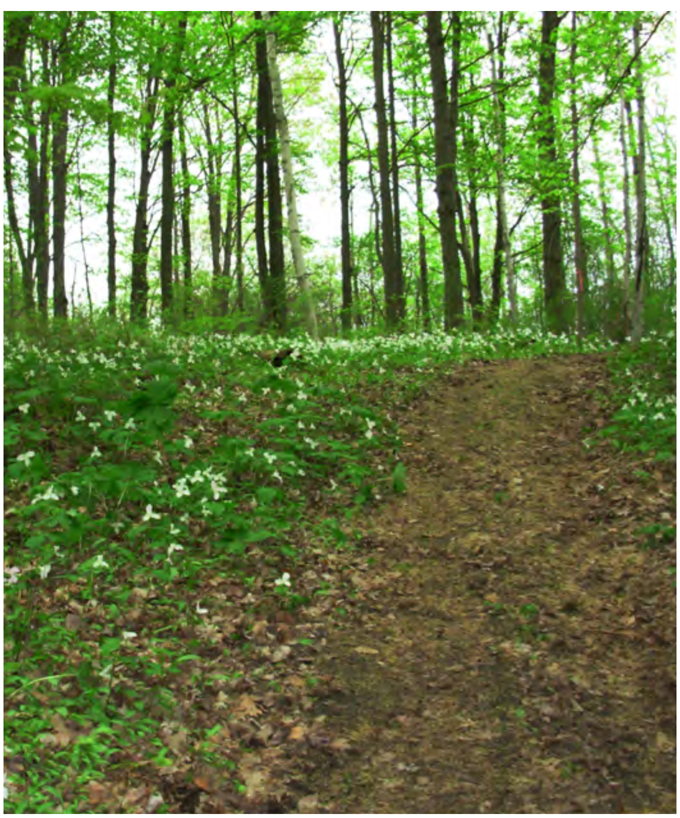
Actions

Increase the redevelopment and clean-up of contaminated lands in Ontario to put land back into good use

- Revise the brownfields regulation and the record of site condition guide to reduce barriers to redevelop and revitalize historically contaminated lands, putting vacant prime land back to good use.

Make it easier and safer to reuse excess soil

- Recognize that excess soil is often a resource that can be reused. Set clear rules to allow industry to reduce construction costs, limit soil being sent to landfill and lower greenhouse gas emissions from trucking by supporting beneficial reuses of safe soils.



- Work with municipalities, conservation authorities, other law enforcement agencies and stakeholders to increase enforcement on illegal dumping of excess soil.

Economic benefits of reusing soil

Traditional excess soil management using "dig and dump" approaches is substantially more expensive than using best practices for reusing soil from construction. According to a recent industry study, projects that use excess soil management best practices for reuse experienced an average of 9% in cost savings (Ontario Society of Professional Engineers, Greater Toronto Sewer and Watermain Contractors Association, Residential and Civil Construction Alliance of Ontario). Savings are due to reduced hauling distances and diverting soils away from landfills.

Improve management of hauled sewage

- Consider approaches for the management and spreading of hauled sewage to better protect human health and the environment (including land and waterways) from the impacts of nutrients and pathogens.

Conserving Land and Greenspace

People travel from around the world to experience the natural wonders that we often take for granted in the province of Ontario. The natural spaces across Ontario, such as forests, wetlands and parks purify our air and water, protect biodiversity and natural heritage, provide recreational opportunities and support Indigenous traditional practices.

We as Ontarians have a long history of putting a strong focus on expanding Ontario's parks and protected areas. In 1999, Ontario's Living Legacy Land Use Strategy was announced. A clear and major goal of this plan was to complete Ontario's system of parks and protected areas. Our government remains dedicated to maintaining the natural beauty of our province.

As mentioned earlier in the plan, we know that climate change poses a serious threat to Ontario's natural areas and that conservation of these areas can play an important role in mitigating and adapting to climate change. We will protect and enhance our natural areas, support conservation efforts, continue to conserve species at risk, develop adaptation strategies, and promote the importance of healthy natural spaces for future generations to use and enjoy.

Quick Fact: Ontario's Living Legacy commitment was one of the greatest expansions of Ontario's provincial parks and conservation reserves in recent history. Over the immediate years that followed, the commitment resulted in the creation of 58 new provincial parks and 268 new conservation reserves, a total area of 1,996,214 hectares.

Action Areas

Improve the resilience of natural ecosystems

- Collaborate with partners to conserve and restore natural ecosystems such as wetlands, and ensure that climate change impacts are considered when developing plans for their protection.
- Strengthen and expand grassland habitats by implementing the province's Grassland Stewardship Initiative that supports on-farm conservation activities to benefit grassland birds at risk.
- Protect against wildland fire incidents through the ongoing development of Community Wildfire Protection Plans and update technical guidance to protect people and property from flooding and water-related hazards.
- Work with leaders in land and water conservation, like Ducks Unlimited Canada and the Nature Conservancy of Canada, to preserve areas of significant environmental and ecological importance.

Success story:
Innovative Wetland in Middlesex County protects Lake Erie

Ducks Unlimited Canada, the Municipality of Southwest Middlesex, Ontario NativeScape and the Ministry of Natural Resources and Forestry built three retention ponds to capture water draining from more than 200 acres of farmland. The wetland acts as a filter to reduce excess nutrients (such as phosphorus that can create harmful algal blooms in water) reaching the Thames River and eventually Lake Erie.

Forest fires increase in Ontario in 2018

Prolonged dry conditions throughout Ontario made 2018 one of the most active forest fire seasons in recent years, with more than 1,300 forest fires burning over 265,000 hectares of forest, nearly double the 10-year average. While the number and intensity of fires varies greatly from year to year and it is difficult to connect any given forest fire to the effects of climate change, most research suggests that Ontario will experience more fires and longer fire seasons in the years ahead. While forest fires pose a serious threat to public safety, communities, and infrastructure, they are also an important natural process in Ontario's forest ecosystems. Managing forest fires in Ontario is about balancing the benefits of forest fires, and protecting public safety and communities.

Support conservation and environmental planning

- Work in collaboration with municipalities and stakeholders to ensure that conservation authorities focus and deliver on their core mandate of protecting people and property from flooding and other natural hazards, and conserving natural resources.
- Look to modernize Ontario's environmental assessment process, which dates back to the 1970s, to address duplication, streamline processes, improve service standards to reduce delays, and better recognize other planning processes.
- Protect vulnerable or sensitive natural areas such as wetlands and other important habitats through good policy, strong science, stewardship and partnerships.
- Improve coordination of land use planning and environmental approval processes by updating ministry guidelines to help municipalities avoid the impacts of conflicting land uses.

The Ontario government is committed to protecting the Greenbelt for future generations. The Greenbelt consists of over two million acres of land in the Greater Golden Horseshoe including farmland, forests, wetlands and watersheds. It includes the Oak Ridges Moraine and the Niagara Escarpment, and provides resilience to extreme weather events by protecting its natural systems and features.

Promote parks and increase recreational opportunities

- Support the creation of new trails across the province.
- Provide Ontario families with more opportunities to enjoy provincial parks and increase the number of Ontarians taking advantage of parks by 10% or approximately one million more visitors while protecting the natural environment.
- Look for opportunities to expand access to parks throughout the province, but ensure Ontario Parks has the tools it needs to conduct its business and create a world-class parks experience.
- Work to ensure that all fish and wildlife licence fees, fines and royalties collected in the Special Purpose Account go towards its stated purpose of conservation, with transparency for hunters and anglers in Ontario.
- Promote the link between nature and human health by supporting the worldwide movement for Healthy Parks Healthy People through Ontario Parks' events, education, and the development of a discussion paper to engage the public.
- Review management of provincial parks and conservation reserves to ensure effectiveness by exploring internationally recognized tools and best practices.
- Share the responsibility of conserving Ontario's protected lands by continuing to partner with municipalities, conservation authorities, Indigenous communities, conservation organizations and other community groups such as trail groups.

Conservation of Ontario's rich biodiversity and natural resources is a shared responsibility - success relies on Ontario working together with First Nation and Métis communities, hunters and anglers, conservation groups and other partners to achieve positive outcomes for our environment.

Quick Fact: Ontario manages and protects 340 provincial parks and 295 conservation reserves totalling 9.8 million hectares or 9% of the province – an area larger than the entire province of New Brunswick. In 2018, Ontario celebrated the 125th anniversary of the provincial parks system and of Algonquin Provincial Park.

Sustainable Forest Management

- Work with Indigenous organizations, the forestry industry and communities involved in managing Ontario's forests under sustainable forest management plans. Ontario will support forest managers to further reduce emissions and increase carbon storage in forests and harvested wood products. Ontario's sustainable forest management provides for the long-term health of Ontario's forests by providing potential opportunities to reduce and store greenhouse gases as trees capture and store carbon dioxide.
- Promote the use of renewable forest biomass, for example, in the steel industry and as heating fuel for northern, rural and Indigenous communities.
- Improve data and information, informed by Indigenous Traditional Knowledge where offered, on greenhouse gas emissions and carbon storage from forests, the changing landscape and permafrost.
- Increase the use of Ontario timber in building, construction and renovation to reduce emissions and increase long-term carbon storage.

What is carbon storage? Carbon storage refers to capturing carbon dioxide – and other greenhouse gases in the atmosphere – through vegetation and soils. Practices that remove carbon dioxide from the atmosphere include sustainable forest management, conserving and restoring natural ecosystems, and enhancing soil carbon in agriculture.

Forests begin to emit greenhouse gases as the trees age and die, while younger forests that are growing vigorously sequester carbon from the atmosphere. Sustainable forestry practices can encourage forests to grow and to increase carbon stored in forests and harvested wood products.

Quick Fact: Sandbanks Provincial Park is one of the busiest parks in the province, welcoming over 750,000 visitors every summer. To meet a growing demand for camping, Ontario Parks opened a new campground in Sandbanks Provincial Park in May 2017, featuring 75 campsites.

Protect species at risk and respond to invasive species

- Reaffirm our commitment to protect species at risk and their habitats, as we mark the 10th anniversary of Ontario's Endangered Species Act. We are committed to ensuring that the legislation provides stringent protections for species at risk, while continuing to work with stakeholders to improve the effectiveness of the program.
- Protect our natural environment from invasive species by working with partners and other governments and using tools to prevent, detect and respond to invasions.

Invasive species impact fish and wildlife, and hurt Ontario's economy

Invasive species like the emerald ash borer are killing our trees, phragmites (a type of grass) are taking over wetlands, and zebra mussels are clogging water intakes for industry and cottagers. Second to habitat loss, invasive species are recognized as the second leading global cause to the loss of biodiversity. In addition, invasive species are impacting our recreational opportunities such as boating, swimming, angling, and hunting, and their economic costs are staggering. A recent study estimated impacts of invasive species in Ontario at $3.6 billion annually with municipalities spending at least $38 million in 2017/18.

Preventing invasive species from arriving and establishing themselves is the single most effective and least costly method to manage invasive species. Ontario is working with a number of conservation partners to coordinate prevention, control, research and management activities to help address this serious threat. Raising public awareness and engaging individuals in taking preventive action is key in preventing new species from arriving and surviving.

Next Steps

IMPLEMENTING OUR PLAN

Ontario's environment plan presents new direction for addressing the pressing challenges we face to protect our air, land and water, clean up litter and waste, build resiliency and reduce our greenhouse gas emissions.

Our plan includes proposed incentives to stimulate growth in clean technologies, enhance leadership and collaboration to build a province-wide commitment to protecting the environment, and take action on climate change.

Our plan will help people and businesses across Ontario take actions that will save money, enhance communities, create new jobs and grow the economy.

Next steps

As part of our work on this plan, we are also undertaking several important steps to finalize our environment actions for Ontario. Over the coming months, we will:

- **Continue to consult with the public and engage with Indigenous communities**
  Throughout the environment plan we have identified areas of action and key initiatives. These are areas where we are engaging with stakeholders and Indigenous communities to develop new approaches that support our common goals for environmental and climate leadership.

- **Establish an advisory panel on climate change**
  An advisory panel on climate change will be established to provide advice to the Minister on implementation and further development of actions and activities in our plan specific to climate change.
- **Begin implementing priority initiatives**
  In the plan we have identified a number of priority initiatives. Some of these initiatives are already underway and we will begin implementation of the remaining initiatives following consultation.
- **Measure and report on progress**
  We want Ontarians to see how our plan is helping them save money and improve the quality of their lives and communities. We are committed to reporting regularly on the progress we make on our plan and to developing key indicators of progress because we believe that transparency is important to the success of this plan. We are also committed to reviewing the environment plan every four years.

Our consultations and engagement with various stakeholders, Indigenous communities and the public will help refine our environment initiatives by incorporating valuable insights that ensure the actions we adopt reflect the needs of Ontarians.

Comments, ideas and suggestions on the actions and initiatives in Ontario's plan to protect the environment can be made on the Environmental Registry.

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TAB 29

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

UNDERTAKING NO. JTC2.30:

Reference(s): **2B-DRC-8(a)**
Exhibit 2B, Section E5.1 and E5.5

To advise whether the energy storage forecast figures that go into that 581-megawatt of incremental DG by 2024 capture energy storage facilitated by EVs.

RESPONSE:

Toronto Hydro confirms that it did not include a projection of energy storage facilitated by EVs (commonly known as “vehicle-to-grid”) in its forecast of incremental distributed generation.

TAB 30

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.

E5.5 Generation Protection, Monitoring, and Control

E5.5.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 13.6	**2020-2024 Cost ($M):** 13.6
Segments: Generation Protection, Monitoring, and Control	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Service, Safety, Reliability, Public Policy	

The Generation Protection, Monitoring, and Control program (the "Program") allows Toronto Hydro to fulfill its regulatory obligations under section 6.2.4 of the Distribution System Code ("DSC") and section 25.36 of the *Electricity Act* to connect distributed generation ("DG") projects to its distribution system; including renewable energy generation ("REG") projects such as solar photovoltaic, wind and bio-gas. It also allows Toronto Hydro to meets its obligations under section 6.1 of its Distribution License and section 26 of the *Electricity Act* to provide generators with non-discriminatory access to its distribution system. Toronto Hydro's investments in this Program consist largely of "renewable-enabling improvements", as defined in sections 1.2 and 3.3.2 of the DSC.

As of the end of 2017, Toronto Hydro has connected over 1,780 DGs totalling 226 MW in capacity. The utility is forecasting a continued increase in DG connections (including energy storage), reaching an estimated 800 MW by the end of 2024. To alleviate existing connection capacity constraints that may prevent the expansion of DG in a number of areas, and to provide Toronto Hydro system controllers with the necessary capabilities to monitor and control DG connections, Toronto Hydro plans to continue making investments in two types of work over the 2020-2024 period:

- generation protection measures, through the installation of bus-tie reactors at five station buses to alleviate short circuit capacity constraints; and
- the installation of 414 monitoring and control systems ("MCS") for REG facilities to provide situational awareness and control of DG facilities on the distribution system.

a typical Dual Element Spot Network ("DESN") type station arrangement. A reactor of 0.5 ohms installed at a bus-tie could allow up to an additional 15 MW of DG capacity. Since they are essentially a linear inductive reactance, their cumulative impedance will add to the system's impedance which will result in a reduction of the fault currents. The main advantage of series reactors is that they allow the use of existing equipment without costly modifications or replacements.

To facilitate Toronto Hydro DG customer connections, coordination with Hydro One is required to install these bus-tie systems. Toronto Hydro plans to work with Hydro One to install bus-tie reactors at stations where fault current constraints become an issue.

Toronto Hydro anticipates that five bus-tie reactors will be required over the 2020 to 2024 period to alleviate short circuit capacity constraints. The station buses where bus tie reactors are proposed are shown in Table 4 below.

Table 4: Bus Tie Reactor Installations

		Forecasted DG Connections by 2019		Forecasted DG Connections by 2024 (without bus-tie reactor)	
Station Name	**Bus**	**Total Capacity (MW)**	**Available Short Circuit Capacity (MVA)**	**Total Capacity (MW)**	**Available Short Circuit Capacity (MVA)**
Ellesmere TS	J	7.9	49.6	12.5	-0.5
Esplanade TS	A1A2	7.3	57.6	17.9	-29.6
Fairbank TS	YZ	2.7	6.0	7.9	-10.6
Horner TS	BY	14.6	92.8	20.8	-4.6
Sheppard TS	BY	3.5	21.7	9.4	-4.0

E5.5.3.3 System Monitoring to Control Distributed Generation

As mentioned, lack of monitoring of and control over the distributed generation on the grid can lead to increased risks of islanding, overloading the system, and increased thermal ratings. These can be addressed through the installation of MCSs.

1. Anti-Islanding Condition for Distributed Generators

Islanding occurs when a DG source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided as it can interfere with grid protection systems. It can also create dangerous backfeeds on the distribution system exposing workers to live circuits they believed to be de-energized.

Monitoring and control can mitigate the risks associated with DG for the public and Toronto Hydro field personnel. DG systems are required by Rule 84-008 of the *Ontario Electricity Safety Code* ("OESC") to have backfeed protection so that in the absence of electrical power (potential) on the utility's supply, generators cannot energize the utility's supply. Protection circuits can and do fail which can energize supply lines creating contact hazards for utility workers, contractors and the others who may be working on circuits expected to be de-energized. As per EUSA Rule 149, backfeed hazards must be identified and eliminated where possible, or controlled using approved temporary grounding procedures. Due to the hazard of backfeed, work is not to be performed on transformers connected in parallel or banked (except for replacing fuses using live line tools) until all sources of electrical energy have been removed from both the secondary and primary sides of the transformer to be worked on. The Electrical Safety Authority ("ESA") Bulletin DSB-07/11, dated August 17th, 2011, outlines an example where an inverter failed to disconnect and started to back feed into the local distribution system.

> *"The Ontario Electrical Safety Code (OESC) rule 84-008 requires a distributed generation system to automatically disconnect electric power production sources when there is a loss of power from the supply authority. In the case of this near miss incident, the solar inverter's "anti-islanding" feature failed to fully disconnect the energy produced from the PV system."*

If the anti-islanding feature of a DG were to fail, as it did in this situation, the DG would backfeed into the local distribution system. The possibility of electric shock due to this scenario would pose a safety risk to the public, Toronto Hydro field personnel and the system in general. Active monitoring and control systems help avoid this situation by automatically issuing an electronic trip or shutdown command when the feeder breaker is opened.

The connection of photovoltaic solar inverters and other DG sources must be accomplished in a manner that ensures that unintentional islanding of DG sources cannot occur. Toronto Hydro plans to deploy real-time monitoring and control investments proposed within this Program at new DG sites greater or equal to 50 kW as per section 3.3.3 of the DSC to provide the needed ability to address anti-islanding concerns.

One of the anti-islanding measures in the IEEE 1547 Standard for Interconnecting Distributed Resources (DR) with Electric Power Systems, section 4.4.1, recommends that a distributor ensure that "*DR aggregate capacity [be] less than one-third of the minimum load of the Local Electric Power System (EPS).*" As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the likelihood of inverters responding to anti-islanding scenarios decreases.

With the proliferation of DG in Toronto in recent years, several feeder circuits have already surpassed the generation to minimum load ratio of one-third. A total of thirteen distribution feeders have ratios ranging from 0.34 to 0.5 (refer to Table 5 below). These feeders currently present an increased risk of unintentional islanding conditions to the distribution system.

Table 5: Existing Feeders with Generation to Load Ratio Greater Than One-Third

Feeder Name	TS Station Name	TS Bus	DG Connected (MW) in 2017	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
47-M1	***Sheppard***	*B*	1.8	3.5	0.50
63-M6	***Agincourt***	*Y*	2.9	6.9	0.43
55-M31	***Finch***	*J*	1.3	3.0	0.42
A-35-T	***Strachan***	*A7A8*	1.0	2.4	0.42
A-31-W	***Wiltshire***	*A5A6*	0.3	0.6	0.41
80-M10	***Fairchild***	*Y*	1.4	3.8	0.35
R29-M5	***Rexdale***	*B*	0.5	1.4	0.35
38-M4	***Manby***	*F*	0.6	1.6	0.35
53-M3	***Bermondsey***	*B*	0.6	1.8	0.35
R43-M31	***Warden***	*J*	0.7	2.0	0.34
88-M13	***Richview***	*E*	0.8	2.5	0.34
55-M1	***Finch***	*B*	2.0	6.0	0.34
R30-M3	***Horner***	*B*	0.8	2.4	0.34

DG penetration is growing rapidly as an additional forty five feeders are approaching the one-third limit (as shown in Table 6). These numbers take into account the forecasted 581 MW of additional DG capacity anticipated by the year 2024. This increase in DG penetration will further exacerbate the existing islanding risks and adversely affect Toronto Hydro's ability to safely and reliably connect additional DG to the distribution system. Monitoring and Control Systems allow Toronto Hydro to prevent concerns of anti-islanding as these give the utility the ability to remotely turn off the DG if they unintentionally island. If not addressed by proactive investments in control and monitoring

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

UNDERTAKING NO. JTC4.24:

Reference(s): **2B-DRC-10(a)**
Exhibit 2B, Section E7.4, p. 10, lines 9-10

To provide a status update to the 25-year load forecast including assessment of EV deployment scenarios; to provide any related reports or working papers, if relevant.

RESPONSE:

As stated in the response to interrogatory 2B-DRC-10(a), the planning process that produces the 25-year load forecast is ongoing. The utility expects the forecast to be published by the fall of 2019 further to the IESO's Integrated Regional Resource Plan (IRRP) for Toronto.

As part of the IRRP process, Toronto Hydro provided the IESO a 25-year outlook of peak demand for consideration in the regional planning work. The outlook is consistent with the station load forecast that underlies Toronto Hydro's current application. Nonetheless, please note that this outlook is not final and may be modified by the IESO in the normal course of the planning process.

The outlook, attached as Appendix A to this response, is the only working paper that Toronto Hydro believes is relevant to deciding the issues in this application.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
2	G		1	REXDALE-LT.LFB	B & Y			2017												61000
3	G		1	REXDALE-LT.LFB	B & Y			2018												64000
4	G		1	REXDALE-LT.LFB	B & Y			2019												65000
5	G		1	REXDALE-LT.LFB	B & Y			2020												66000
6	G		1	REXDALE-LT.LFB	B & Y			2021												66000
7	G		1	REXDALE-LT.LFB	B & Y			2022												67000
8	G		1	REXDALE-LT.LFB	B & Y			2023												67000
9	G		1	REXDALE-LT.LFB	B & Y			2024												68000
10	G		1	REXDALE-LT.LFB	B & Y			2025												68000
11	G		1	REXDALE-LT.LFB	B & Y			2026												68000
12	G		1	REXDALE-LT.LFB	B & Y			2027		-500		-800	100	300	0	900	700	0	0	68000
13	G		1	REXDALE-LT.LFB	B & Y			2028		-500		-800	100	400	0	1000	800	0	0	67000
14	G		1	REXDALE-LT.LFB	B & Y			2029		-500		-800	100	500	0	1100	800	0	0	67000
15	G		1	REXDALE-LT.LFB	B & Y			2030		-500		-800	100	500	0	1200	900	0	0	66000
16	G		1	REXDALE-LT.LFB	B & Y			2031		-500		-800	100	600	0	1300	1000	0	0	65000
17	G		1	REXDALE-LT.LFB	B & Y			2032		-500		-800	100	700	0	1300	1000	0	0	64000
18	G		1	REXDALE-LT.LFB	B & Y			2033		-500		-800	100	800	0	1400	1100	0	0	64000
19	G		1	REXDALE-LT.LFB	B & Y			2034		-500		-800	100	800	0	1500	1100	0	0	63000
20	G		1	REXDALE-LT.LFB	B & Y			2035		-500		-800	100	900	0	1500	1200	0	0	62000
21	G		1	REXDALE-LT.LFB	B & Y			2036		-500		-800	100	1000	0	1500	1200	0	0	61000
22	G		1	REXDALE-LT.LFB	B & Y			2037		-500		-800	100	1100	0	1600	1200	0	0	61000
23	G		1	REXDALE-LT.LFB	B & Y			2038		-500		-800	100	1200	0	1600	1200	0	0	60000
24	G		1	REXDALE-LT.LFB	B & Y			2039		-500		-800	100	1300	0	1600	1200	0	0	59000
25	G		1	REXDALE-LT.LFB	B & Y			2040		-500		-800	100	1400	0	1600	1200	0	0	58000
26	G		1	REXDALE-LT.LFB	B & Y			2041		-500		-800	100	1500	0	1600	1300	0	0	57000
27	G		1	REXDALE-LT.LFB	J & Q			2017												58000
28	G		1	REXDALE-LT.LFB	J & Q			2018												59000
29	G		1	REXDALE-LT.LFB	J & Q			2019												59000
30	G		1	REXDALE-LT.LFB	J & Q			2020												59000
31	G		1	REXDALE-LT.LFB	J & Q			2021												59000
32	G		1	REXDALE-LT.LFB	J & Q			2022												60000
33	G		1	REXDALE-LT.LFB	J & Q			2023												60000
34	G		1	REXDALE-LT.LFB	J & Q			2024												61000
35	G		1	REXDALE-LT.LFB	J & Q			2025												61000
36	G		1	REXDALE-LT.LFB	J & Q			2026												61000
37	G		1	REXDALE-LT.LFB	J & Q			2027		-400		-700	100	300	0	800	600	0	0	61000
38	G		1	REXDALE-LT.LFB	J & Q			2028		-400		-700	100	300	0	900	700	0	0	60000
39	G		1	REXDALE-LT.LFB	J & Q			2029		-400		-700	100	400	0	1000	700	0	0	60000
40	G		1	REXDALE-LT.LFB	J & Q			2030		-400		-700	100	500	0	1000	800	0	0	59000
41	G		1	REXDALE-LT.LFB	J & Q			2031		-400		-700	100	500	0	1100	900	0	0	58000
42	G		1	REXDALE-LT.LFB	J & Q			2032		-400		-700	100	600	0	1200	900	0	0	58000
43	G		1	REXDALE-LT.LFB	J & Q			2033		-400		-700	100	700	0	1200	900	0	0	57000
44	G		1	REXDALE-LT.LFB	J & Q			2034		-400		-700	100	700	0	1300	1000	0	0	56000
45	G		1	REXDALE-LT.LFB	J & Q			2035		-400		-700	100	800	0	1300	1000	0	0	56000
46	G		1	REXDALE-LT.LFB	J & Q			2036		-400		-700	100	900	0	1300	1000	0	0	55000
47	G		1	REXDALE-LT.LFB	J & Q			2037		-400		-700	100	1000	0	1400	1000	0	0	54000
48	G		1	REXDALE-LT.LFB	J & Q			2038		-400		-700	100	1100	0	1400	1100	0	0	53000
49	G		1	REXDALE-LT.LFB	J & Q			2039		-400		-700	100	1100	0	1400	1100	0	0	53000
50	G		1	REXDALE-LT.LFB	J & Q			2040		-400		-700	100	1200	0	1400	1100	0	0	52000
51	G		1	REXDALE-LT.LFB	J & Q			2041		-400		-700	100	1300	0	1400	1100	0	0	51000
52	G		1	RICHVIEW-LT.LFE	B & Y			2017												42000
53	G		1	RICHVIEW-LT.LFE	B & Y			2018												44000
54	G		1	RICHVIEW-LT.LFE	B & Y			2019												45000
55	G		1	RICHVIEW-LT.LFE	B & Y			2020												46000
56	G		1	RICHVIEW-LT.LFE	B & Y			2021												46000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
57	G		1	RICHVIEW-LT.LFE	B & Y			2022												46000
58	G		1	RICHVIEW-LT.LFE	B & Y			2023												47000
59	G		1	RICHVIEW-LT.LFE	B & Y			2024												47000
60	G		1	RICHVIEW-LT.LFE	B & Y			2025												47000
61	G		1	RICHVIEW-LT.LFE	B & Y			2026												48000
62	G		1	RICHVIEW-LT.LFE	B & Y			2027		-300		-500	100	200	0	500	400	0	0	47000
63	G		1	RICHVIEW-LT.LFE	B & Y			2028		-300		-500	100	200	0	600	500	0	0	47000
64	G		1	RICHVIEW-LT.LFE	B & Y			2029		-300		-500	100	300	0	700	500	0	0	46000
65	G		1	RICHVIEW-LT.LFE	B & Y			2030		-300		-500	100	300	0	700	600	0	0	46000
66	G		1	RICHVIEW-LT.LFE	B & Y			2031		-300		-500	100	400	0	800	600	0	0	45000
67	G		1	RICHVIEW-LT.LFE	B & Y			2032		0		-500	100	600	6500	500	800	1100	0	45000
68	G		1	RICHVIEW-LT.LFE	B & Y			2033		0		-500	100	700	6900	600	800	1100	0	45000
69	G		1	RICHVIEW-LT.LFE	B & Y			2034		0		-500	100	800	7200	600	900	1200	0	45000
70	G		1	RICHVIEW-LT.LFE	B & Y			2035		0		-500	100	800	7400	600	900	1200	0	45000
71	G		1	RICHVIEW-LT.LFE	B & Y			2036		0		-500	100	900	7500	600	900	1200	0	45000
72	G		1	RICHVIEW-LT.LFE	B & Y			2037		0		-500	100	1000	7700	600	900	1200	0	44000
73	G		1	RICHVIEW-LT.LFE	B & Y			2038		0		-500	100	1100	7800	600	1000	1300	0	43000
74	G		1	RICHVIEW-LT.LFE	B & Y			2039		0		-500	100	1200	7800	600	1000	1300	0	43000
75	G		1	RICHVIEW-LT.LFE	B & Y			2040		0		-500	100	1300	8000	600	1000	1300	0	43000
76	G		1	RICHVIEW-LT.LFE	B & Y			2041		0		-500	100	1400	8000	700	1000	1300	0	42000
77	G		1	RICHVIEW-LT.LFE	J & E			2017												102000
78	G		1	RICHVIEW-LT.LFE	J & E			2018												102000
79	G		1	RICHVIEW-LT.LFE	J & E			2019												86000
80	G		1	RICHVIEW-LT.LFE	J & E			2020												87000
81	G		1	RICHVIEW-LT.LFE	J & E			2021												88000
82	G		1	RICHVIEW-LT.LFE	J & E			2022												89000
83	G		1	RICHVIEW-LT.LFE	J & E			2023												89000
84	G		1	RICHVIEW-LT.LFE	J & E			2024												90000
85	G		1	RICHVIEW-LT.LFE	J & E			2025												91000
86	G		1	RICHVIEW-LT.LFE	J & E			2026												91000
87	G		1	RICHVIEW-LT.LFE	J & E			2027		-800		-1300	200	500	0	1400	1100	0	0	90000
88	G		1	RICHVIEW-LT.LFE	J & E			2028		-800		-1300	200	600	0	1600	1200	0	0	89000
89	G		1	RICHVIEW-LT.LFE	J & E			2029		-800		-1300	200	700	0	1800	1400	0	0	88000
90	G		1	RICHVIEW-LT.LFE	J & E			2030		-800		-1300	200	800	0	1900	1500	0	0	88000
91	G		1	RICHVIEW-LT.LFE	J & E			2031		-800		-1300	200	1000	0	2000	1600	0	0	87000
92	G		1	RICHVIEW-LT.LFE	J & E			2032		0		-1200	200	1600	17300	1400	2100	2800	0	86000
93	G		1	RICHVIEW-LT.LFE	J & E			2033		0		-1200	200	1800	18100	1500	2200	2900	0	86000
94	G		1	RICHVIEW-LT.LFE	J & E			2034		0		-1200	200	2000	18900	1500	2300	3100	0	86000
95	G		1	RICHVIEW-LT.LFE	J & E			2035		0		-1200	200	2200	19500	1600	2400	3200	0	86000
96	G		1	RICHVIEW-LT.LFE	J & E			2036		0		-1200	200	2400	19800	1600	2400	3200	0	85000
97	G		1	RICHVIEW-LT.LFE	J & E			2037		0		-1200	200	2600	20200	1600	2500	3300	0	83000
98	G		1	RICHVIEW-LT.LFE	J & E			2038		0		-1200	200	2900	20500	1700	2500	3400	0	83000
99	G		1	RICHVIEW-LT.LFE	J & E			2039		0		-1200	200	3100	20700	1700	2600	3400	0	83000
100	G		1	RICHVIEW-LT.LFE	J & E			2040		0		-1200	200	3400	21000	1700	2600	3400	0	82000
101	G		1	RICHVIEW-LT.LFE	J & E			2041		0		-1200	200	3600	21200	1700	2600	3500	0	81000
102	G		1	RICHVIEW-LT.LFE	Q & Z			2017												77000
103	G		1	RICHVIEW-LT.LFE	Q & Z			2018												81000
104	G		1	RICHVIEW-LT.LFE	Q & Z			2019												82000
105	G		1	RICHVIEW-LT.LFE	Q & Z			2020												84000
106	G		1	RICHVIEW-LT.LFE	Q & Z			2021												85000
107	G		1	RICHVIEW-LT.LFE	Q & Z			2022												85000
108	G		1	RICHVIEW-LT.LFE	Q & Z			2023												86000
109	G		1	RICHVIEW-LT.LFE	Q & Z			2024												86000
110	G		1	RICHVIEW-LT.LFE	Q & Z			2025												86000
111	G		1	RICHVIEW-LT.LFE	Q & Z			2026												87000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
112	G		1	RICHVIEW-LT.LFE	Q & Z			2027		-600		-1000	200	400	0	1000	800	0	0	87000
113	G		1	RICHVIEW-LT.LFE	Q & Z			2028		-600		-1000	200	500	0	1200	900	0	0	86000
114	G		1	RICHVIEW-LT.LFE	Q & Z			2029		-600		-1000	200	500	0	1300	1000	0	0	85000
115	G		1	RICHVIEW-LT.LFE	Q & Z			2030		-600		-1000	200	600	0	1400	1100	0	0	84000
116	G		1	RICHVIEW-LT.LFE	Q & Z			2031		-600		-1000	200	700	0	1500	1200	0	0	83000
117	G		1	RICHVIEW-LT.LFE	Q & Z			2032		0		-900	200	1200	12800	1000	1600	2100	0	83000
118	G		1	RICHVIEW-LT.LFE	Q & Z			2033		0		-900	200	1300	13400	1100	1700	2200	0	83000
119	G		1	RICHVIEW-LT.LFE	Q & Z			2034		0		-900	200	1500	14000	1100	1700	2300	0	83000
120	G		1	RICHVIEW-LT.LFE	Q & Z			2035		0		-900	200	1600	14400	1200	1800	2300	0	82000
121	G		1	RICHVIEW-LT.LFE	Q & Z			2036		0		-900	200	1800	14700	1200	1800	2400	0	82000
122	G		1	RICHVIEW-LT.LFE	Q & Z			2037		0		-900	200	2000	15000	1200	1900	2400	0	80000
123	G		1	RICHVIEW-LT.LFE	Q & Z			2038		0		-900	200	2100	15200	1200	1900	2500	0	80000
124	G		1	RICHVIEW-LT.LFE	Q & Z			2039		0		-900	200	2300	15300	1200	1900	2500	0	80000
125	G		1	RICHVIEW-LT.LFE	Q & Z			2040		0		-900	200	2500	15600	1300	1900	2600	0	79000
126	G		1	RICHVIEW-LT.LFE	Q & Z			2041		0		-900	200	2700	15700	1300	1900	2600	0	77000
127	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2017												20000
128	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2018												20000
129	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2019												20000
130	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2020												20000
131	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2021												20000
132	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2022												20000
133	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2023												21000
134	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2024												21000
135	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2025												21000
136	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2026												21000
137	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2027		0		-600	100	500	1600	600	900	1100	0	21000
138	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2028		0		-600	100	600	1800	700	1000	1300	0	21000
139	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2029		0		-600	100	700	2000	700	1100	1400	0	20000
140	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2030		0		-600	100	800	2200	800	1200	1500	0	20000
141	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2031		0		-600	100	900	2300	800	1300	1700	0	20000
142	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2032		0		-600	200	1200	2500	900	1400	1700	0	20000
143	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2033		0		-600	200	1400	2600	900	1500	1800	0	20000
144	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2034		0		-600	200	1500	2700	1000	1500	1900	0	20000
145	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2035		0		-600	200	1700	2800	1000	1600	2000	0	19000
146	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2036		0		-600	200	1900	2900	1000	1600	2000	0	19000
147	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2037		0		-600	200	2000	2900	1000	1600	2100	0	19000
148	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2038		0		-600	200	2200	3000	1100	1700	2100	0	19000
149	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2039		0		-600	200	2400	3000	1100	1700	2100	0	18000
150	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2040		0		-600	200	2600	3000	1100	1700	2200	0	18000
151	G		1	WOODBRIDGE-LT.LFB	FEEDERS-M1 & M4			2041		0		-600	200	2800	3000	1100	1700	2200	0	18000
152	G		2	HORNER-LT.LFB	B & Y			2017												130000
153	G		2	HORNER-LT.LFB	B & Y			2018												133000
154	G		2	HORNER-LT.LFB	B & Y			2019												137000
155	G		2	HORNER-LT.LFB	B & Y			2020												138000
156	G		2	HORNER-LT.LFB	B & Y			2021												140000
157	G		2	HORNER-LT.LFB	B & Y			2022												140000
158	G		2	HORNER-LT.LFB	B & Y			2023												142000
159	G		2	HORNER-LT.LFB	B & Y			2024												143000
160	G		2	HORNER-LT.LFB	B & Y			2025												144000
161	G		2	HORNER-LT.LFB	B & Y			2026												145000
162	G		2	HORNER-LT.LFB	B & Y			2027		0		-2400	200	1300	17400	1500	2400	2700	0	149000
163	G		2	HORNER-LT.LFB	B & Y			2028		0		-2500	200	1600	22500	1800	2800	3200	0	154000
164	G		2	HORNER-LT.LFB	B & Y			2029		0		-2500	200	1900	25000	2000	3100	3600	0	158000
165	G		2	HORNER-LT.LFB	B & Y			2030		0		-2500	200	2200	27200	2200	3400	3800	0	161000
166	G		2	HORNER-LT.LFB	B & Y			2031		0		-2500	200	2500	29300	2400	3600	4100	0	165000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
167	G		2	HORNER-LT.LFB	B & Y			2032		0		-2500	200	2900	31100	2500	3800	4300	0	168000
168	G		2	HORNER-LT.LFB	B & Y			2033		0		-2500	200	3200	32800	2700	4100	4600	0	171000
169	G		2	HORNER-LT.LFB	B & Y			2034		0		-2500	200	3600	34600	2800	4300	4800	0	174000
170	G		2	HORNER-LT.LFB	B & Y			2035		0		-2500	200	4000	35900	2900	4400	5000	0	177000
171	G		2	HORNER-LT.LFB	B & Y			2036		0		-2500	200	4500	36900	3000	4500	5100	0	179000
172	G		2	HORNER-LT.LFB	B & Y			2037		0		-2500	200	4900	37700	3100	4700	5200	0	181000
173	G		2	HORNER-LT.LFB	B & Y			2038		0		-2500	200	5400	38600	3100	4800	5300	0	183000
174	G		2	HORNER-LT.LFB	B & Y			2039		0		-2500	200	5900	39100	3200	4800	5300	0	185000
175	G		2	HORNER-LT.LFB	B & Y			2040		0		-2500	200	6400	40000	3200	4900	5400	0	187000
176	G		2	HORNER-LT.LFB	B & Y			2041		0		-2500	200	6900	40400	3300	5000	5500	0	188000
177	G		2	MANBYW-LT.LFB	B & Y			2017												51000
178	G		2	MANBYW-LT.LFB	B & Y			2018												52000
179	G		2	MANBYW-LT.LFB	B & Y			2019												53000
180	G		2	MANBYW-LT.LFB	B & Y			2020												54000
181	G		2	MANBYW-LT.LFB	B & Y			2021												55000
182	G		2	MANBYW-LT.LFB	B & Y			2022												55000
183	G		2	MANBYW-LT.LFB	B & Y			2023												56000
184	G		2	MANBYW-LT.LFB	B & Y			2024												56000
185	G		2	MANBYW-LT.LFB	B & Y			2025												57000
186	G		2	MANBYW-LT.LFB	B & Y			2026												57000
187	G		2	MANBYW-LT.LFB	B & Y			2027		-500		-1200	100	400	0	1100	800	0	0	57000
188	G		2	MANBYW-LT.LFB	B & Y			2028		-500		-1200	100	500	0	1200	900	0	0	58000
189	G		2	MANBYW-LT.LFB	B & Y			2029		-500		-1200	100	600	0	1400	1000	0	0	58000
190	G		2	MANBYW-LT.LFB	B & Y			2030		-500		-1200	100	700	0	1500	1100	0	0	59000
191	G		2	MANBYW-LT.LFB	B & Y			2031		-500		-1200	100	700	0	1600	1200	0	0	59000
192	G		2	MANBYW-LT.LFB	B & Y			2032		-500		-1200	100	900	0	1700	1300	0	0	60000
193	G		2	MANBYW-LT.LFB	B & Y			2033		-500		-1200	100	1000	0	1800	1400	0	0	60000
194	G		2	MANBYW-LT.LFB	B & Y			2034		-500		-1200	100	1100	0	1900	1400	0	0	60000
195	G		2	MANBYW-LT.LFB	B & Y			2035		0		-1000	100	1600	13000	1100	1700	1900	0	61000
196	G		2	MANBYW-LT.LFB	B & Y			2036		0		-1000	100	1800	13300	1200	1800	2000	0	62000
197	G		2	MANBYW-LT.LFB	B & Y			2037		0		-1000	100	1900	13600	1200	1800	2000	0	62000
198	G		2	MANBYW-LT.LFB	B & Y			2038		0		-1000	100	2100	13900	1200	1900	2100	0	63000
199	G		2	MANBYW-LT.LFB	B & Y			2039		0		-1000	100	2300	14100	1200	1900	2100	0	64000
200	G		2	MANBYW-LT.LFB	B & Y			2040		0		-1000	100	2500	14400	1300	1900	2100	0	64000
201	G		2	MANBYW-LT.LFB	B & Y			2041		0		-1000	100	2700	14600	1300	2000	2200	0	65000
202	G		2	MANBYW-LT.LFB	Q & Z			2017												54000
203	G		2	MANBYW-LT.LFB	Q & Z			2018												55000
204	G		2	MANBYW-LT.LFB	Q & Z			2019												58000
205	G		2	MANBYW-LT.LFB	Q & Z			2020												59000
206	G		2	MANBYW-LT.LFB	Q & Z			2021												59000
207	G		2	MANBYW-LT.LFB	Q & Z			2022												59000
208	G		2	MANBYW-LT.LFB	Q & Z			2023												60000
209	G		2	MANBYW-LT.LFB	Q & Z			2024												60000
210	G		2	MANBYW-LT.LFB	Q & Z			2025												60000
211	G		2	MANBYW-LT.LFB	Q & Z			2026												61000
212	G		2	MANBYW-LT.LFB	Q & Z			2027		-500		-1300	100	400	0	1100	900	0	0	62000
213	G		2	MANBYW-LT.LFB	Q & Z			2028		-500		-1300	100	500	0	1300	1000	0	0	62000
214	G		2	MANBYW-LT.LFB	Q & Z			2029		-500		-1300	100	600	0	1500	1100	0	0	63000
215	G		2	MANBYW-LT.LFB	Q & Z			2030		-500		-1300	100	700	0	1600	1200	0	0	63000
216	G		2	MANBYW-LT.LFB	Q & Z			2031		-500		-1300	100	800	0	1700	1300	0	0	64000
217	G		2	MANBYW-LT.LFB	Q & Z			2032		-500		-1300	100	900	0	1800	1400	0	0	64000
218	G		2	MANBYW-LT.LFB	Q & Z			2033		-500		-1300	100	1000	0	1900	1500	0	0	65000
219	G		2	MANBYW-LT.LFB	Q & Z			2034		-500		-1300	100	1200	0	2000	1600	0	0	65000
220	G		2	MANBYW-LT.LFB	Q & Z			2035		0		-1100	100	1700	14000	1200	1900	2100	0	66000
221	G		2	MANBYW-LT.LFB	Q & Z			2036		0		-1100	100	1900	14400	1300	1900	2200	0	67000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
222	G		2	MANBYW-LT.LFB	Q & Z			2037		0		-1100	100	2100	14800	1300	2000	2200	0	67000
223	G		2	MANBYW-LT.LFB	Q & Z			2038		0		-1100	100	2300	15100	1300	2000	2200	0	68000
224	G		2	MANBYW-LT.LFB	Q & Z			2039		0		-1100	100	2500	15300	1400	2100	2300	0	69000
225	G		2	MANBYW-LT.LFB	Q & Z			2040		0		-1100	100	2700	15600	1400	2100	2300	0	69000
226	G		2	MANBYW-LT.LFB	Q & Z			2041		0		-1100	100	3000	15800	1400	2100	2300	0	70000
227	G		2	MANBYW-LT.LFB	V & F			2017												77000
228	G		2	MANBYW-LT.LFB	V & F			2018												84000
229	G		2	MANBYW-LT.LFB	V & F			2019												91000
230	G		2	MANBYW-LT.LFB	V & F			2020												92000
231	G		2	MANBYW-LT.LFB	V & F			2021												97000
232	G		2	MANBYW-LT.LFB	V & F			2022												98000
233	G		2	MANBYW-LT.LFB	V & F			2023												99000
234	G		2	MANBYW-LT.LFB	V & F			2024												100000
235	G		2	MANBYW-LT.LFB	V & F			2025												100000
236	G		2	MANBYW-LT.LFB	V & F			2026												101000
237	G		2	MANBYW-LT.LFB	V & F			2027		-1100		-1500	100	500	0	1600	1200	-3200	0	101000
238	G		2	MANBYW-LT.LFB	V & F			2028		-1100		-1500	100	500	0	1900	1400	-3700	0	102000
239	G		2	MANBYW-LT.LFB	V & F			2029		-1100		-1500	100	600	0	2100	1500	-4100	0	103000
240	G		2	MANBYW-LT.LFB	V & F			2030		-1100		-1500	100	700	0	2200	1600	-4400	0	104000
241	G		2	MANBYW-LT.LFB	V & F			2031		-1100		-1500	100	800	0	2400	1800	-4700	0	104000
242	G		2	MANBYW-LT.LFB	V & F			2032		-1100		-1500	100	1000	0	2600	1900	-5000	0	105000
243	G		2	MANBYW-LT.LFB	V & F			2033		0		-1500	100	2000	0	1700	2500	2900	0	106000
244	G		2	MANBYW-LT.LFB	V & F			2034		0		-1500	100	2300	0	1800	2700	3000	0	111000
245	G		2	MANBYW-LT.LFB	V & F			2035		0		-1500	100	2500	0	1800	2800	3100	0	113000
246	G		2	MANBYW-LT.LFB	V & F			2036		0		-1500	100	2800	0	1900	2800	3200	0	114000
247	G		2	MANBYW-LT.LFB	V & F			2037		0		-1500	100	3100	0	1900	2900	3200	0	115000
248	G		2	MANBYW-LT.LFB	V & F			2038		0		-1500	100	3400	0	2000	3000	3300	0	116000
249	G		2	MANBYW-LT.LFB	V & F			2039		0		-1500	100	3700	0	2000	3000	3300	0	117000
250	G		2	MANBYW-LT.LFB	V & F			2040		0		-1500	100	4000	0	2000	3100	3400	0	118000
251	G		2	MANBYW-LT.LFB	V & F			2041		0		-1500	100	4300	0	2100	3100	3400	0	119000
252	G		3	AGINCOURT-LT.LFY	B & Y			2017												92000
253	G		3	AGINCOURT-LT.LFY	B & Y			2018												92000
254	G		3	AGINCOURT-LT.LFY	B & Y			2019												95000
255	G		3	AGINCOURT-LT.LFY	B & Y			2020												98000
256	G		3	AGINCOURT-LT.LFY	B & Y			2021												100000
257	G		3	AGINCOURT-LT.LFY	B & Y			2022												101000
258	G		3	AGINCOURT-LT.LFY	B & Y			2023												102000
259	G		3	AGINCOURT-LT.LFY	B & Y			2024												103000
260	G		3	AGINCOURT-LT.LFY	B & Y			2025												104000
261	G		3	AGINCOURT-LT.LFY	B & Y			2026												104000
262	G		3	AGINCOURT-LT.LFY	B & Y			2027		-900		-1900	200	600	0	1700	1300	0	0	105000
263	G		3	AGINCOURT-LT.LFY	B & Y			2028		-900		-1900	200	800	0	1900	1500	0	0	106000
264	G		3	AGINCOURT-LT.LFY	B & Y			2029		-900		-1900	200	900	0	2100	1600	0	0	106000
265	G		3	AGINCOURT-LT.LFY	B & Y			2030		-900		-1900	200	1000	0	2300	1700	0	0	107000
266	G		3	AGINCOURT-LT.LFY	B & Y			2031		-900		-1900	200	1100	0	2400	1900	0	0	107000
267	G		3	AGINCOURT-LT.LFY	B & Y			2032		-900		-1900	200	1300	0	2600	2000	0	0	108000
268	G		3	AGINCOURT-LT.LFY	B & Y			2033		-900		-1900	200	1500	0	2700	2100	0	0	108000
269	G		3	AGINCOURT-LT.LFY	B & Y			2034		-900		-1900	200	1600	0	2800	2200	0	0	109000
270	G		3	AGINCOURT-LT.LFY	B & Y			2035		0		-1400	200	2500	20000	1800	2700	3100	0	110000
271	G		3	AGINCOURT-LT.LFY	B & Y			2036		0		-1400	200	2700	20400	1800	2700	3200	0	111000
272	G		3	AGINCOURT-LT.LFY	B & Y			2037		0		-1400	200	3000	20900	1800	2800	3200	0	111000
273	G		3	AGINCOURT-LT.LFY	B & Y			2038		0		-1400	200	3200	21300	1900	2900	3300	0	112000
274	G		3	AGINCOURT-LT.LFY	B & Y			2039		0		-1400	200	3500	21500	1900	2900	3300	0	113000
275	G		3	AGINCOURT-LT.LFY	B & Y			2040		0		-1400	200	3800	21900	1900	2900	3400	0	114000
276	G		3	AGINCOURT-LT.LFY	B & Y			2041		0		-1400	200	4100	22100	2000	3000	3400	0	114000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
277	G		3	BATHURST-LT.LFB	B & Y			2017												107000
278	G		3	BATHURST-LT.LFB	B & Y			2018												113000
279	G		3	BATHURST-LT.LFB	B & Y			2019												118000
280	G		3	BATHURST-LT.LFB	B & Y			2020												122000
281	G		3	BATHURST-LT.LFB	B & Y			2021												124000
282	G		3	BATHURST-LT.LFB	B & Y			2022												125000
283	G		3	BATHURST-LT.LFB	B & Y			2023												126000
284	G		3	BATHURST-LT.LFB	B & Y			2024												127000
285	G		3	BATHURST-LT.LFB	B & Y			2025												128000
286	G		3	BATHURST-LT.LFB	B & Y			2026												129000
287	G		3	BATHURST-LT.LFB	B & Y			2027		-2000		-2000	200	700	0	2300	1700	-4600	0	129000
288	G		3	BATHURST-LT.LFB	B & Y			2028		-2000		-2000	200	800	0	2600	1900	-5300	0	129000
289	G		3	BATHURST-LT.LFB	B & Y			2029		-2000		-2000	200	900	0	2900	2100	-5900	0	130000
290	G		3	BATHURST-LT.LFB	B & Y			2030		-2000		-2000	200	1000	0	3200	2300	-6300	0	130000
291	G		3	BATHURST-LT.LFB	B & Y			2031		0		-2000	300	2100	22800	2000	3100	3600	0	132000
292	G		3	BATHURST-LT.LFB	B & Y			2032		0		-2000	300	2400	24100	2100	3200	3800	0	134000
293	G		3	BATHURST-LT.LFB	B & Y			2033		0		-2000	300	2700	25300	2200	3400	4000	0	136000
294	G		3	BATHURST-LT.LFB	B & Y			2034		0		-2000	300	3000	26500	2300	3600	4100	0	138000
295	G		3	BATHURST-LT.LFB	B & Y			2035		0		-2000	300	3400	27500	2400	3700	4300	0	139000
296	G		3	BATHURST-LT.LFB	B & Y			2036		0		-2000	300	3700	28100	2500	3800	4400	0	141000
297	G		3	BATHURST-LT.LFB	B & Y			2037		0		-2000	300	4100	28600	2500	3900	4500	0	142000
298	G		3	BATHURST-LT.LFB	B & Y			2038		0		-2000	300	4500	29200	2600	3900	4500	0	143000
299	G		3	BATHURST-LT.LFB	B & Y			2039		0		-2000	300	4800	29500	2600	4000	4600	0	143000
300	G		3	BATHURST-LT.LFB	B & Y			2040		0		-2000	300	5300	30100	2700	4000	4700	0	144000
301	G		3	BATHURST-LT.LFB	B & Y			2041		0		-1900	100	3700	43700	2800	4200	4800	0	145000
302	G		3	BATHURST-LT.LFB	J & Q			2017												88000
303	G		3	BATHURST-LT.LFB	J & Q			2018												97000
304	G		3	BATHURST-LT.LFB	J & Q			2019												102000
305	G		3	BATHURST-LT.LFB	J & Q			2020												104000
306	G		3	BATHURST-LT.LFB	J & Q			2021												105000
307	G		3	BATHURST-LT.LFB	J & Q			2022												106000
308	G		3	BATHURST-LT.LFB	J & Q			2023												107000
309	G		3	BATHURST-LT.LFB	J & Q			2024												108000
310	G		3	BATHURST-LT.LFB	J & Q			2025												108000
311	G		3	BATHURST-LT.LFB	J & Q			2026												109000
312	G		3	BATHURST-LT.LFB	J & Q			2027		-800		-2000	300	800	15800	1500	2000	0	0	110000
313	G		3	BATHURST-LT.LFB	J & Q			2028		-800		-2000	300	1000	18000	1700	2300	0	0	113000
314	G		3	BATHURST-LT.LFB	J & Q			2029		-800		-2000	300	1100	19900	1800	2500	0	0	115000
315	G		3	BATHURST-LT.LFB	J & Q			2030		-800		-2000	300	1300	21500	2000	2700	0	0	117000
316	G		3	BATHURST-LT.LFB	J & Q			2031		0		-1900	300	2100	21900	1900	2900	3400	0	119000
317	G		3	BATHURST-LT.LFB	J & Q			2032		0		-1900	300	2300	23100	2000	3100	3600	0	121000
318	G		3	BATHURST-LT.LFB	J & Q			2033		0		-1900	300	2600	24300	2100	3300	3800	0	123000
319	G		3	BATHURST-LT.LFB	J & Q			2034		0		-1900	300	2900	25400	2300	3400	4000	0	124000
320	G		3	BATHURST-LT.LFB	J & Q			2035		0		-1900	300	3200	26300	2300	3500	4100	0	126000
321	G		3	BATHURST-LT.LFB	J & Q			2036		0		-1900	300	3600	26900	2400	3600	4200	0	127000
322	G		3	BATHURST-LT.LFB	J & Q			2037		0		-1900	300	3900	27500	2400	3700	4300	0	128000
323	G		3	BATHURST-LT.LFB	J & Q			2038		0		-1900	300	4300	28000	2500	3800	4400	0	129000
324	G		3	BATHURST-LT.LFB	J & Q			2039		0		-1900	300	4600	28300	2500	3800	4400	0	129000
325	G		3	BATHURST-LT.LFB	J & Q			2040		0		-1900	300	5000	28800	2500	3900	4500	0	130000
326	G		3	BATHURST-LT.LFB	J & Q			2041		0		-1800	100	3500	41900	2700	4000	4600	0	131000
327	G		3	CAVANAGH-LT.LFJ	J & Q			2017												91000
328	G		3	CAVANAGH-LT.LFJ	J & Q			2018												91000
329	G		3	CAVANAGH-LT.LFJ	J & Q			2019												92000
330	G		3	CAVANAGH-LT.LFJ	J & Q			2020												93000
331	G		3	CAVANAGH-LT.LFJ	J & Q			2021												94000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
332	G		3	CAVANAGH-LT.LFJ	J & Q			2022												95000
333	G		3	CAVANAGH-LT.LFJ	J & Q			2023												95000
334	G		3	CAVANAGH-LT.LFJ	J & Q			2024												95000
335	G		3	CAVANAGH-LT.LFJ	J & Q			2025												96000
336	G		3	CAVANAGH-LT.LFJ	J & Q			2026												97000
337	G		3	CAVANAGH-LT.LFJ	J & Q			2027		-600		-1900	200	900	0	1900	1600	0	0	98000
338	G		3	CAVANAGH-LT.LFJ	J & Q			2028		-600		-1900	200	1000	0	2200	1800	0	0	98000
339	G		3	CAVANAGH-LT.LFJ	J & Q			2029		-600		-1900	200	1200	0	2400	2000	0	0	99000
340	G		3	CAVANAGH-LT.LFJ	J & Q			2030		0		-1800	200	1700	21100	1700	2600	3000	0	100000
341	G		3	CAVANAGH-LT.LFJ	J & Q			2031		0		-1800	200	2000	22600	1800	2800	3300	0	102000
342	G		3	CAVANAGH-LT.LFJ	J & Q			2032		0		-1800	200	2200	23800	1900	2900	3400	0	102000
343	G		3	CAVANAGH-LT.LFJ	J & Q			2033		0		-1800	200	2500	25100	2000	3100	3600	0	105000
344	G		3	CAVANAGH-LT.LFJ	J & Q			2034		0		-1800	200	2800	26300	2100	3300	3800	0	107000
345	G		3	CAVANAGH-LT.LFJ	J & Q			2035		0		-1800	200	3100	27200	2200	3400	3900	0	108000
346	G		3	CAVANAGH-LT.LFJ	J & Q			2036		0		-1800	200	3400	27800	2300	3400	4000	0	108000
347	G		3	CAVANAGH-LT.LFJ	J & Q			2037		0		-1800	200	3700	28400	2300	3500	4100	0	109000
348	G		3	CAVANAGH-LT.LFJ	J & Q			2038		0		-1800	200	4100	29000	2400	3600	4100	0	109000
349	G		3	CAVANAGH-LT.LFJ	J & Q			2039		0		-1800	200	4400	29200	2400	3600	4200	0	111000
350	G		3	CAVANAGH-LT.LFJ	J & Q			2040		0		-1800	200	4800	29800	2400	3700	4200	0	112000
351	G		3	CAVANAGH-LT.LFJ	J & Q			2041		0		-1800	200	5200	30100	2400	3700	4300	0	111000
352	G		3	FAIRCHILD-LT.LFB	B & Y			2017												120000
353	G		3	FAIRCHILD-LT.LFB	B & Y			2018												122000
354	G		3	FAIRCHILD-LT.LFB	B & Y			2019												123000
355	G		3	FAIRCHILD-LT.LFB	B & Y			2020												124000
356	G		3	FAIRCHILD-LT.LFB	B & Y			2021												125000
357	G		3	FAIRCHILD-LT.LFB	B & Y			2022												126000
358	G		3	FAIRCHILD-LT.LFB	B & Y			2023												127000
359	G		3	FAIRCHILD-LT.LFB	B & Y			2024												128000
360	G		3	FAIRCHILD-LT.LFB	B & Y			2025												129000
361	G		3	FAIRCHILD-LT.LFB	B & Y			2026												130000
362	G		3	FAIRCHILD-LT.LFB	B & Y			2027		-1200		-2200	300	800	0	2200	1700	0	0	130000
363	G		3	FAIRCHILD-LT.LFB	B & Y			2028		-1200		-2200	300	1000	0	2500	1900	0	0	131000
364	G		3	FAIRCHILD-LT.LFB	B & Y			2029		-1200		-2200	300	1200	0	2800	2100	0	0	132000
365	G		3	FAIRCHILD-LT.LFB	B & Y			2030		-1200		-2200	300	1300	0	3000	2300	0	0	133000
366	G		3	FAIRCHILD-LT.LFB	B & Y			2031		-1200		-2200	300	1500	0	3200	2500	0	0	133000
367	G		3	FAIRCHILD-LT.LFB	B & Y			2032		-1200		-2200	300	1700	0	3400	2600	0	0	134000
368	G		3	FAIRCHILD-LT.LFB	B & Y			2033		-1200		-2200	300	1900	0	3600	2700	0	0	134000
369	G		3	FAIRCHILD-LT.LFB	B & Y			2034		-1200		-2200	300	2100	0	3700	2900	0	0	135000
370	G		3	FAIRCHILD-LT.LFB	B & Y			2035		-1200		-2200	300	2400	0	3900	3000	0	0	135000
371	G		3	FAIRCHILD-LT.LFB	B & Y			2036		-1200		-2200	300	2600	0	3900	3000	0	0	136000
372	G		3	FAIRCHILD-LT.LFB	B & Y			2037		-1200		-2200	300	2900	0	4000	3100	0	0	136000
373	G		3	FAIRCHILD-LT.LFB	B & Y			2038		-1200		-2200	300	3100	0	4100	3200	0	0	137000
374	G		3	FAIRCHILD-LT.LFB	B & Y			2039		-1200		-2200	300	3400	0	4100	3200	0	0	137000
375	G		3	FAIRCHILD-LT.LFB	B & Y			2040		-1200		-2200	300	3700	0	4200	3200	0	0	138000
376	G		3	FAIRCHILD-LT.LFB	B & Y			2041		-1200		-2200	300	4000	0	4300	3300	0	0	138000
377	G		3	FAIRCHILD-LT.LFB	J & Q			2017												113000
378	G		3	FAIRCHILD-LT.LFB	J & Q			2018												113000
379	G		3	FAIRCHILD-LT.LFB	J & Q			2019												114000
380	G		3	FAIRCHILD-LT.LFB	J & Q			2020												115000
381	G		3	FAIRCHILD-LT.LFB	J & Q			2021												116000
382	G		3	FAIRCHILD-LT.LFB	J & Q			2022												117000
383	G		3	FAIRCHILD-LT.LFB	J & Q			2023												118000
384	G		3	FAIRCHILD-LT.LFB	J & Q			2024												119000
385	G		3	FAIRCHILD-LT.LFB	J & Q			2025												120000
386	G		3	FAIRCHILD-LT.LFB	J & Q			2026												120000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
387	G		3	FAIRCHILD-LT.LFB	J & Q			2027		-1200		-2100	300	800	0	2100	1600	0	0	120000
388	G		3	FAIRCHILD-LT.LFB	J & Q			2028		-1200		-2100	300	1000	0	2400	1900	0	0	121000
389	G		3	FAIRCHILD-LT.LFB	J & Q			2029		-1200		-2100	300	1100	0	2700	2100	0	0	122000
390	G		3	FAIRCHILD-LT.LFB	J & Q			2030		-1200		-2100	300	1300	0	2900	2200	0	0	122000
391	G		3	FAIRCHILD-LT.LFB	J & Q			2031		-1200		-2100	300	1500	0	3100	2400	0	0	123000
392	G		3	FAIRCHILD-LT.LFB	J & Q			2032		-1200		-2100	300	1700	0	3300	2500	0	0	123000
393	G		3	FAIRCHILD-LT.LFB	J & Q			2033		-1200		-2100	300	1900	0	3400	2700	0	0	124000
394	G		3	FAIRCHILD-LT.LFB	J & Q			2034		-1200		-2100	300	2100	0	3600	2800	0	0	125000
395	G		3	FAIRCHILD-LT.LFB	J & Q			2035		-1200		-2100	300	2300	0	3700	2900	0	0	125000
396	G		3	FAIRCHILD-LT.LFB	J & Q			2036		-1200		-2100	300	2500	0	3800	2900	0	0	125000
397	G		3	FAIRCHILD-LT.LFB	J & Q			2037		-1200		-2100	300	2800	0	3900	3000	0	0	126000
398	G		3	FAIRCHILD-LT.LFB	J & Q			2038		-1200		-2100	300	3000	0	4000	3100	0	0	126000
399	G		3	FAIRCHILD-LT.LFB	J & Q			2039		-1200		-2100	300	3300	0	4000	3100	0	0	127000
400	G		3	FAIRCHILD-LT.LFB	J & Q			2040		-1200		-2100	300	3600	0	4100	3100	0	0	127000
401	G		3	FAIRCHILD-LT.LFB	J & Q			2041		-1200		-2100	300	3900	0	4100	3200	0	0	127000
402	G		3	FINCH-LT.LFB	B & Y			2017												116000
403	G		3	FINCH-LT.LFB	B & Y			2018												117000
404	G		3	FINCH-LT.LFB	B & Y			2019												118000
405	G		3	FINCH-LT.LFB	B & Y			2020												120000
406	G		3	FINCH-LT.LFB	B & Y			2021												121000
407	G		3	FINCH-LT.LFB	B & Y			2022												121000
408	G		3	FINCH-LT.LFB	B & Y			2023												122000
409	G		3	FINCH-LT.LFB	B & Y			2024												122000
410	G		3	FINCH-LT.LFB	B & Y			2025												123000
411	G		3	FINCH-LT.LFB	B & Y			2026												124000
412	G		3	FINCH-LT.LFB	B & Y			2027		-1300		-2400	300	900	0	2400	1800	0	0	125000
413	G		3	FINCH-LT.LFB	B & Y			2028		-1300		-2400	300	1100	0	2700	2100	0	0	126000
414	G		3	FINCH-LT.LFB	B & Y			2029		-1300		-2400	300	1200	0	3000	2300	0	0	126000
415	G		3	FINCH-LT.LFB	B & Y			2030		-1300		-2400	300	1400	0	3200	2500	0	0	127000
416	G		3	FINCH-LT.LFB	B & Y			2031		-1300		-2400	300	1600	0	3400	2600	0	0	128000
417	G		3	FINCH-LT.LFB	B & Y			2032		-1300		-2400	300	1800	0	3600	2800	0	0	128000
418	G		3	FINCH-LT.LFB	B & Y			2033		-1300		-2400	300	2100	0	3800	2900	0	0	129000
419	G		3	FINCH-LT.LFB	B & Y			2034		-1300		-2400	300	2300	0	4000	3100	0	0	129000
420	G		3	FINCH-LT.LFB	B & Y			2035		-1300		-2400	300	2500	0	4100	3200	0	0	130000
421	G		3	FINCH-LT.LFB	B & Y			2036		-1300		-2400	300	2800	0	4200	3200	0	0	130000
422	G		3	FINCH-LT.LFB	B & Y			2037		-1300		-2400	300	3100	0	4300	3300	0	0	131000
423	G		3	FINCH-LT.LFB	B & Y			2038		-1300		-2400	300	3400	0	4400	3400	0	0	131000
424	G		3	FINCH-LT.LFB	B & Y			2039		-1300		-2400	300	3700	0	4400	3400	0	0	131000
425	G		3	FINCH-LT.LFB	B & Y			2040		-1300		-2400	300	4000	0	4500	3500	0	0	132000
426	G		3	FINCH-LT.LFB	B & Y			2041		-1300		-2400	300	4300	0	4600	3500	0	0	132000
427	G		3	FINCH-LT.LFB	J & Q			2017												127000
428	G		3	FINCH-LT.LFB	J & Q			2018												132000
429	G		3	FINCH-LT.LFB	J & Q			2019												136000
430	G		3	FINCH-LT.LFB	J & Q			2020												138000
431	G		3	FINCH-LT.LFB	J & Q			2021												139000
432	G		3	FINCH-LT.LFB	J & Q			2022												140000
433	G		3	FINCH-LT.LFB	J & Q			2023												140000
434	G		3	FINCH-LT.LFB	J & Q			2024												141000
435	G		3	FINCH-LT.LFB	J & Q			2025												142000
436	G		3	FINCH-LT.LFB	J & Q			2026												143000
437	G		3	FINCH-LT.LFB	J & Q			2027		-1500		-2700	300	1000	0	2700	2100	0	0	144000
438	G		3	FINCH-LT.LFB	J & Q			2028		-1500		-2700	300	1200	0	3100	2300	0	0	145000
439	G		3	FINCH-LT.LFB	J & Q			2029		-1500		-2700	300	1400	0	3400	2600	0	0	146000
440	G		3	FINCH-LT.LFB	J & Q			2030		-1500		-2700	300	1600	0	3700	2800	0	0	146000
441	G		3	FINCH-LT.LFB	J & Q			2031		-1500		-2700	300	1800	0	3900	3000	0	0	147000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
442	G		3	FINCH-LT.LFB	J & Q			2032		-1500		-2700	300	2100	0	4100	3200	0	0	148000
443	G		3	FINCH-LT.LFB	J & Q			2033		-1500		-2700	300	2300	0	4300	3300	0	0	148000
444	G		3	FINCH-LT.LFB	J & Q			2034		-1500		-2700	300	2600	0	4600	3500	0	0	149000
445	G		3	FINCH-LT.LFB	J & Q			2035		-1500		-2700	300	2900	0	4700	3600	0	0	149000
446	G		3	FINCH-LT.LFB	J & Q			2036		-1500		-2700	300	3200	0	4800	3700	0	0	150000
447	G		3	FINCH-LT.LFB	J & Q			2037		-1500		-2700	300	3500	0	4900	3800	0	0	150000
448	G		3	FINCH-LT.LFB	J & Q			2038		-1500		-2700	300	3800	0	5000	3900	0	0	151000
449	G		3	FINCH-LT.LFB	J & Q			2039		-1500		-2700	300	4200	0	5100	3900	0	0	151000
450	G		3	FINCH-LT.LFB	J & Q			2040		-1500		-2700	300	4500	0	5200	4000	0	0	152000
451	G		3	FINCH-LT.LFB	J & Q			2041		-1500		-2700	300	4900	0	5200	4000	0	0	152000
452	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2017												69000
453	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2018												77000
454	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2019												80000
455	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2020												82000
456	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2021												82000
457	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2022												83000
458	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2023												83000
459	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2024												84000
460	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2025												85000
461	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2026												85000
462	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2027		-600		-1200	200	400	0	1200	900	0	0	85000
463	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2028		-600		-1200	200	500	0	1300	1000	0	0	86000
464	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2029		-600		-1200	200	600	0	1500	1100	0	0	86000
465	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2030		-600		-1200	200	700	0	1600	1200	0	0	87000
466	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2031		-600		-1200	200	800	0	1700	1300	0	0	87000
467	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2032		0		-1100	100	1400	12400	1200	1800	2100	0	88000
468	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2033		0		-1100	100	1500	15100	1200	1900	2200	0	89000
469	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2034		0		-1100	100	1700	15800	1300	2000	2300	0	91000
470	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2035		0		-1100	100	1800	16400	1300	2000	2300	0	92000
471	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2036		0		-1100	100	2100	14500	1400	2100	2400	0	92000
472	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2037		0		-1100	100	2300	14800	1400	2200	2500	0	93000
473	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2038		0		-1100	100	2500	15100	1400	2200	2500	0	94000
474	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2039		0		-1100	100	2600	17600	1400	2200	2500	0	95000
475	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2040		0		-1100	100	2900	17900	1500	2200	2600	0	95000
476	G		3	LESLIE-LT.LFH1	B & Y (27.6 KV)			2041		0		-1100	100	3200	15700	1500	2300	2600	0	95000
477	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2017												15000
478	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2018												10000
479	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2019												7000
480	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2020												0
481	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2021												0
482	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2022												0
483	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2023												0
484	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2024												0
485	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2025												0
486	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2026												0
487	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2027		-200		-300	0	100	0	300	200	0	0	0
488	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2028		-200		-300	0	100	0	400	300	0	0	0
489	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2029		-200		-300	0	200	0	400	300	0	0	0
490	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2030		-200		-300	0	200	0	400	300	0	0	0
491	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2031		-200		-300	0	200	0	500	400	0	0	0
492	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2032		0		-300	0	400	3400	300	500	600	0	0
493	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2033		0		-300	0	400	4100	300	500	600	0	0
494	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2034		0		-300	0	400	4300	300	500	600	0	0
495	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2035		0		-300	0	500	4400	400	500	600	0	0
496	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2036		0		-300	0	600	3900	400	600	700	0	0

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
497	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2037		0		-300	0	600	4000	400	600	700	0	0
498	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2038		0		-300	0	700	4100	400	600	700	0	0
499	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2039		0		-300	0	700	4700	400	600	700	0	0
500	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2040		0		-300	0	800	4800	400	600	700	0	0
501	G		3	LESLIE-LT.LFH1	H1 & H2 (13.8 KV)			2041		0		-300	0	900	4200	400	600	700	0	0
502	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2017												134000
503	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2018												146000
504	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2019												154000
505	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2020												167000
506	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2021												168000
507	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2022												171000
508	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2023												172000
509	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2024												174000
510	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2025												175000
511	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2026												176000
512	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2027		-1200		-2200	300	800	0	2100	1600	0	0	177000
513	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2028		-1200		-2200	300	1000	0	2400	1900	0	0	178000
514	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2029		-1200		-2200	300	1100	0	2700	2100	0	0	179000
515	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2030		-1200		-2200	300	1300	0	2900	2200	0	0	179000
516	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2031		-1200		-2200	300	1500	0	3100	2400	0	0	180000
517	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2032		0		-2000	300	2500	23000	2200	3300	3900	0	182000
518	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2033		0		-2000	300	2800	27900	2300	3500	4000	0	186000
519	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2034		0		-2000	300	3100	29300	2400	3600	4200	0	188000
520	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2035		0		-2000	300	3400	30300	2500	3700	4300	0	191000
521	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2036		0		-2000	300	3800	26900	2600	3900	4500	0	191000
522	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2037		0		-2000	300	4200	27400	2600	4000	4600	0	193000
523	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2038		0		-2000	300	4600	28000	2700	4100	4700	0	194000
524	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2039		0		-2000	300	4900	32500	2600	4000	4600	0	196000
525	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2040		0		-2000	300	5300	33100	2700	4100	4700	0	198000
526	G		3	LESLIE-LT.LFH1	J & Q (27.6 KV)			2041		0		-2000	300	5900	29000	2800	4200	4900	0	198000
527	G		3	MALVERN-LT.LFJ	J & Q			2017												81000
528	G		3	MALVERN-LT.LFJ	J & Q			2018												83000
529	G		3	MALVERN-LT.LFJ	J & Q			2019												84000
530	G		3	MALVERN-LT.LFJ	J & Q			2020												85000
531	G		3	MALVERN-LT.LFJ	J & Q			2021												86000
532	G		3	MALVERN-LT.LFJ	J & Q			2022												86000
533	G		3	MALVERN-LT.LFJ	J & Q			2023												86000
534	G		3	MALVERN-LT.LFJ	J & Q			2024												87000
535	G		3	MALVERN-LT.LFJ	J & Q			2025												88000
536	G		3	MALVERN-LT.LFJ	J & Q			2026												88000
537	G		3	MALVERN-LT.LFJ	J & Q			2027		-600		-1700	300	500	14200	1300	1500	0	0	91000
538	G		3	MALVERN-LT.LFJ	J & Q			2028		-600		-1700	300	600	16100	1500	1700	0	0	93000
539	G		3	MALVERN-LT.LFJ	J & Q			2029		-800		-1900	300	1000	18400	1700	2300	0	0	95000
540	G		3	MALVERN-LT.LFJ	J & Q			2030		-800		-1900	300	1200	19900	1800	2500	0	0	96000
541	G		3	MALVERN-LT.LFJ	J & Q			2031		-800		-1900	300	1400	21300	2000	2700	0	0	98000
542	G		3	MALVERN-LT.LFJ	J & Q			2032		-800		-1900	300	1500	22500	2100	2800	0	0	99000
543	G		3	MALVERN-LT.LFJ	J & Q			2033		-800		-1900	300	1700	23700	2200	3000	0	0	101000
544	G		3	MALVERN-LT.LFJ	J & Q			2034		-800		-1900	300	1900	24800	2300	3100	0	0	102000
545	G		3	MALVERN-LT.LFJ	J & Q			2035		-800		-1900	300	2100	25700	2400	3200	0	0	103000
546	G		3	MALVERN-LT.LFJ	J & Q			2036		-800		-1900	300	2300	26300	2400	3300	0	0	104000
547	G		3	MALVERN-LT.LFJ	J & Q			2037		-800		-1900	300	2600	26800	2500	3400	0	0	104000
548	G		3	MALVERN-LT.LFJ	J & Q			2038		-800		-1900	300	2800	27300	2500	3400	0	0	105000
549	G		3	MALVERN-LT.LFJ	J & Q			2039		-800		-1900	300	3000	27600	2500	3500	0	0	106000
550	G		3	MALVERN-LT.LFJ	J & Q			2040		-800		-1900	300	3300	28100	2600	3500	0	0	106000
551	G		3	MALVERN-LT.LFJ	J & Q			2041		-800		-1900	300	3600	28400	2600	3600	0	0	107000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
552	G		4	BERMONDSEY-LT.LFJ	B & Y			2017												103000
553	G		4	BERMONDSEY-LT.LFJ	B & Y			2018												97000
554	G		4	BERMONDSEY-LT.LFJ	B & Y			2019												100000
555	G		4	BERMONDSEY-LT.LFJ	B & Y			2020												101000
556	G		4	BERMONDSEY-LT.LFJ	B & Y			2021												103000
557	G		4	BERMONDSEY-LT.LFJ	B & Y			2022												103000
558	G		4	BERMONDSEY-LT.LFJ	B & Y			2023												104000
559	G		4	BERMONDSEY-LT.LFJ	B & Y			2024												104000
560	G		4	BERMONDSEY-LT.LFJ	B & Y			2025												105000
561	G		4	BERMONDSEY-LT.LFJ	B & Y			2026												106000
562	G		4	BERMONDSEY-LT.LFJ	B & Y			2027		-700		-2100	400	900	0	2200	1700	0	0	106000
563	G		4	BERMONDSEY-LT.LFJ	B & Y			2028		-700		-2100	400	1000	0	2600	2000	0	0	107000
564	G		4	BERMONDSEY-LT.LFJ	B & Y			2029		-700		-2100	400	1200	0	2800	2200	0	0	107000
565	G		4	BERMONDSEY-LT.LFJ	B & Y			2030		-700		-2100	400	1400	0	3000	2300	0	0	107000
566	G		4	BERMONDSEY-LT.LFJ	B & Y			2031		-700		-2100	400	1500	0	3300	2500	0	0	107000
567	G		4	BERMONDSEY-LT.LFJ	B & Y			2032		-700		-2100	400	1700	0	3400	2600	0	0	107000
568	G		4	BERMONDSEY-LT.LFJ	B & Y			2033		-700		-2100	400	1900	0	3600	2800	0	0	107000
569	G		4	BERMONDSEY-LT.LFJ	B & Y			2034		-700		-2100	400	2200	0	3800	2900	0	0	107000
570	G		4	BERMONDSEY-LT.LFJ	B & Y			2035		-700		-2100	400	2400	0	3900	3000	0	0	108000
571	G		4	BERMONDSEY-LT.LFJ	B & Y			2036		-700		-2100	400	2600	0	4000	3100	0	0	108000
572	G		4	BERMONDSEY-LT.LFJ	B & Y			2037		-700		-2100	400	2900	0	4100	3100	0	0	108000
573	G		4	BERMONDSEY-LT.LFJ	B & Y			2038		0		-1900	200	4700	0	2700	4200	4000	0	108000
574	G		4	BERMONDSEY-LT.LFJ	B & Y			2039		0		-1900	200	5200	0	2800	4200	4100	0	109000
575	G		4	BERMONDSEY-LT.LFJ	B & Y			2040		0		-1900	200	5600	0	2800	4300	4100	0	113000
576	G		4	BERMONDSEY-LT.LFJ	B & Y			2041		0		-1900	200	6100	0	2900	4400	4200	0	114000
577	G		4	BERMONDSEY-LT.LFJ	J & Q			2017												51000
578	G		4	BERMONDSEY-LT.LFJ	J & Q			2018												51000
579	G		4	BERMONDSEY-LT.LFJ	J & Q			2019												52000
580	G		4	BERMONDSEY-LT.LFJ	J & Q			2020												53000
581	G		4	BERMONDSEY-LT.LFJ	J & Q			2021												53000
582	G		4	BERMONDSEY-LT.LFJ	J & Q			2022												56000
583	G		4	BERMONDSEY-LT.LFJ	J & Q			2023												56000
584	G		4	BERMONDSEY-LT.LFJ	J & Q			2024												57000
585	G		4	BERMONDSEY-LT.LFJ	J & Q			2025												57000
586	G		4	BERMONDSEY-LT.LFJ	J & Q			2026												58000
587	G		4	BERMONDSEY-LT.LFJ	J & Q			2027		-500		-1400	200	600	0	1500	1100	0	0	58000
588	G		4	BERMONDSEY-LT.LFJ	J & Q			2028		-500		-1400	200	700	0	1700	1300	0	0	58000
589	G		4	BERMONDSEY-LT.LFJ	J & Q			2029		-500		-1400	200	800	0	1800	1400	0	0	58000
590	G		4	BERMONDSEY-LT.LFJ	J & Q			2030		-500		-1400	200	900	0	2000	1500	0	0	58000
591	G		4	BERMONDSEY-LT.LFJ	J & Q			2031		-500		-1400	200	1000	0	2100	1600	0	0	58000
592	G		4	BERMONDSEY-LT.LFJ	J & Q			2032		-500		-1400	200	1100	0	2200	1700	0	0	58000
593	G		4	BERMONDSEY-LT.LFJ	J & Q			2033		-500		-1400	200	1300	0	2400	1800	0	0	58000
594	G		4	BERMONDSEY-LT.LFJ	J & Q			2034		-500		-1400	200	1400	0	2500	1900	0	0	58000
595	G		4	BERMONDSEY-LT.LFJ	J & Q			2035		-500		-1400	200	1600	0	2600	2000	0	0	58000
596	G		4	BERMONDSEY-LT.LFJ	J & Q			2036		-500		-1400	200	1700	0	2600	2000	0	0	58000
597	G		4	BERMONDSEY-LT.LFJ	J & Q			2037		-500		-1400	200	1900	0	2700	2000	0	0	59000
598	G		4	BERMONDSEY-LT.LFJ	J & Q			2038		-500		-1400	200	2100	0	2700	2100	0	0	59000
599	G		4	BERMONDSEY-LT.LFJ	J & Q			2039		-500		-1400	200	2300	0	2700	2100	0	0	59000
600	G		4	BERMONDSEY-LT.LFJ	J & Q			2040		-500		-1400	200	2500	0	2800	2200	0	0	59000
601	G		4	BERMONDSEY-LT.LFJ	J & Q			2041		-500		-1400	200	2700	0	2800	2200	0	0	59000
602	G		4	ELLESMERE-LT.LFJ	J & Q			2017												122000
603	G		4	ELLESMERE-LT.LFJ	J & Q			2018												124000
604	G		4	ELLESMERE-LT.LFJ	J & Q			2019												126000
605	G		4	ELLESMERE-LT.LFJ	J & Q			2020												128000
606	G		4	ELLESMERE-LT.LFJ	J & Q			2021												129000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
607	G		4	ELLESMERE-LT.LFJ	J & Q			2022												130000
608	G		4	ELLESMERE-LT.LFJ	J & Q			2023												131000
609	G		4	ELLESMERE-LT.LFJ	J & Q			2024												131000
610	G		4	ELLESMERE-LT.LFJ	J & Q			2025												132000
611	G		4	ELLESMERE-LT.LFJ	J & Q			2026												133000
612	G		4	ELLESMERE-LT.LFJ	J & Q			2027		-1000		-2800	500	1200	0	3000	2300	0	0	133000
613	G		4	ELLESMERE-LT.LFJ	J & Q			2028		-1000		-2800	500	1400	0	3400	2600	0	0	134000
614	G		4	ELLESMERE-LT.LFJ	J & Q			2029		-1000		-2800	500	1600	0	3800	2900	0	0	134000
615	G		4	ELLESMERE-LT.LFJ	J & Q			2030		-1000		-2800	500	1800	0	4100	3100	0	0	134000
616	G		4	ELLESMERE-LT.LFJ	J & Q			2031		-1000		-2800	500	2100	0	4400	3400	0	0	134000
617	G		4	ELLESMERE-LT.LFJ	J & Q			2032		-1000		-2800	500	2300	0	4600	3500	0	0	134000
618	G		4	ELLESMERE-LT.LFJ	J & Q			2033		-1000		-2800	500	2600	0	4900	3700	0	0	134000
619	G		4	ELLESMERE-LT.LFJ	J & Q			2034		-1000		-2800	500	2900	0	5100	3900	0	0	135000
620	G		4	ELLESMERE-LT.LFJ	J & Q			2035		-1000		-2800	500	3200	0	5300	4000	0	0	135000
621	G		4	ELLESMERE-LT.LFJ	J & Q			2036		-1000		-2800	500	3600	0	5400	4100	0	0	135000
622	G		4	ELLESMERE-LT.LFJ	J & Q			2037		-1000		-2800	500	3900	0	5500	4200	0	0	135000
623	G		4	ELLESMERE-LT.LFJ	J & Q			2038		-1000		-2800	500	4300	0	5600	4300	0	0	136000
624	G		4	ELLESMERE-LT.LFJ	J & Q			2039		-1000		-2800	500	4700	0	5700	4400	0	0	136000
625	G		4	ELLESMERE-LT.LFJ	J & Q			2040		0		-2400	300	7300	0	3700	5600	5400	0	138000
626	G		4	ELLESMERE-LT.LFJ	J & Q			2041		0		-2400	300	7900	0	3700	5700	5400	0	138000
627	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2017												41000
628	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2018												44000
629	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2019												45000
630	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2020												46000
631	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2021												47000
632	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2022												47000
633	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2023												48000
634	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2024												48000
635	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2025												48000
636	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2026												49000
637	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2027		-200		-1000	200	500	0	1000	900	0	0	49000
638	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2028		-200		-1000	200	600	0	1200	1000	0	0	49000
639	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2029		-200		-1000	200	600	0	1300	1100	0	0	49000
640	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2030		-200		-1000	200	700	0	1400	1200	0	0	49000
641	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2031		-200		-1000	200	800	0	1500	1200	0	0	49000
642	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2032		-200		-1000	200	900	0	1600	1300	0	0	49000
643	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2033		-200		-1000	200	1100	0	1700	1400	0	0	49000
644	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2034		0		-800	100	1400	12000	1100	1600	1600	0	49000
645	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2035		0		-800	100	1500	12400	1100	1700	1600	0	50000
646	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2036		0		-800	100	1700	12600	1100	1700	1600	0	50000
647	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2037		0		-800	100	1800	12900	1100	1700	1700	0	50000
648	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2038		0		-800	100	2000	13200	1200	1800	1700	0	50000
649	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2039		0		-800	100	2200	13300	1200	1800	1700	0	51000
650	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2040		0		-800	100	2400	14800	1200	1800	1800	0	51000
651	G		4	LEASIDE-LT.LFB	A1 & A2 (13.8 KV)			2041		0		-800	100	2600	15000	1200	1900	1800	0	51000
652	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2017												73000
653	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2018												77000
654	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2019												81000
655	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2020												84000
656	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2021												85000
657	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2022												86000
658	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2023												86000
659	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2024												86000
660	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2025												87000
661	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2026												87000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
662	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2027		-300		-1500	200	800	0	1700	1400	0	0	87000
663	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2028		-300		-1500	200	900	0	1900	1600	0	0	88000
664	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2029		-300		-1500	200	1000	0	2100	1700	0	0	88000
665	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2030		-300		-1500	200	1200	0	2300	1900	0	0	88000
666	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2031		-300		-1500	200	1300	0	2400	2000	0	0	88000
667	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2032		-300		-1500	200	1500	0	2500	2100	0	0	88000
668	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2033		-300		-1500	200	1700	0	2700	2200	0	0	88000
669	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2034		0		-1300	200	2200	19200	1700	2600	2500	0	88000
670	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2035		0		-1300	200	2400	19900	1800	2700	2600	0	89000
671	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2036		0		-1300	200	2700	20300	1800	2700	2600	0	89000
672	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2037		0		-1300	200	3000	20800	1800	2800	2700	0	90000
673	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2038		0		-1300	200	3200	21200	1900	2900	2700	0	91000
674	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2039		0		-1300	200	3500	21400	1900	2900	2800	0	91000
675	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2040		0		-1400	200	4200	0	2100	3200	3100	0	94000
676	G		4	LEASIDE-LT.LFB	B & Y (27.6 KV)			2041		0		-1400	200	4500	0	2100	3300	3100	0	95000
677	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2017												24000
678	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2018												30000
679	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2019												30000
680	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2020												30000
681	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2021												31000
682	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2022												31000
683	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2023												31000
684	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2024												31000
685	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2025												32000
686	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2026												32000
687	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2027		-100		-500	100	300	0	600	500	0	0	32000
688	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2028		-100		-500	100	300	0	700	500	0	0	32000
689	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2029		-100		-500	100	400	0	700	600	0	0	32000
690	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2030		-100		-500	100	400	0	800	600	0	0	32000
691	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2031		-100		-500	100	500	0	800	700	0	0	32000
692	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2032		-100		-500	100	500	0	900	700	0	0	32000
693	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2033		-100		-500	100	600	0	900	800	0	0	32000
694	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2034		0		-500	100	800	6600	600	900	900	0	32000
695	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2035		0		-500	100	800	6800	600	900	900	0	32000
696	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2036		0		-500	100	900	7000	600	900	900	0	32000
697	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2037		0		-500	100	1000	7100	600	1000	900	0	32000
698	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2038		0		-500	100	1100	7300	600	1000	900	0	33000
699	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2039		0		-500	100	1200	7300	600	1000	1000	0	33000
700	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2040		0		-500	100	1300	8200	700	1000	1000	0	33000
701	G		4	LEASIDE-LT.LFB	Q1 & Q2 (13.8 KV)			2041		0		-500	100	1400	8300	700	1000	1000	0	33000
702	G		4	SCARBORO-LT.LFJ	B & Y			2017												97000
703	G		4	SCARBORO-LT.LFJ	B & Y			2018												100000
704	G		4	SCARBORO-LT.LFJ	B & Y			2019												102000
705	G		4	SCARBORO-LT.LFJ	B & Y			2020												103000
706	G		4	SCARBORO-LT.LFJ	B & Y			2021												104000
707	G		4	SCARBORO-LT.LFJ	B & Y			2022												104000
708	G		4	SCARBORO-LT.LFJ	B & Y			2023												104000
709	G		4	SCARBORO-LT.LFJ	B & Y			2024												105000
710	G		4	SCARBORO-LT.LFJ	B & Y			2025												106000
711	G		4	SCARBORO-LT.LFJ	B & Y			2026												107000
712	G		4	SCARBORO-LT.LFJ	B & Y			2027		-600		-1800	300	700	0	1900	1500	0	0	107000
713	G		4	SCARBORO-LT.LFJ	B & Y			2028		-600		-1800	300	900	0	2200	1700	0	0	107000
714	G		4	SCARBORO-LT.LFJ	B & Y			2029		-600		-1800	300	1000	0	2400	1900	0	0	108000
715	G		4	SCARBORO-LT.LFJ	B & Y			2030		-600		-1800	300	1200	0	2600	2000	0	0	108000
716	G		4	SCARBORO-LT.LFJ	B & Y			2031		-600		-1800	300	1300	0	2800	2100	0	0	108000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
717	G		4	SCARBORO-LT.LFJ	B & Y			2032		0		-1600	300	2100	22800	1800	2800	2700	0	109000
718	G		4	SCARBORO-LT.LFJ	B & Y			2033		0		-1600	300	2400	23900	1900	3000	2900	0	110000
719	G		4	SCARBORO-LT.LFJ	B & Y			2034		0		-1600	300	2600	25100	2000	3100	3000	0	112000
720	G		4	SCARBORO-LT.LFJ	B & Y			2035		0		-1600	300	2900	25900	2100	3200	3100	0	113000
721	G		4	SCARBORO-LT.LFJ	B & Y			2036		0		-1600	300	3200	26500	2100	3300	3200	0	113000
722	G		4	SCARBORO-LT.LFJ	B & Y			2037		0		-1600	300	3500	27100	2200	3300	3200	0	114000
723	G		4	SCARBORO-LT.LFJ	B & Y			2038		0		-1600	300	3900	27600	2200	3400	3300	0	115000
724	G		4	SCARBORO-LT.LFJ	B & Y			2039		0		-1600	300	4200	27900	2300	3500	3300	0	115000
725	G		4	SCARBORO-LT.LFJ	B & Y			2040		0		-1600	300	4600	28500	2300	3500	3400	0	116000
726	G		4	SCARBORO-LT.LFJ	B & Y			2041		0		-1500	300	7800	26200	2400	3700	3500	0	117000
727	G		4	SCARBORO-LT.LFJ	J & Q			2017												103000
728	G		4	SCARBORO-LT.LFJ	J & Q			2018												104000
729	G		4	SCARBORO-LT.LFJ	J & Q			2019												105000
730	G		4	SCARBORO-LT.LFJ	J & Q			2020												106000
731	G		4	SCARBORO-LT.LFJ	J & Q			2021												107000
732	G		4	SCARBORO-LT.LFJ	J & Q			2022												108000
733	G		4	SCARBORO-LT.LFJ	J & Q			2023												109000
734	G		4	SCARBORO-LT.LFJ	J & Q			2024												109000
735	G		4	SCARBORO-LT.LFJ	J & Q			2025												110000
736	G		4	SCARBORO-LT.LFJ	J & Q			2026												111000
737	G		4	SCARBORO-LT.LFJ	J & Q			2027		-800		-2300	400	900	0	2400	1900	0	0	111000
738	G		4	SCARBORO-LT.LFJ	J & Q			2028		-800		-2300	400	1100	0	2800	2100	0	0	111000
739	G		4	SCARBORO-LT.LFJ	J & Q			2029		-800		-2300	400	1300	0	3100	2400	0	0	111000
740	G		4	SCARBORO-LT.LFJ	J & Q			2030		-800		-2300	400	1500	0	3300	2500	0	0	111000
741	G		4	SCARBORO-LT.LFJ	J & Q			2031		-800		-2300	400	1700	0	3500	2700	0	0	111000
742	G		4	SCARBORO-LT.LFJ	J & Q			2032		0		-2000	400	2700	28900	2300	3600	3400	0	112000
743	G		4	SCARBORO-LT.LFJ	J & Q			2033		0		-2000	400	3000	30300	2500	3800	3600	0	114000
744	G		4	SCARBORO-LT.LFJ	J & Q			2034		0		-2000	400	3300	31800	2600	3900	3800	0	115000
745	G		4	SCARBORO-LT.LFJ	J & Q			2035		0		-2000	400	3700	32900	2700	4100	3900	0	117000
746	G		4	SCARBORO-LT.LFJ	J & Q			2036		0		-2000	400	4100	33600	2700	4100	4000	0	117000
747	G		4	SCARBORO-LT.LFJ	J & Q			2037		0		-2000	400	4500	34300	2800	4200	4100	0	118000
748	G		4	SCARBORO-LT.LFJ	J & Q			2038		0		-2000	400	4900	35100	2800	4300	4200	0	119000
749	G		4	SCARBORO-LT.LFJ	J & Q			2039		0		-2000	400	5300	35400	2900	4400	4200	0	119000
750	G		4	SCARBORO-LT.LFJ	J & Q			2040		0		-2000	400	5800	36100	2900	4500	4300	0	120000
751	G		4	SCARBORO-LT.LFJ	J & Q			2041		0		-1900	400	9900	33200	3000	4700	4400	0	121000
752	G		4	SHEPPARD-LT.LFK	B & Y			2017												83000
753	G		4	SHEPPARD-LT.LFK	B & Y			2018												86000
754	G		4	SHEPPARD-LT.LFK	B & Y			2019												88000
755	G		4	SHEPPARD-LT.LFK	B & Y			2020												90000
756	G		4	SHEPPARD-LT.LFK	B & Y			2021												91000
757	G		4	SHEPPARD-LT.LFK	B & Y			2022												91000
758	G		4	SHEPPARD-LT.LFK	B & Y			2023												92000
759	G		4	SHEPPARD-LT.LFK	B & Y			2024												93000
760	G		4	SHEPPARD-LT.LFK	B & Y			2025												94000
761	G		4	SHEPPARD-LT.LFK	B & Y			2026												94000
762	G		4	SHEPPARD-LT.LFK	B & Y			2027		-300		-1500	200	700	0	1600	1300	0	0	94000
763	G		4	SHEPPARD-LT.LFK	B & Y			2028		0		-1400	200	1100	13700	1200	1800	1800	0	96000
764	G		4	SHEPPARD-LT.LFK	B & Y			2029		0		-1400	200	1300	15100	1300	2000	2000	0	98000
765	G		4	SHEPPARD-LT.LFK	B & Y			2030		0		-1400	200	1400	16300	1400	2200	2100	0	99000
766	G		4	SHEPPARD-LT.LFK	B & Y			2031		0		-1400	200	1600	17500	1500	2400	2300	0	100000
767	G		4	SHEPPARD-LT.LFK	B & Y			2032		0		-1400	200	1900	18400	1600	2500	2400	0	102000
768	G		4	SHEPPARD-LT.LFK	B & Y			2033		0		-1400	200	2100	19300	1700	2600	2500	0	103000
769	G		4	SHEPPARD-LT.LFK	B & Y			2034		0		-1400	200	2300	20300	1800	2700	2600	0	104000
770	G		4	SHEPPARD-LT.LFK	B & Y			2035		0		-1400	200	2600	21000	1900	2800	2700	0	105000
771	G		4	SHEPPARD-LT.LFK	B & Y			2036		0		-1400	200	3500	21800	1900	3000	2800	0	106000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
772	G		4	SHEPPARD-LT.LFK	B & Y			2037		0		-1400	200	3900	22300	1900	3100	2900	0	107000
773	G		4	SHEPPARD-LT.LFK	B & Y			2038		0		-1400	200	4200	22800	2000	3100	2900	0	107000
774	G		4	SHEPPARD-LT.LFK	B & Y			2039		0		-1400	200	4600	23000	2000	3200	2900	0	108000
775	G		4	SHEPPARD-LT.LFK	B & Y			2040		0		-1400	200	5000	23500	2100	3200	3000	0	109000
776	G		4	SHEPPARD-LT.LFK	B & Y			2041		0		-1400	200	5400	23700	2100	3300	3000	0	109000
777	G		4	SHEPPARD-LT.LFK	J & Q			2017												55000
778	G		4	SHEPPARD-LT.LFK	J & Q			2018												55000
779	G		4	SHEPPARD-LT.LFK	J & Q			2019												56000
780	G		4	SHEPPARD-LT.LFK	J & Q			2020												56000
781	G		4	SHEPPARD-LT.LFK	J & Q			2021												57000
782	G		4	SHEPPARD-LT.LFK	J & Q			2022												57000
783	G		4	SHEPPARD-LT.LFK	J & Q			2023												58000
784	G		4	SHEPPARD-LT.LFK	J & Q			2024												58000
785	G		4	SHEPPARD-LT.LFK	J & Q			2025												59000
786	G		4	SHEPPARD-LT.LFK	J & Q			2026												59000
787	G		4	SHEPPARD-LT.LFK	J & Q			2027		-200		-1000	200	500	0	1100	900	0	0	59000
788	G		4	SHEPPARD-LT.LFK	J & Q			2028		0		-1000	200	700	9300	800	1200	1200	0	60000
789	G		4	SHEPPARD-LT.LFK	J & Q			2029		0		-1000	200	900	10200	900	1400	1300	0	61000
790	G		4	SHEPPARD-LT.LFK	J & Q			2030		0		-1000	200	1000	11000	1000	1500	1400	0	62000
791	G		4	SHEPPARD-LT.LFK	J & Q			2031		0		-1000	200	1100	11800	1000	1600	1500	0	63000
792	G		4	SHEPPARD-LT.LFK	J & Q			2032		0		-1000	200	1300	12400	1100	1700	1600	0	64000
793	G		4	SHEPPARD-LT.LFK	J & Q			2033		0		-1000	200	1400	13100	1200	1800	1700	0	64000
794	G		4	SHEPPARD-LT.LFK	J & Q			2034		0		-1000	200	1600	13700	1200	1800	1800	0	65000
795	G		4	SHEPPARD-LT.LFK	J & Q			2035		0		-1000	200	1700	14200	1300	1900	1800	0	66000
796	G		4	SHEPPARD-LT.LFK	J & Q			2036		0		-900	200	2400	14700	1300	2000	1900	0	66000
797	G		4	SHEPPARD-LT.LFK	J & Q			2037		0		-900	200	2600	15100	1300	2100	1900	0	67000
798	G		4	SHEPPARD-LT.LFK	J & Q			2038		0		-900	200	2800	15400	1300	2100	2000	0	67000
799	G		4	SHEPPARD-LT.LFK	J & Q			2039		0		-900	200	3100	15500	1400	2100	2000	0	67000
800	G		4	SHEPPARD-LT.LFK	J & Q			2040		0		-900	200	3400	15900	1400	2200	2000	0	68000
801	G		4	SHEPPARD-LT.LFK	J & Q			2041		0		-900	200	3600	16000	1400	2200	2000	0	68000
802	G		4	WARDEN-LT.LFJ	J & Q			2017												102000
803	G		4	WARDEN-LT.LFJ	J & Q			2018												106000
804	G		4	WARDEN-LT.LFJ	J & Q			2019												108000
805	G		4	WARDEN-LT.LFJ	J & Q			2020												109000
806	G		4	WARDEN-LT.LFJ	J & Q			2021												110000
807	G		4	WARDEN-LT.LFJ	J & Q			2022												111000
808	G		4	WARDEN-LT.LFJ	J & Q			2023												112000
809	G		4	WARDEN-LT.LFJ	J & Q			2024												113000
810	G		4	WARDEN-LT.LFJ	J & Q			2025												113000
811	G		4	WARDEN-LT.LFJ	J & Q			2026												113000
812	G		4	WARDEN-LT.LFJ	J & Q			2027		0		-2500	400	1600	21200	1900	2900	2700	0	117000
813	G		4	WARDEN-LT.LFJ	J & Q			2028		0		-2500	400	1900	24200	2100	3200	3100	0	120000
814	G		4	WARDEN-LT.LFJ	J & Q			2029		0		-2500	400	2200	26700	2400	3600	3400	0	122000
815	G		4	WARDEN-LT.LFJ	J & Q			2030		0		-2500	400	2500	28700	2500	3900	3700	0	124000
816	G		4	WARDEN-LT.LFJ	J & Q			2031		0		-2500	400	2900	33800	2700	4200	4000	0	126000
817	G		4	WARDEN-LT.LFJ	J & Q			2032		0		-2500	400	3300	35600	2900	4400	4200	0	127000
818	G		4	WARDEN-LT.LFJ	J & Q			2033		0		-2500	400	3700	37400	3000	4600	4500	0	129000
819	G		4	WARDEN-LT.LFJ	J & Q			2034		0		-2500	400	4100	39200	3200	4800	4700	0	131000
820	G		4	WARDEN-LT.LFJ	J & Q			2035		0		-2500	400	4600	40500	3300	5000	4800	0	132000
821	G		4	WARDEN-LT.LFJ	J & Q			2036		0		-2500	400	5000	41400	3400	5100	4900	0	133000
822	G		4	WARDEN-LT.LFJ	J & Q			2037		0		-2500	400	5500	42300	3400	5200	5000	0	134000
823	G		4	WARDEN-LT.LFJ	J & Q			2038		0		-2500	400	6000	43200	3500	5300	5100	0	135000
824	G		4	WARDEN-LT.LFJ	J & Q			2039		0		-2500	400	6600	43600	3500	5400	5200	0	135000
825	G		4	WARDEN-LT.LFJ	J & Q			2040		0		-2500	400	7100	44500	3600	5500	5300	0	136000
826	G		4	WARDEN-LT.LFJ	J & Q			2041		0		-2500	400	7700	45000	3600	5600	5300	0	136000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
827	G		5	FAIRBANK-LT.TT1_LF	B & Q			2017												58000
828	G		5	FAIRBANK-LT.TT1_LF	B & Q			2018												60000
829	G		5	FAIRBANK-LT.TT1_LF	B & Q			2019												51000
830	G		5	FAIRBANK-LT.TT1_LF	B & Q			2020												55000
831	G		5	FAIRBANK-LT.TT1_LF	B & Q			2021												58000
832	G		5	FAIRBANK-LT.TT1_LF	B & Q			2022												61000
833	G		5	FAIRBANK-LT.TT1_LF	B & Q			2023												64000
834	G		5	FAIRBANK-LT.TT1_LF	B & Q			2024												65000
835	G		5	FAIRBANK-LT.TT1_LF	B & Q			2025												65000
836	G		5	FAIRBANK-LT.TT1_LF	B & Q			2026												66000
837	G		5	FAIRBANK-LT.TT1_LF	B & Q			2027		-500		-1800	300	800	0	2000	1500	0	0	66000
838	G		5	FAIRBANK-LT.TT1_LF	B & Q			2028		-500		-1800	300	900	0	2200	1700	0	0	67000
839	G		5	FAIRBANK-LT.TT1_LF	B & Q			2029		-500		-1800	300	1000	0	2500	1900	0	0	67000
840	G		5	FAIRBANK-LT.TT1_LF	B & Q			2030		-500		-1800	300	1200	0	2700	2000	0	0	67000
841	G		5	FAIRBANK-LT.TT1_LF	B & Q			2031		-500		-1800	300	1300	0	2900	2200	0	0	68000
842	G		5	FAIRBANK-LT.TT1_LF	B & Q			2032		-500		-1800	300	1500	0	3000	2300	0	0	68000
843	G		5	FAIRBANK-LT.TT1_LF	B & Q			2033		-500		-1800	300	1700	0	3200	2400	0	0	68000
844	G		5	FAIRBANK-LT.TT1_LF	B & Q			2034		-500		-1800	300	1900	0	3300	2600	0	0	69000
845	G		5	FAIRBANK-LT.TT1_LF	B & Q			2035		-500		-1800	300	2100	0	3400	2600	0	0	69000
846	G		5	FAIRBANK-LT.TT1_LF	B & Q			2036		-500		-1800	300	2300	0	3500	2700	0	0	70000
847	G		5	FAIRBANK-LT.TT1_LF	B & Q			2037		-500		-1800	300	2600	0	3600	2800	0	0	70000
848	G		5	FAIRBANK-LT.TT1_LF	B & Q			2038		-500		-1800	300	2800	0	3700	2800	0	0	70000
849	G		5	FAIRBANK-LT.TT1_LF	B & Q			2039		-500		-1800	300	3000	0	3700	2800	0	0	71000
850	G		5	FAIRBANK-LT.TT1_LF	B & Q			2040		-500		-1800	300	3300	0	3800	2900	0	0	71000
851	G		5	FAIRBANK-LT.TT1_LF	B & Q			2041		-500		-1800	300	3600	0	3800	2900	0	0	71000
852	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2017												77000
853	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2018												81000
854	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2019												74000
855	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2020												77000
856	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2021												77000
857	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2022												78000
858	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2023												78000
859	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2024												79000
860	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2025												80000
861	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2026												80000
862	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2027		-400		-1600	300	700	0	1700	1300	0	0	81000
863	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2028		-400		-1600	300	800	0	2000	1500	0	0	81000
864	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2029		-400		-1600	300	900	0	2200	1700	0	0	82000
865	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2030		-400		-1600	300	1000	0	2300	1800	0	0	82000
866	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2031		-400		-1600	300	1200	0	2500	1900	0	0	82000
867	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2032		-400		-1600	300	1300	0	2600	2000	0	0	83000
868	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2033		-400		-1600	300	1500	0	2800	2100	0	0	83000
869	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2034		-400		-1600	300	1700	0	2900	2200	0	0	84000
870	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2035		-400		-1600	300	1800	0	3000	2300	0	0	85000
871	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2036		-400		-1600	300	2000	0	3100	2300	0	0	85000
872	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2037		-400		-1600	300	2200	0	3100	2400	0	0	85000
873	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2038		-400		-1600	300	2400	0	3200	2400	0	0	86000
874	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2039		-400		-1600	300	2600	0	3200	2500	0	0	86000
875	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2040		-400		-1600	300	2900	0	3300	2500	0	0	87000
876	G		5	FAIRBANK-LT.TT1_LF	Y & Z			2041		-400		-1600	300	3100	0	3300	2500	0	0	87000
877	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2017												95000
878	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2018												96000
879	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2019												63000
880	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2020												64000
881	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2021												66000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
882	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2022												66000
883	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2023												67000
884	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2024												67000
885	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2025												68000
886	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2026												68000
887	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2027		-300		-2200	300	1100	0	2300	1900	0	0	68000
888	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2028		-300		-2200	300	1300	0	2700	2200	0	0	68000
889	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2029		-300		-2200	300	1500	0	3000	2400	0	0	69000
890	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2030		-300		-2200	300	1700	0	3200	2600	0	0	69000
891	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2031		-300		-2200	300	1900	0	3400	2800	0	0	69000
892	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2032		-300		-2200	300	2100	0	3600	3000	0	0	70000
893	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2033		0		-2000	400	3000	27900	2500	3800	2900	0	70000
894	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2034		0		-2000	400	3400	29300	2600	3900	3000	0	72000
895	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2035		0		-2000	400	3700	30300	2700	4100	3100	0	72000
896	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2036		0		-2000	400	4100	31000	2700	4200	3200	0	73000
897	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2037		0		-2000	400	4500	31600	2800	4300	3300	0	73000
898	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2038		0		-2000	300	6100	33000	2900	4500	3400	0	74000
899	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2039		0		-2000	300	6600	33300	2900	4600	3400	0	74000
900	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2040		0		-2000	300	7200	34000	3000	4600	3500	0	75000
901	G		5	RUNNYMEDE-LT.T3_LF	B & Y			2041		0		-2000	300	7800	34300	3000	4700	3500	0	75000
902	G		5	RUNNYMEDE-LT.T3_LF	NEW			2017												0
903	G		5	RUNNYMEDE-LT.T3_LF	NEW			2018												0
904	G		5	RUNNYMEDE-LT.T3_LF	NEW			2019												73000
905	G		5	RUNNYMEDE-LT.T3_LF	NEW			2020												77000
906	G		5	RUNNYMEDE-LT.T3_LF	NEW			2021												77000
907	G		5	RUNNYMEDE-LT.T3_LF	NEW			2022												77000
908	G		5	RUNNYMEDE-LT.T3_LF	NEW			2023												79000
909	G		5	RUNNYMEDE-LT.T3_LF	NEW			2024												79000
910	G		5	RUNNYMEDE-LT.T3_LF	NEW			2025												80000
911	G		5	RUNNYMEDE-LT.T3_LF	NEW			2026												80000
912	G		5	RUNNYMEDE-LT.T3_LF	NEW			2027		-300		-2200	300	1100	0	2300	1900	0	0	81000
913	G		5	RUNNYMEDE-LT.T3_LF	NEW			2028		-300		-2200	300	1300	0	2700	2200	0	0	81000
914	G		5	RUNNYMEDE-LT.T3_LF	NEW			2029		-300		-2200	300	1500	0	3000	2400	0	0	82000
915	G		5	RUNNYMEDE-LT.T3_LF	NEW			2030		-300		-2200	300	1700	0	3200	2600	0	0	82000
916	G		5	RUNNYMEDE-LT.T3_LF	NEW			2031		-300		-2200	300	1900	0	3400	2800	0	0	82000
917	G		5	RUNNYMEDE-LT.T3_LF	NEW			2032		-300		-2200	300	2100	0	3600	3000	0	0	83000
918	G		5	RUNNYMEDE-LT.T3_LF	NEW			2033		0		-2000	400	3000	27900	2500	3800	2900	0	84000
919	G		5	RUNNYMEDE-LT.T3_LF	NEW			2034		0		-2000	400	3400	29300	2600	3900	3000	0	85000
920	G		5	RUNNYMEDE-LT.T3_LF	NEW			2035		0		-2000	400	3700	30300	2700	4100	3100	0	86000
921	G		5	RUNNYMEDE-LT.T3_LF	NEW			2036		0		-2000	400	4100	31000	2700	4200	3200	0	86000
922	G		5	RUNNYMEDE-LT.T3_LF	NEW			2037		0		-2000	400	4500	31600	2800	4300	3300	0	87000
923	G		5	RUNNYMEDE-LT.T3_LF	NEW			2038		0		-2000	300	6100	33000	2900	4500	3400	0	88000
924	G		5	RUNNYMEDE-LT.T3_LF	NEW			2039		0		-2000	300	6600	33300	2900	4600	3400	0	88000
925	G		5	RUNNYMEDE-LT.T3_LF	NEW			2040		0		-2000	300	7200	34000	3000	4600	3500	0	89000
926	G		5	RUNNYMEDE-LT.T3_LF	NEW			2041		0		-2000	300	7800	34300	3000	4700	3500	0	89000
927	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2017												14000
928	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2018												14000
929	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2019												11000
930	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2020												11000
931	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2021												11000
932	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2022												11000
933	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2023												11000
934	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2024												11000
935	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2025												11000
936	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2026												11000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
937	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2027		0		-300	100	200	0	400	300	0	0	11000
938	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2028		0		-300	100	200	0	400	400	0	0	11000
939	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2029		0		-300	100	200	0	500	400	0	0	11000
940	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2030		0		-300	100	300	0	500	400	0	0	11000
941	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2031		0		-300	100	400	4100	400	500	400	0	11000
942	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2032		0		-300	100	400	4300	400	600	400	0	11000
943	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2033		0		-400	0	300	6900	700	800	-900	0	11000
944	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2034		0		-400	0	400	7200	700	800	-900	0	12000
945	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2035		0		-400	0	400	7400	800	900	-1000	0	12000
946	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2036		0		-400	0	500	7600	800	900	-1000	0	12000
947	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2037		0		-400	0	500	7800	800	900	-1000	0	12000
948	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2038		0		-400	0	500	7900	800	900	-1000	0	12000
949	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2039		0		-400	0	600	8000	800	900	-1000	0	12000
950	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2040		0		-400	0	600	8200	800	900	-1100	0	12000
951	G		5	WILTSHIRE-LT.TT1_LF	A11-12 (Formerly A1-2)			2041		0		-400	0	700	8200	800	900	-1100	0	13000
952	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2017												18000
953	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2018												18000
954	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2019												19000
955	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2020												19000
956	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2021												19000
957	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2022												19000
958	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2023												19000
959	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2024												19000
960	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2025												19000
961	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2026												20000
962	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2027		-100		-400	100	200	0	400	300	0	0	20000
963	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2028		-100		-400	100	200	0	400	400	0	0	20000
964	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2029		-100		-400	100	200	0	500	400	0	0	20000
965	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2030		-100		-400	100	300	0	500	400	0	0	20000
966	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2031		0		-300	100	400	4200	400	600	400	0	20000
967	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2032		0		-300	100	400	4400	400	600	500	0	21000
968	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2033		0		-400	0	300	7100	700	800	-900	0	21000
969	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2034		0		-400	0	400	7500	800	900	-1000	0	22000
970	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2035		0		-400	0	400	7700	800	900	-1000	0	22000
971	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2036		0		-400	0	500	7900	800	900	-1000	0	22000
972	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2037		0		-400	0	500	8100	800	900	-1000	0	22000
973	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2038		0		-400	0	600	8200	800	900	-1100	0	23000
974	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2039		0		-400	0	600	8300	800	1000	-1100	0	23000
975	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2040		0		-400	0	700	8500	900	1000	-1100	0	23000
976	G		5	WILTSHIRE-LT.TT1_LF	A3-4			2041		0		-400	0	700	8500	900	1000	-1100	0	23000
977	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2017												26000
978	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2018												23000
979	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2019												41000
980	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2020												42000
981	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2021												42000
982	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2022												42000
983	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2023												43000
984	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2024												43000
985	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2025												43000
986	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2026												44000
987	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2027		-100		-400	100	200	0	500	400	0	0	44000
988	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2028		-100		-400	100	300	0	500	400	0	0	45000
989	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2029		-100		-400	100	300	0	600	500	0	0	45000
990	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2030		-100		-400	100	300	0	600	500	0	0	45000
991	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2031		0		-400	100	500	5200	500	700	500	0	45000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
992	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2032		0		-400	100	600	5500	500	700	600	0	46000
993	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2033		0		-500	0	400	8800	900	1000	-1100	0	47000
994	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2034		0		-500	0	500	9200	900	1100	-1200	0	48000
995	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2035		0		-500	0	500	9500	1000	1100	-1200	0	49000
996	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2036		0		-500	0	600	9700	1000	1100	-1300	0	49000
997	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2037		0		-500	0	600	10000	1000	1100	-1300	0	50000
998	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2038		0		-500	0	700	10200	1000	1200	-1300	0	50000
999	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2039		0		-500	0	800	10300	1000	1200	-1300	0	50000
1000	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2040		0		-500	0	800	10500	1100	1200	-1400	0	51000
1001	G		5	WILTSHIRE-LT.TT1_LF	A5-6			2041		0		-500	0	900	10600	1100	1200	-1400	0	51000
1002	G		6	DUPLEX-LT.T1_LF	A1-2			2017												28000
1003	G		6	DUPLEX-LT.T1_LF	A1-2			2018												32000
1004	G		6	DUPLEX-LT.T1_LF	A1-2			2019												32000
1005	G		6	DUPLEX-LT.T1_LF	A1-2			2020												33000
1006	G		6	DUPLEX-LT.T1_LF	A1-2			2021												33000
1007	G		6	DUPLEX-LT.T1_LF	A1-2			2022												34000
1008	G		6	DUPLEX-LT.T1_LF	A1-2			2023												34000
1009	G		6	DUPLEX-LT.T1_LF	A1-2			2024												34000
1010	G		6	DUPLEX-LT.T1_LF	A1-2			2025												35000
1011	G		6	DUPLEX-LT.T1_LF	A1-2			2026												35000
1012	G		6	DUPLEX-LT.T1_LF	A1-2			2027		-100		-600	100	300	0	700	500	0	0	35000
1013	G		6	DUPLEX-LT.T1_LF	A1-2			2028		-100		-600	100	300	0	700	600	0	0	36000
1014	G		6	DUPLEX-LT.T1_LF	A1-2			2029		0		-500	100	500	5500	500	700	900	0	36000
1015	G		6	DUPLEX-LT.T1_LF	A1-2			2030		0		-500	100	500	5900	500	800	1000	0	37000
1016	G		6	DUPLEX-LT.T1_LF	A1-2			2031		0		-500	100	600	6300	600	900	1000	0	37000
1017	G		6	DUPLEX-LT.T1_LF	A1-2			2032		0		-500	100	700	6700	600	900	1100	0	38000
1018	G		6	DUPLEX-LT.T1_LF	A1-2			2033		0		-500	100	800	7000	600	900	1100	0	38000
1019	G		6	DUPLEX-LT.T1_LF	A1-2			2034		0		-500	100	800	7300	600	1000	1200	0	39000
1020	G		6	DUPLEX-LT.T1_LF	A1-2			2035		0		-500	100	900	7600	700	1000	1200	0	39000
1021	G		6	DUPLEX-LT.T1_LF	A1-2			2036		0		-500	100	1000	7700	700	1000	1300	0	40000
1022	G		6	DUPLEX-LT.T1_LF	A1-2			2037		0		-500	100	1100	7900	700	1100	1300	0	40000
1023	G		6	DUPLEX-LT.T1_LF	A1-2			2038		0		-500	100	1200	8000	700	1100	1300	0	40000
1024	G		6	DUPLEX-LT.T1_LF	A1-2			2039		0		-500	100	1300	8100	700	1100	1300	0	40000
1025	G		6	DUPLEX-LT.T1_LF	A1-2			2040		0		-500	100	1400	8300	700	1100	1300	0	41000
1026	G		6	DUPLEX-LT.T1_LF	A1-2			2041		0		-500	100	1600	8300	700	1100	1400	0	41000
1027	G		6	DUPLEX-LT.T1_LF	A3-4			2017												28000
1028	G		6	DUPLEX-LT.T1_LF	A3-4			2018												31000
1029	G		6	DUPLEX-LT.T1_LF	A3-4			2019												32000
1030	G		6	DUPLEX-LT.T1_LF	A3-4			2020												32000
1031	G		6	DUPLEX-LT.T1_LF	A3-4			2021												32000
1032	G		6	DUPLEX-LT.T1_LF	A3-4			2022												32000
1033	G		6	DUPLEX-LT.T1_LF	A3-4			2023												32000
1034	G		6	DUPLEX-LT.T1_LF	A3-4			2024												32000
1035	G		6	DUPLEX-LT.T1_LF	A3-4			2025												32000
1036	G		6	DUPLEX-LT.T1_LF	A3-4			2026												33000
1037	G		6	DUPLEX-LT.T1_LF	A3-4			2027		-100		-500	100	200	0	500	400	0	0	34000
1038	G		6	DUPLEX-LT.T1_LF	A3-4			2028		-100		-500	100	200	0	600	500	0	0	34000
1039	G		6	DUPLEX-LT.T1_LF	A3-4			2029		0		-400	100	400	4400	400	600	700	0	34000
1040	G		6	DUPLEX-LT.T1_LF	A3-4			2030		0		-400	100	400	4700	400	600	800	0	35000
1041	G		6	DUPLEX-LT.T1_LF	A3-4			2031		0		-400	100	500	5100	400	700	800	0	35000
1042	G		6	DUPLEX-LT.T1_LF	A3-4			2032		0		-400	100	500	5300	500	700	900	0	36000
1043	G		6	DUPLEX-LT.T1_LF	A3-4			2033		0		-400	100	600	5600	500	800	900	0	36000
1044	G		6	DUPLEX-LT.T1_LF	A3-4			2034		0		-400	100	700	5900	500	800	1000	0	37000
1045	G		6	DUPLEX-LT.T1_LF	A3-4			2035		0		-400	100	700	6100	500	800	1000	0	37000
1046	G		6	DUPLEX-LT.T1_LF	A3-4			2036		0		-400	100	800	6200	500	800	1000	0	38000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1047	G		6	DUPLEX-LT.T1_LF	A3-4			2037		0		-400	100	900	6300	600	900	1000	0	38000
1048	G		6	DUPLEX-LT.T1_LF	A3-4			2038		0		-400	100	1000	6400	600	900	1100	0	38000
1049	G		6	DUPLEX-LT.T1_LF	A3-4			2039		0		-400	100	1100	6500	600	900	1100	0	38000
1050	G		6	DUPLEX-LT.T1_LF	A3-4			2040		0		-400	100	1200	6600	600	900	1100	0	39000
1051	G		6	DUPLEX-LT.T1_LF	A3-4			2041		0		-400	100	1300	6700	600	900	1100	0	39000
1052	G		6	DUPLEX-LT.T1_LF	A5-6			2017												33000
1053	G		6	DUPLEX-LT.T1_LF	A5-6			2018												36000
1054	G		6	DUPLEX-LT.T1_LF	A5-6			2019												37000
1055	G		6	DUPLEX-LT.T1_LF	A5-6			2020												35000
1056	G		6	DUPLEX-LT.T1_LF	A5-6			2021												33000
1057	G		6	DUPLEX-LT.T1_LF	A5-6			2022												31000
1058	G		6	DUPLEX-LT.T1_LF	A5-6			2023												28000
1059	G		6	DUPLEX-LT.T1_LF	A5-6			2024												28000
1060	G		6	DUPLEX-LT.T1_LF	A5-6			2025												29000
1061	G		6	DUPLEX-LT.T1_LF	A5-6			2026												29000
1062	G		6	DUPLEX-LT.T1_LF	A5-6			2027		-100		-700	100	300	0	700	500	0	0	29000
1063	G		6	DUPLEX-LT.T1_LF	A5-6			2028		-100		-700	100	300	0	800	600	0	0	29000
1064	G		6	DUPLEX-LT.T1_LF	A5-6			2029		0		-600	100	500	5900	500	800	1000	0	30000
1065	G		6	DUPLEX-LT.T1_LF	A5-6			2030		0		-600	100	600	6400	600	900	1100	0	30000
1066	G		6	DUPLEX-LT.T1_LF	A5-6			2031		0		-600	100	600	6900	600	900	1100	0	31000
1067	G		6	DUPLEX-LT.T1_LF	A5-6			2032		0		-600	100	700	7300	600	1000	1200	0	31000
1068	G		6	DUPLEX-LT.T1_LF	A5-6			2033		0		-600	100	800	7600	700	1000	1200	0	31000
1069	G		6	DUPLEX-LT.T1_LF	A5-6			2034		0		-600	100	900	8000	700	1100	1300	0	32000
1070	G		6	DUPLEX-LT.T1_LF	A5-6			2035		0		-600	100	1000	8200	700	1100	1300	0	32000
1071	G		6	DUPLEX-LT.T1_LF	A5-6			2036		0		-600	100	1100	8400	700	1100	1400	0	33000
1072	G		6	DUPLEX-LT.T1_LF	A5-6			2037		0		-600	100	1200	8600	800	1200	1400	0	33000
1073	G		6	DUPLEX-LT.T1_LF	A5-6			2038		0		-600	100	1300	8800	800	1200	1400	0	33000
1074	G		6	DUPLEX-LT.T1_LF	A5-6			2039		0		-600	100	1500	8800	800	1200	1400	0	33000
1075	G		6	DUPLEX-LT.T1_LF	A5-6			2040		0		-600	100	1600	9000	800	1200	1500	0	33000
1076	G		6	DUPLEX-LT.T1_LF	A5-6			2041		0		-600	100	1700	9100	800	1200	1500	0	34000
1077	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2017												19000
1078	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2018												17000
1079	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2019												18000
1080	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2020												18000
1081	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2021												19000
1082	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2022												19000
1083	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2023												19000
1084	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2024												19000
1085	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2025												19000
1086	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2026												19000
1087	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2027		0		-500	100	300	3900	300	500	600	0	19000
1088	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2028		0		-500	100	400	4500	400	600	700	0	20000
1089	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2029		0		-500	100	400	4900	400	700	800	0	20000
1090	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2030		0		-500	100	500	5300	500	700	900	0	21000
1091	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2031		0		-500	100	500	5700	500	800	900	0	21000
1092	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2032		0		-500	100	600	6000	500	800	1000	0	21000
1093	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2033		0		-500	100	700	6300	600	900	1000	0	22000
1094	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2034		0		-500	100	800	6600	600	900	1100	0	22000
1095	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2035		0		-500	100	800	6800	600	900	1100	0	22000
1096	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2036		0		-500	100	900	7000	600	900	1100	0	22000
1097	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2037		0		-500	100	1000	7100	600	1000	1200	0	22000
1098	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2038		0		-500	100	1100	7300	600	1000	1200	0	23000
1099	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2039		0		-500	100	1200	7300	600	1000	1200	0	23000
1100	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2040		0		-500	100	1300	7500	700	1000	1200	0	23000
1101	G		6	GLENGROVE-LT.TT1_LF	A3-4 (formerly A1-2)			2041		0		-500	100	1400	7500	700	1000	1200	0	23000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1102	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2017												31000
1103	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2018												31000
1104	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2019												32000
1105	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2020												32000
1106	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2021												32000
1107	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2022												32000
1108	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2023												32000
1109	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2024												32000
1110	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2025												32000
1111	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2026												32000
1112	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2027		0		-500	100	300	4100	400	600	700	0	33000
1113	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2028		0		-500	100	400	4700	400	600	800	0	34000
1114	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2029		0		-500	100	400	5200	500	700	900	0	35000
1115	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2030		0		-500	100	500	5600	500	800	900	0	35000
1116	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2031		0		-500	100	600	6000	500	800	1000	0	36000
1117	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2032		0		-500	100	600	6300	600	900	1000	0	37000
1118	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2033		0		-500	100	700	6600	600	900	1100	0	37000
1119	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2034		0		-500	100	800	7000	600	900	1100	0	38000
1120	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2035		0		-500	100	900	7200	600	1000	1200	0	38000
1121	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2036		0		-500	100	1000	7300	600	1000	1200	0	38000
1122	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2037		0		-500	100	1100	7500	700	1000	1200	0	39000
1123	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2038		0		-500	100	1200	7600	700	1000	1200	0	39000
1124	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2039		0		-500	100	1300	7700	700	1000	1300	0	39000
1125	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2040		0		-500	100	1400	7900	700	1100	1300	0	39000
1126	G		6	GLENGROVE-LT.TT1_LF	A7-8 (formerly A5-6)			2041		0		-500	100	1500	7900	700	1100	1300	0	40000
1127	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2017												35000
1128	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2018												32000
1129	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2019												32000
1130	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2020												32000
1131	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2021												33000
1132	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2022												33000
1133	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2023												33000
1134	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2024												34000
1135	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2025												34000
1136	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2026												34000
1137	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2027		-100		-700	100	300	0	700	500	0	0	34000
1138	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2028		-100		-700	100	300	0	800	600	0	0	35000
1139	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2029		-100		-700	100	400	0	800	600	0	0	35000
1140	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2030		0		-500	100	500	6000	500	800	1100	0	35000
1141	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2031		0		-500	100	600	6400	600	900	1200	0	36000
1142	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2032		0		-500	100	700	6800	600	900	1300	0	37000
1143	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2033		0		-500	100	800	7200	600	1000	1400	0	37000
1144	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2034		0		-500	100	900	7500	700	1000	1400	0	38000
1145	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2035		0		-500	100	1000	7800	700	1000	1500	0	38000
1146	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2036		0		-500	100	1100	8000	700	1100	1500	0	38000
1147	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2037		0		-500	100	1200	8900	700	1100	1500	0	39000
1148	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2038		0		-500	100	1300	9100	700	1100	1600	0	39000
1149	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2039		0		-500	100	1400	9200	700	1100	1600	0	39000
1150	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2040		0		-500	100	1500	9300	800	1200	1600	0	39000
1151	G		7	BRIDGMAN-LT.TT1_LF	A1-2B			2041		0		-500	100	1600	9400	800	1200	1600	0	40000
1152	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2017												41000
1153	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2018												45000
1154	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2019												45000
1155	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2020												46000
1156	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2021												46000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1157	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2022												46000
1158	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2023												47000
1159	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2024												47000
1160	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2025												47000
1161	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2026												48000
1162	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2027		-100		-800	100	300	0	800	600	0	0	48000
1163	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2028		-100		-800	100	400	0	900	700	0	0	48000
1164	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2029		-100		-800	100	400	0	1000	800	0	0	49000
1165	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2030		0		-700	100	700	7400	700	1000	1400	0	49000
1166	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2031		0		-700	100	800	8000	700	1100	1500	0	50000
1167	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2032		0		-700	100	900	8400	700	1100	1600	0	51000
1168	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2033		0		-700	100	1000	8900	800	1200	1700	0	52000
1169	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2034		0		-700	100	1100	9300	800	1300	1800	0	52000
1170	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2035		0		-700	100	1200	9700	900	1300	1800	0	53000
1171	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2036		0		-700	100	1300	9900	900	1300	1900	0	53000
1172	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2037		0		-700	100	1400	11000	900	1400	1900	0	54000
1173	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2038		0		-700	100	1600	11300	900	1400	2000	0	54000
1174	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2039		0		-700	100	1700	11400	900	1400	2000	0	55000
1175	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2040		0		-700	100	1900	11600	900	1400	2000	0	55000
1176	G		7	BRIDGMAN-LT.TT1_LF	A1-2H			2041		0		-700	100	2000	11700	900	1400	2000	0	55000
1177	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2017												30000
1178	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2018												30000
1179	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2019												29000
1180	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2020												29000
1181	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2021												29000
1182	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2022												29000
1183	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2023												30000
1184	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2024												30000
1185	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2025												30000
1186	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2026												30000
1187	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2027		0		-500	100	200	0	500	400	0	0	30000
1188	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2028		0		-500	100	200	0	600	400	0	0	30000
1189	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2029		0		-500	100	300	0	600	500	0	0	30000
1190	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2030		0		-400	100	400	4600	400	600	900	0	31000
1191	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2031		0		-400	100	500	4900	400	700	900	0	31000
1192	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2032		0		-400	100	500	5200	500	700	1000	0	32000
1193	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2033		0		-400	100	600	5500	500	700	1000	0	32000
1194	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2034		0		-400	100	700	5700	500	800	1100	0	33000
1195	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2035		0		-400	100	700	5900	500	800	1100	0	33000
1196	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2036		0		-400	100	800	6100	500	800	1200	0	33000
1197	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2037		0		-400	100	900	6800	600	800	1200	0	34000
1198	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2038		0		-400	100	1000	6900	600	900	1200	0	34000
1199	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2039		0		-400	100	1100	7000	600	900	1200	0	34000
1200	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2040		0		-400	100	1100	7100	600	900	1200	0	34000
1201	G		7	BRIDGMAN-LT.TT1_LF	A5-6H			2041		0		-400	100	1200	7200	600	900	1200	0	34000
1202	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2017												46000
1203	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2018												47000
1204	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2019												48000
1205	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2020												49000
1206	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2021												49000
1207	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2022												49000
1208	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2023												50000
1209	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2024												50000
1210	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2025												50000
1211	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2026												50000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1212	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2027		-100		-900	100	400	0	900	700	0	0	51000
1213	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2028		-100		-900	100	400	0	1100	800	0	0	51000
1214	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2029		-100		-900	100	500	0	1200	900	0	0	51000
1215	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2030		0		-700	100	700	8400	700	1100	1600	0	52000
1216	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2031		0		-700	100	800	9000	800	1200	1700	0	53000
1217	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2032		0		-700	100	1000	9500	800	1300	1800	0	54000
1218	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2033		0		-700	100	1100	10000	900	1400	1900	0	55000
1219	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2034		0		-700	100	1200	10500	900	1400	2000	0	55000
1220	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2035		0		-700	100	1300	10900	1000	1500	2100	0	56000
1221	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2036		0		-700	100	1500	11100	1000	1500	2100	0	56000
1222	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2037		0		-700	100	1600	12500	1000	1500	2200	0	57000
1223	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2038		0		-700	100	1800	12700	1000	1600	2200	0	57000
1224	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2039		0		-700	100	1900	12800	1000	1600	2200	0	58000
1225	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2040		0		-700	100	2100	13100	1100	1600	2300	0	58000
1226	G		7	BRIDGMAN-LT.TT1_LF	A7-8H			2041		0		-700	100	2300	13200	1100	1600	2300	0	59000
1227	G		7	DUFFERIN-LT.T1_LF	A1-2			2017												29000
1228	G		7	DUFFERIN-LT.T1_LF	A1-2			2018												29000
1229	G		7	DUFFERIN-LT.T1_LF	A1-2			2019												29000
1230	G		7	DUFFERIN-LT.T1_LF	A1-2			2020												29000
1231	G		7	DUFFERIN-LT.T1_LF	A1-2			2021												30000
1232	G		7	DUFFERIN-LT.T1_LF	A1-2			2022												30000
1233	G		7	DUFFERIN-LT.T1_LF	A1-2			2023												30000
1234	G		7	DUFFERIN-LT.T1_LF	A1-2			2024												30000
1235	G		7	DUFFERIN-LT.T1_LF	A1-2			2025												30000
1236	G		7	DUFFERIN-LT.T1_LF	A1-2			2026												31000
1237	G		7	DUFFERIN-LT.T1_LF	A1-2			2027		0		-500	100	300	4400	400	600	900	0	32000
1238	G		7	DUFFERIN-LT.T1_LF	A1-2			2028		0		-500	100	400	5100	400	700	1000	0	32000
1239	G		7	DUFFERIN-LT.T1_LF	A1-2			2029		0		-500	100	500	5600	500	800	1100	0	33000
1240	G		7	DUFFERIN-LT.T1_LF	A1-2			2030		0		-500	100	500	6100	500	800	1200	0	34000
1241	G		7	DUFFERIN-LT.T1_LF	A1-2			2031		0		-500	100	600	6500	600	900	1200	0	34000
1242	G		7	DUFFERIN-LT.T1_LF	A1-2			2032		0		-500	100	700	6900	600	900	1300	0	35000
1243	G		7	DUFFERIN-LT.T1_LF	A1-2			2033		0		-500	100	800	7200	600	1000	1400	0	35000
1244	G		7	DUFFERIN-LT.T1_LF	A1-2			2034		0		-500	100	900	7600	700	1000	1400	0	36000
1245	G		7	DUFFERIN-LT.T1_LF	A1-2			2035		0		-500	100	1000	7900	700	1100	1500	0	36000
1246	G		7	DUFFERIN-LT.T1_LF	A1-2			2036		0		-500	100	1100	8100	700	1100	1500	0	36000
1247	G		7	DUFFERIN-LT.T1_LF	A1-2			2037		0		-500	100	1200	8200	700	1100	1600	0	37000
1248	G		7	DUFFERIN-LT.T1_LF	A1-2			2038		0		-500	100	1300	8400	700	1100	1600	0	37000
1249	G		7	DUFFERIN-LT.T1_LF	A1-2			2039		0		-500	100	1400	8500	700	1100	1600	0	37000
1250	G		7	DUFFERIN-LT.T1_LF	A1-2			2040		0		-500	100	1500	8600	800	1200	1600	0	37000
1251	G		7	DUFFERIN-LT.T1_LF	A1-2			2041		0		-500	100	1600	8700	800	1200	1600	0	38000
1252	G		7	DUFFERIN-LT.T1_LF	A3-4			2017												26000
1253	G		7	DUFFERIN-LT.T1_LF	A3-4			2018												27000
1254	G		7	DUFFERIN-LT.T1_LF	A3-4			2019												27000
1255	G		7	DUFFERIN-LT.T1_LF	A3-4			2020												28000
1256	G		7	DUFFERIN-LT.T1_LF	A3-4			2021												28000
1257	G		7	DUFFERIN-LT.T1_LF	A3-4			2022												28000
1258	G		7	DUFFERIN-LT.T1_LF	A3-4			2023												28000
1259	G		7	DUFFERIN-LT.T1_LF	A3-4			2024												29000
1260	G		7	DUFFERIN-LT.T1_LF	A3-4			2025												29000
1261	G		7	DUFFERIN-LT.T1_LF	A3-4			2026												29000
1262	G		7	DUFFERIN-LT.T1_LF	A3-4			2027		0		-300	0	200	2700	200	400	500	0	30000
1263	G		7	DUFFERIN-LT.T1_LF	A3-4			2028		0		-300	0	200	3100	300	400	600	0	30000
1264	G		7	DUFFERIN-LT.T1_LF	A3-4			2029		0		-300	0	300	3400	300	500	700	0	31000
1265	G		7	DUFFERIN-LT.T1_LF	A3-4			2030		0		-300	0	300	3700	300	500	700	0	32000
1266	G		7	DUFFERIN-LT.T1_LF	A3-4			2031		0		-300	0	400	4000	400	500	800	0	32000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1267	G		7	DUFFERIN-LT.T1_LF	A3-4			2032		0		-300	0	400	4200	400	600	800	0	33000
1268	G		7	DUFFERIN-LT.T1_LF	A3-4			2033		0		-300	0	500	4400	400	600	800	0	33000
1269	G		7	DUFFERIN-LT.T1_LF	A3-4			2034		0		-300	0	500	4600	400	600	900	0	34000
1270	G		7	DUFFERIN-LT.T1_LF	A3-4			2035		0		-300	0	600	4800	400	600	900	0	34000
1271	G		7	DUFFERIN-LT.T1_LF	A3-4			2036		0		-300	0	600	4900	400	700	900	0	34000
1272	G		7	DUFFERIN-LT.T1_LF	A3-4			2037		0		-300	0	700	5000	400	700	900	0	35000
1273	G		7	DUFFERIN-LT.T1_LF	A3-4			2038		0		-300	0	800	5100	500	700	1000	0	35000
1274	G		7	DUFFERIN-LT.T1_LF	A3-4			2039		0		-300	0	800	5200	500	700	1000	0	35000
1275	G		7	DUFFERIN-LT.T1_LF	A3-4			2040		0		-300	0	900	5300	500	700	1000	0	35000
1276	G		7	DUFFERIN-LT.T1_LF	A3-4			2041		0		-300	0	1000	5300	500	700	1000	0	35000
1277	G		7	DUFFERIN-LT.T1_LF	A5-6			2017												41000
1278	G		7	DUFFERIN-LT.T1_LF	A5-6			2018												42000
1279	G		7	DUFFERIN-LT.T1_LF	A5-6			2019												36000
1280	G		7	DUFFERIN-LT.T1_LF	A5-6			2020												37000
1281	G		7	DUFFERIN-LT.T1_LF	A5-6			2021												37000
1282	G		7	DUFFERIN-LT.T1_LF	A5-6			2022												37000
1283	G		7	DUFFERIN-LT.T1_LF	A5-6			2023												38000
1284	G		7	DUFFERIN-LT.T1_LF	A5-6			2024												38000
1285	G		7	DUFFERIN-LT.T1_LF	A5-6			2025												38000
1286	G		7	DUFFERIN-LT.T1_LF	A5-6			2026												39000
1287	G		7	DUFFERIN-LT.T1_LF	A5-6			2027		0		-700	100	400	5700	500	800	1100	0	40000
1288	G		7	DUFFERIN-LT.T1_LF	A5-6			2028		0		-700	100	500	6600	600	900	1300	0	41000
1289	G		7	DUFFERIN-LT.T1_LF	A5-6			2029		0		-700	100	600	7300	600	1000	1400	0	42000
1290	G		7	DUFFERIN-LT.T1_LF	A5-6			2030		0		-700	100	700	7800	700	1100	1500	0	42000
1291	G		7	DUFFERIN-LT.T1_LF	A5-6			2031		0		-700	100	800	8400	700	1100	1600	0	43000
1292	G		7	DUFFERIN-LT.T1_LF	A5-6			2032		0		-700	100	900	8900	800	1200	1700	0	44000
1293	G		7	DUFFERIN-LT.T1_LF	A5-6			2033		0		-700	100	1000	9400	800	1300	1800	0	44000
1294	G		7	DUFFERIN-LT.T1_LF	A5-6			2034		0		-700	100	1100	9800	900	1300	1900	0	45000
1295	G		7	DUFFERIN-LT.T1_LF	A5-6			2035		0		-700	100	1300	10200	900	1400	1900	0	46000
1296	G		7	DUFFERIN-LT.T1_LF	A5-6			2036		0		-700	100	1400	10400	900	1400	2000	0	46000
1297	G		7	DUFFERIN-LT.T1_LF	A5-6			2037		0		-700	100	1500	10600	900	1400	2000	0	46000
1298	G		7	DUFFERIN-LT.T1_LF	A5-6			2038		0		-700	100	1700	10900	1000	1500	2100	0	47000
1299	G		7	DUFFERIN-LT.T1_LF	A5-6			2039		0		-700	100	1800	11000	1000	1500	2100	0	47000
1300	G		7	DUFFERIN-LT.T1_LF	A5-6			2040		0		-700	100	2000	11200	1000	1500	2100	0	47000
1301	G		7	DUFFERIN-LT.T1_LF	A5-6			2041		0		-700	100	2100	11300	1000	1500	2100	0	48000
1302	G		7	DUFFERIN-LT.T1_LF	A7-8			2017												36000
1303	G		7	DUFFERIN-LT.T1_LF	A7-8			2018												38000
1304	G		7	DUFFERIN-LT.T1_LF	A7-8			2019												29000
1305	G		7	DUFFERIN-LT.T1_LF	A7-8			2020												30000
1306	G		7	DUFFERIN-LT.T1_LF	A7-8			2021												30000
1307	G		7	DUFFERIN-LT.T1_LF	A7-8			2022												30000
1308	G		7	DUFFERIN-LT.T1_LF	A7-8			2023												30000
1309	G		7	DUFFERIN-LT.T1_LF	A7-8			2024												30000
1310	G		7	DUFFERIN-LT.T1_LF	A7-8			2025												31000
1311	G		7	DUFFERIN-LT.T1_LF	A7-8			2026												31000
1312	G		7	DUFFERIN-LT.T1_LF	A7-8			2027		0		-600	100	400	5200	500	700	1000	0	32000
1313	G		7	DUFFERIN-LT.T1_LF	A7-8			2028		0		-600	100	500	5900	500	800	1100	0	32000
1314	G		7	DUFFERIN-LT.T1_LF	A7-8			2029		0		-600	100	500	6500	600	900	1300	0	33000
1315	G		7	DUFFERIN-LT.T1_LF	A7-8			2030		0		-600	100	600	7100	600	1000	1400	0	34000
1316	G		7	DUFFERIN-LT.T1_LF	A7-8			2031		0		-600	100	700	7600	700	1000	1500	0	34000
1317	G		7	DUFFERIN-LT.T1_LF	A7-8			2032		0		-600	100	800	8000	700	1100	1500	0	35000
1318	G		7	DUFFERIN-LT.T1_LF	A7-8			2033		0		-600	100	900	8500	700	1100	1600	0	35000
1319	G		7	DUFFERIN-LT.T1_LF	A7-8			2034		0		-600	100	1000	8900	800	1200	1700	0	36000
1320	G		7	DUFFERIN-LT.T1_LF	A7-8			2035		0		-600	100	1100	9200	800	1200	1700	0	36000
1321	G		7	DUFFERIN-LT.T1_LF	A7-8			2036		0		-600	100	1200	9400	800	1300	1800	0	36000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1322	G		7	DUFFERIN-LT.T1_LF	A7-8			2037		0		-600	100	1400	9600	800	1300	1800	0	37000
1323	G		7	DUFFERIN-LT.T1_LF	A7-8			2038		0		-600	100	1500	9800	900	1300	1900	0	37000
1324	G		7	DUFFERIN-LT.T1_LF	A7-8			2039		0		-600	100	1600	9900	900	1300	1900	0	37000
1325	G		7	DUFFERIN-LT.T1_LF	A7-8			2040		0		-600	100	1800	10100	900	1400	1900	0	37000
1326	G		7	DUFFERIN-LT.T1_LF	A7-8			2041		0		-600	100	1900	10200	900	1400	1900	0	38000
1327	G		8	COPELAND	A1-2CL			2017												0
1328	G		8	COPELAND	A1-2CL			2018												0
1329	G		8	COPELAND	A1-2CL			2019												0
1330	G		8	COPELAND	A1-2CL			2020												52000
1331	G		8	COPELAND	A1-2CL			2021												52000
1332	G		8	COPELAND	A1-2CL			2022												52000
1333	G		8	COPELAND	A1-2CL			2023												53000
1334	G		8	COPELAND	A1-2CL			2024												53000
1335	G		8	COPELAND	A1-2CL			2025												54000
1336	G		8	COPELAND	A1-2CL			2026												54000
1337	G		8	COPELAND	A1-2CL			2027		-100		-700	0	200	0	500	400	0	0	55000
1338	G		8	COPELAND	A1-2CL			2028		-100		-700	0	200	0	600	500	0	0	56000
1339	G		8	COPELAND	A1-2CL			2029		-100		-700	0	300	0	700	500	0	0	56000
1340	G		8	COPELAND	A1-2CL			2030		-100		-700	0	300	0	700	600	0	0	57000
1341	G		8	COPELAND	A1-2CL			2031		-100		-700	0	400	0	800	600	0	0	58000
1342	G		8	COPELAND	A1-2CL			2032		-100		-700	0	400	0	800	600	0	0	58000
1343	G		8	COPELAND	A1-2CL			2033		-100		-700	0	500	0	900	700	0	0	59000
1344	G		8	COPELAND	A1-2CL			2034		-100		-700	0	500	0	900	700	0	0	60000
1345	G		8	COPELAND	A1-2CL			2035		-100		-700	0	600	0	1000	700	0	0	60000
1346	G		8	COPELAND	A1-2CL			2036		-100		-700	0	600	0	1000	700	0	0	61000
1347	G		8	COPELAND	A1-2CL			2037		-100		-700	0	700	0	1000	800	0	0	61000
1348	G		8	COPELAND	A1-2CL			2038		-100		-700	0	800	0	1000	800	0	0	62000
1349	G		8	COPELAND	A1-2CL			2039		-100		-700	0	800	0	1000	800	0	0	62000
1350	G		8	COPELAND	A1-2CL			2040		-100		-700	0	900	0	1100	800	0	0	63000
1351	G		8	COPELAND	A1-2CL			2041		-100		-700	0	1000	0	1100	800	0	0	64000
1352	G		8	COPELAND	A3-4CL			2017												0
1353	G		8	COPELAND	A3-4CL			2018												0
1354	G		8	COPELAND	A3-4CL			2019												0
1355	G		8	COPELAND	A3-4CL			2020												0
1356	G		8	COPELAND	A3-4CL			2021												41000
1357	G		8	COPELAND	A3-4CL			2022												41000
1358	G		8	COPELAND	A3-4CL			2023												41000
1359	G		8	COPELAND	A3-4CL			2024												41000
1360	G		8	COPELAND	A3-4CL			2025												42000
1361	G		8	COPELAND	A3-4CL			2026												42000
1362	G		8	COPELAND	A3-4CL			2027		-100		-700	0	200	0	500	400	0	0	43000
1363	G		8	COPELAND	A3-4CL			2028		-100		-700	0	200	0	600	500	0	0	43000
1364	G		8	COPELAND	A3-4CL			2029		-100		-700	0	300	0	700	500	0	0	44000
1365	G		8	COPELAND	A3-4CL			2030		-100		-700	0	300	0	700	600	0	0	45000
1366	G		8	COPELAND	A3-4CL			2031		-100		-700	0	400	0	800	600	0	0	45000
1367	G		8	COPELAND	A3-4CL			2032		-100		-700	0	400	0	800	600	0	0	46000
1368	G		8	COPELAND	A3-4CL			2033		-100		-700	0	500	0	900	700	0	0	46000
1369	G		8	COPELAND	A3-4CL			2034		-100		-700	0	500	0	900	700	0	0	47000
1370	G		8	COPELAND	A3-4CL			2035		-100		-700	0	600	0	1000	700	0	0	47000
1371	G		8	COPELAND	A3-4CL			2036		-100		-700	0	600	0	1000	700	0	0	48000
1372	G		8	COPELAND	A3-4CL			2037		-100		-700	0	700	0	1000	800	0	0	48000
1373	G		8	COPELAND	A3-4CL			2038		-100		-700	0	800	0	1000	800	0	0	48000
1374	G		8	COPELAND	A3-4CL			2039		-100		-700	0	800	0	1000	800	0	0	49000
1375	G		8	COPELAND	A3-4CL			2040		-100		-700	0	900	0	1100	800	0	0	49000
1376	G		8	COPELAND	A3-4CL			2041		-100		-700	0	1000	0	1100	800	0	0	50000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1377	G		8	JOHN-LT.T2_LF	A11-12			2017												41000
1378	G		8	JOHN-LT.T2_LF	A11-12			2018												41000
1379	G		8	JOHN-LT.T2_LF	A11-12			2019												41000
1380	G		8	JOHN-LT.T2_LF	A11-12			2020												41000
1381	G		8	JOHN-LT.T2_LF	A11-12			2021												42000
1382	G		8	JOHN-LT.T2_LF	A11-12			2022												42000
1383	G		8	JOHN-LT.T2_LF	A11-12			2023												42000
1384	G		8	JOHN-LT.T2_LF	A11-12			2024												43000
1385	G		8	JOHN-LT.T2_LF	A11-12			2025												43000
1386	G		8	JOHN-LT.T2_LF	A11-12			2026												43000
1387	G		8	JOHN-LT.T2_LF	A11-12			2027		-100		-700	0	200	0	500	400	0	0	44000
1388	G		8	JOHN-LT.T2_LF	A11-12			2028		-100		-700	0	200	0	600	500	0	0	44000
1389	G		8	JOHN-LT.T2_LF	A11-12			2029		-100		-700	0	300	0	700	500	0	0	45000
1390	G		8	JOHN-LT.T2_LF	A11-12			2030		-100		-700	0	300	0	700	600	0	0	46000
1391	G		8	JOHN-LT.T2_LF	A11-12			2031		-100		-700	0	400	0	800	600	0	0	46000
1392	G		8	JOHN-LT.T2_LF	A11-12			2032		-100		-700	0	400	0	800	600	0	0	47000
1393	G		8	JOHN-LT.T2_LF	A11-12			2033		-100		-700	0	500	0	900	700	0	0	47000
1394	G		8	JOHN-LT.T2_LF	A11-12			2034		-100		-700	0	500	0	900	700	0	0	48000
1395	G		8	JOHN-LT.T2_LF	A11-12			2035		-100		-700	0	600	0	1000	700	0	0	48000
1396	G		8	JOHN-LT.T2_LF	A11-12			2036		-100		-700	0	600	0	1000	700	0	0	49000
1397	G		8	JOHN-LT.T2_LF	A11-12			2037		-100		-700	0	700	0	1000	800	0	0	49000
1398	G		8	JOHN-LT.T2_LF	A11-12			2038		-100		-700	0	800	0	1000	800	0	0	49000
1399	G		8	JOHN-LT.T2_LF	A11-12			2039		-100		-700	0	800	0	1000	800	0	0	50000
1400	G		8	JOHN-LT.T2_LF	A11-12			2040		-100		-700	0	900	0	1100	800	0	0	50000
1401	G		8	JOHN-LT.T2_LF	A11-12			2041		-100		-700	0	1000	0	1100	800	0	0	51000
1402	G		8	JOHN-LT.T2_LF	A13-14			2017												35000
1403	G		8	JOHN-LT.T2_LF	A13-14			2018												35000
1404	G		8	JOHN-LT.T2_LF	A13-14			2019												35000
1405	G		8	JOHN-LT.T2_LF	A13-14			2020												32000
1406	G		8	JOHN-LT.T2_LF	A13-14			2021												32000
1407	G		8	JOHN-LT.T2_LF	A13-14			2022												32000
1408	G		8	JOHN-LT.T2_LF	A13-14			2023												32000
1409	G		8	JOHN-LT.T2_LF	A13-14			2024												32000
1410	G		8	JOHN-LT.T2_LF	A13-14			2025												32000
1411	G		8	JOHN-LT.T2_LF	A13-14			2026												32000
1412	G		8	JOHN-LT.T2_LF	A13-14			2027		-100		-400	0	100	0	400	300	-1300	0	33000
1413	G		8	JOHN-LT.T2_LF	A13-14			2028		-100		-400	0	100	0	400	300	-1400	0	33000
1414	G		8	JOHN-LT.T2_LF	A13-14			2029		-100		-400	0	100	0	500	300	-1600	0	33000
1415	G		8	JOHN-LT.T2_LF	A13-14			2030		-100		-400	0	200	0	500	400	-1700	0	34000
1416	G		8	JOHN-LT.T2_LF	A13-14			2031		-100		-400	0	200	0	600	400	-1800	0	34000
1417	G		8	JOHN-LT.T2_LF	A13-14			2032		-100		-400	0	200	0	600	400	-1900	0	34000
1418	G		8	JOHN-LT.T2_LF	A13-14			2033		-100		-400	0	200	0	600	500	-2100	0	35000
1419	G		8	JOHN-LT.T2_LF	A13-14			2034		-100		-400	0	300	0	700	500	-2200	0	35000
1420	G		8	JOHN-LT.T2_LF	A13-14			2035		-100		-400	0	300	0	700	500	-2300	0	35000
1421	G		8	JOHN-LT.T2_LF	A13-14			2036		-100		-400	0	300	0	700	500	-2400	0	36000
1422	G		8	JOHN-LT.T2_LF	A13-14			2037		-100		-400	0	500	0	700	500	0	0	37000
1423	G		8	JOHN-LT.T2_LF	A13-14			2038		-100		-400	0	500	0	700	500	0	0	37000
1424	G		8	JOHN-LT.T2_LF	A13-14			2039		-100		-400	0	600	0	700	600	0	0	38000
1425	G		8	JOHN-LT.T2_LF	A13-14			2040		-100		-400	0	600	0	700	600	0	0	38000
1426	G		8	JOHN-LT.T2_LF	A13-14			2041		-100		-400	0	700	0	700	600	0	0	38000
1427	G		8	JOHN-LT.T2_LF	A15-16			2017												54000
1428	G		8	JOHN-LT.T2_LF	A15-16			2018												54000
1429	G		8	JOHN-LT.T2_LF	A15-16			2019												54000
1430	G		8	JOHN-LT.T2_LF	A15-16			2020												55000
1431	G		8	JOHN-LT.T2_LF	A15-16			2021												45000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1432	G		8	JOHN-LT.T2_LF	A15-16			2022												46000
1433	G		8	JOHN-LT.T2_LF	A15-16			2023												46000
1434	G		8	JOHN-LT.T2_LF	A15-16			2024												46000
1435	G		8	JOHN-LT.T2_LF	A15-16			2025												47000
1436	G		8	JOHN-LT.T2_LF	A15-16			2026												47000
1437	G		8	JOHN-LT.T2_LF	A15-16			2027		-200		-800	0	200	0	600	500	0	0	47000
1438	G		8	JOHN-LT.T2_LF	A15-16			2028		-200		-800	0	300	0	700	500	0	0	48000
1439	G		8	JOHN-LT.T2_LF	A15-16			2029		-200		-800	0	300	0	800	600	0	0	49000
1440	G		8	JOHN-LT.T2_LF	A15-16			2030		-200		-800	0	400	0	900	700	0	0	49000
1441	G		8	JOHN-LT.T2_LF	A15-16			2031		-200		-800	0	400	0	900	700	0	0	50000
1442	G		8	JOHN-LT.T2_LF	A15-16			2032		-200		-800	0	500	0	1000	700	0	0	51000
1443	G		8	JOHN-LT.T2_LF	A15-16			2033		-200		-800	0	600	0	1000	800	0	0	51000
1444	G		8	JOHN-LT.T2_LF	A15-16			2034		-200		-800	0	600	0	1100	800	0	0	52000
1445	G		8	JOHN-LT.T2_LF	A15-16			2035		-200		-800	0	700	0	1100	900	0	0	52000
1446	G		8	JOHN-LT.T2_LF	A15-16			2036		-200		-800	0	800	0	1100	900	0	0	53000
1447	G		8	JOHN-LT.T2_LF	A15-16			2037		-200		-800	0	800	0	1200	900	0	0	53000
1448	G		8	JOHN-LT.T2_LF	A15-16			2038		-200		-800	0	900	0	1200	900	0	0	54000
1449	G		8	JOHN-LT.T2_LF	A15-16			2039		-200		-800	0	1000	0	1200	900	0	0	54000
1450	G		8	JOHN-LT.T2_LF	A15-16			2040		-200		-800	0	1100	0	1200	900	0	0	55000
1451	G		8	JOHN-LT.T2_LF	A15-16			2041		-200		-800	0	1200	0	1200	1000	0	0	55000
1452	G		8	JOHN-LT.T2_LF	A17-18			2017												39000
1453	G		8	JOHN-LT.T2_LF	A17-18			2018												40000
1454	G		8	JOHN-LT.T2_LF	A17-18			2019												41000
1455	G		8	JOHN-LT.T2_LF	A17-18			2020												32000
1456	G		8	JOHN-LT.T2_LF	A17-18			2021												33000
1457	G		8	JOHN-LT.T2_LF	A17-18			2022												33000
1458	G		8	JOHN-LT.T2_LF	A17-18			2023												33000
1459	G		8	JOHN-LT.T2_LF	A17-18			2024												33000
1460	G		8	JOHN-LT.T2_LF	A17-18			2025												34000
1461	G		8	JOHN-LT.T2_LF	A17-18			2026												34000
1462	G		8	JOHN-LT.T2_LF	A17-18			2027		-200		-500	0	100	0	500	300	-1500	0	35000
1463	G		8	JOHN-LT.T2_LF	A17-18			2028		-200		-500	0	200	0	500	400	-1800	0	35000
1464	G		8	JOHN-LT.T2_LF	A17-18			2029		-200		-500	0	200	0	600	400	-2000	0	35000
1465	G		8	JOHN-LT.T2_LF	A17-18			2030		-200		-500	0	200	0	600	500	-2100	0	36000
1466	G		8	JOHN-LT.T2_LF	A17-18			2031		-200		-500	0	200	0	700	500	-2300	0	36000
1467	G		8	JOHN-LT.T2_LF	A17-18			2032		-200		-500	0	300	0	700	500	-2400	0	36000
1468	G		8	JOHN-LT.T2_LF	A17-18			2033		-200		-500	0	300	0	800	600	-2600	0	37000
1469	G		8	JOHN-LT.T2_LF	A17-18			2034		-200		-500	0	300	0	800	600	-2700	0	37000
1470	G		8	JOHN-LT.T2_LF	A17-18			2035		-200		-500	0	400	0	800	600	-2800	0	37000
1471	G		8	JOHN-LT.T2_LF	A17-18			2036		-200		-500	0	400	0	900	600	-2900	0	38000
1472	G		8	JOHN-LT.T2_LF	A17-18			2037		-100		-500	0	600	0	900	700	0	0	39000
1473	G		8	JOHN-LT.T2_LF	A17-18			2038		-100		-500	0	700	0	900	700	0	0	39000
1474	G		8	JOHN-LT.T2_LF	A17-18			2039		-100		-500	0	700	0	900	700	0	0	40000
1475	G		8	JOHN-LT.T2_LF	A17-18			2040		-100		-500	0	800	0	900	700	0	0	40000
1476	G		8	JOHN-LT.T2_LF	A17-18			2041		-100		-500	0	900	0	900	700	0	0	41000
1477	G		8	JOHN-LT.T2_LF	A3-4			2017												47000
1478	G		8	JOHN-LT.T2_LF	A3-4			2018												47000
1479	G		8	JOHN-LT.T2_LF	A3-4			2019												48000
1480	G		8	JOHN-LT.T2_LF	A3-4			2020												48000
1481	G		8	JOHN-LT.T2_LF	A3-4			2021												49000
1482	G		8	JOHN-LT.T2_LF	A3-4			2022												49000
1483	G		8	JOHN-LT.T2_LF	A3-4			2023												50000
1484	G		8	JOHN-LT.T2_LF	A3-4			2024												0
1485	G		8	JOHN-LT.T2_LF	A3-4			2025												0
1486	G		8	JOHN-LT.T2_LF	A3-4			2026												0

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1487	G		8	JOHN-LT.T2_LF	A3-4			2027		-100		-600	0	200	0	500	400	0	0	0
1488	G		8	JOHN-LT.T2_LF	A3-4			2028		-100		-600	0	200	0	600	500	0	0	0
1489	G		8	JOHN-LT.T2_LF	A3-4			2029		-100		-600	0	300	0	700	500	0	0	0
1490	G		8	JOHN-LT.T2_LF	A3-4			2030		-100		-600	0	300	0	700	600	0	0	0
1491	G		8	JOHN-LT.T2_LF	A3-4			2031		-100		-600	0	400	0	800	600	0	0	0
1492	G		8	JOHN-LT.T2_LF	A3-4			2032		-100		-600	0	400	0	800	600	0	0	0
1493	G		8	JOHN-LT.T2_LF	A3-4			2033		-100		-600	0	500	0	900	700	0	0	0
1494	G		8	JOHN-LT.T2_LF	A3-4			2034		-100		-600	0	500	0	900	700	0	0	0
1495	G		8	JOHN-LT.T2_LF	A3-4			2035		-100		-600	0	600	0	900	700	0	0	0
1496	G		8	JOHN-LT.T2_LF	A3-4			2036		-100		-600	0	600	0	1000	700	0	0	0
1497	G		8	JOHN-LT.T2_LF	A3-4			2037		-100		-600	0	700	0	1000	800	0	0	0
1498	G		8	JOHN-LT.T2_LF	A3-4			2038		-100		-600	0	800	0	1000	800	0	0	0
1499	G		8	JOHN-LT.T2_LF	A3-4			2039		-100		-600	0	800	0	1000	800	0	0	0
1500	G		8	JOHN-LT.T2_LF	A3-4			2040		-100		-600	0	900	0	1000	800	0	0	0
1501	G		8	JOHN-LT.T2_LF	A3-4			2041		-100		-600	0	1000	0	1100	800	0	0	0
1502	G		8	JOHN-LT.T2_LF	A5-6			2017												48000
1503	G		8	JOHN-LT.T2_LF	A5-6			2018												46000
1504	G		8	JOHN-LT.T2_LF	A5-6			2019												47000
1505	G		8	JOHN-LT.T2_LF	A5-6			2020												7000
1506	G		8	JOHN-LT.T2_LF	A5-6			2021												0
1507	G		8	JOHN-LT.T2_LF	A5-6			2022												0
1508	G		8	JOHN-LT.T2_LF	A5-6			2023												0
1509	G		8	JOHN-LT.T2_LF	A5-6			2024												50000
1510	G		8	JOHN-LT.T2_LF	A5-6			2025												50000
1511	G		8	JOHN-LT.T2_LF	A5-6			2026												50000
1512	G		8	JOHN-LT.T2_LF	A5-6			2027		-100		-700	0	200	0	600	400	0	0	51000
1513	G		8	JOHN-LT.T2_LF	A5-6			2028		-100		-700	0	300	0	600	500	0	0	52000
1514	G		8	JOHN-LT.T2_LF	A5-6			2029		-100		-700	0	300	0	700	600	0	0	53000
1515	G		8	JOHN-LT.T2_LF	A5-6			2030		-100		-700	0	300	0	800	600	0	0	53000
1516	G		8	JOHN-LT.T2_LF	A5-6			2031		-100		-700	0	400	0	800	600	0	0	54000
1517	G		8	JOHN-LT.T2_LF	A5-6			2032		-100		-700	0	500	0	900	700	0	0	54000
1518	G		8	JOHN-LT.T2_LF	A5-6			2033		-100		-700	0	500	0	900	700	0	0	55000
1519	G		8	JOHN-LT.T2_LF	A5-6			2034		-100		-700	0	600	0	1000	800	0	0	56000
1520	G		8	JOHN-LT.T2_LF	A5-6			2035		-100		-700	0	600	0	1000	800	0	0	56000
1521	G		8	JOHN-LT.T2_LF	A5-6			2036		-100		-700	0	700	0	1000	800	0	0	57000
1522	G		8	JOHN-LT.T2_LF	A5-6			2037		-100		-700	0	800	0	1100	800	0	0	57000
1523	G		8	JOHN-LT.T2_LF	A5-6			2038		-100		-700	0	800	0	1100	800	0	0	58000
1524	G		8	JOHN-LT.T2_LF	A5-6			2039		-100		-700	0	900	0	1100	800	0	0	58000
1525	G		8	JOHN-LT.T2_LF	A5-6			2040		-100		-600	0	1000	0	1100	900	0	0	59000
1526	G		8	JOHN-LT.T2_LF	A5-6			2041		-100		-600	0	1100	0	1200	900	0	0	59000
1527	G		8	STRACHAN-LT.TT1_LF	A1-2			2017												43000
1528	G		8	STRACHAN-LT.TT1_LF	A1-2			2018												44000
1529	G		8	STRACHAN-LT.TT1_LF	A1-2			2019												45000
1530	G		8	STRACHAN-LT.TT1_LF	A1-2			2020												45000
1531	G		8	STRACHAN-LT.TT1_LF	A1-2			2021												46000
1532	G		8	STRACHAN-LT.TT1_LF	A1-2			2022												46000
1533	G		8	STRACHAN-LT.TT1_LF	A1-2			2023												46000
1534	G		8	STRACHAN-LT.TT1_LF	A1-2			2024												47000
1535	G		8	STRACHAN-LT.TT1_LF	A1-2			2025												47000
1536	G		8	STRACHAN-LT.TT1_LF	A1-2			2026												47000
1537	G		8	STRACHAN-LT.TT1_LF	A1-2			2027		0		-600	0	300	3800	300	500	1000	0	48000
1538	G		8	STRACHAN-LT.TT1_LF	A1-2			2028		0		-600	0	400	4400	400	600	1200	0	50000
1539	G		8	STRACHAN-LT.TT1_LF	A1-2			2029		0		-600	0	400	4900	400	700	1300	0	51000
1540	G		8	STRACHAN-LT.TT1_LF	A1-2			2030		0		-600	0	500	5400	500	700	1400	0	52000
1541	G		8	STRACHAN-LT.TT1_LF	A1-2			2031		0		-600	0	500	5800	500	800	1500	0	53000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1542	G		8	STRACHAN-LT.TT1_LF	A1-2			2032		0		-600	0	600	6100	500	800	1600	0	54000
1543	G		8	STRACHAN-LT.TT1_LF	A1-2			2033		0		-600	0	700	6500	600	900	1700	0	55000
1544	G		8	STRACHAN-LT.TT1_LF	A1-2			2034		0		-600	0	800	6800	600	900	1800	0	56000
1545	G		8	STRACHAN-LT.TT1_LF	A1-2			2035		0		-600	0	900	7000	600	900	1900	0	57000
1546	G		8	STRACHAN-LT.TT1_LF	A1-2			2036		0		-600	0	1000	7200	600	1000	1900	0	57000
1547	G		8	STRACHAN-LT.TT1_LF	A1-2			2037		0		-600	0	1000	7400	700	1000	2000	0	58000
1548	G		8	STRACHAN-LT.TT1_LF	A1-2			2038		0		-600	0	1200	8300	700	1000	2100	0	59000
1549	G		8	STRACHAN-LT.TT1_LF	A1-2			2039		0		-600	0	1300	8300	700	1000	2100	0	60000
1550	G		8	STRACHAN-LT.TT1_LF	A1-2			2040		0		-600	0	1400	8500	700	1100	2200	0	60000
1551	G		8	STRACHAN-LT.TT1_LF	A1-2			2041		0		-600	0	1500	8600	700	1100	2200	0	61000
1552	G		8	STRACHAN-LT.TT1_LF	A5-6			2017												23000
1553	G		8	STRACHAN-LT.TT1_LF	A5-6			2018												26000
1554	G		8	STRACHAN-LT.TT1_LF	A5-6			2019												27000
1555	G		8	STRACHAN-LT.TT1_LF	A5-6			2020												28000
1556	G		8	STRACHAN-LT.TT1_LF	A5-6			2021												28000
1557	G		8	STRACHAN-LT.TT1_LF	A5-6			2022												28000
1558	G		8	STRACHAN-LT.TT1_LF	A5-6			2023												28000
1559	G		8	STRACHAN-LT.TT1_LF	A5-6			2024												29000
1560	G		8	STRACHAN-LT.TT1_LF	A5-6			2025												29000
1561	G		8	STRACHAN-LT.TT1_LF	A5-6			2026												29000
1562	G		8	STRACHAN-LT.TT1_LF	A5-6			2027		0		-300	0	100	1700	200	200	500	0	30000
1563	G		8	STRACHAN-LT.TT1_LF	A5-6			2028		0		-300	0	200	2000	200	300	500	0	30000
1564	G		8	STRACHAN-LT.TT1_LF	A5-6			2029		0		-300	0	200	2200	200	300	600	0	31000
1565	G		8	STRACHAN-LT.TT1_LF	A5-6			2030		0		-300	0	200	2400	200	300	600	0	32000
1566	G		8	STRACHAN-LT.TT1_LF	A5-6			2031		0		-300	0	200	2600	200	400	700	0	33000
1567	G		8	STRACHAN-LT.TT1_LF	A5-6			2032		0		-300	0	300	2700	200	400	700	0	33000
1568	G		8	STRACHAN-LT.TT1_LF	A5-6			2033		0		-300	0	300	2900	300	400	800	0	34000
1569	G		8	STRACHAN-LT.TT1_LF	A5-6			2034		0		-300	0	300	3000	300	400	800	0	34000
1570	G		8	STRACHAN-LT.TT1_LF	A5-6			2035		0		-300	0	400	3200	300	400	800	0	35000
1571	G		8	STRACHAN-LT.TT1_LF	A5-6			2036		0		-300	0	400	3200	300	400	900	0	35000
1572	G		8	STRACHAN-LT.TT1_LF	A5-6			2037		0		-300	0	500	3300	300	400	900	0	36000
1573	G		8	STRACHAN-LT.TT1_LF	A5-6			2038		0		-300	0	500	3700	300	500	900	0	36000
1574	G		8	STRACHAN-LT.TT1_LF	A5-6			2039		0		-300	0	600	3700	300	500	900	0	37000
1575	G		8	STRACHAN-LT.TT1_LF	A5-6			2040		0		-300	0	600	3800	300	500	1000	0	37000
1576	G		8	STRACHAN-LT.TT1_LF	A5-6			2041		0		-300	0	700	3900	300	500	1000	0	38000
1577	G		8	STRACHAN-LT.TT1_LF	A7-8			2017												32000
1578	G		8	STRACHAN-LT.TT1_LF	A7-8			2018												32000
1579	G		8	STRACHAN-LT.TT1_LF	A7-8			2019												32000
1580	G		8	STRACHAN-LT.TT1_LF	A7-8			2020												32000
1581	G		8	STRACHAN-LT.TT1_LF	A7-8			2021												32000
1582	G		8	STRACHAN-LT.TT1_LF	A7-8			2022												32000
1583	G		8	STRACHAN-LT.TT1_LF	A7-8			2023												32000
1584	G		8	STRACHAN-LT.TT1_LF	A7-8			2024												32000
1585	G		8	STRACHAN-LT.TT1_LF	A7-8			2025												32000
1586	G		8	STRACHAN-LT.TT1_LF	A7-8			2026												33000
1587	G		8	STRACHAN-LT.TT1_LF	A7-8			2027		0		-400	0	200	2400	200	300	700	0	34000
1588	G		8	STRACHAN-LT.TT1_LF	A7-8			2028		0		-400	0	200	2800	200	400	700	0	35000
1589	G		8	STRACHAN-LT.TT1_LF	A7-8			2029		0		-400	0	300	3100	300	400	800	0	36000
1590	G		8	STRACHAN-LT.TT1_LF	A7-8			2030		0		-400	0	300	3400	300	500	900	0	37000
1591	G		8	STRACHAN-LT.TT1_LF	A7-8			2031		0		-400	0	300	3700	300	500	1000	0	38000
1592	G		8	STRACHAN-LT.TT1_LF	A7-8			2032		0		-400	0	400	3900	300	500	1000	0	38000
1593	G		8	STRACHAN-LT.TT1_LF	A7-8			2033		0		-400	0	400	4100	400	600	1100	0	39000
1594	G		8	STRACHAN-LT.TT1_LF	A7-8			2034		0		-400	0	500	4300	400	600	1100	0	40000
1595	G		8	STRACHAN-LT.TT1_LF	A7-8			2035		0		-400	0	600	4500	400	600	1200	0	40000
1596	G		8	STRACHAN-LT.TT1_LF	A7-8			2036		0		-400	0	600	4600	400	600	1200	0	41000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1597	G		8	STRACHAN-LT.TT1_LF	A7-8			2037		0		-400	0	700	4700	400	600	1300	0	41000
1598	G		8	STRACHAN-LT.TT1_LF	A7-8			2038		0		-400	0	700	5300	400	700	1300	0	42000
1599	G		8	STRACHAN-LT.TT1_LF	A7-8			2039		0		-400	0	800	5300	400	700	1300	0	42000
1600	G		8	STRACHAN-LT.TT1_LF	A7-8			2040		0		-400	0	900	5400	400	700	1400	0	43000
1601	G		8	STRACHAN-LT.TT1_LF	A7-8			2041		0		-400	0	900	5500	400	700	1400	0	43000
1602	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2017												35000
1603	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2018												37000
1604	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2019												39000
1605	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2020												40000
1606	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2021												40000
1607	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2022												41000
1608	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2023												41000
1609	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2024												41000
1610	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2025												41000
1611	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2026												41000
1612	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2027		0		-400	0	200	2900	300	400	800	0	43000
1613	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2028		0		-400	0	300	3300	300	400	900	0	44000
1614	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2029		0		-400	0	300	3700	300	500	1000	0	45000
1615	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2030		0		-400	0	400	4000	400	500	1000	0	46000
1616	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2031		0		-400	0	400	4400	400	600	1100	0	47000
1617	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2032		0		-400	0	500	4600	400	600	1200	0	48000
1618	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2033		0		-400	0	500	4800	400	700	1300	0	49000
1619	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2034		0		-400	0	600	5100	500	700	1300	0	49000
1620	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2035		0		-400	0	600	5300	500	700	1400	0	50000
1621	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2036		0		-400	0	700	5400	500	700	1400	0	51000
1622	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2037		0		-400	0	800	5500	500	700	1500	0	51000
1623	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2038		0		-400	0	900	6200	500	800	1500	0	52000
1624	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2039		0		-400	0	900	6300	500	800	1600	0	53000
1625	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2040		0		-400	0	1000	6400	500	800	1600	0	53000
1626	G		8	STRACHAN-LT.TT1_LF	A9-10 (Formerly A3-4)			2041		0		-400	0	1100	6500	500	800	1700	0	54000
1627	G		9	CECIL-LT.TT1_LF	A1-2			2017												24000
1628	G		9	CECIL-LT.TT1_LF	A1-2			2018												24000
1629	G		9	CECIL-LT.TT1_LF	A1-2			2019												24000
1630	G		9	CECIL-LT.TT1_LF	A1-2			2020												24000
1631	G		9	CECIL-LT.TT1_LF	A1-2			2021												24000
1632	G		9	CECIL-LT.TT1_LF	A1-2			2022												24000
1633	G		9	CECIL-LT.TT1_LF	A1-2			2023												25000
1634	G		9	CECIL-LT.TT1_LF	A1-2			2024												25000
1635	G		9	CECIL-LT.TT1_LF	A1-2			2025												25000
1636	G		9	CECIL-LT.TT1_LF	A1-2			2026												25000
1637	G		9	CECIL-LT.TT1_LF	A1-2			2027		0		-200	0	100	0	200	200	1300	0	25000
1638	G		9	CECIL-LT.TT1_LF	A1-2			2028		0		-200	0	200	0	200	300	1400	0	25000
1639	G		9	CECIL-LT.TT1_LF	A1-2			2029		0		-200	0	200	0	200	300	1600	0	25000
1640	G		9	CECIL-LT.TT1_LF	A1-2			2030		0		-200	0	200	0	200	300	1700	0	25000
1641	G		9	CECIL-LT.TT1_LF	A1-2			2031		0		-200	0	300	0	300	400	1900	0	25000
1642	G		9	CECIL-LT.TT1_LF	A1-2			2032		0		-200	0	300	0	300	400	2000	0	25000
1643	G		9	CECIL-LT.TT1_LF	A1-2			2033		0		-200	0	300	0	300	400	2100	0	25000
1644	G		9	CECIL-LT.TT1_LF	A1-2			2034		0		-200	0	400	0	300	500	2200	0	24000
1645	G		9	CECIL-LT.TT1_LF	A1-2			2035		0		-200	0	400	0	300	500	2200	0	24000
1646	G		9	CECIL-LT.TT1_LF	A1-2			2036		0		-200	0	500	0	300	500	2300	0	24000
1647	G		9	CECIL-LT.TT1_LF	A1-2			2037		0		-200	0	500	0	400	500	2300	0	24000
1648	G		9	CECIL-LT.TT1_LF	A1-2			2038		0		-200	0	600	0	400	500	2400	0	24000
1649	G		9	CECIL-LT.TT1_LF	A1-2			2039		0		-200	0	700	0	400	500	2400	0	24000
1650	G		9	CECIL-LT.TT1_LF	A1-2			2040		0		-200	0	700	0	400	600	2500	0	24000
1651	G		9	CECIL-LT.TT1_LF	A1-2			2041		0		-200	0	800	0	400	600	2500	0	23000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1652	G		9	CECIL-LT.TT1_LF	A3-4			2017												32000
1653	G		9	CECIL-LT.TT1_LF	A3-4			2018												32000
1654	G		9	CECIL-LT.TT1_LF	A3-4			2019												33000
1655	G		9	CECIL-LT.TT1_LF	A3-4			2020												33000
1656	G		9	CECIL-LT.TT1_LF	A3-4			2021												33000
1657	G		9	CECIL-LT.TT1_LF	A3-4			2022												34000
1658	G		9	CECIL-LT.TT1_LF	A3-4			2023												34000
1659	G		9	CECIL-LT.TT1_LF	A3-4			2024												34000
1660	G		9	CECIL-LT.TT1_LF	A3-4			2025												34000
1661	G		9	CECIL-LT.TT1_LF	A3-4			2026												35000
1662	G		9	CECIL-LT.TT1_LF	A3-4			2027		-100		-400	0	100	0	400	300	0	0	35000
1663	G		9	CECIL-LT.TT1_LF	A3-4			2028		-100		-400	0	200	0	400	300	0	0	34000
1664	G		9	CECIL-LT.TT1_LF	A3-4			2029		-100		-400	0	200	0	500	400	0	0	34000
1665	G		9	CECIL-LT.TT1_LF	A3-4			2030		-100		-400	0	200	0	500	400	0	0	34000
1666	G		9	CECIL-LT.TT1_LF	A3-4			2031		-100		-400	0	300	0	600	400	0	0	33000
1667	G		9	CECIL-LT.TT1_LF	A3-4			2032		0		-300	0	400	4100	400	500	2500	0	33000
1668	G		9	CECIL-LT.TT1_LF	A3-4			2033		0		-300	0	500	4300	400	600	2700	0	33000
1669	G		9	CECIL-LT.TT1_LF	A3-4			2034		0		-300	0	500	4600	400	600	2800	0	34000
1670	G		9	CECIL-LT.TT1_LF	A3-4			2035		0		-300	0	600	4800	400	600	2900	0	34000
1671	G		9	CECIL-LT.TT1_LF	A3-4			2036		0		-300	0	700	5000	400	700	3000	0	34000
1672	G		9	CECIL-LT.TT1_LF	A3-4			2037		0		-300	0	700	5100	500	700	3000	0	34000
1673	G		9	CECIL-LT.TT1_LF	A3-4			2038		0		-300	0	800	5300	500	700	3100	0	34000
1674	G		9	CECIL-LT.TT1_LF	A3-4			2039		0		-300	0	900	5400	500	700	3100	0	34000
1675	G		9	CECIL-LT.TT1_LF	A3-4			2040		0		-300	0	1000	5600	500	800	3200	0	34000
1676	G		9	CECIL-LT.TT1_LF	A3-4			2041		0		-300	0	1100	5700	500	800	3200	0	34000
1677	G		9	CECIL-LT.TT1_LF	A5-6			2017												51000
1678	G		9	CECIL-LT.TT1_LF	A5-6			2018												55000
1679	G		9	CECIL-LT.TT1_LF	A5-6			2019												60000
1680	G		9	CECIL-LT.TT1_LF	A5-6			2020												64000
1681	G		9	CECIL-LT.TT1_LF	A5-6			2021												66000
1682	G		9	CECIL-LT.TT1_LF	A5-6			2022												66000
1683	G		9	CECIL-LT.TT1_LF	A5-6			2023												67000
1684	G		9	CECIL-LT.TT1_LF	A5-6			2024												67000
1685	G		9	CECIL-LT.TT1_LF	A5-6			2025												68000
1686	G		9	CECIL-LT.TT1_LF	A5-6			2026												68000
1687	G		9	CECIL-LT.TT1_LF	A5-6			2027		-200		-600	0	200	0	500	400	0	0	67000
1688	G		9	CECIL-LT.TT1_LF	A5-6			2028		-200		-600	0	200	0	600	400	0	0	66000
1689	G		9	CECIL-LT.TT1_LF	A5-6			2029		-200		-600	0	300	0	600	500	0	0	65000
1690	G		9	CECIL-LT.TT1_LF	A5-6			2030		-200		-600	0	300	0	700	500	0	0	65000
1691	G		9	CECIL-LT.TT1_LF	A5-6			2031		-200		-600	0	400	0	800	600	0	0	64000
1692	G		9	CECIL-LT.TT1_LF	A5-6			2032		0		-500	0	600	5600	500	800	3500	0	63000
1693	G		9	CECIL-LT.TT1_LF	A5-6			2033		0		-500	0	600	6000	500	800	3700	0	64000
1694	G		9	CECIL-LT.TT1_LF	A5-6			2034		0		-500	0	700	6300	600	900	3900	0	64000
1695	G		9	CECIL-LT.TT1_LF	A5-6			2035		0		-500	0	800	6600	600	900	4000	0	65000
1696	G		9	CECIL-LT.TT1_LF	A5-6			2036		0		-500	0	900	6900	600	900	4100	0	65000
1697	G		9	CECIL-LT.TT1_LF	A5-6			2037		0		-500	0	1000	7100	600	1000	4200	0	65000
1698	G		9	CECIL-LT.TT1_LF	A5-6			2038		0		-500	0	1100	7400	700	1000	4300	0	65000
1699	G		9	CECIL-LT.TT1_LF	A5-6			2039		0		-500	0	1200	7500	700	1000	4300	0	65000
1700	G		9	CECIL-LT.TT1_LF	A5-6			2040		0		-500	0	1400	7800	700	1000	4400	0	65000
1701	G		9	CECIL-LT.TT1_LF	A5-6			2041		0		-500	0	1500	7900	700	1100	4500	0	65000
1702	G		9	CECIL-LT.TT1_LF	A7-8			2017												51000
1703	G		9	CECIL-LT.TT1_LF	A7-8			2018												51000
1704	G		9	CECIL-LT.TT1_LF	A7-8			2019												53000
1705	G		9	CECIL-LT.TT1_LF	A7-8			2020												54000
1706	G		9	CECIL-LT.TT1_LF	A7-8			2021												54000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1707	G		9	CECIL-LT.TT1_LF	A7-8			2022												55000
1708	G		9	CECIL-LT.TT1_LF	A7-8			2023												55000
1709	G		9	CECIL-LT.TT1_LF	A7-8			2024												56000
1710	G		9	CECIL-LT.TT1_LF	A7-8			2025												56000
1711	G		9	CECIL-LT.TT1_LF	A7-8			2026												56000
1712	G		9	CECIL-LT.TT1_LF	A7-8			2027		-200		-600	0	200	0	500	400	0	0	55000
1713	G		9	CECIL-LT.TT1_LF	A7-8			2028		-200		-600	0	300	0	600	500	0	0	55000
1714	G		9	CECIL-LT.TT1_LF	A7-8			2029		-200		-600	0	300	0	700	600	0	0	54000
1715	G		9	CECIL-LT.TT1_LF	A7-8			2030		-200		-600	0	400	0	800	600	0	0	53000
1716	G		9	CECIL-LT.TT1_LF	A7-8			2031		-200		-600	0	400	0	900	700	0	0	53000
1717	G		9	CECIL-LT.TT1_LF	A7-8			2032		0		-500	0	600	6200	500	800	3900	0	52000
1718	G		9	CECIL-LT.TT1_LF	A7-8			2033		0		-500	0	700	6600	600	900	4100	0	53000
1719	G		9	CECIL-LT.TT1_LF	A7-8			2034		0		-500	0	800	7000	600	900	4300	0	53000
1720	G		9	CECIL-LT.TT1_LF	A7-8			2035		0		-500	0	900	7400	700	1000	4400	0	54000
1721	G		9	CECIL-LT.TT1_LF	A7-8			2036		0		-500	0	1000	7600	700	1000	4500	0	54000
1722	G		9	CECIL-LT.TT1_LF	A7-8			2037		0		-500	0	1100	7900	700	1100	4600	0	54000
1723	G		9	CECIL-LT.TT1_LF	A7-8			2038		0		-500	0	1200	8200	700	1100	4700	0	54000
1724	G		9	CECIL-LT.TT1_LF	A7-8			2039		0		-500	0	1400	8300	700	1100	4800	0	54000
1725	G		9	CECIL-LT.TT1_LF	A7-8			2040		0		-500	0	1500	8600	800	1200	4900	0	54000
1726	G		9	CECIL-LT.TT1_LF	A7-8			2041		0		-500	0	1600	8800	800	1200	4900	0	54000
1727	G		9	CHARLES-LT.TT_LF	A1-2			2017												27000
1728	G		9	CHARLES-LT.TT_LF	A1-2			2018												28000
1729	G		9	CHARLES-LT.TT_LF	A1-2			2019												30000
1730	G		9	CHARLES-LT.TT_LF	A1-2			2020												30000
1731	G		9	CHARLES-LT.TT_LF	A1-2			2021												30000
1732	G		9	CHARLES-LT.TT_LF	A1-2			2022												30000
1733	G		9	CHARLES-LT.TT_LF	A1-2			2023												31000
1734	G		9	CHARLES-LT.TT_LF	A1-2			2024												31000
1735	G		9	CHARLES-LT.TT_LF	A1-2			2025												31000
1736	G		9	CHARLES-LT.TT_LF	A1-2			2026												31000
1737	G		9	CHARLES-LT.TT_LF	A1-2			2027		0		-400	0	300	3300	300	400	2200	0	31000
1738	G		9	CHARLES-LT.TT_LF	A1-2			2028		0		-400	0	300	3800	300	500	2500	0	32000
1739	G		9	CHARLES-LT.TT_LF	A1-2			2029		0		-400	0	400	4300	400	600	2800	0	32000
1740	G		9	CHARLES-LT.TT_LF	A1-2			2030		0		-400	0	400	4700	400	600	3000	0	32000
1741	G		9	CHARLES-LT.TT_LF	A1-2			2031		0		-400	0	500	5200	500	700	3300	0	33000
1742	G		9	CHARLES-LT.TT_LF	A1-2			2032		0		-400	0	600	5500	500	700	3400	0	33000
1743	G		9	CHARLES-LT.TT_LF	A1-2			2033		0		-400	0	600	5900	500	800	3600	0	33000
1744	G		9	CHARLES-LT.TT_LF	A1-2			2034		0		-500	0	700	6900	600	800	3800	0	34000
1745	G		9	CHARLES-LT.TT_LF	A1-2			2035		0		-500	0	800	7200	600	900	4000	0	34000
1746	G		9	CHARLES-LT.TT_LF	A1-2			2036		0		-500	0	900	7400	600	900	4100	0	34000
1747	G		9	CHARLES-LT.TT_LF	A1-2			2037		0		-500	0	1000	7700	600	1000	4100	0	34000
1748	G		9	CHARLES-LT.TT_LF	A1-2			2038		0		-500	0	1100	8000	600	1000	4200	0	34000
1749	G		9	CHARLES-LT.TT_LF	A1-2			2039		0		-500	0	1200	8100	700	1000	4300	0	34000
1750	G		9	CHARLES-LT.TT_LF	A1-2			2040		0		-500	0	1300	8400	700	1000	4400	0	34000
1751	G		9	CHARLES-LT.TT_LF	A1-2			2041		0		-500	0	1500	8600	700	1100	4400	0	34000
1752	G		9	CHARLES-LT.TT_LF	A3-4			2017												31000
1753	G		9	CHARLES-LT.TT_LF	A3-4			2018												34000
1754	G		9	CHARLES-LT.TT_LF	A3-4			2019												35000
1755	G		9	CHARLES-LT.TT_LF	A3-4			2020												36000
1756	G		9	CHARLES-LT.TT_LF	A3-4			2021												37000
1757	G		9	CHARLES-LT.TT_LF	A3-4			2022												37000
1758	G		9	CHARLES-LT.TT_LF	A3-4			2023												37000
1759	G		9	CHARLES-LT.TT_LF	A3-4			2024												37000
1760	G		9	CHARLES-LT.TT_LF	A3-4			2025												38000
1761	G		9	CHARLES-LT.TT_LF	A3-4			2026												38000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1762	G		9	CHARLES-LT.TT_LF	A3-4			2027		0		-300	0	200	2300	200	300	1500	0	39000
1763	G		9	CHARLES-LT.TT_LF	A3-4			2028		0		-300	0	200	2600	200	400	1700	0	39000
1764	G		9	CHARLES-LT.TT_LF	A3-4			2029		0		-300	0	200	3000	300	400	1900	0	40000
1765	G		9	CHARLES-LT.TT_LF	A3-4			2030		0		-300	0	300	3300	300	400	2100	0	40000
1766	G		9	CHARLES-LT.TT_LF	A3-4			2031		0		-300	0	300	3600	300	500	2200	0	40000
1767	G		9	CHARLES-LT.TT_LF	A3-4			2032		0		-300	0	400	3800	300	500	2400	0	41000
1768	G		9	CHARLES-LT.TT_LF	A3-4			2033		0		-300	0	400	4100	400	500	2500	0	41000
1769	G		9	CHARLES-LT.TT_LF	A3-4			2034		0		-300	0	500	4700	400	600	2600	0	41000
1770	G		9	CHARLES-LT.TT_LF	A3-4			2035		0		-300	0	600	5000	400	600	2700	0	42000
1771	G		9	CHARLES-LT.TT_LF	A3-4			2036		0		-300	0	600	5100	400	600	2800	0	42000
1772	G		9	CHARLES-LT.TT_LF	A3-4			2037		0		-300	0	700	5300	400	700	2900	0	42000
1773	G		9	CHARLES-LT.TT_LF	A3-4			2038		0		-300	0	800	5500	400	700	2900	0	42000
1774	G		9	CHARLES-LT.TT_LF	A3-4			2039		0		-300	0	800	5600	500	700	3000	0	42000
1775	G		9	CHARLES-LT.TT_LF	A3-4			2040		0		-300	0	900	5800	500	700	3000	0	42000
1776	G		9	CHARLES-LT.TT_LF	A3-4			2041		0		-300	0	1000	5900	500	700	3000	0	42000
1777	G		9	CHARLES-LT.TT_LF	A5-6			2017												36000
1778	G		9	CHARLES-LT.TT_LF	A5-6			2018												37000
1779	G		9	CHARLES-LT.TT_LF	A5-6			2019												38000
1780	G		9	CHARLES-LT.TT_LF	A5-6			2020												39000
1781	G		9	CHARLES-LT.TT_LF	A5-6			2021												39000
1782	G		9	CHARLES-LT.TT_LF	A5-6			2022												39000
1783	G		9	CHARLES-LT.TT_LF	A5-6			2023												40000
1784	G		9	CHARLES-LT.TT_LF	A5-6			2024												40000
1785	G		9	CHARLES-LT.TT_LF	A5-6			2025												40000
1786	G		9	CHARLES-LT.TT_LF	A5-6			2026												40000
1787	G		9	CHARLES-LT.TT_LF	A5-6			2027		0		-400	0	200	2800	200	400	1900	0	40000
1788	G		9	CHARLES-LT.TT_LF	A5-6			2028		0		-400	0	300	3200	300	400	2100	0	41000
1789	G		9	CHARLES-LT.TT_LF	A5-6			2029		0		-400	0	300	3700	300	500	2400	0	41000
1790	G		9	CHARLES-LT.TT_LF	A5-6			2030		0		-400	0	400	4000	400	500	2600	0	42000
1791	G		9	CHARLES-LT.TT_LF	A5-6			2031		0		-400	0	400	4400	400	600	2800	0	42000
1792	G		9	CHARLES-LT.TT_LF	A5-6			2032		0		-400	0	500	4700	400	600	2900	0	42000
1793	G		9	CHARLES-LT.TT_LF	A5-6			2033		0		-400	0	500	5000	400	700	3100	0	43000
1794	G		9	CHARLES-LT.TT_LF	A5-6			2034		0		-400	0	600	5800	500	700	3200	0	43000
1795	G		9	CHARLES-LT.TT_LF	A5-6			2035		0		-400	0	700	6100	500	800	3400	0	43000
1796	G		9	CHARLES-LT.TT_LF	A5-6			2036		0		-400	0	800	6300	500	800	3400	0	43000
1797	G		9	CHARLES-LT.TT_LF	A5-6			2037		0		-400	0	800	6500	500	800	3500	0	44000
1798	G		9	CHARLES-LT.TT_LF	A5-6			2038		0		-400	0	900	6700	500	800	3600	0	44000
1799	G		9	CHARLES-LT.TT_LF	A5-6			2039		0		-400	0	1000	6900	600	900	3600	0	44000
1800	G		9	CHARLES-LT.TT_LF	A5-6			2040		0		-400	0	1100	7100	600	900	3700	0	44000
1801	G		9	CHARLES-LT.TT_LF	A5-6			2041		0		-400	0	1200	7300	600	900	3700	0	44000
1802	G		9	CHARLES-LT.TT_LF	A7-8			2017												41000
1803	G		9	CHARLES-LT.TT_LF	A7-8			2018												46000
1804	G		9	CHARLES-LT.TT_LF	A7-8			2019												48000
1805	G		9	CHARLES-LT.TT_LF	A7-8			2020												49000
1806	G		9	CHARLES-LT.TT_LF	A7-8			2021												49000
1807	G		9	CHARLES-LT.TT_LF	A7-8			2022												50000
1808	G		9	CHARLES-LT.TT_LF	A7-8			2023												50000
1809	G		9	CHARLES-LT.TT_LF	A7-8			2024												50000
1810	G		9	CHARLES-LT.TT_LF	A7-8			2025												50000
1811	G		9	CHARLES-LT.TT_LF	A7-8			2026												50000
1812	G		9	CHARLES-LT.TT_LF	A7-8			2027		0		-400	0	200	3100	300	400	2100	0	51000
1813	G		9	CHARLES-LT.TT_LF	A7-8			2028		0		-400	0	300	3600	300	500	2400	0	52000
1814	G		9	CHARLES-LT.TT_LF	A7-8			2029		0		-400	0	300	4000	400	500	2600	0	53000
1815	G		9	CHARLES-LT.TT_LF	A7-8			2030		0		-400	0	400	4400	400	600	2800	0	53000
1816	G		9	CHARLES-LT.TT_LF	A7-8			2031		0		-400	0	500	4800	400	700	3000	0	54000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1817	G		9	CHARLES-LT.TT_LF	A7-8			2032		0		-400	0	500	5200	500	700	3200	0	54000
1818	G		9	CHARLES-LT.TT_LF	A7-8			2033		0		-400	0	600	5500	500	700	3400	0	55000
1819	G		9	CHARLES-LT.TT_LF	A7-8			2034		0		-400	0	700	6400	500	800	3600	0	55000
1820	G		9	CHARLES-LT.TT_LF	A7-8			2035		0		-400	0	800	6700	500	800	3700	0	56000
1821	G		9	CHARLES-LT.TT_LF	A7-8			2036		0		-400	0	800	7000	600	900	3800	0	56000
1822	G		9	CHARLES-LT.TT_LF	A7-8			2037		0		-400	0	900	7200	600	900	3900	0	56000
1823	G		9	CHARLES-LT.TT_LF	A7-8			2038		0		-400	0	1000	7400	600	900	4000	0	56000
1824	G		9	CHARLES-LT.TT_LF	A7-8			2039		0		-400	0	1100	7600	600	900	4000	0	56000
1825	G		9	CHARLES-LT.TT_LF	A7-8			2040		0		-400	0	1300	7900	600	1000	4100	0	56000
1826	G		9	CHARLES-LT.TT_LF	A7-8			2041		0		-400	0	1400	8000	700	1000	4100	0	56000
1827	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2017												56000
1828	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2018												59000
1829	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2019												48000
1830	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2020												49000
1831	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2021												50000
1832	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2022												50000
1833	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2023												50000
1834	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2024												50000
1835	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2025												50000
1836	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2026												50000
1837	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2027		-200		-700	0	200	0	600	500	0	0	50000
1838	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2028		-200		-700	0	300	0	700	500	0	0	49000
1839	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2029		-200		-700	0	300	0	800	600	0	0	49000
1840	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2030		-200		-700	0	400	0	900	700	0	0	48000
1841	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2031		0		-600	0	600	6500	600	900	4100	0	48000
1842	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2032		0		-600	0	700	6900	600	900	4300	0	48000
1843	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2033		0		-600	0	800	7400	700	1000	4500	0	49000
1844	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2034		0		-600	0	900	7900	700	1100	4800	0	49000
1845	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2035		0		-600	0	1000	8200	700	1100	4900	0	49000
1846	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2036		0		-600	0	1100	8500	800	1100	5100	0	50000
1847	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2037		0		-600	0	1300	8800	800	1200	5200	0	50000
1848	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2038		0		-600	0	1400	9100	800	1200	5300	0	50000
1849	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2039		0		-600	0	1500	9300	800	1300	5400	0	49000
1850	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2040		0		-600	0	1700	9600	900	1300	5500	0	50000
1851	G		9	ESPLANADE-LT.TT_LF	A1-2GD			2041		0		-600	0	1800	9800	900	1300	5500	0	49000
1852	G		9	ESPLANADE-LT.TT_LF	A1-2X			2017												46000
1853	G		9	ESPLANADE-LT.TT_LF	A1-2X			2018												50000
1854	G		9	ESPLANADE-LT.TT_LF	A1-2X			2019												40000
1855	G		9	ESPLANADE-LT.TT_LF	A1-2X			2020												41000
1856	G		9	ESPLANADE-LT.TT_LF	A1-2X			2021												41000
1857	G		9	ESPLANADE-LT.TT_LF	A1-2X			2022												41000
1858	G		9	ESPLANADE-LT.TT_LF	A1-2X			2023												42000
1859	G		9	ESPLANADE-LT.TT_LF	A1-2X			2024												42000
1860	G		9	ESPLANADE-LT.TT_LF	A1-2X			2025												42000
1861	G		9	ESPLANADE-LT.TT_LF	A1-2X			2026												43000
1862	G		9	ESPLANADE-LT.TT_LF	A1-2X			2027		-200		-600	0	200	0	500	400	0	0	43000
1863	G		9	ESPLANADE-LT.TT_LF	A1-2X			2028		-200		-600	0	200	0	600	400	0	0	42000
1864	G		9	ESPLANADE-LT.TT_LF	A1-2X			2029		-200		-600	0	300	0	700	500	0	0	42000
1865	G		9	ESPLANADE-LT.TT_LF	A1-2X			2030		-200		-600	0	300	0	700	500	0	0	41000
1866	G		9	ESPLANADE-LT.TT_LF	A1-2X			2031		0		-500	0	500	5400	500	700	3400	0	41000
1867	G		9	ESPLANADE-LT.TT_LF	A1-2X			2032		0		-500	0	600	5800	500	800	3600	0	41000
1868	G		9	ESPLANADE-LT.TT_LF	A1-2X			2033		0		-500	0	700	6100	500	800	3800	0	42000
1869	G		9	ESPLANADE-LT.TT_LF	A1-2X			2034		0		-500	0	700	6500	600	900	4000	0	42000
1870	G		9	ESPLANADE-LT.TT_LF	A1-2X			2035		0		-500	0	800	6800	600	900	4100	0	42000
1871	G		9	ESPLANADE-LT.TT_LF	A1-2X			2036		0		-500	0	900	7100	600	900	4200	0	42000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1872	G		9	ESPLANADE-LT.TT_LF	A1-2X			2037		0		-500	0	1000	7300	600	1000	4300	0	42000
1873	G		9	ESPLANADE-LT.TT_LF	A1-2X			2038		0		-500	0	1200	7600	700	1000	4400	0	43000
1874	G		9	ESPLANADE-LT.TT_LF	A1-2X			2039		0		-500	0	1300	7700	700	1000	4400	0	42000
1875	G		9	ESPLANADE-LT.TT_LF	A1-2X			2040		0		-500	0	1400	8000	700	1100	4500	0	42000
1876	G		9	ESPLANADE-LT.TT_LF	A1-2X			2041		0		-500	0	1500	8200	700	1100	4600	0	42000
1877	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2017												51000
1878	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2018												53000
1879	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2019												54000
1880	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2020												55000
1881	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2021												55000
1882	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2022												55000
1883	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2023												56000
1884	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2024												56000
1885	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2025												57000
1886	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2026												57000
1887	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2027		-200		-600	0	200	0	500	400	0	0	56000
1888	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2028		-200		-600	0	200	0	600	500	0	0	56000
1889	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2029		-200		-600	0	300	0	700	500	0	0	55000
1890	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2030		-200		-600	0	300	0	700	600	0	0	54000
1891	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2031		0		-500	0	500	5500	500	700	3500	0	54000
1892	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2032		0		-500	0	600	5900	500	800	3700	0	54000
1893	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2033		0		-500	0	700	6300	600	800	3900	0	55000
1894	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2034		0		-500	0	800	6700	600	900	4100	0	55000
1895	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2035		0		-500	0	900	7000	600	900	4200	0	56000
1896	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2036		0		-500	0	1000	7200	600	1000	4300	0	56000
1897	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2037		0		-500	0	1100	7500	700	1000	4400	0	56000
1898	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2038		0		-500	0	1200	7700	700	1000	4500	0	56000
1899	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2039		0		-500	0	1300	7900	700	1100	4500	0	56000
1900	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2040		0		-500	0	1400	8200	700	1100	4600	0	56000
1901	G		9	ESPLANADE-LT.TT_LF	A3-4GD			2041		0		-500	0	1600	8300	700	1100	4700	0	56000
1902	G		9	TERAULEY-LT.T1_LF	A1-2			2017												41000
1903	G		9	TERAULEY-LT.T1_LF	A1-2			2018												41000
1904	G		9	TERAULEY-LT.T1_LF	A1-2			2019												43000
1905	G		9	TERAULEY-LT.T1_LF	A1-2			2020												47000
1906	G		9	TERAULEY-LT.T1_LF	A1-2			2021												43000
1907	G		9	TERAULEY-LT.T1_LF	A1-2			2022												45000
1908	G		9	TERAULEY-LT.T1_LF	A1-2			2023												45000
1909	G		9	TERAULEY-LT.T1_LF	A1-2			2024												46000
1910	G		9	TERAULEY-LT.T1_LF	A1-2			2025												46000
1911	G		9	TERAULEY-LT.T1_LF	A1-2			2026												46000
1912	G		9	TERAULEY-LT.T1_LF	A1-2			2027		-200		-500	0	200	0	500	400	0	0	45000
1913	G		9	TERAULEY-LT.T1_LF	A1-2			2028		-200		-500	0	200	0	600	400	0	0	45000
1914	G		9	TERAULEY-LT.T1_LF	A1-2			2029		-200		-500	0	300	0	600	500	0	0	44000
1915	G		9	TERAULEY-LT.T1_LF	A1-2			2030		-200		-500	0	300	0	700	500	0	0	44000
1916	G		9	TERAULEY-LT.T1_LF	A1-2			2031		-200		-500	0	400	0	800	600	0	0	43000
1917	G		9	TERAULEY-LT.T1_LF	A1-2			2032		-100		-400	0	200	5500	500	600	0	0	43000
1918	G		9	TERAULEY-LT.T1_LF	A1-2			2033		-100		-400	0	300	5800	600	600	0	0	43000
1919	G		9	TERAULEY-LT.T1_LF	A1-2			2034		-100		-400	0	300	6200	600	700	0	0	43000
1920	G		9	TERAULEY-LT.T1_LF	A1-2			2035		-100		-500	0	600	7700	600	800	0	0	43000
1921	G		9	TERAULEY-LT.T1_LF	A1-2			2036		0		-400	0	900	7200	600	900	3900	0	43000
1922	G		9	TERAULEY-LT.T1_LF	A1-2			2037		0		-400	0	1000	7500	600	900	4000	0	44000
1923	G		9	TERAULEY-LT.T1_LF	A1-2			2038		0		-400	0	1100	7700	600	1000	4100	0	44000
1924	G		9	TERAULEY-LT.T1_LF	A1-2			2039		0		-400	0	1200	7900	600	1000	4200	0	44000
1925	G		9	TERAULEY-LT.T1_LF	A1-2			2040		0		-400	0	1300	8200	700	1000	4300	0	44000
1926	G		9	TERAULEY-LT.T1_LF	A1-2			2041		0		-400	0	1400	8300	700	1000	4300	0	44000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1927	G		9	TERAULEY-LT.T1_LF	A3-4			2017												46000
1928	G		9	TERAULEY-LT.T1_LF	A3-4			2018												49000
1929	G		9	TERAULEY-LT.T1_LF	A3-4			2019												58000
1930	G		9	TERAULEY-LT.T1_LF	A3-4			2020												59000
1931	G		9	TERAULEY-LT.T1_LF	A3-4			2021												59000
1932	G		9	TERAULEY-LT.T1_LF	A3-4			2022												59000
1933	G		9	TERAULEY-LT.T1_LF	A3-4			2023												59000
1934	G		9	TERAULEY-LT.T1_LF	A3-4			2024												60000
1935	G		9	TERAULEY-LT.T1_LF	A3-4			2025												60000
1936	G		9	TERAULEY-LT.T1_LF	A3-4			2026												60000
1937	G		9	TERAULEY-LT.T1_LF	A3-4			2027		-200		-500	0	200	0	500	400	0	0	60000
1938	G		9	TERAULEY-LT.T1_LF	A3-4			2028		-200		-500	0	200	0	500	400	0	0	59000
1939	G		9	TERAULEY-LT.T1_LF	A3-4			2029		-200		-500	0	300	0	600	500	0	0	58000
1940	G		9	TERAULEY-LT.T1_LF	A3-4			2030		-200		-500	0	300	0	700	500	0	0	58000
1941	G		9	TERAULEY-LT.T1_LF	A3-4			2031		-200		-500	0	300	0	700	600	0	0	57000
1942	G		9	TERAULEY-LT.T1_LF	A3-4			2032		-100		-400	0	200	5300	500	600	0	0	57000
1943	G		9	TERAULEY-LT.T1_LF	A3-4			2033		-100		-400	0	300	5700	500	600	0	0	57000
1944	G		9	TERAULEY-LT.T1_LF	A3-4			2034		-100		-400	0	300	6100	600	700	0	0	57000
1945	G		9	TERAULEY-LT.T1_LF	A3-4			2035		-100		-500	0	500	7500	600	800	0	0	57000
1946	G		9	TERAULEY-LT.T1_LF	A3-4			2036		0		-400	0	900	7000	600	900	3800	0	57000
1947	G		9	TERAULEY-LT.T1_LF	A3-4			2037		0		-400	0	1000	7300	600	900	3900	0	57000
1948	G		9	TERAULEY-LT.T1_LF	A3-4			2038		0		-400	0	1100	7500	600	900	4000	0	57000
1949	G		9	TERAULEY-LT.T1_LF	A3-4			2039		0		-400	0	1200	7700	600	1000	4100	0	57000
1950	G		9	TERAULEY-LT.T1_LF	A3-4			2040		0		-400	0	1300	8000	600	1000	4100	0	57000
1951	G		9	TERAULEY-LT.T1_LF	A3-4			2041		0		-400	0	1400	8100	700	1000	4200	0	57000
1952	G		9	TERAULEY-LT.T1_LF	A5-6			2017												44000
1953	G		9	TERAULEY-LT.T1_LF	A5-6			2018												47000
1954	G		9	TERAULEY-LT.T1_LF	A5-6			2019												48000
1955	G		9	TERAULEY-LT.T1_LF	A5-6			2020												49000
1956	G		9	TERAULEY-LT.T1_LF	A5-6			2021												49000
1957	G		9	TERAULEY-LT.T1_LF	A5-6			2022												50000
1958	G		9	TERAULEY-LT.T1_LF	A5-6			2023												50000
1959	G		9	TERAULEY-LT.T1_LF	A5-6			2024												50000
1960	G		9	TERAULEY-LT.T1_LF	A5-6			2025												50000
1961	G		9	TERAULEY-LT.T1_LF	A5-6			2026												50000
1962	G		9	TERAULEY-LT.T1_LF	A5-6			2027		-200		-500	0	200	0	500	300	0	0	50000
1963	G		9	TERAULEY-LT.T1_LF	A5-6			2028		-200		-500	0	200	0	500	400	0	0	49000
1964	G		9	TERAULEY-LT.T1_LF	A5-6			2029		-200		-500	0	200	0	600	500	0	0	49000
1965	G		9	TERAULEY-LT.T1_LF	A5-6			2030		-200		-500	0	300	0	700	500	0	0	48000
1966	G		9	TERAULEY-LT.T1_LF	A5-6			2031		-200		-500	0	300	0	700	500	0	0	48000
1967	G		9	TERAULEY-LT.T1_LF	A5-6			2032		-100		-400	0	200	5200	500	600	0	0	48000
1968	G		9	TERAULEY-LT.T1_LF	A5-6			2033		-100		-400	0	300	5500	500	600	0	0	48000
1969	G		9	TERAULEY-LT.T1_LF	A5-6			2034		-100		-400	0	300	5900	600	600	0	0	48000
1970	G		9	TERAULEY-LT.T1_LF	A5-6			2035		-100		-500	0	500	7300	600	800	0	0	48000
1971	G		9	TERAULEY-LT.T1_LF	A5-6			2036		0		-400	0	800	6800	600	800	3700	0	48000
1972	G		9	TERAULEY-LT.T1_LF	A5-6			2037		0		-400	0	900	7100	600	900	3800	0	48000
1973	G		9	TERAULEY-LT.T1_LF	A5-6			2038		0		-400	0	1000	7300	600	900	3900	0	48000
1974	G		9	TERAULEY-LT.T1_LF	A5-6			2039		0		-400	0	1100	7500	600	900	3900	0	48000
1975	G		9	TERAULEY-LT.T1_LF	A5-6			2040		0		-400	0	1200	7700	600	1000	4000	0	48000
1976	G		9	TERAULEY-LT.T1_LF	A5-6			2041		0		-400	0	1400	7900	600	1000	4100	0	48000
1977	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2017												36000
1978	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2018												38000
1979	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2019												39000
1980	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2020												39000
1981	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2021												39000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
1982	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2022												34000
1983	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2023												34000
1984	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2024												35000
1985	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2025												35000
1986	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2026												35000
1987	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2027		-100		-400	0	100	0	300	300	0	0	35000
1988	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2028		-100		-400	0	200	0	400	300	0	0	34000
1989	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2029		-100		-400	0	200	0	400	300	0	0	34000
1990	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2030		-100		-400	0	200	0	500	400	0	0	34000
1991	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2031		-100		-400	0	200	0	500	400	0	0	33000
1992	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2032		-100		-300	0	200	3800	400	400	0	0	33000
1993	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2033		-100		-300	0	200	4100	400	400	0	0	33000
1994	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2034		-100		-300	0	200	4300	400	500	0	0	33000
1995	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2035		-100		-300	0	400	5400	400	600	0	0	33000
1996	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2036		0		-300	0	600	5000	400	600	2700	0	33000
1997	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2037		0		-300	0	700	5200	400	600	2800	0	33000
1998	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2038		0		-300	0	800	5400	400	700	2900	0	33000
1999	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2039		0		-300	0	800	5500	400	700	2900	0	33000
2000	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2040		0		-300	0	900	5700	500	700	3000	0	33000
2001	G		9	TERAULEY-LT.T1_LF	A9-10 (Formerly A7-8)			2041		0		-300	0	1000	5800	500	700	3000	0	33000
2002	G		10	BASIN-LT.TT1_LF	A5-6			2017												32000
2003	G		10	BASIN-LT.TT1_LF	A5-6			2018												40000
2004	G		10	BASIN-LT.TT1_LF	A5-6			2019												42000
2005	G		10	BASIN-LT.TT1_LF	A5-6			2020												44000
2006	G		10	BASIN-LT.TT1_LF	A5-6			2021												44000
2007	G		10	BASIN-LT.TT1_LF	A5-6			2022												45000
2008	G		10	BASIN-LT.TT1_LF	A5-6			2023												45000
2009	G		10	BASIN-LT.TT1_LF	A5-6			2024												45000
2010	G		10	BASIN-LT.TT1_LF	A5-6			2025												46000
2011	G		10	BASIN-LT.TT1_LF	A5-6			2026												46000
2012	G		10	BASIN-LT.TT1_LF	A5-6			2027		-100		-600	100	200	5500	400	600	0	0	47000
2013	G		10	BASIN-LT.TT1_LF	A5-6			2028		-100		-600	100	300	6300	500	700	0	0	48000
2014	G		10	BASIN-LT.TT1_LF	A5-6			2029		-100		-600	100	300	6900	600	800	0	0	49000
2015	G		10	BASIN-LT.TT1_LF	A5-6			2030		-100		-600	100	400	7400	600	800	0	0	49000
2016	G		10	BASIN-LT.TT1_LF	A5-6			2031		0		-500	100	400	9500	600	900	1000	0	50000
2017	G		10	BASIN-LT.TT1_LF	A5-6			2032		0		-500	100	500	10000	700	1000	1100	0	51000
2018	G		10	BASIN-LT.TT1_LF	A5-6			2033		0		-500	100	500	10500	700	1000	1100	0	52000
2019	G		10	BASIN-LT.TT1_LF	A5-6			2034		0		-500	100	600	11000	700	1100	1200	0	52000
2020	G		10	BASIN-LT.TT1_LF	A5-6			2035		0		-500	100	600	11400	700	1100	1300	0	53000
2021	G		10	BASIN-LT.TT1_LF	A5-6			2036		0		-500	100	700	11600	800	1100	1300	0	53000
2022	G		10	BASIN-LT.TT1_LF	A5-6			2037		0		-500	100	800	11900	800	1100	1400	0	54000
2023	G		10	BASIN-LT.TT1_LF	A5-6			2038		0		-500	100	800	12100	800	1200	1400	0	54000
2024	G		10	BASIN-LT.TT1_LF	A5-6			2039		0		-500	100	900	12200	800	1200	1500	0	54000
2025	G		10	BASIN-LT.TT1_LF	A5-6			2040		0		-500	100	1000	12500	800	1200	1500	0	55000
2026	G		10	BASIN-LT.TT1_LF	A5-6			2041		0		-500	100	1100	12600	800	1200	1500	0	55000
2027	G		10	BASIN-LT.TT1_LF	A7-8			2017												24000
2028	G		10	BASIN-LT.TT1_LF	A7-8			2018												25000
2029	G		10	BASIN-LT.TT1_LF	A7-8			2019												29000
2030	G		10	BASIN-LT.TT1_LF	A7-8			2020												31000
2031	G		10	BASIN-LT.TT1_LF	A7-8			2021												32000
2032	G		10	BASIN-LT.TT1_LF	A7-8			2022												32000
2033	G		10	BASIN-LT.TT1_LF	A7-8			2023												32000
2034	G		10	BASIN-LT.TT1_LF	A7-8			2024												33000
2035	G		10	BASIN-LT.TT1_LF	A7-8			2025												33000
2036	G		10	BASIN-LT.TT1_LF	A7-8			2026												33000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
2037	G		10	BASIN-LT.TT1_LF	A7-8			2027		-100		-400	100	200	3900	300	400	0	0	34000
2038	G		10	BASIN-LT.TT1_LF	A7-8			2028		-100		-400	100	200	4400	400	500	0	0	35000
2039	G		10	BASIN-LT.TT1_LF	A7-8			2029		-100		-400	100	200	4800	400	500	0	0	35000
2040	G		10	BASIN-LT.TT1_LF	A7-8			2030		-100		-400	100	300	5200	400	600	0	0	36000
2041	G		10	BASIN-LT.TT1_LF	A7-8			2031		0		-400	0	300	6700	400	600	700	0	36000
2042	G		10	BASIN-LT.TT1_LF	A7-8			2032		0		-400	0	300	7000	500	700	700	0	37000
2043	G		10	BASIN-LT.TT1_LF	A7-8			2033		0		-400	0	400	7400	500	700	800	0	38000
2044	G		10	BASIN-LT.TT1_LF	A7-8			2034		0		-400	0	400	7700	500	700	800	0	38000
2045	G		10	BASIN-LT.TT1_LF	A7-8			2035		0		-400	0	400	8000	500	800	900	0	38000
2046	G		10	BASIN-LT.TT1_LF	A7-8			2036		0		-400	0	500	8100	500	800	900	0	39000
2047	G		10	BASIN-LT.TT1_LF	A7-8			2037		0		-400	0	500	8300	500	800	1000	0	39000
2048	G		10	BASIN-LT.TT1_LF	A7-8			2038		0		-400	0	600	8500	600	800	1000	0	39000
2049	G		10	BASIN-LT.TT1_LF	A7-8			2039		0		-400	0	600	8600	600	800	1000	0	39000
2050	G		10	BASIN-LT.TT1_LF	A7-8			2040		0		-400	0	700	8700	600	800	1100	0	40000
2051	G		10	BASIN-LT.TT1_LF	A7-8			2041		0		-400	0	700	8800	600	800	1100	0	40000
2052	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2017												10000
2053	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2018												3000
2054	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2019												3000
2055	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2020												3000
2056	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2021												3000
2057	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2022												3000
2058	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2023												3000
2059	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2024												3000
2060	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2025												3000
2061	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2026												3000
2062	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2027		0		-200	0	100	0	200	200	0	0	3000
2063	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2028		0		-200	0	100	0	200	200	0	0	3000
2064	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2029		0		-200	0	100	1800	200	200	200	0	3000
2065	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2030		0		-200	0	200	1900	200	300	300	0	3000
2066	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2031		0		-200	0	200	2000	200	300	300	0	3000
2067	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2032		0		-200	0	200	2200	200	300	300	0	3000
2068	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2033		0		-200	0	200	2300	200	300	300	0	3000
2069	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2034		0		-200	0	300	2400	200	300	400	0	3000
2070	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2035		0		-200	0	300	2400	200	300	400	0	3000
2071	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2036		0		-200	0	300	2500	200	300	400	0	3000
2072	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2037		0		-200	0	400	2500	200	300	400	0	3000
2073	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2038		0		-200	0	400	2900	200	400	400	0	3000
2074	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2039		0		-200	0	400	2900	200	400	400	0	3000
2075	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2040		0		-200	0	600	3000	200	400	500	0	3000
2076	G		10	CARLAW-LT.T1_LF	A4-5 (Supplied by Gerrard TS)			2041		0		-200	0	600	3000	200	400	500	0	3000
2077	G		10	CARLAW-LT.T1_LF	A6-7			2017												22000
2078	G		10	CARLAW-LT.T1_LF	A6-7			2018												32000
2079	G		10	CARLAW-LT.T1_LF	A6-7			2019												32000
2080	G		10	CARLAW-LT.T1_LF	A6-7			2020												32000
2081	G		10	CARLAW-LT.T1_LF	A6-7			2021												32000
2082	G		10	CARLAW-LT.T1_LF	A6-7			2022												32000
2083	G		10	CARLAW-LT.T1_LF	A6-7			2023												32000
2084	G		10	CARLAW-LT.T1_LF	A6-7			2024												33000
2085	G		10	CARLAW-LT.T1_LF	A6-7			2025												33000
2086	G		10	CARLAW-LT.T1_LF	A6-7			2026												33000
2087	G		10	CARLAW-LT.T1_LF	A6-7			2027		-100		-400	100	200	0	400	300	0	0	33000
2088	G		10	CARLAW-LT.T1_LF	A6-7			2028		-100		-400	100	200	0	400	400	0	0	33000
2089	G		10	CARLAW-LT.T1_LF	A6-7			2029		0		-300	0	300	3300	300	400	500	0	33000
2090	G		10	CARLAW-LT.T1_LF	A6-7			2030		0		-300	0	300	3500	300	500	500	0	34000
2091	G		10	CARLAW-LT.T1_LF	A6-7			2031		0		-300	0	400	3800	300	500	500	0	34000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
2092	G		10	CARLAW-LT.T1_LF	A6-7			2032		0		-300	0	400	4000	300	500	600	0	34000
2093	G		10	CARLAW-LT.T1_LF	A6-7			2033		0		-300	0	400	4200	400	600	600	0	34000
2094	G		10	CARLAW-LT.T1_LF	A6-7			2034		0		-300	0	500	4300	400	600	700	0	34000
2095	G		10	CARLAW-LT.T1_LF	A6-7			2035		0		-300	0	600	4500	400	600	700	0	34000
2096	G		10	CARLAW-LT.T1_LF	A6-7			2036		0		-300	0	600	4600	400	600	700	0	34000
2097	G		10	CARLAW-LT.T1_LF	A6-7			2037		0		-300	0	700	4700	400	600	800	0	35000
2098	G		10	CARLAW-LT.T1_LF	A6-7			2038		0		-300	0	700	5200	400	600	800	0	34000
2099	G		10	CARLAW-LT.T1_LF	A6-7			2039		0		-300	0	800	5300	400	700	800	0	34000
2100	G		10	CARLAW-LT.T1_LF	A6-7			2040		0		-300	0	1100	5500	400	700	800	0	34000
2101	G		10	CARLAW-LT.T1_LF	A6-7			2041		0		-300	0	1100	5500	400	700	900	0	34000
2102	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2017												32000
2103	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2018												31000
2104	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2019												32000
2105	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2020												32000
2106	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2021												32000
2107	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2022												33000
2108	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2023												33000
2109	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2024												33000
2110	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2025												33000
2111	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2026												34000
2112	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2027		-100		-600	100	300	0	600	500	0	0	34000
2113	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2028		-100		-600	100	300	0	700	600	0	0	34000
2114	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2029		0		-500	100	400	5300	500	700	700	0	34000
2115	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2030		0		-500	100	500	5700	500	800	800	0	35000
2116	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2031		0		-500	100	600	6100	500	800	900	0	35000
2117	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2032		0		-500	100	600	6400	600	900	900	0	35000
2118	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2033		0		-500	100	700	6700	600	900	1000	0	35000
2119	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2034		0		-500	100	800	7000	600	900	1100	0	35000
2120	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2035		0		-500	100	900	7300	600	1000	1100	0	35000
2121	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2036		0		-500	100	1000	7400	700	1000	1200	0	35000
2122	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2037		0		-500	100	1100	7600	700	1000	1200	0	35000
2123	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2038		0		-500	100	1200	8500	700	1100	1300	0	35000
2124	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2039		0		-500	100	1300	8600	700	1100	1300	0	35000
2125	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2040		0		-500	100	1700	8900	700	1100	1400	0	35000
2126	G		10	CARLAW-LT.T1_LF	A8-9 (Formerly A1-2)			2041		0		-500	100	1900	9000	700	1100	1400	0	35000
2127	G		10	GERRARD-LT.TT1_LF	A1-2			2017												29000
2128	G		10	GERRARD-LT.TT1_LF	A1-2			2018												32000
2129	G		10	GERRARD-LT.TT1_LF	A1-2			2019												41000
2130	G		10	GERRARD-LT.TT1_LF	A1-2			2020												44000
2131	G		10	GERRARD-LT.TT1_LF	A1-2			2021												46000
2132	G		10	GERRARD-LT.TT1_LF	A1-2			2022												46000
2133	G		10	GERRARD-LT.TT1_LF	A1-2			2023												47000
2134	G		10	GERRARD-LT.TT1_LF	A1-2			2024												47000
2135	G		10	GERRARD-LT.TT1_LF	A1-2			2025												47000
2136	G		10	GERRARD-LT.TT1_LF	A1-2			2026												48000
2137	G		10	GERRARD-LT.TT1_LF	A1-2			2027		0		-600	100	400	0	500	800	700	0	48000
2138	G		10	GERRARD-LT.TT1_LF	A1-2			2028		0		-600	100	500	0	600	900	900	0	48000
2139	G		10	GERRARD-LT.TT1_LF	A1-2			2029		0		-600	100	600	0	600	900	1000	0	48000
2140	G		10	GERRARD-LT.TT1_LF	A1-2			2030		0		-600	100	700	0	700	1000	1100	0	48000
2141	G		10	GERRARD-LT.TT1_LF	A1-2			2031		0		-600	100	800	0	700	1100	1200	0	48000
2142	G		10	GERRARD-LT.TT1_LF	A1-2			2032		0		-600	100	900	0	800	1100	1300	0	48000
2143	G		10	GERRARD-LT.TT1_LF	A1-2			2033		0		-600	100	1000	0	800	1200	1300	0	48000
2144	G		10	GERRARD-LT.TT1_LF	A1-2			2034		0		-600	100	1100	0	800	1300	1400	0	49000
2145	G		10	GERRARD-LT.TT1_LF	A1-2			2035		0		-600	100	1100	6500	800	1200	1400	0	49000
2146	G		10	GERRARD-LT.TT1_LF	A1-2			2036		0		-600	100	1200	6600	800	1200	1500	0	49000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	Outlook_Name		Region	StationName	Bus			Year		PV		CS	CDM	EV	SH	Transit	WH	Storage	ICI	Outlook G
2147	G		10	GERRARD-LT.TT1_LF	A1-2			2037		0		-600	100	1300	6700	800	1300	1500	0	49000
2148	G		10	GERRARD-LT.TT1_LF	A1-2			2038		0		-600	100	1500	6900	900	1300	1600	0	49000
2149	G		10	GERRARD-LT.TT1_LF	A1-2			2039		0		-600	100	1600	6900	900	1300	1600	0	50000
2150	G		10	GERRARD-LT.TT1_LF	A1-2			2040		0		-600	100	1700	7100	900	1300	1700	0	50000
2151	G		10	GERRARD-LT.TT1_LF	A1-2			2041		0		-600	100	1900	7200	900	1400	1700	0	50000
2152	G		10	MAINS-LT.T3_LF	A1-2MN			2017												23000
2153	G		10	MAINS-LT.T3_LF	A1-2MN			2018												23000
2154	G		10	MAINS-LT.T3_LF	A1-2MN			2019												24000
2155	G		10	MAINS-LT.T3_LF	A1-2MN			2020												24000
2156	G		10	MAINS-LT.T3_LF	A1-2MN			2021												24000
2157	G		10	MAINS-LT.T3_LF	A1-2MN			2022												25000
2158	G		10	MAINS-LT.T3_LF	A1-2MN			2023												25000
2159	G		10	MAINS-LT.T3_LF	A1-2MN			2024												25000
2160	G		10	MAINS-LT.T3_LF	A1-2MN			2025												25000
2161	G		10	MAINS-LT.T3_LF	A1-2MN			2026												25000
2162	G		10	MAINS-LT.T3_LF	A1-2MN			2027		0		-500	100	300	4400	400	600	600	0	26000
2163	G		10	MAINS-LT.T3_LF	A1-2MN			2028		0		-500	100	400	5000	400	700	700	0	26000
2164	G		10	MAINS-LT.T3_LF	A1-2MN			2029		0		-500	100	500	5500	500	700	800	0	26000
2165	G		10	MAINS-LT.T3_LF	A1-2MN			2030		0		-500	100	500	5900	500	800	800	0	27000
2166	G		10	MAINS-LT.T3_LF	A1-2MN			2031		0		-500	100	600	6300	600	900	900	0	27000
2167	G		10	MAINS-LT.T3_LF	A1-2MN			2032		0		-500	100	700	6600	600	900	1000	0	27000
2168	G		10	MAINS-LT.T3_LF	A1-2MN			2033		0		-500	100	800	7000	600	900	1000	0	27000
2169	G		10	MAINS-LT.T3_LF	A1-2MN			2034		0		-500	100	800	7300	600	1000	1100	0	27000
2170	G		10	MAINS-LT.T3_LF	A1-2MN			2035		0		-500	100	900	7500	700	1000	1200	0	27000
2171	G		10	MAINS-LT.T3_LF	A1-2MN			2036		0		-500	100	1000	7700	700	1000	1200	0	27000
2172	G		10	MAINS-LT.T3_LF	A1-2MN			2037		0		-500	100	1100	7800	700	1100	1300	0	27000
2173	G		10	MAINS-LT.T3_LF	A1-2MN			2038		0		-500	100	1200	8000	700	1100	1300	0	27000
2174	G		10	MAINS-LT.T3_LF	A1-2MN			2039		0		-500	100	1300	8100	700	1100	1300	0	27000
2175	G		10	MAINS-LT.T3_LF	A1-2MN			2040		0		-500	100	1400	8200	700	1100	1400	0	27000
2176	G		10	MAINS-LT.T3_LF	A1-2MN			2041		0		-500	100	1600	8300	700	1100	1400	0	27000
2177	G		10	MAINS-LT.T3_LF	A3-4MN			2017												32000
2178	G		10	MAINS-LT.T3_LF	A3-4MN			2018												33000
2179	G		10	MAINS-LT.T3_LF	A3-4MN			2019												33000
2180	G		10	MAINS-LT.T3_LF	A3-4MN			2020												33000
2181	G		10	MAINS-LT.T3_LF	A3-4MN			2021												34000
2182	G		10	MAINS-LT.T3_LF	A3-4MN			2022												34000
2183	G		10	MAINS-LT.T3_LF	A3-4MN			2023												34000
2184	G		10	MAINS-LT.T3_LF	A3-4MN			2024												34000
2185	G		10	MAINS-LT.T3_LF	A3-4MN			2025												35000
2186	G		10	MAINS-LT.T3_LF	A3-4MN			2026												35000
2187	G		10	MAINS-LT.T3_LF	A3-4MN			2027		0		-600	100	400	4700	400	600	600	0	36000
2188	G		10	MAINS-LT.T3_LF	A3-4MN			2028		0		-600	100	400	5400	500	700	700	0	36000
2189	G		10	MAINS-LT.T3_LF	A3-4MN			2029		0		-600	100	500	5900	500	800	800	0	37000
2190	G		10	MAINS-LT.T3_LF	A3-4MN			2030		0		-600	100	600	6400	600	900	900	0	37000
2191	G		10	MAINS-LT.T3_LF	A3-4MN			2031		0		-600	100	600	6800	600	900	1000	0	37000
2192	G		10	MAINS-LT.T3_LF	A3-4MN			2032		0		-600	100	700	7200	600	1000	1100	0	38000
2193	G		10	MAINS-LT.T3_LF	A3-4MN			2033		0		-600	100	800	7500	700	1000	1100	0	38000
2194	G		10	MAINS-LT.T3_LF	A3-4MN			2034		0		-600	100	900	7900	700	1100	1200	0	38000
2195	G		10	MAINS-LT.T3_LF	A3-4MN			2035		0		-600	100	1000	8100	700	1100	1300	0	38000
2196	G		10	MAINS-LT.T3_LF	A3-4MN			2036		0		-600	100	1100	8300	700	1100	1300	0	38000
2197	G		10	MAINS-LT.T3_LF	A3-4MN			2037		0		-600	100	1200	8500	700	1100	1400	0	38000
2198	G		10	MAINS-LT.T3_LF	A3-4MN			2038		0		-600	100	1300	8600	800	1200	1400	0	38000
2199	G		10	MAINS-LT.T3_LF	A3-4MN			2039		0		-600	100	1400	8700	800	1200	1400	0	38000
2200	G		10	MAINS-LT.T3_LF	A3-4MN			2040		0		-600	100	1600	8900	800	1200	1500	0	38000
2201	G		10	MAINS-LT.T3_LF	A3-4MN			2041		0		-600	100	1700	9000	800	1200	1500	0	38000

TAB 31

Ontario

ONTARIO ENERGY BOARD

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

VOLUME:	**Technical Conference**
DATE:	**February 20, 2019**

POLES

MR. HANN: Thank you. That's all.

MR. MILLAR: Thank you very much, Mr. Hann. I want to do a time check here and see --

MR. BRETT: Mr. Millar, just a quick procedural thing. I wanted to check for all of our benefits. Mr. Keizer a while back referred to questions dealing with the consultation that innovative launched as belonging in number 2. My notes say it is number 3.

MR. KEIZER: No, you are right, Mr. Brett. It is number 3.

MR. BRETT: All right.

MR. MILLAR: Is that clear then? We have Mr. McGillivray and Mr. Garner left. Mr. McGillivray, how long will you be?

MR. MCGILLIVRAY: I estimated 20 minutes. There is a chance I could be a little bit shorter than that, but I don't know.

MR. MILLAR: If I stare at you a lot can you? Mr. Garner, you are down for about 30; is that still right?

MR. GARNER: Yes, I could fit it into that.

MR. MILLAR: We are not going to finish both of you today. We can probably get through Mr. McGillivray, so I will turn it to you, sir.

MR. MCGILLIVRAY: Sure, thank you, Mr. Millar. And good afternoon, panel. I will try to move as quickly as I can.

EXAMINATION BY MR. MCGILLIVRAY:

MR. MCGILLIVRAY: If I could take you to interrogatory 1C DRC 6, this is Toronto Hydro corporation's management's discussion and analysis included in the application.

The disclosure excerpted -- if we just go up a little bit, and the preamble discusses the asset integrity risk arising from, among other things, electrification or urban electrification in line 13. Do I have that right?

MR. LYBEROGIANNIS: Yes, line 13 makes reference to urban intensification and electrification.

MR. MCGILLIVRAY: Then policies and programs to respond to climate change in lines 14 and 15?

MR. LYBEROGIANNIS: Lines 14 and 15 do make reference to that.

MR. MCGILLIVRAY: And widespread quote-unquote adoption of EVs in line 16?

MR. LYBEROGIANNIS: Yes. Is that a question?

MR. MCGILLIVRAY: Yes, that was a question.

MR. LYBEROGIANNIS: Yes.

MR. MCGILLIVRAY: We asked you in part A to provide all data and/or studies related to EVs and EV-related loads relied upon in the disclosure. And you referred us in your answer to your approach to incorporating and EV-related load -- and I won't give the reference, but it is there.

I will get to that approach to load in a moment. But for now, can you confirm that there are no other data or studies of any kind that support the disclosure with respect to widespread adoption of electric vehicles?

[Witness panel confers]

MR. LYBEROGIANNIS: To the best of our knowledge, there are no other documents.

MR. MCGILLIVRAY: Okay. So now if we could look at that approach -- I won't go through it in detail. I don't think that is necessary, especially for the sake of time, and I will just refer back to our question related to the widespread adoption.

We asked for a quantitative assessment of that widespread adoption. You didn't give one, which I think may mean that you don't have such a quantitative assessment. And I am asking whether or not you can confirm that there is nothing other than that EV loading approach, or approach to EV loading that goes to the widespread adoption characterization.

[Witness panel confers]

MR. LYBEROGIANNIS: So what has been included in the reference that is included there to Exhibit 3, tab 1, schedule 1, which section 3.2 at page 7 -- we can bring it up. But in that reference, Toronto Hydro does confirm that to date, any impacts on overall loads and demands on Toronto Hydro's system have not been determined to be material.

MR. MCGILLIVRAY: Okay. I think that at one point in that approach, probably on this page that we're looking at here, you say -- you make reference to multivariate regression models that are discussed, I think, in the prior section.

I am helping you can help me understand what potential load impacts from EVs and distributed generation may already be reflected in the multivariate regression models.

MR. LYBEROGIANNIS: If you are asking specifically for the models that are discussed in Exhibit 3, I believe that is panel 3, if I am not mistaken. They can provide details about specifically how all of that was derived.

MR. MCGILLIVRAY: Okay. So my next question is going to be would you be able to elaborate on what additional data and information you believe may be -- you may need in order to be able to confidently include and back the EVs, and distributed energy resources on loads and demands. But maybe I will take that to panel 3 as well?

MR. KEIZER: Yes, you should.

MR. MCGILLIVRAY: If I could move back to that interrogatory, so it is 1C-DRC-6, and part B, in the response you make reference to Exhibit 2B, section D3.3, the asset utilization policies and practices.

Could you explain how D3.3 addresses system upgrades to address EV loading considerations?

MR. LYBEROGIANNIS: Sorry, Mr. McGillivray, may I ask you to repeat your question?

MR. MCGILLIVRAY: Sure. I didn't go through the whole response, but you gave us a few examples, a few sections from Exhibit 2B, the Distribution System Plan.

And what I am wondering -- I think I understand the other two examples, but I don't know the connection between D3.3 and the EV loading considerations.

So my question is whether or not you can explain how

D3.3 addresses system upgrades to address EV loading considerations.

MR. LYBEROGIANNIS: So section D3.3 speaks to simply our asset utilization policies and practices. Let me just bring that up on my notes here.

So if we are to bring up D3.3, which is at page 37 of Exhibit 2B, section D3. Specifically there, it speaks to Toronto Hydro's approach to load forecasting. The implications of EV-related load are considered as part of Toronto Hydro's load forecasts, which then --you mentioned in the precursor to your question that you understood the relationship to the station expansion program, which is the second bullet. So the load forecast that is done underpins the station expansion program that Toronto Hydro is looking to implement.

MR. MCGILLIVRAY: Okay. So if I am right, D3.3 feeds into 7.4 as it relates to EV load?

[Witness panel confers]

MR. LYBEROGIANNIS: Yes, that's correct.

MR. MCGILLIVRAY: Thank you. If we could move back to 1C-DRC-6 and look at your response to part C and the final paragraph.

> "Toronto Hydro continues to monitor the technology and the effect of EVs on the safety and reliability of the distribution system."

I am wondering if you can tell me more about what those monitoring efforts look like.

MR. LYBEROGIANNIS: Broadly speaking, the monitoring efforts can be broken out into two categories. One would be simply monitoring publicly available information around the adoption of EVs, more broadly. The second category would be in relation to the aforementioned load forecasting that Toronto Hydro does on an annual basis in review of the load that we are seeing at the station level, at the feeder level, to determine if the adoption of EVs is placing the system at risk or if there is growth that we would need to respond to through a program such as station expansion.

MR. MCGILLIVRAY: Thank you. And I guess my follow-up would be, of those two forms or streams of monitoring, are either of them formalized or documented in any way?

MR. LYBEROGIANNIS: Our load forecasting certainly is, yes.

MR. MCGILLIVRAY: Specifically with respect to electric vehicles?

MR. LYBEROGIANNIS: The information from our load forecast can be found in the application itself, such as the station expansion program, and how loads at particular stations are -- are trending or forecasts associated with those. So those are published. Those are available within the filing itself.

MR. MCGILLIVRAY: So there is nothing related to electric vehicles that I am missing on that front?

MR. LYBEROGIANNIS: With respect to electric vehicles I think, as we have said in a couple of the interrogatory responses, we don't see that adoption as a material issue for us at this point in time.

MR. MCGILLIVRAY: Okay, thank you. If we could move to 1B-DRC-2, part B. If you could scroll down a little bit. I think also the last paragraph here, Toronto Hydro makes reference for a need for further analysis.

My question broadly is, if such further analysis were to be undertaken, what would it look like? What additional information does Toronto Hydro need in order to conduct the analysis? And this relates to electric vehicles and distributed energy resources and their capacity to potentially enhance electricity reliability generally, and any specific load reliability areas of the service territory.

MR. TAKI: For clarity, are you referring specifically to what is known as vehicle to grid technologies?

MR. MCGILLIVRAY: I think that could be one example.

MR. TAKI: Do you have other examples?

MR. MCGILLIVRAY: No. Not at my fingertips.

MR. TAKI: Okay. With respect to that example, it is Toronto Hydro's position that that technology is not yet mature. We recognize that it may have potential, and in this IR, when we say there is a need for further analysis, what we're saying is that we would like to continue to monitor that technology and see how it evolves and what opportunities and benefits it may provide, and we will continue to assess those potential benefits.

MR. MCGILLIVRAY: Okay, thank you.

I think this is my final area. If we move to 2B-DRC-8. I think it is in part A, under the second bullet:

"Toronto Hydro expects over 581 megawatts of incremental distributed generation by 2024."

And then references are made to Exhibit 2B, E5.1 and E5.5. My question is, do the energy storage forecast figures capture any energy storage that may be facilitated by the adoption of electric vehicles? And this goes back to the original question in part A, but just looking for some clarity on that.

MR. TAKI: May I ask you to repeat your question, please?

MR. MCGILLIVRAY: Sure. The question is, do the energy storage forecast figures capture any energy storage that may be facilitated by the adoption of EVs? And maybe for more colour, in Exhibit 2B E5.5, it seems that it includes initial consultations regarding net metering, CHP closed transition, load displacement, and certain IESO programs and the energy storage procurement. That may be one of the IESO programs. But I am not sure if any of those would also capture energy storage facilitated by EVs.

MR. TAKI: Can you clarify what you mean by "energy storage facilitated by EVs"?

MR. MCGILLIVRAY: So I think it goes to what you asked me a moment ago, vehicle-to-grid sort of situation.

MR. TAKI: Like I said, vehicle-to-grid from our perspective is not a mature technology, from our perspective, and we will continue to monitor the opportunities that it does provide.

Where there are specific projects that come forward requesting connection, where they entail vehicle to grid, those will be opportunities that Toronto Hydro will leverage to further evaluate the technology.

MR. MCGILLIVRAY: So I think I can take from that that the energy storage forecast figures that go into that 581-megawatt of incremental DG by 2024, they don't capture energy storage facilitated by EVs?

MR. TAKI: I think in the interests of time it is something we could take away and confirm.

MR. MILLAR: That would be JTC2.30.

UNDERTAKING NO. JTC2.30: TO ADVISE WHETHER THE ENERGY STORAGE FORECAST FIGURES THAT GO INTO THAT 581-MEGAWATT OF INCREMENTAL DG BY 2024 CAPTURE ENERGY STORAGE FACILITATED BY EVS.

MR. MCGILLIVRAY: Those are my questions, thank you, panel.

PROCEDURAL MATTERS:

MR. MILLAR: Thank you, Mr. McGillivray.

We're going to call it a day here, and I am going to suggest we have some discussions about the schedule, but we can go offline for that, I think, and release the poor court reporter to crack her knuckles and stretch her hands after a very long day. So unless there are any final matters that need to be said on the record I am going to conclude today's session, and we are now offline.

--- Whereupon the conference adjourned at 5:11 p.m.

TAB 32

ONTARIO ENERGY BOARD

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

VOLUME: **Technical Conference**

DATE: **February 21, 2019**

EXAMINATION BY MR. MCGILLIVRAY:

MR. McGILLIVRAY: Thank you, Mr. Millar and good afternoon, panel. My name is Donald McGillivray and I am counsel for the Distributed Resource Coalition.

If we can go to 2B-DRC-11 and stop at the preamble, generally we are looking here at control centre operations, which goes to Exhibit 4A, tab 2, schedule 7, and the control centre operations reinforcement program, which goes to Exhibit 2B, section E8.1.

And one of the themes here, if I can summarize, is that control centre support, what is termed the smart grid echo system which comprises renewable and other distributed energy resources, electric vehicles and energy storage. Am I summarizing that fairly?

MR. NAHYAAN: Yes.

MR. McGILLIVRAY: And you also acknowledge that market penetration of these things will likely increase the volume or complexity of control centre activities. Do I have that right as well?

MR. NAHYAAN: Yes.

MR. McGILLIVRAY: We asked you in the interrogatory to explain that in some detail, and you provided in the table starting on page 2, a directional summary of the general impacts on complexity and volume of control centre operations.

And we also made reference in our question to any supporting data. So my first question is whether you can confirm that there is no supporting data on these impacts that's not included in this response?

MR. KEIZER: Sorry, can you just clarify what you mean by supporting data?

MR. McGILLIVRAY: Sure. I think we are referring probably to background information, whether it's quantitative or qualitative, that would support the directional summary that's produced in this table 1, or if this table 1 is the whole of it?

MR. NAHYAAN: Subject to check, the only piece of background data that's available to us are the electrical utility safety rules, which essentially describe what safety precautions are required for operating in an environment where there is distributed energy resources in terms of isolations, as well as grounding practices.

There is a reference to that evidence -- I am having a little difficult time finding where exactly it is. That would be the specific background data that I can refer to in terms of writing this response. The rest of it is directional and based on our expert opinion.

MR. McGILLIVRAY: Okay, thank you. And just to be clear, are those rules Toronto Hydro's rules or are they external to Toronto Hydro?

MR. NAHYAAN: Those would be the safety rules actually implemented in Ontario.

MR. McGILLIVRAY: Okay, thank you. If we scroll down to page 3 of 3 here, I am interested in particular in the second and third bullets under the electrical vehicles row.

The first one -- well, the second one, I guess, is electric vehicles can feed excess power back to the grid. And I have the same question for both of these, so I can also look at the second one:

"Mobility of electric vehicles can result in more volatility in local electricity demand. (Vehicles will be connected to different circuits depending on what charging stations they are using at a given point in time)."

My question is for each of these bullets, can you help me make the link between the bullet and the impact on complexity and volume of control centre operations, which is the heading for that column in the table?

MR. NAHYAAN: So in terms of the -- both these references underpin the actual geographical position or the locational difference from a traditional static load on the system versus an electric vehicle. The vehicle could be loading from a different part in the system, if it's in loading mode, and that puts a strain on that specific part of the system.

And if it's in back feed mode where it's actually becomes a resource into the grid, depending on the location, that has an impact in terms of analysis.

So if there is a proliferation of electric vehicles -- even if it's not a proliferation, but a specific certain number, maybe not material in size, but still a certain number exists, the control centre needs to at a minimum monitor those specific electric vehicles connecting to the grid.

It is our view that with the advent of smart grid, these capabilities need to be inherently built in an advanced control centre operations.

MR. McGILLIVRAY: Have you looked at what that threshold is? At what level of EV adoption does the control centre need to start doing that?

MR. NAHYAAN: I don't think there is an industry-acceptable threshold that's available publicly beyond which a control centre has to evolve to another level of sophistication. It really is dependent on the actual grid operating, depending on the proliferation of the EVs in a certain jurisdiction, and also the sophistication and the business impact that that specific utility will face in terms of responding to that kind of a new technology being added to the grid. So my understanding would be there is no acceptable or accepted or widely used threshold to make that determination.

MR. McGILLIVRAY: Okay. And just to be clear, Toronto Hydro doesn't have a threshold of its own on that point either?

MR. NAHYAAN: No.

MR. McGILLIVRAY: Okay. I am going to move to 4A-DRC-12, and I just have a few brief questions on part B of your response to this interrogatory, which refers to a modification to PowerLens, the residential PowerLens portal, in late 2018 to enable residential customers to better understand electricity consumption associated with EV charging, and you're saying that the modification was funded by the IESO's conservation program and focuses solely on electricity conservation.

Would it be easy for you to provide screenshots of what this aspect of PowerLens looks like?

MR. KEIZER: That's fine.

MR. McGILLIVRAY: Can we do that by undertaking?

MR. MILLAR: JTC3.24.

UNDERTAKING NO. JTC3.25: TO PROVIDE SCREENSHOTS OF WHAT ASPECTS OF POWERLENS LOOKS LIKE.

MR. McGILLIVRAY: Thank you.

And then to look just briefly --

MR. SASSO: Sorry, is that 34 or 25?

MR. MILLAR: I had it 24, but do I have 24 twice? Let's call it 25 so there's no confusion, and if there's no 24 that's fine. Okay. So that's 3.25.

MR. McGILLIVRAY: Thank you. And just to go back briefly to the question in part B, how we are asking about expanding the capabilities, and you referred to that one from late 2018.

My question is whether Toronto Hydro currently intends to carry out any further modification of My Toronto Hydro or PowerLens in relation to electric vehicles and electric vehicle charging?

MS. PAGE: So this is something we are monitoring. It's an evolving industry and we're -- we take our direction from our customers, so as we hear from our customers and understand their needs then we will look to evolve any systems or services that we offer to our customers.

MR. McGILLIVRAY: And is that through the customer engagement portion of your activities or does PowerLens accomplish any sort of customer feedback? Or is it something else?

MS. PAGE: It would be typically through all channels dealing with customers, not just a formal customer engagement approach, but any of the avenues or communication channels we have with customers, where we take information and we use that information and build that into our plans.

MR. McGILLIVRAY: Have you received any feedback to date in relation to this specific thing, PowerLens, the use of PowerLens or My Toronto Hydro in relation to electric vehicles?

MS. PAGE: Not specifically beyond the modification we made recently to the PowerLens portal.

MR. McGILLIVRAY: Okay. Thank you. Those are my questions.

MR. MILLAR: Thank you, Mr. McGillivray, and I think that concludes the questions for this panel, so thank you very much, and you are excused.

Can we call up the next panel, at least get them introduced.

MR. KEIZER: Yes.

MR. MILLAR: And if we have a few minutes -- you have a few questions, Mr. Rubenstein -- we will see what we can get through. We obviously cannot stay much longer, but

TAB 33

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Ontario

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: