REVENUE REQUIREMENT

1. SUMMARY OF REVENUE REQUIREMENT

Hydro One Transmission follows standard regulatory practice and has calculated its revenue requirement as follows:

Table 1: Revenue Requirement ($ Millions)

Components	2018[1]	2019[2]	2020	Reference
OM&A	394.3		375.8	Exhibit F, Tab 1, Schedule1
Depreciation and Amortization	468.6		474.6	Exhibit F, Tab 6, Schedule 1
Income Taxes	57.2		48.3	Exhibit F, Tab 7, Schedule 2, Attachment 1
Return on Capital	703.6		775.0	Exhibit G, Tab 1, Schedule 1
Total Revenue Requirement	**1,623.8**	**1,644.4**	**1,673.8**	
Deduct External Revenues and Other [3]	(54.7)	(54.5)	(52.6)	
Rates Revenue Requirement	**1,569.1**	**1,589.9**	**1,621.2**	
Regulatory Deferral and Variance Accounts Disposition / Foregone Revenue	(58.4)	(37.6)	6.8	Exhibit H, Tab 1, Schedule 3
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,510.7**	**1,552.3**	**1,628.0**	

Note 1: Represents OEB approved 2018 revenue requirement from Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160
Note 2: Represents OEB approved 2019 revenue requirement in EB-2018-0130
Note 3: External Revenue and Other includes External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit

The above Revenue Requirement is the amount required by Hydro One Transmission to achieve its business objectives and aligns customer needs and preferences, responsible stewardship of a safe and reliable system, and impact on rates. The proposed Revenue Requirement is a reflection Hydro One's commitment to pursuing efficiencies and improved productivity before requesting its customers pay more.

2. CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components are as follows:

2.1 OM&A EXPENSE

Table 2: OM&A Expense ($ Millions)

	2020
Sustaining	214.2
Development	6.9
Operations	48.9
Customer Service	7.5
Common Corporate Costs and Other Costs	30.3
Property Taxes & Rights Payments	68.1
Directive *	-0.1
Total OM&A	**375.8**

*Directive refers to the Government Directive as detailed and defined in Exhibit F, Tab 4, Schedule 1.

2.2 DEPRECIATION AND AMORTIZATION EXPENSE

Table 3: Depreciation and Amortization Expense ($ Millions)

	2020
Depreciation	461.8
Amortization	12.8
Total Expense	**474.6**

2.3 CORPORATE INCOME TAXES

Table 4: Corporate Income Taxes ($ Millions)

	2020
Regulatory Taxable Income	307.3
Tax Rate	26.5%
Subtotal	**81.4**
Less: Credits	(0.3)
Less: Deferred Tax Asset Sharing	(32.8)
Total Income Taxes	**48.3**

2.4 RETURN ON CAPITAL

Table 5: Return on Capital ($ Millions)

	2020
Return on Debt	330.6
Return on Equity	444.5
Return on Capital	**775.0**

3. REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

Table 6 below provides a summary of the value of the key impacts compared to the Year 2018 approved Revenue Requirement (as per EB-2016-0160) with the Year 2020 proposed Revenue Requirement. 2018 is used as a basis of comparison, instead of 2019, as it represents the last rebasing year for Hydro One Transmission.

Table 6: **Impact of the Individual Component on Rates Revenue Requirement**

Description	**2020 vs. 2018 ($ millions)**	**2020 vs. 2018 (%)**
Increase in OM&A	-18.5	-1.2%
Rate Base Growth	82.0	5.4%
Lower cost of debt	-4.5	-0.3%
Tax	-8.9	-0.6%
Impact on Revenue Requirement	**50.1**	**3.3%**
External Revenue	2.1	0.1%
Regulatory Deferral and Variance Accounts Disposition	65.2	4.3%
Total Change	**117.3**	**7.8%**

Revenue Requirement: 2020 vs. 2018 ($ Millions)

The increase in revenue requirement is predominantly driven by rate base growth and regulatory deferral account disposition, which is partially offset by lower OM&A costs and lower cost of debt.

CALCULATION OF REVENUE REQUIREMENT

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Revenue Requirement
Year Ending December 31
($ Millions)

Line No.	Particulars	2020 (a)
	Cost of Service	
1	Operating, maintenance & administrative	$ 375.8
2	Depreciation & amortization	474.6
3	Income taxes	48.3
4	Cost of service excluding return on capital	$ 898.8
5	Return on capital	775.0
6	Total revenue requirement	$ 1,673.8

Witness: Joel Jodoin

EXTERNAL REVENUES

1. INTRODUCTION

This Exhibit describes Hydro One's work and associated external revenues that are used to calculate rates revenue requirement as detailed in Exhibit E, Tab 1, Schedule 1.

Hydro One's strategy is to focus on core work, while continuing to be responsive to external customer work requests where Hydro One has available resources and/or assets to accommodate the request.

External revenues earned through the provision of services to third parties are forecast to be $31.4 million in 2020 and remain relatively flat through to 2022. External revenues account for approximately 1.9% of Hydro One Transmission revenues in 2020. These external revenues are used to offset the revenue requirement from Hydro One Transmission tariffs and thereby reduce the required revenue to be collected from transmission ratepayers.

2. COSTING AND PRICING

The costing of external work is determined on the basis of cost causality, with estimates calculated in the same way as internal work estimates, using the standard labour rates, equipment rates, material surcharge, and overhead rates. (See Exhibits C, Tab 9, Schedule 1 to 4 for a description of costing of work.) An appropriate margin is added to cover, at a minimum, market level pricing in order to ensure there is an overall benefit for the transmission ratepayers.

3. DESCRIPTION

Table 1 details Hydro One Transmission’s external revenues for the period 2015 to 2019.

Table 1: External Revenues ($ Millions)

$M	2015 Historic	2016 Historic	2017 Historic	2018 Historic	2019 Bridge (Forecast)
Secondary Land Use	34.3	24.9	20.1	25.6	17.6
Station Maintenance	9.5	6.2	3.9	4.6	4.0
Engineering & Construction	0.4	0.2	0.3	0.1	0.3
Other External Revenues	10.1	11.0	11.2	9.1	9.4
Totals	**54.3**	**42.3**	**35.5**	**39.4**	**31.3**

Table 2 details Hydro One Transmission’s external revenues for the period 2020 to 2022.

Table 2: External Revenues ($ Millions)

$M	2020 Test	2021 Test	2022 Test
Secondary Land Use	17.9	18.2	18.5
Station Maintenance	4.0	4.0	4.0
Engineering & Construction	0.3	0.3	0.3
Other External Revenues	9.2	10.3	9.4
Totals	**31.4**	**32.7**	**32.2**

3.1 SECONDARY LAND USE

Hydro One manages the Provincial Secondary Land Use Program ("PSLUP") on behalf of the Province, to whom Hydro One's transmission corridor lands were transferred under Bill 58 on December 31, 2002. The program focuses on licensing and leasing the transmission corridor lands to external parties for "secondary" land use purposes that are compatible with Hydro One Transmission's primary business operations. Typical uses include parking lots, municipal roadways, parks and trails, agricultural areas, water mains and other municipal infrastructure occupations, as well as public transit parking lots and station operations. The PSLUP revenue stream is generated by charging land rentals to external parties for new license and lease occupations and subsequent agreement renewals, as well as lump sum consideration for easements granted (e.g., water mains) and operational land sales completed (e.g., roadway).

Under Bill 58 provisions (*An Act to amend certain statutes in relation to the energy sector*, c.1, S.O. 2002) and subsequently negotiated arrangements, all expiring corridor PSLUP agreements were transferred to the Province as of December 31, 2002. Remaining unexpired corridor agreements and associated revenue streams are retained by Hydro One until such time as these agreements expire. Upon expiration, the previously retained agreements and revenue streams by Hydro One are then also transferred to the Province under the PSLUP.

Notwithstanding this transfer, Hydro One has provided front-line delivery services for the PSLUP on behalf of the Province since 2002. As of April 1, 2015, Hydro One was granted the right under agreement to continue delivery of the program through March 31, 2020. The arrangements set out in the agreement include Hydro One's retention of PSLUP revenues for unexpired agreements until their expiry, as well as a results-based compensation model involving the sharing of revenues between Hydro One and the

Province for new PSLUP agreements and for renewals of expired agreements which were previously transferred to the Province. Hydro One also manages a small portion of secondary land use revenue that does not fall under current PSLUP arrangements.

As a result, responsibility for the management and re-negotiation (as required) of all existing secondary land use agreements (including those previously transferred to the Province under the corridor land transfer arrangements) now rests with Hydro One. Hydro One will continue promoting and negotiating all new secondary land use business opportunities, where these are consistent with Hydro One Transmission’s short and longer-term operational requirements.

The secondary land use revenue levels were $25.6 million in 2018. They are forecasted to drop to $17.6 million in 2019 and remain relatively flat during the test years as the one-time transactions described below are not anticipated. Historical figures in years 2015 to 2018 are higher due to unbudgeted one-time transactions involving easement grants (e.g. water mains) and operational land sales (e.g. roadways).

3.2 STATION SERVICES

Revenues from external work in the station services segment include specialized activities similar to those performed internally for Hydro One Transmission. These activities include repairing electrical equipment (such as transformers, breakers and switches), specialty machining (spindles), protective relay installation, maintenance and calibration, coordinating services to reconnect modified systems to the network, as well as providing meter services and emergency services. Customers seek out station services skills resident within Hydro One, requiring highly specialized staff able to perform work on a variety of high voltage equipment in a variety of work settings (such as nuclear environments). Work is performed according to commercially negotiated contracts which reflect market level pricing.

Hydro One provides support to the external market place in areas which are related to Hydro One Transmission. This work is primarily tied to support Ontario's key generation suppliers: Bruce Power LLP, Ontario Power Generation Inc. and Siemens Westinghouse Inc. in support of Ontario Power Generation Inc.

As can be seen in Table 2, this segment of external revenue is expected to remain flat in 2020 through to 2022, primarily due to a consistent volume of work from major customers. The reduction in revenue beginning in 2015 was mainly due to Hydro One concentrating more on its own work program requirements. The biggest customer impacted was OPG, and it contracted most of the shortfall from Hydro One to Areva. Hydro One helped with the transition. In 2019, Hydro One anticipates this segment of external revenue to continue to stabilize at the level anticipated for the test period.

3.3 ENGINEERING AND CONSTRUCTION

Hydro One's engineering and construction activities focus on internal work supporting the growing Hydro One Transmission work program, while striving to reduce external work to a minimal level. This segment of external revenue was derived from upgrading revenue meters at various sites pursuant to IESO requirements. This work was completed in 2015. There is minimal work that remains for Hydro One Telecom, and the revenue forecast will stay flat for the period 2020-2022.

3.4 OTHER

"Other" external revenues include revenues from providing telecommunications services to Ontario Hydro successor companies (such as lease of fibre), revenues from special transmission planning studies, customer shortfall payments (e.g. true-ups, temporary bypass), and other miscellaneous external revenues. These include transfer price charges to Hydro One's affiliate companies as described in Exhibit E, Tab 2, Schedule 2. Revenue in 2018 is lower relative to 2017 levels mainly due to a decrease in customer shortfall payments. From 2020 to 2022, forecasted revenues include approximately $4 million each year for the lease of idle transmission lines.

Appendix 2-H
Tx External Revenue

USoA #	USoA Description	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Bridge 2019	Test Year 2020	Test Year 2021	Test Year 2022
	Reporting Basis								
4235	**Tx External Revenue**	$ 54.3	$ 42.3	$ 35.5	$ 39.4	$ 31.3	$ 31.4	$ 32.7	$ 32.2
Total		$ 54.3	$ 42.3	$ 35.5	$ 39.4	$ 31.3	$ 31.4	$ 32.7	$ 32.2

Description	**Account(s)**
Tx External Revenue:	4235

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

Account 4235 -Tx External Revenue

	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Bridge 2019	Test Year 2020	Test Year 2021	Test Year 2022
Reporting Basis								
Secondary Land Use	$ 34.3	$ 24.9	$ 20.1	$ 25.6	$ 17.6	$ 17.9	$ 18.2	$ 18.5
Station Maintenance	$ 9.5	$ 6.2	$ 3.9	$ 4.6	$ 4.0	$ 4.0	$ 4.0	$ 4.0
Engineering & Construction	$ 0.4	$ 0.2	$ 0.3	$ 0.1	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Other External Revenues	$ 10.1	$ 11.0	$ 11.2	$ 9.1	$ 9.4	$ 9.2	$ 10.3	$ 9.4
Total	$ 54.3	$ 42.3	$ 35.5	$ 39.4	$ 31.3	$ 31.4	$ 32.7	$ 32.2

AFFILIATE REVENUES

1. INTRODUCTION

This Exhibit discusses the agreements between Hydro One Networks Inc. (in this Exhibit, "Hydro One Networks") and its affiliates for common administrative and corporate services, utility operation and maintenance services, and telecommunication services. It does not address connection agreements, connection and cost recovery agreements, asset leases (unless otherwise specified), grants of real property rights, or agreements for project work, or agreements to purchase or deliver power. The costs included here are not included in External Revenues as they are allocated directly through the Common Corporate Cost Allocation methodology as described in Exhibit F, Tab 2, Schedule 6 or directly charged based on the cost of the service provided.

Hydro One Limited's corporate structure is detailed in Exhibit A, Tab 5, Schedule 1, Attachment 1.

2. AFFILIATE AGREEMENTS FOR SERVICES THAT CONTINUE THROUGH THE TEST YEARS

Inter-affiliate agreements define the services being sold and purchased between affiliated companies. They are reviewed and approved by each company's chief executive officer or other accountable officer.

Table 1 lists the current agreements between Hydro One affiliates that govern the inter-affiliate transactions which should continue through the bridge year 2019 and the test year 2020.

Table 1: Service Level Agreements

Service Provider	**Service Recipient(s)**	**Description of Services**
Hydro One Inc.	Hydro One Limited Hydro One Networks Hydro One Remote Communities Inc. Hydro One Telecom Inc. Hydro One Sault Ste. Marie	***a) General Counsel and Secretary services*** – Professional legal advice and input as well as guidance on business ethics and support in the form of a business code of conduct. ***b) President / CEO / Chairman services*** – Strategic direction and management. ***c) Chief Financial Officer services*** – Review of policies and procedures, investment decisions, treasury operations and tax planning, financial control and reporting.
Hydro One Networks	Hydro One Limited Hydro One Inc. Hydro One Remote Communities Inc. Hydro One Telecom Inc. B2M GP Inc. on behalf of B2M Limited Partnership Hydro One Sault Ste. Marie	***a) General Counsel, Regulatory Services and Secretary Services*** – Professional legal advice and input and regulatory services. ***b) Financial Services*** – Financial information, business planning and decision support, budgeting and financial reporting as well as other financial services such as treasury/pension, taxation, financial systems and services, cost and inventory accounting, decision support, and fixed asset and general accounting and audit-related services. ***c) Corporate Services*** – Facility management and support services, outsourcing services, human resource services, labour relations, corporate communications and security, First Nations and Métis relations, information technology services, computer equipment leases, telecommunication services, and EVP office operations. ***d) Telecommunications Services*** – Various telecommunications-related services, including field and engineering, logistics, corporate, construction, telecommunication and information technology services. ***e) System Services*** – Use of Common computer infrastructure and software such as SAP (Remote Communities and Telecom only). ***f) Other Services*** – Inergi-related services including customer services operation, settlements, finance, human resources and information technology.

Service Provider	Service Recipient(s)	Description of Services
Hydro One Telecom Inc.	Hydro One Networks	***Telecommunication Management Services*** – Monitoring of power system tele-protection, including analogue and digital microwave, PLC, fibre optic, radio and other systems; monitoring, management and operation of power system and business system telecom services; and providing alarm based services, coordinated network management services, systems analysis services and carrier/vendor management services on behalf of both power system and business system telecommunications.
Hydro One Networks	Hydro One Remote Communities Inc.	***Master Agreement for Utility Operation Services*** – Forestry services, work methods and training services, metering/technician services, lines services, safety services, fleet services, environmental services, engineering services, flight services, distribution planning and technical services, joint use services, and health and safety services.
Hydro One Networks	B2M GP Inc. on behalf of B2M Limited Partnership	***a) Lines and Forestry Services*** –Line patrols and maintenance, and vegetation management services. ***b) Management Services -*** Services to assist with the performance of B2M GP Inc.'s management activities.
Hydro One Networks	Hydro One Sault Ste. Marie	***Network Operations Services*** – Monitoring, control and operation of the transmission system, emergency response to transmission system events, outage processing, crew dispatching, record maintenance, power system IT support.
Hydro One Networks	Hydro One Telecom Inc.	***Supply Chain Services*** – Management and procurement, vendor management, process development, data management, and investment recovery.
Hydro One Networks	Hydro One Remote Communities Inc.	***Supply Chain Services*** – Management and procurement, vendor management, process development, data management, and investment recovery.
Hydro One Remote Communities Inc.	Hydro One Networks	***Metering and Lines Services*** – Metering/technician work, lines work, and training.

Service Provider	**Service Recipient(s)**	**Description of Services**
Hydro One Networks	Hydro One Sault Ste. Marie	***Master Agreement*** – Asset and work management services, engineering services, environmental services, facilities, fleet services, flight safety services, forestry services, health and safety services, joint use services, large customer account services, safety services, settlement services, supply chain, transmission, construction and maintenance services

3. KEY TERMS

The affiliate agreements govern Hydro One Networks' provision of certain common administrative and corporate services and utility operation and maintenance services to its affiliates, as well as the receipt by Hydro One Networks of operating, certain common administrative and corporate, and telecommunications services from its affiliates.

In accordance with the OEB's Affiliate Relationships Code, the affiliate agreements describe the nature of, and the fees payable for, the services they govern. The agreements include reasonable confidentiality, liability, and indemnification provisions. They also describe dispute resolution processes to which the parties must adhere in resolving disputes under the agreements. More details on the key terms relevant to this Application are provided below.

3.1 FEES PAYABLE

As prescribed by the Affiliate Relationships Code, where Hydro One Networks provides a service, resource product or use of asset to an affiliate, it charges no less than the greater of: (i) the market price of that service, product, resource or use of asset; and (ii) the company's fully-allocated cost to provide that service, product, resource or use of asset. In purchasing a service, resource, product or use of asset from an affiliate, Hydro One Networks pays no more than the market price for that service, product, resource or use of asset. Where no market exists, Hydro One Networks charges no less than its fully-allocated cost to provide the service, product, resource or use of asset, and shall pay no more than the affiliate's fully-allocated cost to provide the service, product, resource or use of asset.

Where the fees payable for the services delivered between affiliates are cost-based, such costs may be billed directly to the affiliate, and the governing agreement will specify these fees. Alternatively, costs may be allocated across a number of affiliates, based on the proportion of a given service used by the affiliate or the benefit derived. Where this is done, a cost allocation model is used, as described in Exhibit F, Tab 2, Schedule 6.

Attachment 1 to Exhibit F, Tab 2, Schedule 1 sets out the fees paid to Hydro One Networks by its affiliates for certain administrative, corporate and operational services for the years 2015 through 2017 and the forecasted fees payable for 2018, the 2019 bridge year and the 2020 test year. Attachment 1 also sets out the forecasted annual fees payable by Hydro One Networks to its affiliates for certain common administrative and corporate services, telecommunications and security-related services, and certain operational services for the same period of time.

3.2 OTHER KEY TERMS

The affiliate agreements contain reasonable confidentiality clauses requiring each party to protect the confidentiality of the other party's non-public, sensitive information, such as information relating to a customer, electricity end user, smart sub-metering provider, wholesaler, retailer, or generator. The agreements also prescribe security safeguards to be adhered to by the party receiving such confidential information.

Generally, under the affiliate agreements, intellectual property rights to any reports or other deliverable that is to be delivered under an affiliate agreement vests with the service recipient, and the recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate.

The affiliate agreements also contain reciprocal indemnification clauses wherein each party agrees to indemnify the other against damages attributable to the indemnifying party's wrongful actions. These clauses contain common exclusions of liability for certain categories of damages.

BUSINESS LOAD FORECAST AND METHODOLOGY

1. INTRODUCTION

This Exhibit discusses the Hydro One Transmission system load forecast and the related methodology. The key load forecast supporting Hydro One's transmission rate case is the hourly demand load forecast by customer delivery point. This forecast is used to prepare the charge determinant forecast for the following rate categories: Network Pool, Line Connection Pool, and Transformation Connection Pool. The load forecast in support of this Application was prepared in December 2018, using the available economic and forecast information.

Hydro One Transmission's forecast of average 12-month peak load for 2020 to 2022 for Ontario as a whole and for its three rate categories are shown in Table 1. The impacts of Conservation and Demand Management ("CDM") and embedded generation are included.

Table 1: Hydro One's 2020-2022 Load Forecast (12-Month Average Peak in MW)

		Hydro One Rate Categories (Charge Determinants)		
	Ontario Demand	**Network Connection**	**Line Connection**	**Transformation Connection**
2020	19,586	19,604	19,071	16,252
2021	19,451	19,469	18,941	16,142
2022	19,304	19,322	18,800	16,021

Hydro One worked with the Independent Electricity System Operator ("IESO") and used their latest CDM assumptions in preparing the load forecast in this rate application, as detailed in Section 3.6 below.

2. A SUMMARY OF HYDRO ONE'S LOAD FORECAST METHODOLOGY AND ASSUMPTIONS

Hydro One uses a number of methods, such as econometric models, end-use models, customer forecast surveys and hourly load shape analyses to produce the forecasts required for its transmission business. This is the same load forecast methodology used and approved by the Ontario Energy Board ("OEB") in previous Hydro One rate applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, and EB-2016-0160) taking into account the implications of latest available information (e.g., statistical significance of variables used). In the EB-2014-0140 proceeding, for the purposes of reaching settlement, the forecast was modified as discussed in Section 4.1.2. All forecasts presented in this Exhibit are weather-normalized, meaning that abnormal weather effects are removed from the base year for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years. Hydro One Transmission continues to believe that this methodology is appropriate for reasons specified below.

All of the forecasts produced are internally consistent. Therefore, forecasts for all customer delivery points add up to the total for the entire customer base served by Hydro One Transmission's system. Hydro One Transmission's forecasting methodology comprises a combination of elements that include consensus input, updates to changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and efficiency improvement standards.

Section 3 discusses in detail, the various economic inputs taken into consideration when applying the methodology for deriving the load forecasts. Economic inputs are based on analyses prepared by major economic establishments in the country, such as all major banks, IHS Global Insight, the Conference Board of Canada, the Centre for Spatial Economics and the University of Toronto. Efficiency standard assumptions used in the end-use models are based on discussions with the IESO staff. Specific customer development is based on forecast survey results from major customers. Inputs from these entities form the economic database (referred to henceforth as the economic forecast) that is used to establish Hydro One Transmission's load forecast. The forecasts presented in this Exhibit are consistent with the economic assumptions used in the investment planning process as described in Section 2.1 of the TSP provided at Exhibit B, Tab 1, Schedule 1.

3. KEY ASSUMPTIONS THAT INFLUENCE HYDRO ONE TRANSMISSION'S LOAD FORECASTS

Key assumptions must be taken into account in the process of developing load forecasts and in the application of the forecasting methodologies. The elements of the forecasting process used by Hydro One are based on the knowledge of how the major economic drivers that affect the usage of electricity demand are likely to evolve over the forecast period of 2019 to 2022. Consequently, for the purpose of this Application, the focus is on the forecast period and the load forecast will reflect those impacts that are likely to have a major effect in this respect. The key assumptions used in the analysis are summarized in Figure 1.

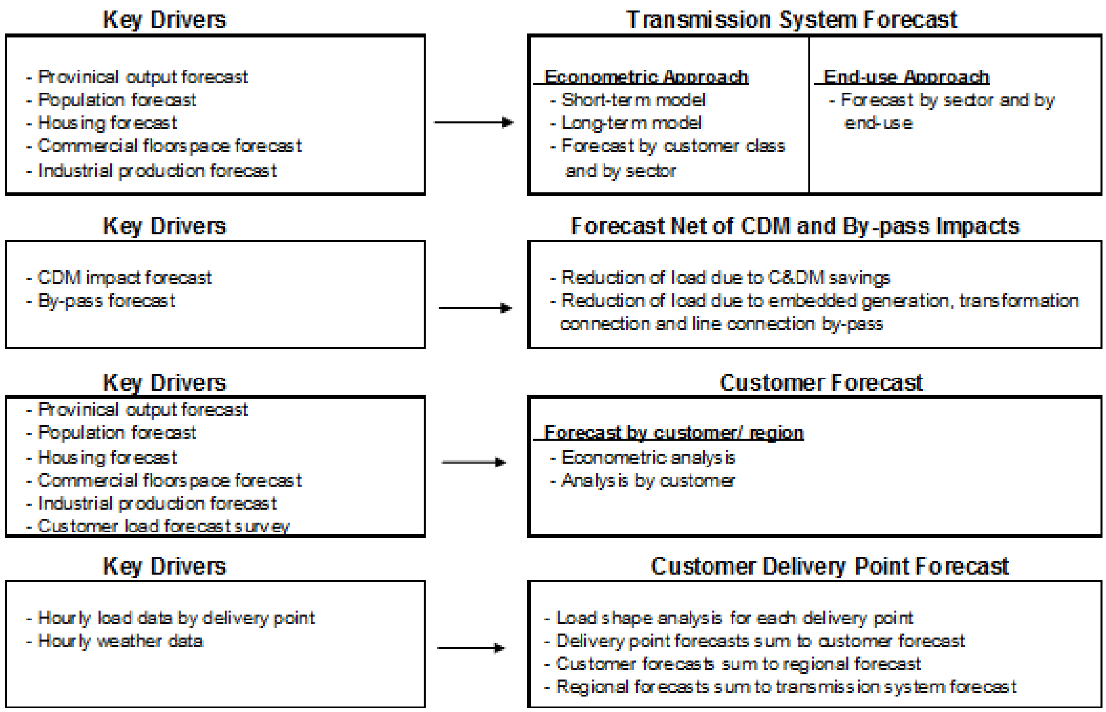


Figure 1: Key Assumptions Used in the Forecast

Key information used in the analysis includes Ontario GDP, provincial demographics, industrial production and commercial floor space forecasts and regional analysis included in the economic forecast. Also taken into consideration are the provincial CDM plans and embedded generation, which have a direct impact on Hydro One Transmission's system energy demands. The load forecast also takes into account 2018 actual load, the planned cuts to electricity bills announced by the provincial government on March 2, 2017 and included in Fair Hydro Plan in October 2017 as well as the subsequent announcement made by the provincial government of a 12% reduction in electricity price.

3.1 PROVINCIAL GDP FORECAST

The provincial GDP forecast is a key driver for the load forecast. During the last three years, the manufacturing sector continued to experience a slow recovery, and the world economy experienced slow growth. This growth was not experienced broadly. Demand for fabricated metals, petroleum and coal, transportation equipment, and miscellaneous manufacturing experienced an overall decline during the past three years. Ontario GDP grew by 2.9 percent in 2015, 2.6 percent in 2016, 2.7 percent in 2017, and is expected to grow by 2.1 percent in 2018. Based on the consensus forecast, Ontario GDP is expected to grow by, 2.0 percent in 2019, 1.8 percent in 2020, and by an average of 2.0 percent per year over 2021 to 2022. Appendix E provides the details of the consensus forecast for Ontario GDP.

3.2 PROVINCIAL POPULATION FORECAST

The Ontario population grew by 0.8 percent in 2015, 1.4 percent in 2016, 1.6 percent in 2017, and is expected to grow by 1.7% in 2018. The economic forecast indicates that the Ontario population is expected to grow at 1.4 percent in 2019, 1.3 percent in 2020, and by an average rate of 1.2 percent over 2021 to 2022. Steady population growth contributes positively to the load forecast.

3.3 PROVINCIAL HOUSING FORECAST

Helped by population growth and relatively low but rising interest rates, housing demand in Ontario continued to grow at a moderate pace over the last four years. Housing starts statistics showed growth of 69,000 houses in 2015, 75,000 in 2016, 78,000 in 2017, and is expected to be 75,000 in 2018. The consensus forecast calls for 71,000 housing starts in 2019, 71,000 in 2020, and an average of 70,000 per year between the years 2021 and

2022. Appendix E provides the details of the consensus forecast for Ontario housing starts.

3.4 COMMERCIAL FLOOR SPACE FORECAST

Due to continued economic recovery and relatively low but rising interest rates, the pace of commercial construction activities was moderate over the recent years. Commercial floor space grew by 1.3 percent in 2015, 1.8 percent in 2016, and 1.8 percent in 2017 and is expected to grow by 0.6% in 2018. The economic forecast calls for 0.5 percent growth in 2019, and average of 0.5 percent per year between 2020 and 2022. The forecast for commercial floor space additions is an important contributor to the commercial sector load forecast.

3.5 INDUSTRIAL PRODUCTION FORECAST

During the last three years, the manufacturing sector continued its slow recovery. As previously discussed, demand for fabricated metals, petroleum and coal, transportation equipment, and miscellaneous manufacturing experienced an overall decline during the past three years. Industrial GDP grew by 1.2 percent in 2015, 2.1 percent in 2016, 1.4 percent in 2017 and is expected to grow by 1.1 percent in 2018. The economic forecast calls for a growth of 1.8 percent in 2019, 1.3 percent in 2020, and an average annual growth rate of 1.5 percent between 2021 and 2022. The industrial production forecast is an important contributor to the industrial sector load forecast, but it is also prone to economic cycles.

3.6 CONSERVATION AND DEMAND MANAGEMENT FORECAST

In EB-2010-0002, the OEB directed Hydro One to "work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA." In EB-2012-0031, Hydro One worked with stakeholders and the OPA to satisfy this directive, and the methodology set out in the report "Incorporating CDM Impacts in the Load Forecast" (EB-2012-0031, Exhibit A-15-2 Attachment 1) was accepted by the OEB.

In December of 2013, the Ministry of Energy released the updated Long-Term Energy Plan, Achieving Balance (the "2013 LTEP"). The detailed breakdown of assumptions underpinning the 2013 LTEP was released by the OPA in February 2014. In 2016, IESO provided the Ontario Planning Outlook ("OPO") reflecting a scenario analysis regarding Ontario. The OPO did not introduce new CDM figures for the peak load.

In October 2017, the Ministry of Energy released an update to the Long-Term Energy Plan, which did not provide updated figures for peak CDM relating to conservation programs. Hydro One has taken into account all the latest IESO's province-wide conservation forecast and used a similar methodology to incorporate these CDM impacts into the load forecast. Hydro One adopted two CDM categories that are consistent with the IESO's (then the OPA) 2013 LTEP information: energy efficiency programs and codes and standards. Details of the latest information that was provided in March 2018 by the IESO and the methodology used by Hydro One to derive the CDM impacts for the three charge determinants have been documented as part of this Application.

Table 2 summarizes the CDM peak impacts assumed in Hydro One Transmission's system load forecast for 2006 to 2022. These CDM peak impacts are consistent with the 2013 LTEP and the latest figures from IESO.

Table 2: Load Impact of CDM on Ontario Demand (MW)

Year	Cumulative CDM Impact on Peak Demand *	Cumulative CDM Impact on 12-month Average Peak Demand **
2006	289	211
2007	778	568
2008	893	652
2009	997	729
2010	1,167	852
2011	1,318	963
2012	1,470	1,074
2013	1,621	1,184
2014	1,820	1,319
2015	1,942	1,434
2016	2,167	1,638
2017	2,099	1,638
2018	2,391	1,924
2019	2,799	2,252
2020	3,197	2,552
2021	3,341	2,654
2022	3,509	2,775

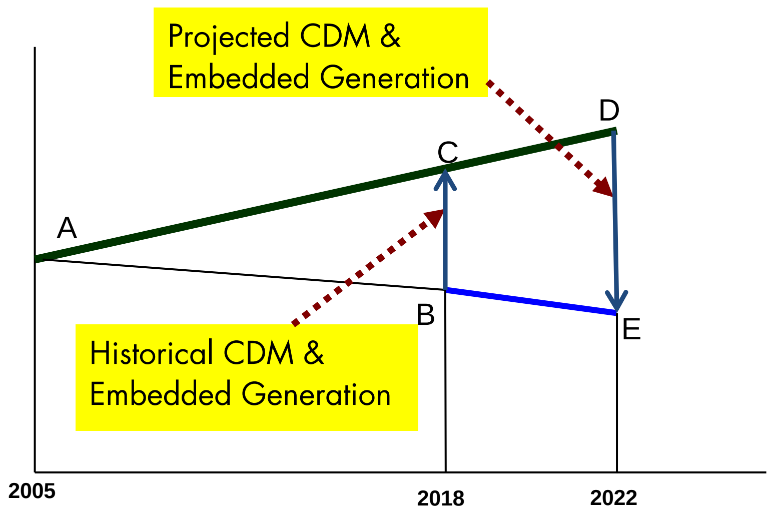
* The figures represent the load impact of CDM on summer peaks.
** The figures represent the load impact of CDM on monthly peaks, averaged over 12 months in the year.

3.7 EMBEDDED GENERATION FORECAST

In relation to Ontario demand, a total of 568 MW of embedded generation was assumed to be in place in 2017. An additional 10 MW in 2018, 24 MW in 2019, 101 MW in 2020, and an average of 8 MW per year over the years 2021 to 2022 of new embedded generation is assumed in the load forecast. The figures represent 12-month average peak and are based on information provided by IESO, which reflects renewable energy projects initiated by the IESO (and previously the OPA).

4. LOAD FORECASTING METHODOLOGY

Hydro One Transmission's system load forecast is developed using both econometric and end-use approaches. The forecast base year is corrected for abnormal weather conditions as explained in Section 4.1 and the forecast growth rates are applied to the normalized base year value. The load impacts of CDM and embedded generation are added back to the historical values during the modeling process (see Figure 2 and Section 4.2).



A: 2005 actual load

B: 2018 actual load

C: Estimated load without CDM and Embedded Generation (EG) impacts in 2018

D: Projected load without CDM and EG impacts in 2022

E: Projected load with CDM and EG impacts in 2022

Figure 2: Incorporation of CDM and Embedded Generation in the Load Forecast

The derivation of each of the customer forecast and the customer delivery point forecast is addressed in sections 4.3 and 4.4 of this Exhibit, respectively.

4.1 WEATHER CORRECTION ANALYSIS

Weather correction analysis is a statistical process that removes the abnormal or extreme weather effects from the load data to yield average conditions that reflect the normal or expected weather that is used in the forecast. This is essential because the volatility of abnormal or extreme weather conditions can adversely impact the provision of a consistent and meaningful forecast for load growth. Hourly load data and hourly weather data of various weather stations across the province are used in the analysis.

4.1.1 HYDRO ONE'S WEATHER CORRECTION METHODOLOGY

Hydro One's weather correction methodology was originally developed by the forecasting and meteorology staff of the former Ontario Hydro. This weather correction method has been used to forecast the total system load since 1988 and for forecasting local electric utility load since 1994. The weather correction methodology used by Hydro One is a proven technique that has performed well in the past years. The same methodology was reviewed and approved by the OEB in previous Hydro One transmission rate applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, and EB-2016-0160). Normal weather data is based on the average weather conditions experienced over the last 31 years. This methodology is also used by the IESO. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year.

Hydro One's weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud cover and humidity. The estimated weather effects are then aggregated up to the required time interval. Past experience shows that weather correction should best be done on a daily basis, rather than weekly, monthly or annual basis as timing of extreme temperatures combined with wind speed and humidity can have a substantial impact on load that would otherwise not be captured by averages over a longer period of time. In particular, when abnormal weather conditions continue for several days, the cumulative impact is much greater than any single day's impact.

The loads that are most impacted by changes in weather conditions are electric space heating and cooling in residential and commercial buildings. Across Ontario, the penetration rate of such loads varies widely. Weather sensitivity of load supplied from one transformer station or delivery point may differ quite significantly from that of load supplied from another transformer station or delivery point, even in the same climate zone. The climate in Ontario varies considerably from the Niagara Peninsula to Thunder Bay, so it is important to use data from the appropriate weather stations that are in close proximity to the transformer station or the customer delivery point when correcting for weather effects. Data for five weather stations across Ontario are used in the analysis. They include Toronto, Windsor, Ottawa, North Bay and Thunder Bay. Each delivery point is linked to the closest weather station.

4.1.2 WEATHER CORRECTION PRACTICES IN OTHER JURISDICTIONS

Hydro One completed a study in 2008 on weather normalization practices by surveying over 50 utilities in North America. The study was submitted to the OEB for review in the transmission rate case EB-2008-0272. The major findings of the study are summarized below.

- Most utilities use long-term weather data to calculate the weather normal conditions.
- The most commonly used period for weather normalization is at least 30 years; no utilities use less than 10 years of weather data to do weather normalization.
- Weather normalization surveys undertaken by Edison Electric Institute, BC Hydro and ITRON show similar results as Hydro One’s survey.
- Most utilities update their weather data set and weather normalization analysis on an annual basis.
- Very few utilities have changed their weather normalization practices in response to global warming or other reasons.

- The survey results were supportive of Hydro One's weather-normalization methodology, which is based on the use of 31 years of weather data to define normal weather conditions.

The above study confirms that the weather normalization methodology used by Hydro One is appropriate.

For the purposes of settlement only, in Hydro One's 2014 transmission rate submission (EB-2014-0140), Hydro One agreed to use the mid-point between its conventional weather-normal forecast and an alternative forecast based on a 20-year, upward-sloping temperature trend (i.e. maximum and minimum temperatures are getting warmer). However, as shown in Figures 3 and 4, the "trend" has not been upward-sloping in recent years. For example, the maximum temperature, after achieving a peak in 2011, is in a downward trend. The Figures present the maximum and minimum daily temperatures between 1953 and 2018.

Figure 3. Toronto Pearson International Airport: Maximum of Average Daily Temperature

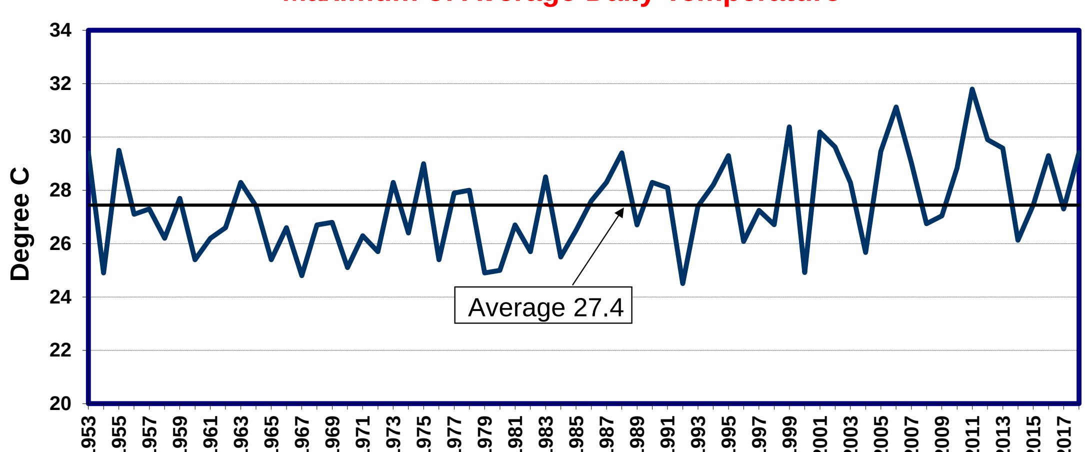
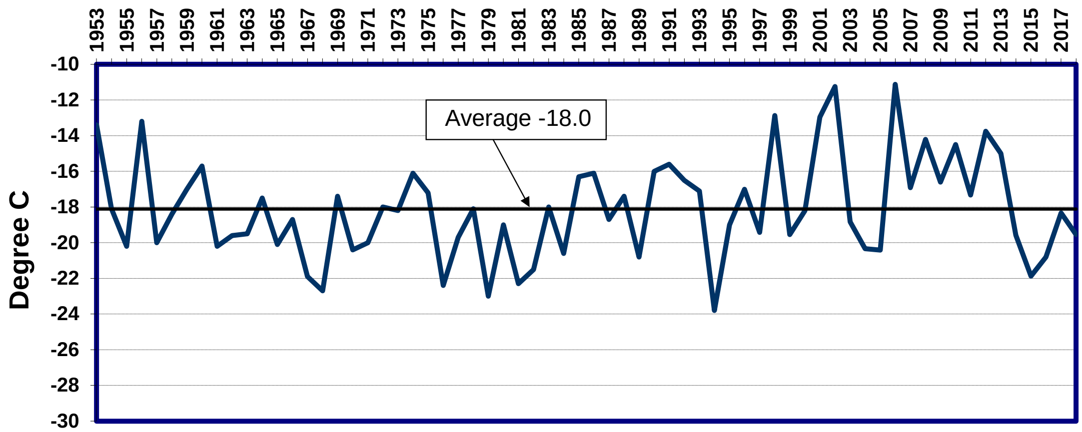


Figure 4: Toronto Pearson International Airport: Minimum of Average Daily Temperature



4.2 HYDRO ONE FORECASTING METHODOLOGY

Hydro One uses econometric (top-down) and end-use (bottom-up) models to forecast the transmission system load. For the top-down approach, both monthly and annual econometric models are used. For the bottom-up approach, end-use models are used to analyse the transmission system load by sector (i.e. residential, commercial, and industrial customers). Key information used in the analysis includes economic data, demographics, industrial production and commercial floor space forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives. This forecasting methodology was reviewed and approved by the OEB in previous Hydro One's transmission rate cases (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, and EB-2016-0160).

4.2.1 MONTHLY ECONOMETRIC MODEL

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the total transmission system load. The model links monthly energy consumption to Ontario GDP and residential building permits, taking into account the August 2003 blackout. The load impacts of CDM and embedded generation are added back to the historical data set during the modelling process. The transmission system load used in the model is weather-normal. Appendix A to this Exhibit provides the detailed regression equations and definitions.

4.2.2 ANNUAL ECONOMETRIC MODEL

The annual econometric models cover five sectors of the economy: residential, commercial, industrial, agricultural, and transportation. Appendix B to this Exhibit provides the detailed regression equations and definitions. Moreover, Hydro One has also looked at the alternate data sources available for forecast energy prices and is using the National Energy Board ("NEB") as the consistent data source, except for the price of coal which is not available from the NEB. The Global Insight forecast for the price of coal is used instead.

The residential sector is modelled as a two-equation system for saturation and usage of electric equipment. Explanatory variables used include energy prices, personal disposable income per household and weather conditions as measured by heating degree days.

The commercial sector links energy usage to electricity and natural gas prices, commercial GDP and weather conditions as measured by cooling degree days.

The industrial model consists of an equation for total energy and a two-equation model to determine shares of electricity usage. Total energy is modelled as a function of energy price and industrial GDP. The share of each fuel source in total energy is linked to relative energy prices. Dummy variables are used to capture unusual changes in energy growth in the 70's and early 80's and to measure the impact of technical change and the retirement of coal-fired generating stations on the share of each fuel source in total energy.

The agricultural sector is modelled in relation to population, while accounting for cyclical and trend changes.

The transportation sector, which consists mainly of pipeline and road transport, is modelled by an equation relating electricity usage to electricity and natural gas prices as well as cooling degree days.

4.2.3 END-USE MODELS

The end-use models cover the residential, commercial, industrial, agricultural and transportation sectors. As in the case of monthly and annual econometric models previously discussed, the resulting forecast is gross of the load impact of CDM and embedded generation. Appendix C to this Exhibit provides details of the methodology used in the end-use analyses.

In the residential sector, the end-uses analysed include space heating, water heating, air conditioning, and base load. The forecast of each end-use is based on the number of households having that end-use and unit energy consumption of the equipment. The commercial model analyses energy use by building type. Key drivers used in the analysis are the commercial sector floor space and the intensity of end-use demand per unit of floor space. The industrial forecast is based on analysis for each major industrial segment, energy intensity and expected economic growth. The agricultural and transportation sector models are based on base year electricity consumption and the expected growth rates for each sector and segment as determined by the corresponding end-use model.

4.3 METHODOLOGY FOR CUSTOMER FORECAST

Both econometric and customer analyses based on survey results from customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.

During January to March 2018, Hydro One conducted a customer load forecast survey with customers having more than 5 MW of load. The survey also covered the station service load requirements of generating stations when they are not producing electricity. In addition to questions relating to the total load of the customer, information at each of the delivery points was also collected. The customer survey results are used in the preparation of the customer forecast.

In addition to the information contained in the customer survey, a number of forecasting techniques are used to prepare the load forecast by customer. For large utility customers, each customer is modeled individually using the econometric approach. The drivers used in these models include provincial economic variables such as Ontario GDP, population, number of households, energy prices, as well as local demographic and economic variables such as population, households, and production (reflecting related GDP). The impact on load of weather conditions is also taken into account. The best subset of the drivers is selected on the basis of regression criteria.

For industrial customers, several information sources are used to prepare the forecast. They include:

- historical load profile of the customer;

- knowledge of the customer through industry monitoring;
- forecast provided by customer through the survey;
- company information from Hydro One Transmission account executives, industry and company forecasts from industry associations and government agencies; and
- production and industry forecasts provided in the economic forecast.

4.4 METHODOLOGY FOR CUSTOMER DELIVERY POINT FORECAST

This section discusses the forecasting methodology for the customer delivery point forecast. Electricity Power Research Institute's Hourly Electric Load Model ("HELM") is used to normalize the hourly load for each of the transmission customer delivery points, removing abnormal weather effects and abnormal load patterns. Key information used in analyzing the load shape for each delivery point includes hourly load and weather data. The load growth for each delivery point is linked to the customer forecast discussed above. The forecasts for all customer delivery points add up to the regional and the total transmission system forecast.

The most updated customer totalization table is used to retrieve hourly peak electricity demand data for each of the customer delivery points connected to the transmission system. The totalization table reflects the latest records from Hydro One and the IESO. For each customer delivery point, at least one full year of hourly data is retrieved and checked for data quality. Hourly weather data is also retrieved to prepare weather sensitivity analysis as discussed in Section 4.1.

In preparing the database for the load shape analysis, missing values are estimated by load on a similar day and hour during the same month. For weather-sensitive load, local weather conditions are also taken into account in estimating the missing values.

The HELM is used to prepare the hourly weather response analysis by each delivery point. The model takes into account differences in load depending upon time of use (weekdays, weekends and holidays) and weather conditions. Load of industrial customers is assumed to be insensitive to weather and as such are forecast in relation to load on a similar day and hour during the historical period. The customer forecast is used to drive the customer delivery point forecast. The resulting customer delivery point forecast is therefore consistent with the customer load forecast and the total transmission forecast as discussed above. The charge determinant forecasts at the delivery point level add up to the total charge determinant forecasts presented in Table 3 in the next section. The customer delivery point forecast uses the latest customer totalization table that shows which customers pay Network, Line Connection and Transformation Connection charges to determine the charge determinant forecast for each transmission service tariff.

5. LOAD FORECAST FOR 2020 TO 2022

Hydro One's charge determinant forecast is derived from the Ontario peak demand forecast based on the econometric, end-use, and customer forecasts. Before deducting the load impact of CDM and embedded generation, the 12-month average charge determinant forecasts grow from 2018 at the same rate as the 12-month average peak for Ontario. Table 3 presents the forecast prepared for this application before and after deducting the load impacts attributed to embedded generation and CDM for the period 2017 to 2022. The charge determinant forecast is based on the methodology approved by the OEB in its Decisions for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, and EB-2016-0160. Appendix D to this Exhibit provides the historical actual and weather-corrected charge determinant data for years 2007 to 2018.

Table 3: Load Forecast Before and After Embedded Generation and CDM
(12-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand	Network Connection	Line Connection	Transformation Connection
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2017	21,902	21,912	21,202	18,100
2018	22,159	22,183	21,535	18,375
2019	22,450	22,470	21,807	18,584
2020	22,842	22,863	22,188	18,909
2021	22,812	22,833	22,159	18,884
2022	22,799	22,820	22,147	18,873
Load Impact of Embedded Generation				
2017	568	568	513	438
2018	578	579	525	448
2019	602	603	543	463
2020	703	704	639	545
2021	706	707	641	546
2022	719	720	653	556
Load Impact of CDM				
2017	1,638	1,639	1,589	1,356
2018	1,924	1,926	1,873	1,598
2019	2,252	2,254	2,186	1,863
2020	2,552	2,555	2,478	2,112
2021	2,654	2,657	2,577	2,196
2022	2,775	2,778	2,695	2,296
Load Forecast after Deducting Embedded Generation and CDM				
2017	19,696	19,705	19,100	16,306
2018	19,657	19,678	19,137	16,329
2019	19,595	19,614	19,078	16,258
2020	19,586	19,604	19,071	16,252
2021	19,451	19,469	18,941	16,142
2022	19,304	19,322	18,800	16,021

Note: All figures are weather-normal.

Before adjusting for the load impacts arising from embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 22,159 MW in 2018 (12-month average peak), 22,450 MW in 2019, 22,842 MW in 2020, 22,812 MW in 2021, and 22,799 MW in 2022. After deducting the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 19,657 MW in 2018 (12-month average peak), 19,595 MW in 2019, 19,586 MW in 2020, 19,451 MW in 2021, and 19,304 MW in 2022.

The 2020 Ontario Demand forecast is 3.9% lower relative to the currently approved 2018 forecast of 20,378 MW (per EB-2016-0160). The key drivers of the reduction in the 2020 load forecast are i) the actual load in 2017 was 3.3% lower than the forecast approved in the previous application for the year 2017, and 3.5% lower in 2018, ii) the load is expected to further decline by 0.4% between 2018 and 2020 due to a combination of slower economic growth and conservation initiatives during this period.

The reduction in the 2017 and 2018 actual load relative to the previously approved load forecast for 2017 and 2018 is primarily driven by the impact from the expanded Industrial Conservation Initiative (“ICI”) program. In September 2016, the Government of Ontario expanded the ICI program to include more than one thousand newly eligible Class A customers with monthly peak demand greater than one megawatt, down from three megawatts. Sector restrictions were also removed so that institutional and commercial businesses became eligible to participate. In April 2017, the Government of Ontario further reduced the ICI threshold from 1 MW to 500 kW to make Ontario consumers/market participants in targeted manufacturing and industrial sectors eligible to opt-in to the ICI. The reduction in peak demand driven by the new Class A customers participating in the ICI program were not reflected in Hydro One’s approved load forecast for 2017 and 2018 in EB-2016-0160. A decrease in load growth due to slow economic growth and associated uncertainties (e.g., NAFTA negotiations) also contributed to a lower 2017 and 2018 actual load. Appendix H provides year-over-year comparison of load over historical, bridge year (2019) and the forecast period.

The forecast is weather-normal and the actual load could be below or above the forecast depending on unexpected events such as a different economic growth pattern. Table 4 of this Exhibit presents the upper and lower bands associated with one standard deviation for the charge determinant forecast. Based on historical data, there is a two-in-three chance that the actual load between the years 2019 and 2022 will fall within the upper and lower bands. The bands are derived using Monte Carlo simulation technique.

Table 4: One Standard Deviation Uncertainty Bands for Hydro One Transmission's Charge Determinants (MW)

Year	Lower Band	Forecast	Upper Band
Network			
2018 (Actual)	19,678	19,678	19,678
2019	19,300	19,614	19,930
2020	19,129	19,604	20,083
2021	18,949	19,469	19,988
2022	18,709	19,322	19,933
Line Connection			
2018 (Actual)	19,137	19,137	19,137
2019	18,773	19,078	19,386
2020	18,608	19,071	19,537
2021	18,435	18,941	19,446
2022	18,203	18,800	19,394
Transformation Connection			
2018 (Actual)	16,329	16,329	16,329
2019	15,998	16,258	16,520
2020	15,858	16,252	16,649
2021	15,710	16,142	16,572
2022	15,512	16,021	16,527

6. VARIABILITY OF HYDRO ONE'S LOAD FORECASTS

Hydro One has significant expertise in preparing provincial electricity demand forecasts as well as hourly load shape analysis. As part of the load research work associated with EB-2005-0317, Hydro One prepared the load shape analysis for over 80 Local Distribution Companies ("LDCs") in Ontario for use in their distribution rate applications to the OEB, using the same load-shape methodology used in this Application. The performance of Hydro One's transmission system load forecast since 1999 has been consistently accurate as shown in Table 5.

The higher variances associated with the 2015 row (3rd year forecast) and 2016 row (2nd and 3rd year forecasts) in Table 5 are largely attributable to the load reductions driven by the impact from the expanded ICI program, as previously discussed.

Table 5: Comparison of Average Monthly Transmission Peak Demand Forecast with Actual (Variance of forecast as percentage of actual on weather corrected basis)

Forecast made In Year	Forecast for current year	Forecast for 2nd Year	Forecast for 3rd Year
1999	-0.92%	-2.22%	-2.30%
2000	0.18%	0.26%	0.22%
2001	-0.14%	-0.29%	0.41%
2002	0.15%	0.36%	-0.14%
2003	0.25%	0.09%	0.83%
2004	0.08%	0.59%	0.89%
2005	0.17%	0.36%	0.97%
2006	-0.69%	0.41%	0.15%
2007	0.93%	0.18%	0.70%
2008	-0.38%	0.24%	0.24%.
2009	-0.23%	-0.88%	0.83%
2010	1.00%	0.32%	-0.28%
2011	-0.40%	-1.35%	-2.58%
2012	-0.05%	-0.20%	-3.47%
2013	-0.22%	-3.46%	-1.69%
2014	-0.68%	1.94%	2.66%
2015	1.50%	1.19%	4.14%
2016*	-0.20%	3.43%	3.66%
2017	0.69%	0.17%.	n.a.
2018	-0.95%		
Mean	0.01%	0.06%	0.20%
One standard deviation (+/-)	1.60%	2.43%	2.67%

Note: The forecasts are net of the load impact of CDM and embedded generation and are compared to the weather corrected actual.
** Last OEB-Approved forecast.*

Between 1999 and 2018, the average variance of the transmission peak demand forecast compared to the weather corrected actual peak is well within one standard deviation, meaning there is a one-in-three chance that the actual peak demand will be outside of the plus or minus one standard deviation range. The use of the one standard deviation as a measure of forecasting accuracy is an accepted standard in the utility industry.

Forecast accuracy for previous OEB-approved forecasts of charge determinants is presented in Table 6. The figures reflect the percent deviation of the forecast for each charge determinant over the forecast period compared to the historical actual on a weather corrected basis. The 2006-2008 forecasts were approved by the OEB in EB-2006-0501. Similarly, the 2008-2012 and 2017-2018 forecasts were approved in proceedings EB-2008-0272, EB-2010-0002, EB-2012-0031, and EB-2016-0160. The 2014-2016 load forecast was modified as part of a settlement reached in Hydro One's transmission application EB-2014-0140, which was ultimately approved by the OEB. Detailed comparison of forecasts for each forecast year separately is provided in Appendix F which includes Tables 6a to 6c.

Table 6
Historical Board Approved Forecasts
vs. Historical Actual-Weather Corrected

	Difference from Actual-Weather Corrected (%) *						
Type of Connection	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	EB-2012-0031 Forecast	EB-2014-0140 Forecast	EB-2016-0160 Forecast	**Average**
Network	-0.49	-0.45	-0.42	-2.10	0.89	2.46	**-0.02**
Line	-0.71	0.79	0.68	-0.83	1.27	1.84	**0.24**
Transformation	-1.02	0.16	0.52	-0.37	1.71	2.36	**0.20**
Average	**-0.74**	**0.17**	**0.26**	**-1.10**	**1.29**	**2.22**	**0.14**
One Standard Deviation (+/-) **	2.26	2.26	2.26	2.26	2.26	2.26	

* A negative (positive) variance shows that the forecast was below (above) actual.
** Reflects expected deviation of forecast from actual-weather corrected based on historical variations. All forecasts are consistent with one standard deviation.
Note. EB-2014-0140 approved forecast was the modified forecast.

As shown in Table 6, the deviations of previous OEB-approved charge determinant forecasts from historical actuals on a weather-corrected basis are well within one standard deviation of error, and the average deviation over the past six OEB-approved forecasts (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, and EB-2014-0140) is close to zero.

APPENDIX A

MONTHLY ECONOMETRIC MODEL

The monthly econometric model uses the State-Space Approach in the regression equation, where the left-hand side of the equation represents the energy estimates, and the right-hand side contains the explanatory variables including the dummy variables that are used to capture special events that affect the energy estimates as these events can cause variations in the load. The dummy variables are used to minimize the variability of the energy estimates around the forecast.

LWCTSE = f (LGDPONT, LBPONT, D0803)

where:

LWCTSE = logarithm of Networks' load,

- Based on hourly figures for Ontario Demand from IESO

LGDPONT = logarithm of Ontario GDP in chained 2002 dollars,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance
- Forecast is based on annual consensus forecast for Ontario GDP as presented in Appendix E

LBPONT = logarithm of Ontario residential building permits in constant dollar,

- History is based on monthly value of Ontario residential building permits from Statistics Canada
- Forecast is based on consensus forecast of housing starts as presented in Appendix E

D0803 = dummy variable for the August 2003 Blackout, equals 1 in that month and zero elsewhere.

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

Seasonal Factors	SS parameters:
A[1]	0.133342
K[1]	-0.527968
Non-seasonal Factors	SS parameters:
A[1]	0.581576
K[1]	-0.285079

GDPONT	LOG 1 1	Exogenous
G[1][1]	0.203112	
BPONT[-8]	LOG 1 1	Exogenous
G[1][2]	0.00124951	
D0803	1 1	Exogenous
G[1][3]	-0.00561511	

R-squared = 0.996, R-squared corrected for mean = 0.996, Durbin-Watson Statistics = 2.3

The goodness of fit, or the extent to which variability in the energy estimates is captured in the forecast, is measured in terms of R-squared (adjusted for mean), which in this case is close to 1. This result reflects statistical significance of the explanatory variables that are used to explain for the variations in load. The regression results show that the fit is very good and there is confidence that the forecast will produce outcomes that are within the expected range of variability.

Using the forecast values for GDP, building permits and dummy variables, the parameters are used in the monthly regression equation to generate the forecast for the transmission system load.

APPENDIX B

ANNUAL ECONOMETRIC MODEL

Residential Model

Residential sector equations consist of a saturation equation and a use equation. Saturation at year t is measured as sum of penetration of household equipment i at year t, Ei (t) – which is measured as the percentage of households using that equipment - multiplied by the annual electricity usage of equipment i in 2016 (Ui); normalized to be 1 in 2016:

$$\text{Saturation}(t) = (\Sigma\ Ei(t) * Ui) / (\Sigma\ Ei(2016) * Ui)$$

Usage at year t is measured as the ratio of per household residential consumption to saturation in that year, again normalized to be 1 in 2016.

$$\text{Usage}(t) = [(\text{per household consumption}(t)) / \text{Saturation}(t)] / [\text{per household consumption}(2016) / \text{Saturation}(2016)]$$

Ontario residential electricity consumption can then be calculated as:

$$\text{Total residential electricity consumption} = \text{Saturation}(t) * \text{Usage}(t) * N(t)$$

where N(t) is a normalizing factor to account for the number of households in Ontario in year t times per household consumption in 2016.

Saturation and usage are modelled as a function of energy prices, income per household in Ontario, lagged value of saturation and usage, heating degree days and two dummy variables:

LELSAT= C(1)*(LPELRES+LPELRES(-1))/2 + C(2)*LYPDPHH
+ C(3)*LELSAT(-1) + C(4)*LELSAT(-2) + C(5)*D81

LELUSE = C(6)*(LPELRES(-4)-LPLIQRES(-4)) + C(7)
*LYPDPHH + C(8)*LHDD^0.5 + (1 + C(9) + C(10))*LELUSE(-1) +
C(9)*LELSAT + C(10)*LELSAT(-1)-C(8)* (1 + C(9) + C(10))
*LHDD(-1) + C(11)*TR3

where:

LELSAT = logarithm of residential electricity saturation in Ontario,

- History is constructed from residential load, number of households and Survey of Household Spending by Statistics Canada, and associated load impact of CDM

LPELRES = logarithm of electricity price in Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2018
- Forecast is from NEB 2018 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

LPLIQRES = logarithm of liquid-fuel price in Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2018 Outlook
- Forecast is from NEB 2018 Outlook, includes carbon tax

LYPDPHH = logarithm of Ontario personal disposable income per household /house in constant $,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance, deflated by CPI from Statistic Canada, and divided by the number of households / houses based on Global Insight housing starts,
- Forecast is based on forecasts of disposable income from C4SE and University of Toronto Policy and Economic Analysis Program, CPI from IHS Global Insight, and number of households is based on consensus forecast of housing starts as presented in Appendix E

D81 = dummy variable to account for an outlier, equals 1 in 1981, 0 elsewhere,

LELUSE = logarithm of residential electricity usage in Ontario,

- History is constructed from residential load, number of households and Survey of Household Spending by Statistics Canada, and associated load impact of CDM

LHDD = logarithm of heating-degree-days for Pearson International Airport,

- History is from Environment Canada
- Forecast is 31-year average of historical annual HDD figures

TR3 = dummy variable to capture trend, equals 1 in 1961 and increases by 1 per year thereafter.

c(1) to c(11) = variable coefficients.

The equations are estimated simultaneously using 3-Stage Least Squares, as presented:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.055847	0.016247	-3.437358	0.0009
C(2)	0.151387	0.043937	3.445528	0.0009
C(3)	0.627896	0.126789	4.952297	0.0000
C(4)	0.283969	0.120446	2.357645	0.0205
C(5)	-0.039526	0.021218	-1.862888	0.0657
C(6)	-0.030492	0.016540	-1.843523	0.0685
C(7)	0.131825	0.058167	2.266307	0.0258
C(8)	0.094002	0.050731	1.852933	0.0671
C(9)	-1.084792	0.259077	-4.187134	0.0001
C(10)	0.988609	0.249526	3.961948	0.0001
C(11)	-0.001948	0.000551	-3.536728	0.0006

Saturation Model Fit:

R-squared =0.96, Adjusted R-squared = 0.96, Durbin-Watson Statistics =2.10

Usage Model Fit:

R-squared =0.95, Adjusted R-squared = 0.94, Durbin-Watson Statistics =1.86

The regression results show the goodness of fit of the model, as measured by (Adjusted) R-square, is good. The t-ratios also show that all the factors used to explain the variations in load are statistically significant at 93% probability level or higher. Using the forecast values for personal disposable income, energy prices, heating degree days and dummy variables, the parameters are used in the annual regression equation to generate the forecast for the residential load.

Commercial Model

The commercial model uses the price of electricity and of natural gas, commercial GDP and cooling and degree days to forecast the commercial load. The commercial model can be represented by the following equation:

LELCOM = C(1)*(LPELCOM-LPGASCOM)*(D07B*LOG(ELCOM(-1)
/GDPCOM(-1))+1)+C(2)*(LGDPCOM(-1))+C(3)*LELCOM(-1)
+C(4)*LCDD+C(5)*D(LELCOM(-1))

where

LELCOM = logarithm of electricity consumption in Ontario commercial sector,

- History is based on commercial load from Statistics Canada, and associated load impact of CDM

LPELCOM = logarithm of price of electricity in the commercial sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2018 Outlook
- Forecast is from NEB 2018 Outlook

LPGASCOM = logarithm of price of natural gas in the commercial sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2018 Outlook
- Forecast is from NEB 2018 Outlook

LGDPCOM = logarithm of Ontario commercial GDP in constant $,

- History is from Statistics Canada figures for GDP by industry
- Forecast is prepared by Hydro One in a manner consistent with consensus forecast as presented in Appendix E

LCDD = logarithm of cooling-degree-days for Pearson International Airport.

- History is from Environment Canada
- Forecast is 31-year average of historical annual CDD figures

D07B = dummy variable to account for change in price elasticity, equals 1 before 2007 and 0 otherwise.

The estimated equation is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.021002	0.005715	-3.674978	0.0006
C(2)	0.078736	0.021389	3.681130	0.0006
C(3)	0.893150	0.024002	37.21184	0.0000
C(4)	0.027493	0.012384	2.220165	0.0313
C(5)	0.210696	0.120774	1.744548	0.0876

R-squared =0.998, Adjusted R-squared = 0.998, Durbin-Watson Statistics =2.00

The regression results reflect a high goodness fit and statistical significance for all estimates at 91% probability level or higher.

Industrial Model

The industrial load is modelled as one source of energy in the industrial sector of Ontario economy. The model consists of an equation for total energy and a 2-equation model to determine share of electricity usage out of the total energy.

The total energy model is represented by the following equation:

LENIND=C(1)+C(2)*LGDPIND+C(3)*LGDPIND(-1)+C(4)
LOG(ENIND(-1))+C(5)(LOG(PENIND)+LOG(PENIND(-8)
)/2+C(6)*D13

where

LENIND = logarithm of electricity consumption in Ontario industrial sector,

- History is based on energy series from Statistics Canada, and associated load impact of CDM

PENIND = logarithm of price of energy in the industrial sector, defined as the weighted average of price of electricity, liquid fuel and coal in that sector,

- History of energy prices, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2018 Outlook
- Forecast is from Global Insight for coal and NEB 2018 Outlook for other energy prices, include carbon tax,

LGDPIND = logarithm of Ontario industrial GDP in constant $.

- History is from Statistics Canada figures for GDP by industry
- Forecast is prepared by Hydro One in a manner consistent with consensus forecast as presented in Appendix E

D13 = a dummy variable, equals 1 in 2013 and zero elsewhere.

The estimated model is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	1.269559	0.852786	1.488719	0.1442
C(2)	0.664148	0.106968	6.208842	0.0000
C(3)	-0.567558	0.112979	-5.023554	0.0000
C(4)	0.835057	0.066273	12.60019	0.0000
C(5)	-0.038482	0.017779	-2.164495	0.0363
C(6)	-0.151744	0.041391	-3.666079	0.0007

R-squared =0.901, Adjusted R-squared = 0.889, Durbin-Watson Statistics =2.05

The regression results show a strong correlation between energy consumption and explanatory variables, despite higher variability in the industrial sector compared to the residential and commercial sectors in Ontario.

The equations for determining the share of electricity in total energy (LW13 and LW23) are:

LW13=C(1)-(W2S*C(12)+(W1S+W3S)*C(13))*LP13
+(C(12)-C(23))*W2S*LP23+C(20)*DCR+C(5)*LT
+[AR(1)=C(60), AR(2)=C(61)]

LW23=C(2)-(W1S*C(12)+(W2S+W3S)*C(23))*LP23
+(C(12)-C(13))*W1S*LP13+C(21)*DCR+C(6)*LT+C(7)*DG
+[AR(1)=C(60), AR(2)=C(61)]

where
LW13 = logarithm of electricity cost relative to coal in Ontario industrial sector,
LW23 = logarithm of liquid-fuel cost relative to coal in Ontario industrial sector,

W1S, W2S, W3S = quantity share of electricity, liquid fuel and coal in total energy in Ontario, respectively,- History of all cost shares are based on energy series and associated energy prices

LP12 = logarithm of price of electricity relative to liquid fuel in Ontario industrial sector,

LP23 = logarithm of price of liquid fuel relative to coal in Ontario industrial sector,

LP13 = logarithm of price of electricity relative to coal in Ontario industrial sector,

- History of energy prices, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and NEB 2018 Outlook
- Forecast is from Global Insight for price of coal and NEB 2018 Outlook for other energy prices, include carbon tax,

DG = dummy variable to account for abnormal changes in energy growth between 1969 and 1982, equals 0.5 in 1969 to 1970, 1 in 1971 to 1982, and 0 elsewhere,

DCR=dummy variable to account for closure of coal-fired generating stations in Ontario. It reflects share of reduction in each year in total reduction based on the generating capacity: equals 0 prior to 2005, 0.15 for the years 2005-2009, 0.41 in 2010, 0.54 in 2011, 0.57 in 2012, 0.96 in 2013, and 1 in 2014 and after.

LT = logarithm of a trend variable equals 1 in 1963, increasing by 1 each year thereafter. This would pick up impact of technical change on energy shares apart from movements in relative energy prices.

The equations are estimated using the weighted Seemingly Unrelated Equations (SUR) method. The estimated model is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-1.963672	0.133986	-14.65581	0.0000
C(12)	-0.913834	0.047096	-19.40378	0.0000
C(13)	-1.411664	0.112260	-12.57496	0.0000
C(23)	-0.659115	0.107377	-6.138308	0.0000
C(20)	1.119724	0.136655	8.193820	0.0000
C(5)	0.498359	0.032251	15.45238	0.0000
C(60)	0.683859	0.097446	7.017855	0.0000
C(61)	-0.235556	0.086548	-2.721687	0.0078
C(2)	-0.663932	0.143761	-4.618291	0.0000
C(21)	1.031264	0.157655	6.541270	0.0000
C(6)	0.380040	0.036956	10.28347	0.0000
C(7)	0.224039	0.037350	5.998312	0.0000

LW13 Model Fit:

R-squared =0.982, Adjusted R-squared = 0.979, Durbin-Watson Statistics =2.16

LW23 Model Fit:

R-squared =0.978, Adjusted R-squared = 0.974, Durbin-Watson Statistics =1.99

The regression results show the model has a good fit with historical values and all the model parameters are statistically significant.

Agricultural Model

The agricultural electricity consumption is affected by population as well as trend and cyclical variations. The agricultural electricity model therefore includes trend and moving average terms in addition to population, as follows:

ELAGR = C(1)+C(2)*D(POPONT(-4))+C(3)*TREND
+C(4)*LELAGR(-2) +C(5)*D08+MA(4)

where

ELAGR = electricity consumption in Ontario agricultural sector,

- History is based on commercial load from Statistics Canada, and associated load impact of CDM.

POPONT = Ontario population,

- History is from Statistics Canada
- Forecast is from C4SE and Conference Board of Canada

TREND = a trend variable, equals 1 in 1961 and increases by 1 per year thereafter,

D08 = dummy variable to account for an outlier, equals 1 in 2008, 0 elsewhere,

MA(4) = a moving average error term of order 4.

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1128.914	511.6233	2.206534	0.0381
D(POPONT(-4))	0.860424	0.580763	1.481541	0.1526
TREND	-13.89638	6.072926	-2.288250	0.0321
ELAGR(-2)	0.690644	0.106925	6.459143	0.0000
D08	344.8987	76.23250	4.524300	0.0002
MA(4)	-0.954584	0.015635	-61.05399	0.0000

R-squared =0.904, Adjusted R-squared = 0.883, Durbin-Watson Statistics =1.75

The regression results show the model captures most of the variations in the agricultural load in Ontario despite a great volatility in the data series.

Transportation Model

The transportation model is represented by an equation basically relating electricity usage to weather conditions as measured by cooling degree days, and price variables.

LTRANS=C(1)+C(2)*LTRANS(-1)+ C(3)*(PELRES-PGASRES)+C(4) *D0708+C(5)*CDD+C(6)*D12+C(7)*D98

where

LTRANS = logarithm of electricity consumption in Ontario transportation sector,

- History is based on transportation load from Statistics Canada, and associated load impact of CDM

PELRES = electricity price in Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2018
- Forecast is from NEB 2018 Outlook further adjusted for cuts to residential hydro bills introduced by the provincial government

PGASRES = natural gas price in Ontario residential sector,

- History, for different time periods, from Ontario Hydro, IHS GI, 2013 LTEP and National Energy Board (NEB) 2018
- Forecast is from NEB 2018, includes carbon tax

D0708 = a dummy variable to capture an opposite move in load, equals -1 in 2007 and 1 in 2008.

D12 = a dummy variable to capture drop in load, equals 1 in 2012, 0 elsewhere.

D98 = a dummy variable to capture drop in load, equals 1 in 1998, 0 elsewhere.

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	1.462398	0.581743	2.513820	0.0180
C(2)	0.761950	0.088150	8.643821	0.0000
C(3)	-2.13E-06	1.11E-06	-1.910022	0.0664
C(4)	0.190154	0.064380	2.953621	0.0063
C(5)	0.000542	0.000162	3.347937	0.0023
C(6)	-0.530646	0.095066	-5.581842	0.0000
C(7)	0.340138	0.091908	3.700848	0.0009

R-squared =0.852, Adjusted R-squared = 0.820, Durbin-Watson Statistics =2.27

The model fit is good despite extreme volatility in the transportation electricity consumption in Ontario. However, transportation load is less than 0.5 per cent of Ontario electricity load and, as such, its volatility does not significantly affect the forecast accuracy of total load.

APPENDIX C

END-USE MODEL

<u>Residential Sector</u>

The end-uses considered in the residential sector include space heating, water heating, air conditioning and base load (lighting and appliances). The forecast of each of the end-use is based on the following equation:

kWh = number of households * end-use share * end-use UEC

where:

- end-use share refers to the fraction of houses with the particular end-use considered,
- UEC (unit energy consumption) refers to the annual energy consumption of that end-use per household.

The following section describes each component of the equation in detail.

- The base-year number of households was taken from Ontario residential household information from Statistics Canada.
- The base year end-use shares (space heating, water heating and air conditioning) information and fuel switching (space/water heating) information are based on Statistics Canada residential appliance survey results.
- The trends for end-use shares and fuel switching over the forecasting period are based on historical time series from Statistics Canada residential appliance surveys.
- The base year end-use UEC's were estimated based on Statistics Canada Ontario residential electricity consumption data (CANSIM DATA) and Statistics Canada residential appliance survey results.

Commercial Sector

The commercial forecast for the total transmission system is developed using the COMMEND (Commercial end-use planning system). The model uses an end-use framework to provide estimates of energy use by building type. The 12 building types include office, elementary and secondary school, college and universities, health, public service, retail, grocery, accommodation, recreation, religious/cultural, warehouse and commercial miscellaneous. Non-building related segments, such as transportation, communication and utilities etc., were prepared outside the model using spreadsheet analysis. The forecast is the product of the commercial sector building floor space and the intensity of end-use demand per unit floor space.

Industrial Sector

Industrial sector analysis includes large industrial customers with monthly demand >5 MW and general service customers with demand <5 MW. The forecast is based on detailed analysis of each major industrial sub-sector. Various segments are considered in this analysis, including abrasives, motor vehicle assembly, vehicle parts, non-metallic minerals, electronic products, fabricated metal products, foods & beverage, glass, industrial chemicals, iron and steel, lime, smelting & mining, petroleum refining, pulp and paper, rubber and plastics, clothing and textiles, and miscellaneous manufacturing. The forecast for industrial customers is based on customer level data and the effect of the economy on their production prospects. Pattern in energy intensity is considered in relation to technological change.

Agricultural and Transportation Sectors

Transportation sector is comprised mainly of pipeline transport and road transport. The forecast for the agricultural and transportation sectors is based on the following equation:

kWh = base year consumption * expected annual growth rates

For each component of this equation, data is gathered from:

- The base year consumption by segment is taken from the Statistics Canada;
- Expected annual growth rates are determined by the corresponding end-use model.

APPENDIX D

HISTORICAL ONTARIO DEMAND AND CHARGE DETERMINANT DATA

This Appendix provides the historical actual and weather corrected Ontario demand and Hydro One charge determinants for 2007-2018.

Actual Ontario Demand and Hydro One Charge Determinants
(MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2007												
Ontario Demand	23,537	23,935	22,969	20,016	21,490	25,737	24,561	25,584	24,046	19,233	21,814	22,935
Network Connection	22,766	23,278	22,406	19,614	21,020	24,926	23,864	24,951	23,277	18,909	21,539	22,220
Line Connection	21,370	21,872	21,126	19,181	20,358	23,572	23,126	23,620	22,239	19,197	20,466	21,190
Transformation Connection	18,550	19,078	18,291	16,205	17,203	20,433	20,040	20,638	19,253	16,464	17,720	18,567
2008												
Ontario Demand	22,782	23,054	20,990	19,512	18,650	24,195	23,787	22,707	22,975	19,366	21,279	22,541
Network Connection	22,112	22,227	20,395	19,114	18,260	23,502	23,302	22,182	22,502	19,183	20,740	22,169
Line Connection	21,148	21,065	19,719	18,564	17,836	22,514	22,414	21,218	21,255	18,390	19,574	20,940
Transformation Connection	18,500	18,472	17,093	15,912	15,057	19,316	19,368	18,269	18,263	15,717	16,953	18,418
2009												
Ontario Demand	22,983	22,110	21,466	18,744	17,560	22,540	20,011	24,380	19,731	18,420	19,710	21,921
Network Connection	22,414	21,446	21,194	18,461	17,647	22,053	20,089	23,705	19,343	18,011	19,413	21,146
Line Connection	21,084	20,175	20,262	17,799	17,170	20,795	19,042	22,244	18,520	17,249	18,160	19,968
Transformation Connection	18,568	17,898	17,701	15,481	14,705	18,166	16,687	19,622	16,182	15,118	16,009	17,856
2010												
Ontario Demand	22,045	21,367	19,393	17,398	22,904	21,527	25,075	24,917	24,444	17,704	19,970	22,114
Network Connection	21,656	20,845	18,931	17,360	22,162	21,181	24,903	24,227	24,108	17,640	19,477	21,868
Line Connection	20,381	19,594	18,280	17,049	21,143	20,338	23,589	22,945	22,527	17,174	18,607	20,312
Transformation Connection	18,106	17,268	15,747	14,533	18,394	17,698	20,736	19,991	19,601	14,732	15,969	17,841
2011												
Ontario Demand	22,733	21,871	20,667	17,945	20,870	22,765	25,450	22,051	21,552	18,234	19,673	20,204
Network Connection	21,844	21,184	20,115	17,737	20,647	22,661	25,395	21,831	21,398	18,104	19,450	19,964
Line Connection	20,629	19,927	19,023	17,396	19,764	21,620	24,252	21,411	20,551	17,569	18,576	19,331
Transformation Connection	18,115	17,394	16,433	14,811	16,858	18,582	21,077	18,454	17,671	15,006	16,057	16,827
2012												
Ontario Demand	21,847	19,956	20,332	17,874	21,106	24,107	24,636	23,188	21,183	18,829	20,144	20,382
Network Connection	21,175	19,441	19,874	17,564	20,977	24,135	24,818	22,865	21,021	18,662	19,749	20,136
Line Connection	19,931	19,057	18,768	17,310	20,276	23,193	23,700	21,922	20,294	18,024	18,877	19,211
Transformation Connection	17,382	16,436	16,085	14,645	17,298	20,147	20,693	19,033	17,528	15,363	16,304	16,588
2013												
Ontario Demand	22,610	21,426	19,825	18,854	20,488	22,662	24,927	22,833	22,682	18,445	20,615	22,556
Network Connection	21,960	20,995	19,670	18,649	20,570	22,835	25,403	22,793	22,740	18,418	20,355	21,837
Line Connection	20,570	19,836	18,700	17,978	19,633	21,834	24,189	21,810	21,988	18,060	19,495	20,767
Transformation Connection	17,931	17,219	15,949	15,209	16,674	18,757	20,904	18,810	18,850	15,318	16,795	18,018
2014												
Ontario Demand	22,774	21,905	21,656	18,557	18,844	20,807	21,300	21,363	21,123	17,784	20,102	20,938
Network Connection	22,636	21,426	21,232	18,317	18,858	21,260	21,742	21,875	21,975	17,734	20,150	20,507
Line Connection	21,450	20,285	19,903	17,697	18,385	20,738	21,171	20,980	21,247	17,455	19,255	19,553
Transformation Connection	18,731	17,553	17,265	15,119	15,445	17,579	17,974	17,954	18,151	14,841	16,605	16,862
2015												
Ontario Demand	21,814	21,494	20,827	18,462	19,158	19,339	22,516	22,383	22,063	17,667	19,239	19,161
Network Connection	21,762	21,707	20,597	18,212	19,475	19,351	22,931	22,880	22,347	17,575	18,927	18,841
Line Connection	20,722	20,983	19,639	17,531	19,019	19,057	22,275	22,195	22,251	17,374	18,278	18,619
Transformation Connection	18,017	18,234	16,999	14,898	15,992	16,077	19,151	19,014	19,118	14,612	15,473	15,839
2016												
Ontario Demand	20,836	20,766	20,063	17,821	19,885	21,692	22,659	23,100	23,213	18,189	19,369	20,688
Network Connection	20,219	20,161	19,698	17,993	19,786	22,311	23,193	23,551	23,413	17,919	18,866	20,445
Line Connection	19,422	19,438	18,808	17,547	19,800	21,779	22,715	23,141	22,568	17,528	18,113	19,470
Transformation Connection	16,643	16,718	15,955	14,768	16,657	18,449	19,379	19,759	19,294	14,844	15,321	16,698
2017												
Ontario Demand	20,372	19,838	19,174	17,349	17,738	21,168	20,627	20,158	21,786	17,418	19,115	20,306
Network Connection	19,797	19,176	18,955	17,137	17,880	21,189	20,996	21,073	22,159	17,501	18,999	20,432
Line Connection	19,131	18,466	18,436	16,648	17,611	20,457	20,805	20,603	21,566	17,141	18,124	19,785
Transformation Connection	16,403	15,727	15,706	13,992	14,761	17,480	17,672	17,555	18,563	14,575	15,452	17,078
2018												
Ontario Demand	20,906	20,076	18,462	18,011	20,473	21,369	23,046	21,990	23,240	18,205	20,152	19,891
Network Connection	20,955	19,488	18,271	18,035	20,690	21,752	23,756	22,806	23,613	18,599	19,682	19,375
Line Connection	20,178	18,792	17,649	17,603	20,578	21,843	23,084	22,177	22,971	18,240	18,675	18,691
Transformation Connection	17,413	16,122	15,057	14,913	17,505	18,600	19,930	19,220	19,670	15,422	15,961	15,999

Weather Corrected Ontario Demand and Hydro One Charge Determinants
(MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2007												
Ontario Demand	23,229	22,715	20,536	19,539	18,656	22,022	22,369	22,401	20,543	19,755	22,459	23,487
Network Connection	22,469	22,092	20,032	19,147	18,248	21,328	21,734	21,848	19,887	19,422	22,175	22,755
Line Connection	21,091	20,757	18,888	18,724	17,673	20,169	21,062	20,682	19,000	19,717	21,071	21,701
Transformation Connection	18,307	18,105	16,353	15,819	14,935	17,483	18,252	18,070	16,448	16,910	18,244	19,014
2008												
Ontario Demand	23,409	23,058	21,009	19,967	18,559	22,677	22,847	22,848	20,436	19,562	21,577	22,937
Network Connection	22,721	22,231	20,414	19,559	18,171	22,027	22,381	22,319	20,015	19,377	21,030	22,558
Line Connection	21,728	21,067	19,736	18,996	17,748	21,099	21,527	21,348	18,904	18,575	19,846	21,305
Transformation Connection	19,005	18,471	17,105	16,279	14,980	18,100	18,599	18,378	16,241	15,872	17,186	18,737
2009												
Ontario Demand	22,639	22,128	21,246	18,635	18,943	22,935	23,575	23,639	20,224	19,466	20,671	21,977
Network Connection	22,078	21,464	20,977	18,353	19,037	22,439	22,668	22,984	19,827	19,034	20,360	21,199
Line Connection	20,768	20,191	20,054	17,696	18,522	21,159	21,322	21,568	18,983	18,229	19,045	20,019
Transformation Connection	18,290	17,913	17,520	15,391	15,863	18,485	18,259	19,026	16,587	15,976	16,789	17,901
2010												
Ontario Demand	21,817	21,551	20,413	18,082	18,373	21,760	23,144	22,299	20,901	18,275	19,881	21,709
Network Connection	21,432	21,025	19,927	18,042	17,778	21,411	22,986	21,681	20,614	18,209	19,389	21,467
Line Connection	20,170	19,763	19,242	17,719	16,960	20,558	21,773	20,535	19,262	17,728	18,524	19,940
Transformation Connection	17,919	17,417	16,575	15,104	14,755	17,890	19,140	17,891	16,760	15,207	15,898	17,514
2011												
Ontario Demand	21,964	21,734	20,621	18,062	18,114	21,349	22,728	21,671	20,655	18,262	19,977	21,427
Network Connection	21,104	21,052	20,070	17,853	17,920	21,252	22,679	21,454	20,508	18,131	19,750	21,173
Line Connection	19,931	19,803	18,980	17,509	17,153	20,275	21,658	21,042	19,696	17,596	18,864	20,501
Transformation Connection	17,502	17,285	16,397	14,908	14,632	17,426	18,823	18,136	16,936	15,029	16,305	17,846
2012												
Ontario Demand	21,233	21,188	20,169	17,638	18,118	21,463	22,735	21,905	20,743	18,208	19,529	21,253
Network Connection	20,579	20,641	19,714	17,332	18,007	21,488	22,902	21,600	20,585	18,047	19,145	20,996
Line Connection	19,370	20,233	18,617	17,082	17,406	20,648	21,871	20,709	19,873	17,430	18,300	20,031
Transformation Connection	16,893	17,450	15,956	14,451	14,849	17,937	19,095	17,980	17,165	14,856	15,805	17,297
2013												
Ontario Demand	21,696	21,609	20,242	18,035	18,223	21,058	22,434	21,470	20,575	18,181	19,609	21,191
Network Connection	21,072	21,175	20,084	17,838	18,296	21,218	22,862	21,432	20,628	18,155	19,362	20,515
Line Connection	19,738	20,005	19,094	17,197	17,462	20,288	21,770	20,508	19,946	17,802	18,544	19,510
Transformation Connection	17,206	17,366	16,284	14,548	14,831	17,429	18,813	17,687	17,100	15,099	15,976	16,928
2014												
Ontario Demand	21,998	21,694	20,488	18,335	18,207	21,378	22,719	21,708	20,552	18,364	19,856	21,350
Network Connection	21,866	21,211	20,082	18,094	18,217	21,839	23,185	22,223	21,377	18,308	19,899	20,906
Line Connection	20,530	19,904	18,651	17,320	17,595	21,105	22,367	21,117	20,477	17,853	18,840	19,748
Transformation Connection	17,927	17,226	16,181	14,798	14,773	17,893	18,992	18,074	17,496	15,182	16,249	17,034
2015												
Ontario Demand	22,038	20,124	20,005	18,580	17,554	20,798	22,710	22,039	20,244	18,183	19,708	20,454
Network Connection	21,985	20,323	19,784	18,329	17,845	20,811	23,128	22,528	20,509	18,089	19,384	20,112
Line Connection	20,819	19,537	18,759	17,546	17,331	20,382	22,343	21,732	20,306	17,783	18,616	19,766
Transformation Connection	18,098	16,974	16,235	14,907	14,569	17,191	19,206	18,615	17,456	14,952	15,755	16,817
2016												
Ontario Demand	21,460	20,931	20,403	17,779	18,542	21,370	22,579	21,365	20,550	18,167	19,390	20,753
Network Connection	21,102	20,611	20,114	17,656	18,618	21,683	23,040	21,706	20,880	18,057	19,136	20,333
Line Connection	20,031	19,697	19,091	17,074	18,183	21,101	22,331	20,994	20,324	17,748	18,366	19,546
Transformation Connection	17,384	17,050	16,390	14,477	15,325	17,921	19,126	17,995	17,406	15,025	15,687	16,799
2017												
Ontario Demand	20,674	20,992	18,863	17,693	16,742	20,491	21,906	20,897	20,369	17,515	19,808	20,408
Network Connection	20,331	20,601	18,578	17,565	16,827	20,757	22,347	21,477	20,771	17,436	19,581	20,190
Line Connection	19,449	19,780	17,736	17,019	16,561	20,248	21,875	20,884	20,249	17,133	18,774	19,495
Transformation Connection	16,810	17,042	15,221	14,406	13,913	17,174	18,655	17,847	17,359	14,513	15,993	16,736
2018												
Ontario Demand	20,323	19,699	18,913	17,516	18,516	21,128	21,747	21,093	19,810	17,843	19,152	20,147
Network Connection	20,028	19,295	18,672	17,452	18,656	21,382	22,240	21,748	20,080	17,872	18,810	19,904
Line Connection	19,237	18,611	17,957	16,952	18,454	21,012	21,759	21,238	19,607	17,545	18,003	19,275
Transformation Connection	16,577	16,001	15,349	14,320	15,552	17,843	18,634	18,196	16,819	14,842	15,301	16,516

APPENDIX E

CONSENSUS FORECAST FOR ONTARIO GDP AND HOUSING STARTS

This Appendix provides the consensus forecast details for Ontario GDP and Ontario housing starts undertaken by Hydro One in November, 2018 for 2017-2022.

Survey of Ontario GDP Forecast (annual growth rate in %)

	2017	2018	2019	2020	2021	2022
Global Insight (Nov 2018)	2.7	2.0	2.4	2.4	2.1	2.1
Conference Board (Nov 2018)	2.7	2.2	1.9	1.9	2.1	2.0
U of T (Oct 2018)	2.7	2.2	1.9	2.1	2.2	2.2
C4SE (Sep 2018)	2.8	1.9	1.9	2.0	1.8	1.9
CIBC (Oct 2018)	2.7	2.1	1.8	1.3		
BMO (Nov 2018)	2.8	2.2	2.0			
RBC (Sep 2018)	2.7	2.0	1.9			
Scotia (Oct 2018)	2.8	2.1	2.0			
TD (Dec 2017)	2.7	2.2	2.2	1.7		
Desjardins (Nov 2018)	2.8	2.2	2.0			
Central 1 (Sep 2018)	2.8	2.2	1.8	1.8	1.7	
National Bank (Nov 2018)	2.7	2.2	1.8	1.6		
Laurentian Bank (Sep 2018)	2.7	1.9	1.7	1.8		
Average	**2.7**	**2.1**	**2.0**	**1.8**	**2.0**	**2.1**

Survey of Ontario Housing Starts Forecast (in 000's)

	2017	2018	2019	2020	2021	2022
Global Insight (Nov 2018)	80.1	77.0	71.2	63.7	62.8	61.3
Conference Board (Nov 2018)	79.0	75.7	74.0	76.7	78.1	79.2
U of T (Oct 2018)	79.1	75.9	69.0	69.8	70.7	71.6
C4SE (Sep 2018)	79.0	77.5	74.7	72.9	70.3	68.8
CIBC (Oct 2018)	80.2	74.0	68.0	63.0		
BMO (Nov 2018)	61.1	58.6	69.0			
RBC (Sep 2018)	79.1	76.0	70.0			
Scotia (Oct 2018)	80.0	78.0	72.0			
TD (Dec 2017)	80.1	77.5	75.4	78.6		
Desjardins (Nov 2018)	79.1	79.0	70.9			
Central 1 (Sep 2018)	79.1	76.2	71.6	71.2	69.2	
National Bank (Nov 2018)	79.0	77.9	68.6	70.0		
Laurentian Bank (Sep 2018)	79.1	76.0	73.0	72.0		
Average	**78.0**	**75.3**	**71.3**	**70.9**	**70.2**	**70.2**

Forecast updated on November 25, 2018

APPENDIX F

FORECAST ACCURACY

Tables 6a to 6c present the forecast accuracy of the OEB-approved forecasts of the three charge determinants on a weather-corrected basis for the past six rate applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-00140, and EB-2016-0160).

All forecasts are weather-normal and compared with weather-corrected actuals. In all tables, a negative or positive percent deviation indicates that the forecast was below or above actual-weather corrected.

Table 6a
Historical Board Approved for Network Connection Forecast
vs. Historical Actual and Historical Actual-Weather Normalized

	12-Month Average in MW								Difference from Actual Weather Corrected (%)					
Year	EB-2006-0501 Forecast (1)	EB-2008-0272 Forecast (2)	EB-2010-0002 Forecast (3)	EB-2012-0031 Forecast (4)	EB-2014-0140 Forecast (5)	EB-2016-0160 Forecast (6)	Actual: Weather Corrected	Actual	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	EB-2012 0031 Forecast	EB-2014-0140 Forecast	EB-2016-0160 Forecast
2005	21,704						21,702	22,507	0.01					
2006	21,259						21,275	22,028	-0.08					
2007	20,827	20,928					20,928	22,398	-0.48	0.00				
2008	20,872	20,943					21,067	21,307	-0.92	-0.59				
2009		20,842	20,868				20,868	20,410		-0.13	0.00			
2010		20,199	20,414				20,330	21,196		-0.64	0.41			
2011			20,150	20,245			20,245	20,861			-0.47	0.00		
2012			19,845	20,042			20,086	20,868			-1.20	-0.22		
2013				20,023	20,220		20,220	21,352				-0.97	0.00	
2014				19,552	20,276		20,601	20,643				-5.09	-1.58	
2015					20,559	20,236	20,236	20,384					1.60	0.00
2016					20,779	20,265	20,245	20,630					2.64	0.10
2017						20,405	19,705	19,608						3.55
2018						20,410	19,678	20,585						3.72
Average Excluding First Year (Actual) (7)									-0.49	-0.45	-0.42	-2.10	0.89	2.46

(1) Forecast: EB-2006-0501; Ex A; T14; S 3; P 19 of 20.
(2) Forecast: EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) Forecast: EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Forecast: EB-2012-0031; Ex A; T15; S 2; P 22 of 24.
(5) Forecast: EB-2014-0140; Ex A; T15; S 2; P 20 of 23, settlement amount shown.
(6) Forecast: EB-2016-0160; Ex E1; T3; S 1; P 20 of 52.
(7) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, and EB-2016-0160 forecast).

Table 6b
Historical Board Approved for Line Connection Forecast
vs. Historical Actual and Historical Actual-Weather Normalized

	12-Month Average in MW								Difference from Actual Weather Corrected (%) (5)					
Year	EB-2006-0501 Forecast (1)	EB-2008-0272 Forecast (2)	EB-2010-0002 Forecast (3)	EB-2012-0031 Forecast (4)	EB-2014-0140 Forecast (5)	EB-2016-0160 Forecast (6)	Actual: Weather Corrected	Actual	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	EB-2012 0031 Forecast	EB-2014-0140 Forecast	EB-2016-0160 Forecast
2005	20,590						20,590	21,345	0.00					
2006	20,242						20,282	20,991	-0.20					
2007	19,875	20,044					20,044	21,443	-0.84	0.00				
2008	19,940	20,111					20,156	20,386	-1.07	-0.23				
2009		20,100	19,796				19,796	19,372		1.53	0.00			
2010		19,555	19,674				19,348	20,162		1.07	1.69			
2011			19,500	19,417			19,417	20,004			0.42	0.00		
2012			19,286	19,359			19,298	20,047			-0.06	0.32		
2013				19,406	19,322		19,322	20,405				0.44	0.00	
2014				18,990	19,488		19,626	19,843				-3.24	-0.70	
2015					19,851	19,576	19,576	19,829					1.40	0.00
2016					20,150	19,605	19,540	20,027					3.12	0.33
2017						19,741	19,100	19,064						3.35
2018						19,746	19,137	20,040						3.18
Average Excluding First Year (Actual) (7)									-0.71	0.79	0.68	-0.83	1.27	1.84

(1) Forecast: EB-2006-0501; Ex A; T14; S 3; P 19 of 20.
(2) Forecast: EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) Forecast: EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Forecast: EB-2012-0031; Ex A; T15; S 2; P 22 of 24.
(5) Forecast: EB-2014-0140; Ex A; T15; S 2; P 20 of 23, settlement amount shown.
(6) Forecast: EB-2016-0160; Ex E1; T3; S 1; P 20 of 52.
(7) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, and EB-2016-0160 forecast).

Table 6c
Historical Board Approved for Transforer Connection Forecast
vs. Historical Actual and Historical Actual-Weather Corrected

	12-Month Average in MW								Difference from Actual Weather Corrected (%) (5)					
Year	EB-2006-0501 Forecast (1)	EB-2008-0272 Forecast (2)	EB-2010-0002 Forecast (3)	EB-2012-0031 Forecast (4)	EB-2014-0140 Forecast (5)	EB-2016-0160 Forecast (6)	Actual: Weather Corrected	Actual	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	EB-2012 0031 Forecast	EB-2014-0140 Forecast	EB-2016-0160 Forecast
2005	17,702						17,701	18,355	0.01					
2006	17,401						17,419	18,031	-0.10					
2007	17,086	17,329					17,329	18,537	-1.40	0.00				
2008	17,142	17,386					17,413	17,611	-1.56	-0.16				
2009		17,376	17,333				17,333	16,999		0.25	0.00			
2010		16,905	16,999				16,839	17,551		0.39	0.95			
2011			16,850	16,769			16,769	17,274			0.48	0.00		
2012			16,667	16,718			16,645	17,292			0.14	0.44		
2013				16,759	16,606		16,606	17,536				0.92	0.00	
2014				16,400	16,748		16,819	17,007				-2.49	-0.42	
2015					17,060	16,731	16,731	16,952					1.96	0.00
2016					17,317	16,756	16,715	17,040					3.60	0.24
2017						16,872	16,306	16,247						3.47
2018						16,876	16,329	17,151						3.35
Average Excluding First Year (Actual) (7)									-1.02	0.16	0.52	-0.37	1.71	2.36

(1) Forecast: EB-2006-0501; Ex A; T14; S 3; P 19 of 20.
(2) Forecast: EB-2008-0272; Ex A; T14; S 3; P 22 of 24.
(3) Forecast: EB-2010-0002; Ex A; T14; S 3; P 19 of 21.
(4) Forecast: EB-2012-0031; Ex A; T15; S 2; P 22 of 24.
(5) Forecast: EB-2014-0140; Ex A; T15; S 2; P 20 of 23, settlement amount shown.
(6) Forecast: EB-2016-0160; Ex E1; T3; S 1; P 20 of 52.
(7) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, EB-2014-0140, and EB-2016-0160 forecast).

APPENDIX G

COMPARISON WITH IESO FORECAST

IESO does not produce a forecast for transmission charge determinants. In this Appendix, a comparison between latest IESO 18-month forecast and corresponding Hydro One forecast is discussed. The comparison is consistent with latest Hydro One consultation with IESO in 2018 as well as an earlier joint study between the two organizations as documented in EB-2008-0272 (Exhibit A, Tab 14, Schedule 3, Attachment B).

Over the 18-month forecast period starting in January 2019, for which IESO has a monthly peak forecast, the difference between IESO and Hydro One forecasts averages to 422 MW. Following the same methodology as in the joint study between Hydro One and IESO noted above, sources of difference can be shown to be basically due to the following two factors.

1. Extreme weather may occur on any week day including weekends and holidays as well, where non-weather related load is low compared to other weekdays. Due to reliability concerns, IESO assumes that the extreme weather occurs on the day of highest demand (Wednesdays) only. In contrast, Hydro One needs to take account of all possibilities, such as the extreme weather occurring during a weekend, when it comes to forecasting load for revenue purposes. The difference between the two forecasts due to this factor is 650 MW.

2. IESO does not deduct demand response from its demand forecast, but rather takes it into account as an additional resource (or supply) in balancing demand and supply. In contrast, Hydro One needs to forecast load net of demand response because load and, thereby, transmission revenue decreases due to demand response. Hydro one does so by implicit method where demand response is not added to the actual and forecast.

Thus, assuming no incremental demand response, the forecast is implicitly net of demand response impact on load. The amount of demand response is about 300 MW.

In short, the total difference between IESO and Hydro One forecasts due to the factors noted above is 950 (= 650 + 300) MW. Comparing the latter figure with the actual difference between the two forecast (422 MW) reveals that Hydro One's forecast is actually higher by 528 MW compared to the IESO forecast over the January 2019 to June 2020 period.

APPENDIX H

YEAR-OVER-YEAR COMPARISON OF LOAD

This Appendix provides year-over-year comparison of load weather-normalized over historical, bridge year (2019) and test years.

Comparison of Historical, Bridge-Year, and Test-Years Load Weather-Normalized
(12-month average peak in MW)

			Charge Determinants					
Year	Ontario Peak	% Change	Network	% Change	Line Connection	% Change	Transformation Connection	% Change
2008	21,574	0.5	21,067	0.7	20,156	0.6	17,413	0.5
2009	21,340	-1.1	20,868	-0.9	19,796	-1.8	17,333	-0.5
2010	20,684	-3.1	20,330	-2.6	19,348	-2.3	16,839	-2.9
2011	20,547	-0.7	20,245	-0.4	19,417	0.4	16,769	-0.4
2012	20,348	-1.0	20,086	-0.8	19,298	-0.6	16,645	-0.7
2013	20,360	0.1	20,220	0.7	19,322	0.1	16,606	-0.2
2014	20,554	1.0	20,601	1.9	19,626	1.6	16,819	1.3
2015	20,203	-1.7	20,236	-1.8	19,576	-0.3	16,731	-0.5
2016	20,274	0.4	20,245	0.0	19,540	-0.2	16,715	-0.1
2017	19,696	-2.8	19,705	-2.7	19,100	-2.3	16,306	-2.4
2018	19,657	-0.2	19,678	-0.1	19,137	0.2	16,329	0.1
2019	19,595	-0.3	19,614	-0.3	19,078	-0.3	16,258	-0.4
2020	19,586	0.0	19,604	0.0	19,071	0.0	16,252	0.0
2021	19,451	-0.7	19,469	-0.7	18,941	-0.7	16,142	-0.7
2022	19,304	-0.8	19,322	-0.8	18,800	-0.7	16,021	-0.7

LOAD FORECAST DATA

This Exhibit has been filed in MS Excel format.

Witness: Bijan Alagheband