REVENUE REQUIREMENT

1. SUMMARY OF REVENUE REQUIREMENT

Hydro One Transmission has followed standard regulatory practice in the calculation of revenue requirement as follows:

Table 1: Revenue Requirement ($ Millions)

Particulars	2017	2018	Reference
OM&A	413.1	411.2	C1, Tab 2, Schedule 1
Depreciation & Amortization	435.7	470.7	C2, Tab 3, Schedule 1
Income Taxes	81.3	90.4	C1, Tab 8, Schedule 1
Cost of Capital[1]	676.1	714.9	D1, Tab 4, Schedule 1
Total Revenue Requirement	**1,606.3**	**1,687.2**	E2, Tab 1, Schedule 1

[1] Includes Interest Capitalized recovery on the Niagara Reinforcement Project (2017 - $5 million and 2018 - $5 million).

The resultant revenue requirement of $1,606.3 million for 2017 and $1,687.2 million for 2018 are the amounts required by Hydro One Transmission to safely address customer service and system reliability needs at the lowest practical cost.

2. CALCULATION OF REVENUE REQUIREMENT

The details of the OM&A and Depreciation components of the revenue requirement are as follows:

2.1 OM&A Expense ($ Millions)

	2017	**2018**
Sustaining	241.2	238.5
Development	4.8	5.0
Operations	61.3	62.1
Customer Care	4.0	3.9
Common Corporate and Other Costs	49.9	47.5
Taxes Other Than Income Tax	63.6	64.3
Pension Adjustment	-11.0	-8.0
B2M LP Adjustment	-0.8	-2.1
Total OM&A	**413.1**	**411.2**

2.2 Depreciation Expense ($ Millions)

	2017	**2018**
Depreciation	424.0	460.6
Amortization	11.8	10.1
Total Expense	**435.7**	**470.7**

3. RATES REVENUE REQUIREMENT - COMPARISON OF YEAR 2016 TO YEAR 2017

Table 2 compares, by element, the 2016 rates revenue requirement (as per EB-2014-0140) against the 2017 proposed rates revenue requirement.

Table 2: Comparison of Rates Revenue Requirements:
Board Approved 2016 vs. 2017 ($Millions)

Line no.	Description	Year 2016	Year 2017	Difference
1	OM&A	436.7	413.1	(23.6)
2	Depreciation	397.3	435.7	38.5
3	Income Taxes	72.2	81.3	9.1
4	Cost of Capital [1]	661.5	676.1	14.6
5	Total Revenue Requirement	1,567.7	1,606.3	38.6
	Deduct External Revenues [2]	**(32.2)**	**(28.2)**	**4.0**
6	Revenue Requirement less External Revenues	1,535.4	1,578.1	42.7
	Deduct Export Revenue Credit [3]	**(31.7)**	**(39.2)**	**(7.5)**
7	Deduct Regulatory Accounts Disposition [4]	(36.1)	(47.8)	(11.7)
8	Add Low Voltage Switch Gear [5]	13.0	14.0	1.0
9	Rates Revenue Requirement	**1,480.7**	**1,505.1**	**24.4**

1 Includes recovery of Interest Capitalized on the Niagara Reinforcement Project.
2 External revenues addressed in Exhibit E1, Tab 2, Schedule 1.
3 Export revenue is addressed in Exhibit H1, Tab 4, Schedule 1.
4 See Exhibit F1, Tab 1, Schedule 3 for further details.
5 Low Voltage Switch Gear is addressed in Exhibit G1, Tab 3, Schedule 1.

There are a number of key operational and financial factors contributing to the increased rates revenue requirement that have an impact across the cost components in Table 2. The increase in total rates revenue requirement is largely attributable to the impact of rate base growth reflected in the increase in depreciation and the return on capital. Also contributing to the difference is higher income taxes, and lower external revenues. These increases were partially offset by a lower cost of debt, lower OM&A, increased regulatory account disposition, and a higher export revenue credit.

Table 3 illustrates the value of the key impacts on the increase in the rates revenue requirement.

Table 3: Components of Change to Rates Revenue Requirement 2016[1] vs. 2017

Description	Amount ($M)
Decrease in OM&A	(23.6)
Rate Base Growth	70.7
Decrease in Cost of Debt	(17.7)
No Change in Cost of Equity	-
Tax - timing differences and other	9.1
External Revenue	4.0
Increase in Export Revenue Credit	(7.5)
Increase in Regulatory Accounts Disposition	(11.6)
Increase in Low Voltage Switch Gear	1.0
Total Change	**24.4**

4. RATES REVENUE REQUIREMENT - COMPARISON OF YEAR 2017 TO YEAR 2018

Table 4 compares, by element, the 2017 rates revenue requirement against the 2018 rates revenue requirement.

[1] 2014 Amounts as per Hydro One Transmission's 2014 Revenue Requirement and Charge Determinants for EB-2012-0031 and EB-2011-0268.

Table 4: Comparison of Rates Revenue Requirements 2017 vs. 2018 ($ Millions)

Line no.	Description	Year 2017	Year 2018	Difference
1	OM&A	413.1	411.2	(1.9)
2	Depreciation	435.7	470.7	35.0
3	Income Taxes	81.3	90.4	9.1
4	Cost of Capital[1]	676.1	714.9	38.8
	Total Revenue Requirement	**1,606.3**	**1,687.2**	**80.9**
5	Deduct External Revenues[2]	(28.2)	(28.5)	(0.3)
	Revenue Requirement less External Revenues	**1,578.1**	**1,658.7**	**80.6**
6	Deduct Export Revenue Credit[3]	(39.2)	(40.1)	(0.9)
7	Deduct Regulatory Accounts Disposition[4]	(47.8)	(47.8)	-
8	Add Low Voltage Switch Gear[5]	14.0	14.7	0.7
	Rates Revenue Requirement	**1,505.1**	**1,585.6**	**80.5**

[1] Includes recovery of Interest Capitalized on the Niagara Reinforcement Project.
[2] External revenues addressed in Exhibit E1, Tab 2, Schedule 1.
[3] Export revenue is addressed in Exhibit H1, Tab 4, Schedule 1.
[4] See Exhibit F1, Tab 1, Schedule 3 for further details.
[5] Low Voltage Switch Gear is addressed in Exhibit G1, Tab 3, Schedule 1.

The increase in 2018 rates revenue requirement is primarily due to the increase in core rate base as reflected in the increase in depreciation and the return on capital. Also contributing the increased rate base is due to higher income taxes. These increases are partially offset by a lower cost of debt, lower OM&A, and a higher export revenue credit.

Table 5 illustrates the value of the key impacts on the movement in the rates revenue requirement.

Table 5: **Components of Change to Rates Revenue Requirement 2017 vs. 2018**

Description	Amount ($M)
Decrease in OM&A	(1.9)
Rate Base Growth	77.5
Decrease in Cost of Debt	(3.7)
No Change in Cost of Equity	-
Tax - timing differences and other	9.1
External Revenue	(0.3)
Increase in Export Revenue Credit	(0.9)
No Change in Regulatory Accounts Disposition	-
Increase in Low Voltage Switch Gear	0.7
Other	-
Total change	**80.5**

[1] Net of External Revenue

Exhibit G1, Tab 1, Schedule 1 provides information on how the rates revenue requirements will be recovered through rates.

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 $28.2 million in 2017 and $28.5 million in 2018 and account for approximately 1.8% and 1.7% of Hydro One Transmission revenues for 2017 and 2018 respectively. 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 Exhibit C1, Tab 5, Schedule 1 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. The costs associated with external work are described in more detail in Exhibit C1, Tab 3, Schedule 6.

3. DESCRIPTION

Table 1 details Hydro One Transmission's external revenues for the period 2012 to 2018.

Table 1: External Revenues ($ Millions)

$M	2012 Historic	2013 Historic	2014 Historic	2015 Historic	2016 Bridge	2017 Test	2018 Test
Secondary Land Use	22.0	21.1	19.1	31.6	15.2	15.4	15.6
Station Maintenance	13.9	12.6	14.7	9.5	5.2	5.3	5.3
Engineering & Construction	2.3	2.2	0.1	0.4	0.0	0.0	0.0
Other External Revenues	3.8	10.7	10.5	12.8	7.4	7.5	7.6
Totals	**42.0**	**46.6**	**44.4**	**54.3**	**27.9**	**28.2**	**28.5**

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 $31.6 million in 2015. They are forecasted to drop to $15.2 million in 2016 and stabilize during the test years. Historical figures in years 2013 to 2015 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 Maintenance

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 1, this segment of external revenue is expected to decrease in 2016 through to 2018, primarily due to a lower volume of work from major customers.

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.

3.4 Other External Revenues

"Other" external revenues set out in Table 1 include revenues from providing telecommunications services to Ontario Hydro successor companies (such as lease of fiber), revenues from special transmission planning studies, customer shortfall payments (e.g. true-ups, temporary bypass), and other miscellaneous external revenues. These include a transfer price charge to Hydro One Telecom Inc. and Hydro One Remote Communities Inc. as described in Exhibit B1, Tab 3, Schedule 9. In 2017 and 2018, forecasted revenues include $4.0 million each year for the lease of idle transmission lines.

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 March 2016, using economic and forecast information that was available in March 2016.

Hydro One Transmission's forecast of average 12-month peak load for 2017 and 2018 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 2017-2018 Load Forecast
(12-Month Average Peak in MW)

	Ontario Demand	Hydro One Rate Categories (Charge Determinants)		
		Network Connection	Line Connection	Transformation Connection
2017	20,373	20,405	19,741	16,872
2018	20,378	20,410	19,746	16,876

Hydro One worked with 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.

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 OEB in previous Hydro One rate applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031). In the last rate application EB-2014-0140, 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.

The forecasts presented in this Exhibit are consistent with the economic assumptions used in the business planning process as described in Exhibit B1, Tab 2, Schedule 7. 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 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.

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 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 2016 to 2018. Consequently, for the purpose of this Application, the focus is on the short term 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.

Key Assumptions Used in the Forecast

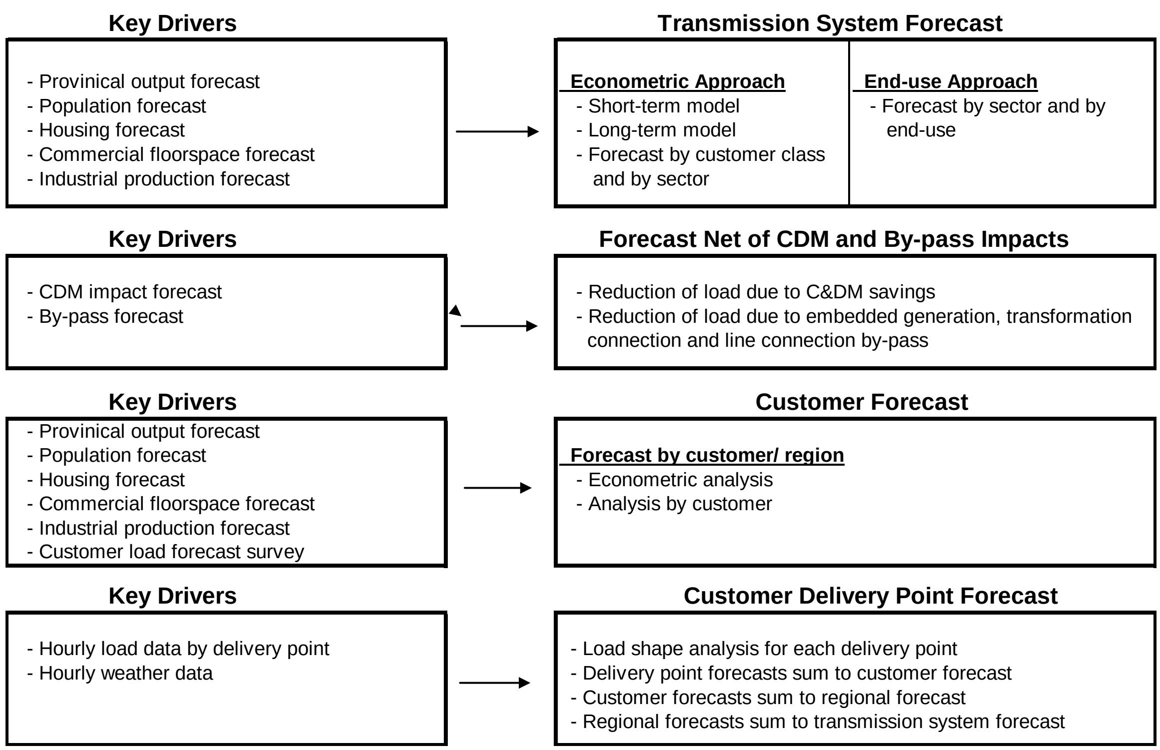


Figure 1

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 by-pass risks, which have a direct impact on Hydro One Transmission's system energy demands.

3.1 Provincial GDP Forecast

The provincial GDP forecast is a key driver for the load forecast. During last three years, the manufacturing sector experienced a slow recovery, and the world economy experienced slow growth. This growth was not broadly based. Textiles, petroleum and coal, and computer industries continued an overall decline during the last four years. Ontario GDP grew by 1.3 percent in 2012, 1.3 percent in 2013, 2.7 percent in 2014, and is expected to have grown by 2.5 percent in 2015. Based on the consensus forecast, Ontario GDP is expected to grow by, 2.3 percent in 2016, 2.4 percent in 2017, and by 2.3 percent in 2018 as the economy continues recovering. Appendix E provides the details of the consensus forecast for Ontario GDP.

3.2 Provincial Population Forecast

The Ontario population grew 1.1 percent in 2012 and 2013, 0.9 percent in 2014, and 0.8 percent in 2015. Population growth in Ontario is forecast to grow at about the same pace as the nation in the forecast period. The economic forecast indicates that the Ontario population is expected to grow at 1.0 percent per year between 2016 and 2018. Steady population growth contributes positively to the load forecast.

3.3 Provincial Housing Forecast

Helped by population growth and low interest rates, housing demand in Ontario continued to grow at a moderate pace over the last four years. Housing starts statistics showed growth of 63,000 houses in 2012, 59,000 in 2013 58,000 in 2014, and is expected to be 69,000 in 2015. The consensus forecast calls for 68,000 housing starts in 2016, 66,000 in 2017, and 69,000 in 2018. Appendix E provides the details of the consensus forecast for Ontario housing starts.

3.4 Commercial Floor Space Forecast

The pace of commercial construction activities has slowed in recent years. Commercial floor space grew by 1.3 percent in 2012, 0.8 percent in 2013, and 0.9 percent in 2014. Commercial floor space is expected to grow by 1.3 percent in 2015. The economic forecast shows commercial floor space is going to moderately grow over the forecast horizon. The forecast calls for 1.0 percent growth in 2016, 1.2 percent in 2017, and 1.4 percent in 2018. 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, textiles, petroleum and coal, and computer products experienced an overall decline during this period. Industrial GDP grew by 1.2 percent in 2012, declined by 0.2 percent in 2013, and grew by 3.8 percent in 2014 and is expected to have declined by 1.1 percent in 2015. The economic forecast calls for a decline of 0.5 percent in 2016, moderate growth of 1.4 percent in 2017, followed by growth of 0.9 percent in 2018. 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. Hydro One has adopted 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 three CDM categories that are consistent with the IESO’s (then the OPA) 2013 LTEP information: energy efficiency programs, codes and standards, and demand reduction from demand response resources. Details of the latest information that was provided in early 2016 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 2018. 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

* 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 By-Pass Forecast

Hydro One collects its transmission revenue through four types of OEB-approved transmission charges (Network, Line Connection, Transformation Connection, and Wholesale Meter). When Hydro One's transmission customers get power from their own embedded generation or build their own transformation station or line connections to their distribution system, Hydro One's transmission charges cannot be applied. The following summarizes the by-pass forecast assumptions used in the test years.

Embedded Generation By-pass

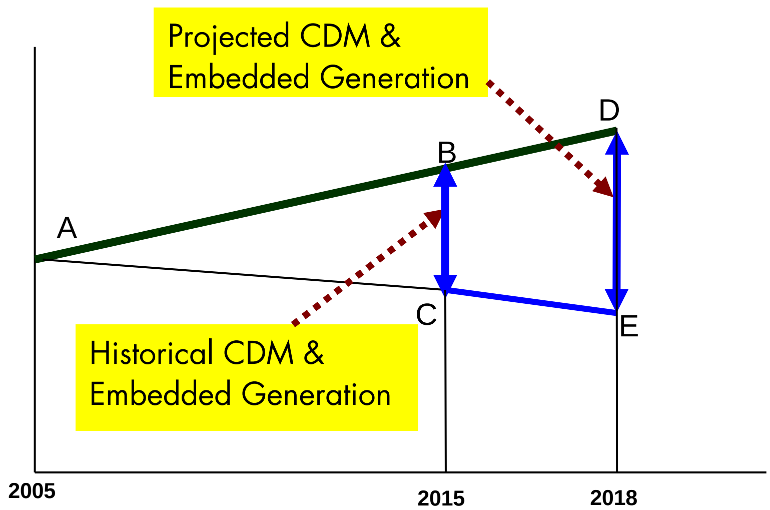
In relation to Ontario demand, a total of 608 MW of embedded generation was assumed to be in place in 2014. An additional 107 MW in 2015, 19 MW in 2016, 38 MW in 2017, and 30 MW in 2018 of new embedded generation is assumed in the load forecast. The figures represent 12-month average peak and are based on information provided by IESO, which reflects renewable energy projects initiated by the OPA (now the IESO).

Transformation and Line Connection By-pass

No transformation and line connection by-pass is assumed in the load forecast in this Application.

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: Estimated load without CDM and Embedded Generation impacts in 2015

C: 2015 actual load

D: Projected load without CDM and Embedded Generation impacts in 2018

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 more 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, and EB-2012-0031). Normal weather data is based on the average weather conditions experienced over the last 31 years. This methodology is consistent with the approach 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. Weather data analyzed include temperature, wind speed, cloud cover and humidity. 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 on weather normalization practices by surveying over 50 utilities in North America in 2008. 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.

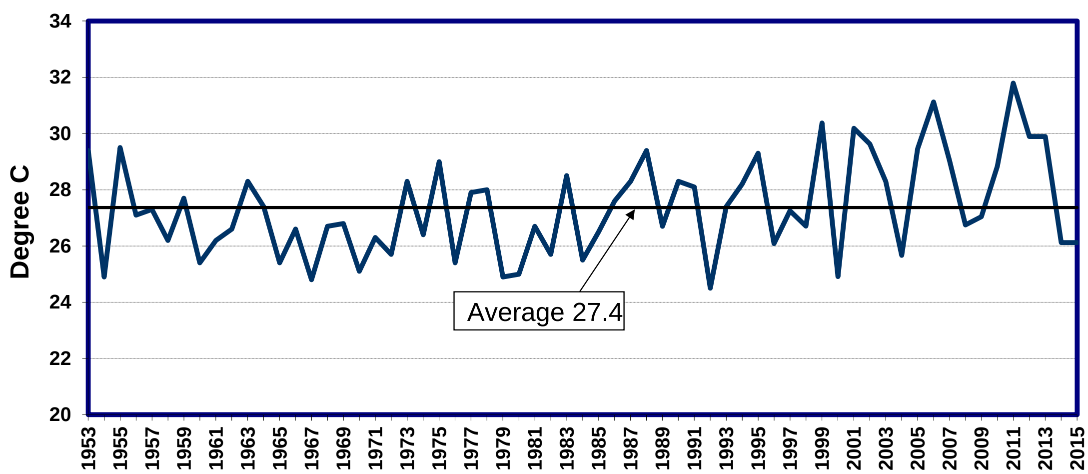
- Most utilities use long-term weather data to calculate the weather normal conditions.
- The most commonly used period for weather normalization is at least 30 years; no utilities use less than 10 years of weather data to do weather normalization.
- Weather normalization surveys undertaken by Edison 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 recent years 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 last 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 temperature trend. However, as shown in Figures 3 and 4, this 20-year "trend" has been broken since 2014 as the actual figures fall significantly below the normal line, in both 2014 and 2015, rather than being close to the 20-year trend line somewhere above the normal line. The Figures present the maximum and minimum daily temperatures between 1953 and 2015 as a measure of peak-generating weather conditions during summer and winter, respectively.

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



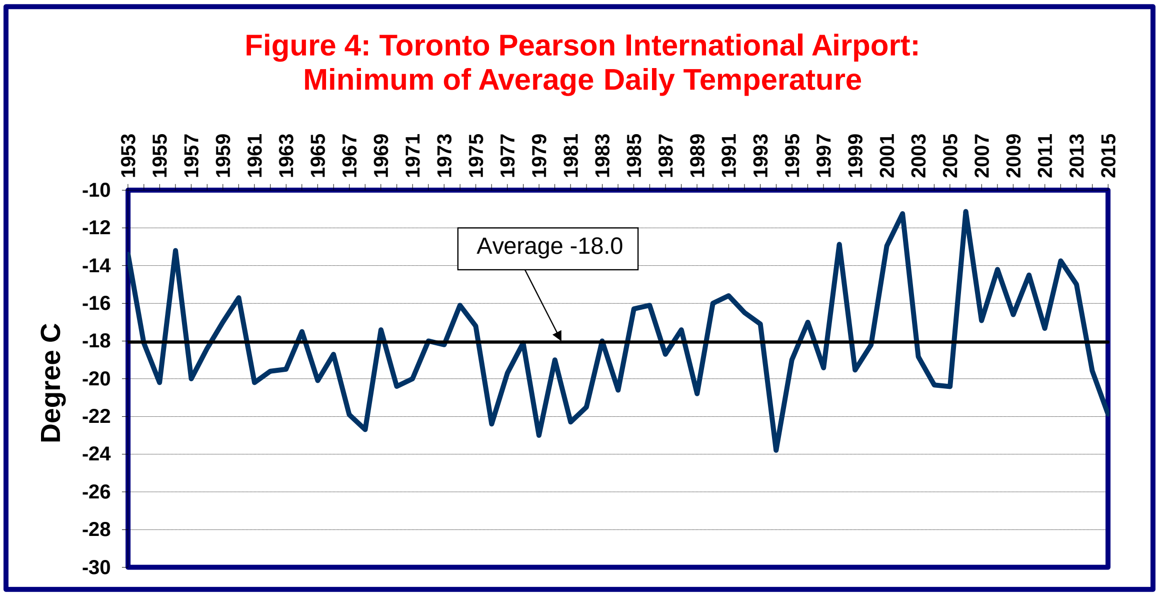


Figure 4: Toronto Pearson International Airport:
Minimum of Average Daily Temperature

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, and EB-2012-0031).

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.

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. As in monthly and end-use models, the load impact of CDM and embedded generation is added back to historical figures.

The commercial sector links energy usage to electricity price, commercial GDP and weather conditions as measured by heating and 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 electricity price and income, 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 electricity price, cooling and heating degree days, and a dummy variable to capture a change in load pattern since 1997.

4.2.3 End-Use Models

The end-use models cover the residential, commercial, industrial, agricultural and transportation sectors. As in the monthly and annual econometric models previously discussed, the load impact of CDM and embedded generation is added back to historical figures. 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.

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.

In January 2016, 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 and related industrial and commercial loads. 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 2017 AND 2018

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 2015 at the same rate as the 12-month average peak for Ontario. Table 3 presents the forecast before and after deducting the load impacts attributed to embedded generation and CDM for the period 2015 to 2018. 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, and EB-2012-0031. Appendix D to this Exhibit provides the historical actual and weather-corrected charge determinant data for years 2004 to 2015.

Table 3: Load Forecast Before and After Embedded Generation and CDM

(12-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand (MW)	Network Connection (MW)	Line Connection (MW)	Transformation Connection (MW)
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2015	22,353	22,389	21,622	18,479
2016	22,606	22,642	21,862	18,685
2017	22,784	22,820	22,034	18,832
2018	23,105	23,142	22,344	19,096
Load Impact of Embedded Generation				
2015	716	717	655	560
2016	735	736	673	575
2017	773	774	709	606
2018	803	805	737	630
Load Impact of CDM				
2015	1,434	1,436	1,390	1,188
2016	1,638	1,641	1,584	1,354
2017	1,638	1,641	1,584	1,354
2018	1,924	1,927	1,860	1,590
Load Forecast after Deducting Embedded Generation and CDM				
2015	20,203	20,236	19,576	16,731
2016	20,233	20,265	19,605	16,756
2017	20,373	20,405	19,741	16,872
2018	20,378	20,410	19,746	16,876

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 22,606 MW in 2016 (12-month average peak), 22,784 MW in 2017, and 23,105 MW in 2018. After deducting the load impacts of embedded generation and CDM, Hydro One Transmission is forecast to deliver an average of 20,233 MW in 2016 (12-month average peak), to 20,373 MW in 2017, and 20,378 MW in 2018.

The forecast is weather-normal and the actual load could be below or above the forecast depending on the weather conditions and/or 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 in 2016, 2017, and 2018 will fall within the upper and lower bands. The bands are derived using Monte Carlo simulation technique relating variations in load to variations in Ontario GDP and weather.

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

Year	Lower Band	Forecast	Upper Band
Network			
2015 (Actual)	20,236	20,236	20,236
2016	19,895	20,265	20,639
2017	19,916	20,405	20,897
2018	19,862	20,410	20,956
Line Connection			
2015 (Actual)	19,497	19,576	20,222
2016	19,248	19,605	19,964
2017	19,267	19,741	20,216
2018	19,218	19,746	20,275
Transformation Connection			
2015 (Actual)	16,742	16,731	17,363
2016	16,452	16,756	17,063
2017	16,467	16,872	17,278
2018	16,425	16,876	17,325

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 LDCs in Ontario for use in their distribution rate applications to the OEB, using 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.

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%	n.a.
2015	1.50%	n.a.	n.a.
Mean	0.03%	-0.23%	-0.46%
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.

Between 1999 and 2015, 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 forecasts were approved in EB-2008-0272, EB-2010-0002, and EB-2012-0031. The 2014-2016 load forecast was modified as part of a settlement reached in Hydro One's transmission application EB-2014-0140. Detailed comparison of forecasts for each forecast year separately is provided in Appendix F and 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	**Average**
Network	-0.49	-0.45	-0.42	-2.10	-0.24	**-0.74**
Line	-0.71	0.79	0.68	-0.83	0.10	**0.01**
Transformation	-1.02	0.16	0.52	-0.37	0.52	**-0.04**
Average	**-0.74**	**0.17**	**0.26**	**-1.10**	**0.12**	**-0.26**
One Standard Deviation (+/-) **	2.26	2.26	2.26	2.26	1.96	

* 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.
For EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031 forecasts 3-year standard deviation is shown.
For EB-2014-0140 forecast, only two years of actual (2014 and 2015) were available for comparison with forecast, therefore 2-year standard deviation is presented, which is naturally smaller compared to 3-year standard deviation as the forecast horizon is shorter. All forecasts are within one standard deviation.

As shown in Table 6, the deviations of previous OEB-approved charge determinant forecasts from historical actuals on a weather-corrected basis are all within one standard deviation of errors, and the average deviation over the past five OEB-approved forecasts (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, 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).

	SS		
Seasonal Factors	parameters:		
A[1]	0.153655		
K[1]	-0.50695		
Non-seasonal			
Factors	SS parameters:		
A[1]	0.619766		
K[1]	-0.262627		
GDPONT	LOG 1 1	Exogenous	
G[1][1]	0.195329		
BPONT[-8]	LOG 1 1	Exogenous	
G[1][2]	0.00177839		
D0803	1 1	Exogenous	
G[1][3]	-0.00487583		

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 2014 (Ui); normalized to be 1 in 2014:

$$\text{Saturation (t)} = (\Sigma \text{ Ei (t)} * \text{Ui}) / (\Sigma \text{ Ei (2014)} * \text{Ui})$$

Usage at year t is measured as the ratio of per capita residential consumption to saturation in that year, again normalized to be 1 in 2014.

$$\text{Usage (t)} = [(\text{per capita consumption (t)}) / \text{Saturation (t)}] / [\text{per capita consumption (2014)} / \text{Saturation (2014)}]$$

Ontario residential electricity consumption can then be calculated as:

Total residential electricity consumption = Saturation (t) * Usage (t) * N(t)
where N(t) is a normalizing factor to account for the number of households in Ontario.

Saturation is modelled as a function of energy prices, income per household in Ontario, lagged value of saturation and a dummy variable:

LELSAT = C(1)*(LPELRES+LPELRES(-1))/2+C(2)*LPLIQRES+C(3)*LYPDPHH + C(4)*LELSAT (-1) +C(5)*LELSAT(-2)+ C(6)* D81

LELUSE = C(7)*(LPELRES+LPELRES(-1))/2+C(8)*LPLIQRES(-1)

+C(9)* LYPDPHH+C(10)*LHDD+(1+C(11)+C(12))*LELUSE(-1)+C(11)*LELSAT

+C(12)*LELSAT(-1)-C(10)*(1+C(11)+C(12))*LHDD(-1)

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 is from Statistics Canada
- Forecast is prepared by Hydro One

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

- History is from Statistics Canada
- Forecast is prepared by Hydro One

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

- Disposable income history is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance and Ontario population history is from Statistics Canada, deflated by CPI from Statistics Canada
- Forecast is based on forecasts of disposable income from C4SE and University of Toronto (PEAP), CPI from IHS Global Insight, and population from IHS Global Insight and C4SE

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

c(1) to c(12) = variable coefficients.

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

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.062292	0.016656	-3.739809	0.0003
C(2)	0.009178	0.008444	1.086977	0.2800
C(3)	0.145279	0.043332	3.352670	0.0012
C(4)	0.603187	0.126922	4.752428	0.0000
C(5)	0.292236	0.119867	2.438003	0.0168
C(6)	-0.038365	0.021080	-1.819939	0.0722
C(7)	-0.032501	0.012820	-2.535246	0.0130
C(8)	0.019715	0.005303	3.718068	0.0004
C(9)	0.252764	0.066493	3.801338	0.0003
C(10)	0.086500	0.051052	1.694356	0.0937
C(11)	-1.210926	0.311603	-3.886113	0.0002
C(12)	1.040198	0.297755	3.493474	0.0007

Saturation Model Fit:

R-squared =0.97, Adjusted R-squared = 0.96, Durbin-Watson Statistics =2.12

Usage Model Fit:

R-squared =0.95, Adjusted R-squared = 0.94, Durbin-Watson Statistics =1.61

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 most of the factors used to explain the variations in load are statistically significant. 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.

<u>Commercial Model</u>

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

LELCOM = C(1) +C(2)*(LPELCOM(-1)+PELCOM(-2))/2+C(3)
*LGDPCOM+(1-C(3))*LELCOM(-1) +C(4)*LCDD+C(5)*LHDD-(1
-C(3))*(C(4)*LCDD(-1)+C(5)*LHDD(-1))+C(6)*D08ON
+[AR(1)=C(7)]

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 is from Statistics Canada
- Forecast is prepared by Hydro One

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

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

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

D08ON = dummy variable equals 0 for years prior to 2008 and 1 elsewhere.

The estimated equation is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-0.489145	0.236305	-2.069975	0.0445
C(2)	-1.66E-06	1.73E-06	-0.959715	0.3426
C(3)	0.172659	0.062341	2.769604	0.0083
C(4)	0.022381	0.007518	2.977018	0.0048
C(5)	0.142957	0.046057	3.103915	0.0034
C(6)	-0.044810	0.019370	-2.313339	0.0256
C(7)	0.455496	0.157129	2.898874	0.0059

R-squared =0.998, Adjusted R-squared = 0.998, Durbin-Watson Statistics =2.15

The regression results reflect a high goodness fit and statistical significance for most estimates.

<u>Industrial Model</u>

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(-1)))/2

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 is from Statistics Canada
- Forecast is prepared by Hydro One

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

The estimated model is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	0.843876	0.682691	1.236102	0.2227
C(2)	0.643460	0.110779	5.808485	0.0000
C(3)	-0.605108	0.114751	-5.273224	0.0000
C(4)	0.928816	0.059081	15.72104	0.0000
C(5)	-0.042251	0.031626	-1.335975	0.1881

R-squared =0.865, Adjusted R-squared = 0.853, Durbin-Watson Statistics =2.21

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,
W1, W2, W3 = 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 from Statistics Canada

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 for all price series is from Statistics Canada
- Forecast is prepared by Hydro One

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 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 Seemingly Unrelated Equations (SUR) method. The estimated model is presented as follows:

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	-1.900648	0.182062	-10.43958	0.0000
C(12)	-0.917452	0.056346	-16.28239	0.0000
C(13)	-1.469172	0.146904	-10.00091	0.0000
C(23)	-0.553527	0.153400	-3.608397	0.0005
C(20)	1.319425	0.173366	7.610642	0.0000
C(5)	0.455663	0.040296	11.30779	0.0000
C(60)	0.938035	0.105145	8.921379	0.0000
C(61)	-0.518889	0.102042	-5.085078	0.0000
C(2)	-0.604148	0.179977	-3.356801	0.0012
C(21)	1.271240	0.197831	6.425881	0.0000
C(6)	0.354826	0.046242	7.673326	0.0000
C(7)	0.219460	0.041786	5.251945	0.0000

LW13 Model Fit:

R-squared =0.977, Adjusted R-squared = 0.973, Durbin-Watson Statistics =1.89

LW23 Model Fit:

R-squared =0.976, Adjusted R-squared = 0.971, Durbin-Watson Statistics =1.86

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 income, electricity prices as well as trend and cyclical variations. The agricultural electricity model therefore includes trend and moving average terms in addition to income and price variables, as follows:

ELAGR = C(1)+C(2)*D(LYPD(-3))+C(3)*D(RPELRES(-1)/PLIQRES(-1))+C(4)*TREND
+C(5)*LELAGR(-2) +C(6)*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.

YPD = logarithm of Ontario personal disposable income in constant $,

- History is based on quarterly figures in Ontario Economic Accounts published by Ontario Ministry of Finance History, deflated by CPI from Statistics Canada
- Forecast is based on forecasts of disposable income from C4SE and University of Toronto (PEAP), and CPI from IHS Global Insight

RPELRES = electricity price in Ontario residential sector divided by
liquid-fuel price in Ontario residential sector,

- History is from Statistics Canada
- Forecast is prepared by Hydro One

TREND = a trend variable, equals 1 in 1961 and increase 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	2460.423	832.4814	2.955529	0.0081
D(YPD(-3))	0.001632	0.006777	0.240797	0.8123
D(PELRES(-1)/PLIQRES(-1))	-107.2805	80.89825	-1.326116	0.2005
TREND	-26.89656	10.30658	-2.609649	0.0172
ELAGR(-2)	0.417427	0.185477	2.250566	0.0365
D08	326.6523	102.2157	3.195716	0.0048
MA(4)	-0.990001	0.050565	-19.57868	0.0000

R-squared =0.874, Adjusted R-squared = 0.834, Durbin-Watson Statistics =1.47

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. Not all the model parameters are statistically significant due to correlation between the variables included in the model. However, the inclusion of all the variables was warranted due to theoretical considerations.

Transportation Model

The transportation model is represented by an equation basically relating electricity usage to income and price variables.

LTRANS=C(1)+C(2)*LTRANS(-1)+ C(3)*(LPELRES+LPELRES(-1)
+LPELRES(-2)+LPELRES(-3))/4+C(4)*D98ON(-1)+C(5)*D0812
+C(6)*LHDD+C(7)*LCDD

where

LTRANS = logarithm of electricity consumption in Ontario transportation sector,

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

LPELRES = logarithm of electricity price in Ontario residential sector,

- History is from Statistics Canada
- Forecast is prepared by Hydro One

D98ON = a dummy variable to capture change in load pattern since 1998, equals zero prior to 1998 and 1 elsewhere.

D0812 = a dummy variable to capture a transitory reduction in load, equals 1 for the years 2008 to 2012 and zero elsewhere.

	Coefficient	Std. Error	t-Statistic	Prob.
C(1)	25.93009	5.213129	4.973998	0.0000
C(2)	-0.191417	0.113697	-1.683575	0.1042
C(3)	-0.284284	0.236818	-1.200429	0.2408
C(4)	0.202912	0.099687	2.035489	0.0521
C(5)	-0.951320	0.096430	-9.865385	0.0000
C(6)	-1.834389	0.482733	-3.800010	0.0008
C(7)	-0.001185	0.096602	-0.012262	0.9903

R-squared =0.923, Adjusted R-squared = 0.906, Durbin-Watson Statistics =2.13

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

APPENDIX C

END-USE MODEL

Residential Sector

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 based on the economic forecast by sector and segment.

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 2004-2015.

Actual Ontario Demand and Hydro One Charge Determinants
(MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004												
Ontario Demand	24,937	22,608	21,634	19,911	20,327	23,163	23,976	23,159	21,911	19,829	22,066	24,979
Network Connection	24,166	21,860	20,990	19,448	20,034	22,752	22,304	22,687	21,435	19,454	21,055	24,299
Line Connection	22,297	20,643	20,014	18,770	19,241	21,611	20,890	21,361	20,388	18,868	19,963	22,337
Transformation Connection	19,795	18,091	17,211	16,110	16,344	18,573	18,060	18,481	17,472	15,992	17,068	19,570
2005												
Ontario Demand	24,362	22,322	22,724	19,343	19,007	26,157	26,160	25,816	23,914	20,752	22,564	23,766
Network Connection	23,713	21,684	22,075	18,899	18,739	25,520	25,447	25,023	23,305	20,611	22,072	23,000
Line Connection	22,237	20,712	20,581	18,424	18,328	24,163	24,123	23,507	21,807	19,937	20,672	21,651
Transformation Connection	19,351	17,846	17,818	15,466	15,314	20,806	20,945	20,311	18,747	17,008	17,800	18,854
2006												
Ontario Demand	23,052	22,321	21,772	19,582	24,857	23,349	26,092	27,005	19,976	19,590	21,267	22,941
Network Connection	22,083	21,562	21,028	19,073	24,272	22,491	25,405	26,292	19,692	19,372	20,726	22,343
Line Connection	20,821	20,727	19,900	18,415	22,909	21,519	24,198	24,732	19,214	18,919	19,666	20,870
Transformation Connection	18,017	17,964	17,170	15,649	19,748	18,337	20,911	21,371	16,285	15,999	16,822	18,098
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

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

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004												
Ontario Demand	23,676	23,560	22,128	20,016	19,373	22,658	23,187	23,008	21,524	20,199	22,822	23,824
Network Connection	22,944	22,781	21,469	19,551	19,094	22,256	21,570	22,539	21,056	19,817	21,776	23,175
Line Connection	21,170	21,513	20,471	18,869	18,337	21,139	20,203	21,222	20,028	19,220	20,647	21,304
Transformation Connection	18,794	18,853	17,603	16,195	15,576	18,168	17,465	18,361	17,164	16,290	17,653	18,665
2005												
Ontario Demand	23,877	23,685	22,187	20,209	19,407	22,951	23,476	23,395	21,746	20,118	22,276	23,632
Network Connection	23,241	23,008	21,553	19,745	19,133	22,393	22,836	22,676	21,193	19,982	21,790	22,871
Line Connection	21,794	21,976	20,094	19,249	18,714	21,202	21,648	21,303	19,830	19,328	20,408	21,529
Transformation Connection	18,966	18,935	17,397	16,158	15,637	18,256	18,796	18,407	17,048	16,488	17,573	18,748
2006												
Ontario Demand	23,899	23,218	22,006	19,966	19,351	22,826	23,119	22,927	20,510	19,816	21,746	23,160
Network Connection	22,895	22,429	21,254	19,448	18,896	21,988	22,510	22,322	20,219	19,596	21,192	22,555
Line Connection	21,585	21,560	20,114	18,777	17,834	21,037	21,441	20,997	19,728	19,138	20,109	21,069
Transformation Connection	18,679	18,686	17,354	15,956	15,373	17,926	18,528	18,144	16,721	16,184	17,201	18,270
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

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 March, 2016 for 2015-2020.

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

	2016	2017	2018	2019	2020	2021
Global Insight (Feb 2016)	2.0	2.0	2.3	2.4	2.3	2.2
Conference Board (Feb 2016)	2.4	2.4	2.1	2.1	2.2	
U of T (Feb 2016)	2.4	2.7	2.7	2.2	2.0	
C4SE (Jan 2016)	2.4	2.6	2.2	2.2	1.7	1.4
CIBC (Mar 2016)	2.3	2.6				
BMO (Mar 2016)	2.5	2.2				
RBC (Dec 2015)	2.5	2.7				
Scotia (Mar 2016)	2.3	2.7				
TD (Jan 2016)	2.2	2.0				
Desjardins (Feb 2016)	2.1	2.4				
Central 1 (Jan 2016)	2.7	3.1				
National Bank (Feb 2016)	2.0	2.0				
Laurentian Bank (Jan 2016)	2.4	2.5				
Average	**2.3**	**2.4**	**2.3**	**2.2**	**2.1**	**1.8**

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

	2016	2017	2018	2019	2020	2021
Global Insight (Feb 2016)	69.1	65.7	63.1	60.7	59.1	58.1
Conference Board (Feb 2016)	68.9	64.1	65.3	72.7	79.4	
U of T (Feb 2016)	66.3	67.6	68.4	69.3	70.2	71.1
C4SE (Jan 2016)	75.7	81.0	79.7	78.0	74.8	71.7
CIBC (Nov 2015)	63.0	63.0				
BMO (Mar 2016)	70.0	65.5				
RBC (Dec 2015)	68.5	59.0				
Scotiabank Group (Mar 2016)	70.0	66.0				
TD (Jan 2016)	60.1	56.0				
Desjardins (Feb 2016)	67.5	62.3				
Central 1 (Jan 2016)	78.7	87.8				
National Bank (Feb 2016)	63.0	59.0				
Laurentian Bank (Jan 2016)	64.4	63.5				
Average	**68.1**	**66.2**	**69.1**	**70.2**	**70.9**	**67.0**

Forecast updated on Oct 7, 2015

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 five rate applications (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031, and EB-2014-0040).

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)	Actual: Weather Corrected	Actual	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	EB-2012 0031 Forecast	EB-2014-0140 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					20,457	20,236	20,384					1.09
Average Excluding First Year (Actual) (5)								-0.49	-0.45	-0.42	-2.10	-0.24

(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.
(6) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031 forecasts, and 2 years for EB-2014-0140 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)	Actual: Weather Corrected	Actual	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	EB-2012 0031 Forecast	EB-2014-0140 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					19,752	19,576	19,829					0.90
Average Excluding First Year (Actual) (4)								-0.71	0.79	0.68	-0.83	0.10

(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.
(6) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031 forecasts, and 2 years for EB-2014-0140 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)	Actual: Weather Corrected	Actual	EB-2006-0501 Forecast	EB-2008-0272 Forecast	EB-2010-0002 Forecast	EB-2012 0031 Forecast	EB-2014-0140 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					16,975	16,731	16,952					1.46
Average Excluding First Year (Actual) (4)								-1.02	0.16	0.52	-0.37	0.52

(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.
(6) Compares actual-weather corrected with forecast (3 years of forecast for EB-2006-0501, EB-2008-0272, EB-2010-0002, and EB-2012-0031 forecasts, and 2 years for EB-2014-0140 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 February 2016 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 April 2016, for which IESO has a monthly peak forecast, the difference between IESO and Hydro One forecasts averages to 195 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 them into account as additional resources (or supply) in balancing demand and supply. In contrast, Hydro One needs to deduct demand response from its forecast because transmission revenue decreases. However, no incremental demand response

was assumed over the forecast 18-month horizon noted above (April 2016 to September 2017) so that this factor does not contribute to the difference.

In short, the total difference between IESO and Hydro One forecasts due to the factors noted above is 650 MW. Comparing the latter figure with the actual difference between the two forecast (195 MW) reveals that Hydro One's forecast is actually higher by 455 MW compared to the IESO forecast over the April 2016 to September 2017 period.

CALCULATION OF REVENUE REQUIREMENT

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

Line No.	Particulars	2017 (a)	2018 (b)
	Cost of Service		
1	Operating, maintenance & administrative	$ 413.1	$ 411.2
2	Depreciation & amortization	435.7	470.7
3	Capital taxes	0.0	0.0
4	Income taxes	81.3	90.4
5	Cost of service excluding return	$ 930.1	$ 972.3
6	Return on capital	671.5	710.3
7	AFUDC recovery on Niagara Reinforcement Project	4.6	4.6
8	Total revenue requirement	$ 1606.3	$ 1687.2

LOAD FORECAST DATA

Broad Annual Series

	Cooling Degree Days	Heating Degree Days	Ontario GDP in 2007 $M	Ontario Population (1000's)	Ontario Disposable Income in 2002 $M	Ontario Commercial GDP in 2007 $M	Ontario Industrial GDP in 2007 $M	Ontario Housing Stock (1000's)
1961	305.9	3,958.1	112,560.5	6,296.3	66,457.7	84,181.8	26,355.3	
1962	271.5	4,073.6	120,375.6	6,414.1	67,129.0	74,561.7	28,055.6	1,705.3
1963	253.6	4,106.3	125,923.5	6,546.4	77,394.6	78,619.6	29,756.0	1,743.4
1964	213.5	4,087.6	135,098.7	6,696.2	74,474.9	84,346.7	32,584.0	1,798.0
1965	159.4	4,268.1	143,605.4	6,854.4	80,002.2	90,344.7	35,243.9	1,849.1
1966	246.9	4,211.6	153,593.8	7,026.9	85,649.8	98,344.0	37,669.7	1,916.1
1967	157.4	4,250.3	160,019.6	7,196.4	89,372.2	103,297.2	39,441.8	1,972.5
1968	179.0	4,221.9	170,542.0	7,333.9	93,924.3	110,135.1	41,924.1	2,039.9
1969	257.1	4,212.4	180,448.2	7,462.7	99,438.1	117,279.2	44,144.2	2,119.6
1970	234.2	4,238.9	184,449.2	7,627.9	103,751.8	123,836.8	44,802.7	2,188.7
1971	201.0	4,089.4	195,366.4	7,849.0	110,523.9	130,591.0	47,374.4	2,265.0
1972	168.9	4,440.0	207,448.2	7,963.1	119,793.0	137,873.0	50,837.4	2,333.6
1973	306.1	3,887.1	217,451.3	8,075.5	129,932.6	146,860.5	56,687.5	2,412.9
1974	187.0	4,152.7	224,256.1	8,204.3	137,480.1	154,088.3	57,120.2	2,503.3
1975	279.1	3,910.2	225,681.2	8,319.8	144,705.8	158,817.7	52,040.3	2,581.9
1976	186.9	4,369.3	241,112.6	8,413.8	151,966.4	166,213.9	56,125.4	2,652.5
1977	207.0	4,102.7	250,216.3	8,504.1	156,522.5	172,182.5	57,841.0	2,727.2
1978	231.6	4,391.0	260,422.7	8,590.1	163,226.7	178,742.3	59,165.1	2,786.4
1979	204.2	4,179.2	269,568.9	8,662.1	167,928.1	185,381.2	61,247.6	2,856.6
1980	243.7	4,308.9	268,127.8	8,746.0	170,398.1	192,874.0	57,534.1	2,916.0
1981	205.8	4,074.6	281,577.0	8,812.3	177,272.9	201,316.2	59,158.0	2,970.0
1982	140.6	4,113.8	272,527.0	8,920.3	179,018.2	198,647.0	52,049.7	3,015.6
1983	378.2	3,991.4	286,504.0	9,039.6	181,806.7	204,542.5	57,197.8	3,073.4
1984	239.5	4,048.6	311,861.8	9,167.5	190,090.7	216,748.2	67,833.8	3,135.4
1985	198.5	4,033.1	327,841.0	9,294.7	197,410.1	228,858.5	71,496.7	3,185.1
1986	197.4	3,920.4	339,930.0	9,437.4	199,722.8	242,642.6	72,049.3	3,258.6
1987	347.1	3,704.6	356,441.0	9,637.9	204,735.3	253,148.5	74,062.5	3,342.7
1988	388.5	4,025.5	372,718.0	9,838.6	214,382.0	265,702.2	78,674.5	3,432.0
1989	278.7	4,197.8	385,055.0	10,103.3	220,024.9	277,695.8	78,804.5	3,520.0
1990	280.8	3,593.3	378,829.3	10,295.8	218,315.4	274,771.6	73,687.4	3,599.8
1991	394.2	3,657.9	366,074.0	10,431.3	215,517.7	271,884.8	67,806.3	3,656.5
1992	104.9	4,045.8	370,697.0	10,572.2	220,512.6	271,157.2	68,805.5	3,723.7
1993	267.8	4,096.9	376,057.0	10,690.0	222,873.9	272,735.4	71,573.9	3,785.1
1994	251.7	4,082.8	396,536.0	10,819.1	225,425.7	282,481.0	76,016.8	3,847.6
1995	350.5	3,992.9	409,324.0	10,950.1	227,417.0	288,320.7	81,610.5	3,895.0
1996	234.8	4,129.6	416,265.0	11,082.9	226,486.1	293,728.8	82,340.7	3,944.1
1997	248.9	3,955.5	436,414.3	11,227.7	233,756.7	305,283.6	87,375.9	3,993.0
1998	397.6	3,197.0	456,248.3	11,365.9	244,600.2	319,322.0	92,495.7	4,058.7
1999	448.8	3,488.9	487,831.0	11,504.8	252,759.1	345,554.0	99,158.7	4,125.4
2000	243.9	3,787.3	518,657.8	11,683.3	264,028.6	363,492.7	107,303.5	4,204.3
2001	389.6	3,387.0	528,036.0	11,896.7	264,161.6	376,013.3	103,062.8	4,219.4
2002	521.4	3,590.2	545,852.0	12,091.0	268,496.9	390,733.5	103,964.1	4,308.7
2003	321.1	3,932.0	552,082.0	12,242.3	272,261.7	399,707.9	103,606.2	4,382.4
2004	236.1	3,748.5	567,600.0	12,390.6	279,476.0	414,571.8	103,617.1	4,453.2
2005	537.7	3,724.5	585,843.0	12,528.5	283,019.4	428,618.1	104,325.3	4,519.4
2006	386.4	3,335.6	596,797.0	12,665.3	296,121.8	442,142.4	100,939.2	4,583.1
2007	442.6	3,644.8	601,735.0	12,791.0	303,443.8	457,831.9	96,246.7	4,641.3
2008	286.5	3,782.4	601,723.0	12,932.5	309,531.0	462,778.5	89,369.7	4,699.9
2009	208.3	3,767.1	582,904.0	12,997.7	318,360.2	460,287.1	73,033.3	4,750.3
2010	453.8	3,456.3	600,131.0	13,135.1	313,467.4	471,205.9	78,033.6	4,794.2
2011	440.1	3,572.9	614,605.8	13,263.5	311,737.6	482,113.8	81,505.9	4,846.4
2012	495.1	3,173.4	622,717.0	13,409.6	313,662.4	488,754.5	82,501.4	4,899.4
2013	337.1	3,722.7	631,068.0	13,551.0	321,849.4	496,096.6	82,340.1	4,948.2
2014	271.3	4,033.9	648,352.0	13,677.7	322,585.1	507,665.3	85,504.1	4,994.6
2015	369.1	3,704.0	664,379.0	13,792.1	329,262.0	521,236.4	84,578.6	5,045.4
2016	333.2	3,757.6	679,787.5	13,923.4	336,642.7	535,493.6	84,180.7	5,100.4
2017	333.2	3,757.6	696,415.3	14,062.7	342,895.9	549,451.9	85,326.5	5,153.9
2018	333.2	3,757.6	712,527.2	14,202.7	347,699.0	563,392.2	86,059.3	5,207.7

Residential Building Permit Index in 2007 $

	Month											
Year	1	2	3	4	5	6	7	8	9	10	11	12
1970	0.1963	0.2015	0.3580	0.6698	0.7614	0.7506	0.5671	0.6687	0.8549	0.9508	0.6761	0.5724
1971	0.2814	0.5040	0.6418	0.9663	1.0247	1.1654	0.9892	0.8164	0.8169	0.8381	0.6837	0.4785
1972	0.3568	0.4738	0.7537	1.0636	1.1467	1.2078	0.9239	0.9284	0.8853	0.8184	0.7771	0.5562
1973	0.4326	0.5282	0.8689	0.8762	1.2727	1.1323	0.9886	1.3334	0.8904	1.0905	1.1963	0.8342
1974	0.3806	0.5504	0.9408	0.9337	1.1214	0.6973	0.7173	0.6731	0.6243	0.6324	0.4052	0.3557
1975	0.2454	0.4377	0.5865	0.8885	1.0039	0.9360	0.9999	1.0080	0.9045	0.9474	0.7071	0.5571
1976	0.3430	0.4489	0.7658	0.8901	0.8832	1.0149	0.7735	0.7997	0.8817	0.8148	0.7894	0.4080
1977	0.2476	0.3287	0.8258	0.9591	1.0953	1.0247	0.8744	0.8023	0.7741	0.6061	0.6867	0.4791
1978	0.1898	0.3541	0.4375	0.7248	1.1082	0.9530	0.8017	0.8613	0.7529	0.7852	0.5876	0.3825
1979	0.1471	0.2520	0.4892	0.6150	0.8749	0.7523	0.6754	0.8682	0.6270	0.6616	0.5511	0.4401
1980	0.2117	0.1494	0.3619	0.4753	0.4564	0.5382	0.4976	0.4273	0.5870	0.6528	0.4537	0.3287
1981	0.2181	0.2612	0.5848	0.8771	0.9758	0.7534	0.7369	0.5083	0.3984	0.3580	0.5264	0.6980
1982	0.2071	0.1465	0.3162	0.4012	0.4049	0.3997	0.4068	0.4507	0.4300	0.5549	0.6437	0.5023
1983	0.2988	0.3869	0.6846	1.0471	0.6854	0.6360	0.7229	0.5858	0.6714	0.6372	0.5493	0.4015
1984	0.3120	0.3954	0.5764	0.7856	0.8720	0.7884	0.8765	0.6075	0.5394	0.6060	0.6391	0.3210
1985	0.2867	0.4144	0.7628	1.0770	1.1474	1.0554	1.0715	0.9538	1.0719	1.0329	0.8119	0.5552
1986	0.5451	0.6536	0.9245	1.2611	1.3061	1.2243	1.1328	1.1520	1.0951	1.1239	0.8411	0.7404
1987	0.7269	0.8244	1.5027	1.4693	1.4711	1.4027	1.2234	1.1717	1.2153	1.0098	0.8566	0.7134
1988	0.5635	0.6921	1.2922	1.4565	1.5160	1.5988	1.1818	1.2925	1.3494	0.9084	0.9820	0.9069
1989	0.7023	0.8846	1.2217	1.4742	1.3671	1.2647	1.2074	1.1332	1.0269	0.9505	0.9274	0.7385
1990	0.7487	0.6341	0.9901	1.0914	1.0221	0.8394	0.6832	0.8099	0.6286	0.8071	0.5114	0.3359
1991	0.2506	0.3469	0.5442	0.9673	1.1140	1.0711	1.1687	0.9368	0.9153	1.0410	1.1923	0.3760
1992	0.3636	0.5072	0.8519	0.8159	0.8277	0.9361	0.7116	0.6435	0.6737	0.7089	0.5089	0.3842
1993	0.3061	0.3121	0.5486	0.6768	0.6852	0.7841	0.6615	0.6707	0.7033	0.5819	0.5490	0.3602
1994	0.3099	0.2864	0.6415	0.7390	0.8845	0.9225	0.7519	0.7595	0.7969	0.6048	0.5168	0.5059
1995	0.3199	0.2571	0.5082	0.5744	0.6328	0.6259	0.5158	0.5493	0.5339	0.5868	0.4566	0.3514
1996	0.3134	0.3895	0.6423	0.6339	0.7205	0.6491	0.7362	0.6582	0.6290	0.6612	0.6425	0.4206
1997	0.5137	0.4334	0.6704	0.9676	0.9238	0.8560	1.0154	0.8244	0.9076	0.8406	0.7281	0.5032
1998	0.4101	0.4351	0.9614	0.9964	0.8886	0.7965	0.8423	0.7459	0.8392	0.7295	0.8273	0.6135
1999	0.4501	0.5039	0.9628	1.0199	1.1047	1.0764	1.1075	0.9690	0.9501	0.9378	1.0647	0.7073
2000	0.5313	0.5888	1.1025	0.8810	1.1493	1.0699	1.0337	1.1187	0.9479	0.9964	1.0088	0.5495
2001	0.6471	0.7605	1.1156	0.8632	1.2701	1.1950	1.0425	1.0018	0.9419	0.9754	1.1269	0.6717
2002	0.7522	0.7043	1.1505	1.5704	1.4899	1.2736	1.2514	1.3460	1.0888	1.2283	1.0688	0.7053
2003	0.8010	0.6500	1.1224	1.1992	1.3629	1.4784	1.3296	1.1097	1.2898	1.1497	1.2163	0.7711
2004	0.6749	0.6356	1.2415	1.3871	1.1191	1.5479	1.3319	1.3787	1.0947	1.1410	0.9205	1.0450
2005	0.6540	0.7432	1.1095	1.1095	1.2931	1.3509	1.0957	1.0236	1.0111	0.9871	0.9229	1.4644
2006	0.7794	0.6218	0.9061	0.9610	1.2559	1.1765	1.0777	1.2611	0.9884	1.0823	0.8587	0.7375
2007	0.8248	0.5013	0.9007	0.9257	1.1614	1.2459	1.1180	1.0273	1.2322	1.1943	0.9874	0.8811
2008	0.5980	0.6354	0.9232	1.2041	1.1478	1.2081	1.1659	0.9505	0.8529	0.8413	0.5885	0.6648
2009	0.4052	0.3653	0.5425	0.6069	0.9173	0.9016	0.7000	0.8445	0.9459	1.0034	1.0633	0.8307
2010	0.7518	0.5187	1.0738	1.0660	1.0795	1.0048	0.9804	0.9353	1.0594	0.7655	0.7553	1.0350
2011	0.6888	0.3889	1.2297	0.8382	1.0498	1.0300	1.0379	0.8632	0.9252	0.9000	0.8972	1.1662
2012	0.9498	0.6931	0.9186	0.9102	1.0754	1.3143	1.1794	1.0199	1.1587	1.0651	0.6817	0.4587
2013	0.6438	0.5264	0.7609	1.0813	1.2993	1.0996	1.1092	0.9529	0.9717	1.0892	0.8823	0.6911
2014	0.7927	0.5669	0.7776	0.9379	1.0816	1.2161	1.4384	0.8440	1.1124	1.0372	1.0354	0.8887
2015	0.7690	0.4916	0.9900	1.2369	1.1110	1.2628	1.4154	1.2783	1.0967	1.1423	0.9754	0.9275
2016	0.6184	0.6091	1.2261	1.0710	1.2195	1.2745	1.2169	1.0725	1.1962	1.0391	0.8882	1.0122
2017	0.8640	0.5786	1.1646	1.0173	1.1584	1.2106	1.1558	1.0187	1.1362	0.9870	0.8437	0.9614
2018	0.9021	0.6041	1.2160	1.0622	1.2094	1.2639	1.2068	1.0637	1.1863	1.0305	0.8809	1.0038

Ontario GDP in 2007 $

	Month											
Year	1	2	3	4	5	6	7	8	9	10	11	12
1971	184655	189962	187894	186696	194091	200619	200351	200279	194159	201484	199796	204412
1972	201811	200571	205742	202300	205588	212647	210133	208286	204607	209456	212580	215658
1973	211901	217207	219614	212454	215589	222630	218722	218351	211655	217923	220827	222543
1974	222009	224999	226406	216950	223990	228458	226456	227280	221740	224198	223620	224968
1975	225172	226564	219707	223914	223735	227168	227413	224756	224679	225007	227616	232445
1976	234297	235769	239114	241161	241812	241419	242729	244848	244133	239721	245131	243217
1977	244688	247206	248014	247079	249151	249644	252732	249477	248923	253494	256160	256026
1978	254699	258204	256625	256507	259545	262823	259758	260530	263288	261455	265637	266002
1979	267609	273173	271439	266359	265669	271053	271985	273525	268529	270648	267479	267361
1980	271736	263989	268886	265395	267346	268227	265757	264168	266024	270633	273650	271722
1981	274802	277561	281415	280106	282669	279652	287819	278079	282234	285323	286409	282853
1982	276244	282020	275082	273760	275201	271887	264787	269678	269685	270982	272843	268155
1983	273202	272430	275708	281848	283482	286440	290983	293044	295546	290777	296070	298519
1984	302100	300253	300146	307039	309447	310062	312603	318546	316047	323216	323765	319117
1985	322580	322181	325094	321551	326458	326312	326536	325523	337107	331282	336214	333253
1986	340271	337572	329113	343233	341008	333546	343178	339147	342953	343256	341453	344432
1987	345549	349893	348116	351366	354015	355788	360563	356355	361768	361809	366574	365495
1988	365276	365254	374043	372483	368535	364389	371148	372806	377689	379116	379644	382234
1989	386184	380949	379884	387691	386530	380539	382668	383699	391443	385779	387394	387898
1990	383216	387026	385712	384382	382963	377944	376717	378400	370354	377725	370922	370590
1991	365086	362539	358267	360876	369017	365425	366465	366894	372141	370155	372386	363637
1992	366137	371572	371217	370835	368597	367504	362209	367360	374472	376494	379900	372065
1993	370418	373389	374836	375863	374676	372487	371236	376154	384174	379918	383723	375810
1994	385146	388978	390485	393005	392512	390591	394970	398141	406240	406618	410296	401449
1995	402471	407254	410006	409152	407860	405476	403848	409033	417749	413128	417261	408650
1996	408153	413004	415795	416864	415547	413117	411610	416894	425778	419590	423787	415042
1997	419225	424207	427074	430997	429636	427124	435769	441364	450769	450395	454900	445513
1998	450797	456154	459237	457622	456176	453509	449575	455346	465050	457299	461873	452342
1999	464635	470158	473335	483354	481827	479010	486653	492900	503404	506373	511438	500884
2000	505656	511666	515123	519960	518318	515287	514638	521245	532352	523362	528597	517689
2001	518752	524918	528465	530121	528447	525357	518853	525514	536713	533246	538580	527466
2002	534751	541107	544763	544008	542290	539120	541298	548247	559930	551724	557243	545743
2003	549043	555569	559323	554481	552729	549498	541242	548190	559872	551833	557353	545851
2004	549403	555932	559689	567526	565734	562426	565001	572254	584449	576423	582189	570175
2005	573418	580233	584154	586170	584319	580902	578893	586324	598819	592460	598386	586038
2006	591191	598218	602260	599996	598101	594604	586179	593704	606356	597152	603125	590679
2007	594211	601274	605337	604464	602555	599032	592992	600604	613403	602484	608510	595953
2008	597523	604624	608710	608797	606875	603327	594897	602534	615374	592837	598767	586411
2009	577982	584851	588804	580336	578504	575121	570132	577451	589756	590802	596711	584398
2010	591074	598100	602141	601360	599461	595956	592588	600195	612986	602738	608767	596205
2011	603089	610257	614380	611041	609111	605550	609026	616844	629990	622168	628391	615424
2012	616091	623414	627626	625279	623305	619660	613209	621081	634317	623048	629280	616294
2013	619156	626515	630748	631498	629504	625824	622951	630948	644393	637271	643645	630363
2014	632376	639892	644216	647467	645422	641649	642081	650324	664183	657722	664300	650592
2015	652252	660004	664464	664421	662322	658450	657075	665510	679693	669639	676337	662380
2016	666578	674501	679059	680242	678094	674129	671403	680023	694514	686494	693361	679053
2017	683352	691474	696146	697191	694990	690926	687606	696433	711274	702727	709756	695109
2018	699371	707683	712465	713393	711140	706982	703445	712476	727659	718771	725960	710980

Physical Production Unit

Year	Glass	Abrasives	Ammonia	Paperboard	Cement	Clay	Copper	Ethylene	Gold	Gypsum	Polyethylene	Iron	Lime	Newsprint	Nickel	Nitrogen	Oxygen	Packaging	Paper	Pulp	Salt	Tissue and Specialty Paper	Zinc
2011	660.6	61126.3	241529.5	706504.9	499600.0	109.2	209427.0	739186.2	53.6	357.5	709296.1	1276569.0	772.0	796000.0	89452.0	600974.1	1204406.5	29633.8	275154.2	1980747.5	8502.0	197000.0	68487.0
2012	652.4	60366.5	239526.4	723418.0	531000.0	113.5	184993.0	730775.2	48.0	353.1	700479.9	1260701.9	779.0	717000.0	79071.0	593504.3	1189436.3	22143.0	228889.3	1732039.4	6886.0	201000.0	71024.0
2013	719.5	66382.5	257510.7	787226.4	502600.0	104.1	212758.0	799026.5	66.5	359.4	770288.2	1263950.5	772.4	691000.0	99556.0	652651.7	1307973.0	27960.0	202104.4	2024345.8	8159.0	202000.0	64952.0
2014	697.7	64556.6	253602.3	764163.1	503700.0	102.0	204712.0	779516.1	75.4	345.4	749100.2	1230282.9	734.0	672000.0	105065.0	634699.5	1271995.1	26807.6	99834.7	1953003.2	8228.7	200000.0	55795.0
2015	731.1	64604.3	253158.5	710457.8	505169.6	103.5	207483.0	786433.2	78.4	316.5	751555.2	1199661.8	722.4	630705.3	102842.4	633759.2	1278772.0	25080.3	100514.6	1768252.2	8220.7	196088.1	53810.0
2016	744.6	64859.3	253625.7	658184.1	506098.8	106.0	210030.5	790373.5	81.8	290.2	749609.9	1180630.9	713.7	587948.4	100672.8	638207.5	1280068.4	23696.3	99781.9	1766041.0	8272.2	193442.2	51716.1
2017	757.0	65250.3	253487.9	601306.0	504374.2	105.6	212551.3	788834.4	85.4	268.4	749025.0	1172312.5	706.9	547452.4	99352.7	643026.2	1274981.0	24555.5	98717.9	1775597.3	8335.9	193198.3	47926.6
2018	772.3	65812.1	254338.7	540661.8	504621.8	105.3	215979.1	790408.0	89.4	249.1	749416.7	1168749.7	701.9	516308.7	98440.6	650516.9	1274450.8	25541.0	98143.7	1822489.6	8432.2	193743.0	44330.7

Floor Space

Year	Colleges/ Universities	Elementary / Secondary Schools	Grocery	Health	Hotel	Miscellaneous	Offices	Public Services	Recreation	Religious/ Cultural	Multi-Residential	Retail	Warehouse/ Wholesale
2011	131	272	60	136	107	152	427	91	77	79	1,166	220	359
2012	131	274	61	138	107	153	429	92	78	79	1,193	222	362
2013	133	276	62	138	108	153	431	93	80	79	1,205	225	363
2014	133	278	62	140	108	153	433	94	80	79	1,225	226	365
2015	134	280	63	142	108	153	436	95	81	79	1,255	229	365
2016	136	283	64	143	109	154	437	96	82	80	1,275	230	366
2017	137	287	64	145	109	155	439	98	83	80	1,297	234	367
2018	139	290	65	148	110	155	441	99	85	80	1321	238	369

GDP Components

Components of Manufacturing in 2007 $

	2011	2012	2013	2014	2015	2016	2017	2018
Manufacturing	74958	76494	75567	78399	77741	77397	78311	78967
Food	11373	11442	11569	11897	12076	12215	12363	12454
Textiles, Clothing & Leather	948	935	838	876	844	860	879	889
Wood	1082	1106	1160	1209	1221	1212	1203	1206
Paper	2509	2479	2335	2415	2408	2419	2418	2429
Printing	2296	2341	2400	2417	2290	2239	2257	2258
Petroleum & Coal	1591	1573	1483	1493	1426	1369	1405	1435
Chemical	6134	6343	6418	6514	6771	6855	6960	7075
Plastics & Rubber	4450	4553	4934	4921	5067	5087	5172	5250
Non-Metallic Minerals	1811	1805	1721	1719	1643	1585	1628	1662
Primary Metals	5450	5371	5239	5765	5388	5305	5337	5378
Fabricated Metals	5504	5756	5630	5855	5593	5566	5599	5644
Machinery	5589	5823	5638	5726	5487	5373	5440	5489
Computers	4405	3677	3163	3317	3379	3388	3450	3482
Electrical Products	1844	1771	1708	1779	1728	1725	1756	1768
Transportation Equipment	16366	18058	17373	18563	18307	18084	18260	18343
Furniture	1799	1814	1931	2002	2047	2046	2089	2096
Miscellaneous	1808	1645	2027	1929	2067	2069	2095	2112

Components of Services in 2007 $

	2011	2012	2013	2014	2015	2016	2017	2018
Wholesale Trade	37338	38662	38683	40693	41183	42107	43013	44212
Retail Trade	29738	29562	30455	31684	32619	33698	34693	35879
Transportation, Warehousing	16366	18058	17373	18563	18307	18084	18260	18343
Information, Culture	21417	21567	21897	21972	21931	22564	23111	23688
Finance, Insurance	51629	52786	55030	57392	60457	62131	63802	65413
Professional Services	35337	35879	36618	37783	38538	39726	41175	42252
Other Business Services	103510	104191	106950	108146	111918	116033	119452	122827
Education	33292	33975	34364	34528	35174	36025	36838	37713
Health, Social Assistance	39292	39631	40094	40563	41268	42102	43211	44267
Arts, Entertainment, Rec.	4369	4369	4473	4512	4783	4874	5006	5125
Accommodation	10589	10861	11136	11640	11659	12049	12364	12632
Other Services	10921	11118	11523	11800	11926	12217	12473	12745
Public Administration	42411	41733	41431	41859	42271	43368	44286	45367
Total Services	436209	442389	450026	461135	472035	484978	497684	510463

Agriculture/Forestry in 2007 $

	2011	2012	2013	2014	2015	2016	2017	2018
Agriculture & Fishing	4683	4689	4955	4964	4776	4949	5078	5195
Forestry & Logging	691	679	747	797	848	867	902	924

Other Components in 2007 $

	2011	2012	2013	2014	2015	2016	2017	2018
Mining	6548	6007	6773	7105	6837	6784	7015	7092
Construction	33891	34823	33908	34342	37063	38414	39407	40255
Utilities	12014	11542	12163	12188	12139	12101	12361	12674

Energy Usage by Sector

Gross Ontario Electricity Usage by Sector in GWh

	Residential	Commercial	Agriculture	Transportation & Pipeline	Industrial
1961					
1962	11,257.3				18,367.7
1963	11,972.1	6,615.3			19,013.7
1964	12,634.3	7,510.1			20,283.6
1965	13,589.0	8,338.3			21,999.3
1966	14,521.6	9,313.1			23,912.6
1967	15,582.6	10,131.0			24,964.3
1968	16,699.5	11,196.6			26,612.4
1969	17,733.6	12,995.6			27,085.7
1970	18,873.1	14,354.2			28,778.5
1971	19,942.7	16,005.2			29,208.3
1972	21,041.6	18,553.3			30,310.2
1973	22,125.1	20,374.7			32,310.8
1974	23,565.8	21,787.5			33,725.9
1975	24,707.2	23,022.6			30,182.9
1976	26,641.2	24,613.6			32,578.1
1977	27,412.7	26,243.0			34,108.7
1978	28,228.9	27,575.1			34,147.8
1979	28,939.8	27,590.4			37,272.2
1980	29,392.6	27,654.2			37,918.9
1981	29,964.2	28,018.9	2,547.2	641.1	39,609.2
1982	30,934.7	28,954.7	2,641.4	620.3	35,580.3
1983	31,356.9	30,438.1	2,558.6	596.9	37,358.3
1984	34,061.4	32,435.3	2,628.6	548.3	40,683.3
1985	33,399.4	32,395.6	2,682.8	550.6	43,684.7
1986	36,186.9	34,660.6	2,801.7	573.1	44,639.7
1987	38,278.6	35,794.7	2,173.1	569.4	46,742.5
1988	41,202.8	38,767.2	2,523.9	566.1	46,951.9
1989	44,963.1	40,320.6	2,387.5	630.8	47,315.0
1990	45,274.4	40,712.2	2,009.2	626.9	45,640.3
1991	44,773.1	42,103.3	2,850.0	819.7	43,526.9
1992	43,720.0	41,404.2	2,806.1	566.7	43,019.7
1993	43,040.0	43,103.3	2,827.5	531.4	41,514.7
1994	42,844.7	43,295.6	2,806.4	529.7	42,280.8
1995	41,811.4	44,251.9	2,713.9	563.6	43,605.6
1996	41,860.3	45,543.9	2,741.1	567.8	43,441.7
1997	40,875.0	46,879.7	2,763.6	563.9	43,573.9
1998	40,370.6	47,526.1	2,733.1	837.8	44,495.3
1999	41,501.4	51,121.9	2,567.8	838.1	44,642.2
2000	42,690.3	52,764.7	2,349.2	855.6	46,096.9
2001	44,401.9	53,193.3	2,415.8	789.2	45,678.9
2002	44,113.6	58,678.3	2,060.3	723.6	44,899.7
2003	44,578.3	61,747.8	2,257.8	747.2	40,783.3
2004	45,266.4	63,209.4	2,258.6	775.3	40,476.7
2005	45,630.0	63,528.9	2,257.5	843.6	42,693.6
2006	42,999.9	61,151.4	2,226.0	955.0	48,771.5
2007	42,771.8	60,358.1	2,251.5	531.7	50,581.0
2008	41,430.5	58,159.3	2,524.6	443.5	49,982.4
2009	40,466.3	57,488.0	2,339.3	402.9	42,409.6
2010	41,761.6	58,690.6	2,562.2	489.8	43,445.0
2011	41,761.0	58,571.2	2,402.6	468.9	44,846.9
2012	41,925.6	59,428.7	2,390.5	543.5	44,972.2
2013	42,229.4	59,756.1	2,377.5	544.9	43,982.2
2014	42,270.7	60,695.2	2,364.7	560.8	43,477.1

Industrial: Other Energy Usage in Equivalent GWh

	Natural Gas & Oil	Coal
1962	44,921.5	59,537.3
1963	50,494.0	60,438.7
1964	58,152.7	62,915.6
1965	64,206.4	64,442.5
1966	70,065.9	64,354.3
1967	75,512.4	61,790.0
1968	81,547.1	62,118.4
1969	85,460.5	53,382.5
1970	96,534.2	57,401.6
1971	104,621.5	49,802.3
1972	112,866.7	50,472.7
1973	116,475.8	54,603.5
1974	126,308.0	53,233.5
1975	114,374.3	51,449.1
1976	131,320.7	54,092.0
1977	125,276.3	50,054.2
1978	129,162.3	51,513.9
1979	134,887.0	54,530.5
1980	126,027.9	53,732.6
1981	112,124.4	49,780.8
1982	91,379.7	45,693.9
1983	90,347.5	50,078.3
1984	101,932.8	55,758.1
1985	99,810.8	57,023.1
1986	104,684.2	51,686.9
1987	113,175.8	51,636.1
1988	120,630.0	54,203.3
1989	125,912.5	51,479.7
1990	111,284.4	39,633.9
1991	107,607.2	42,576.7
1992	107,164.4	42,046.4
1993	104,235.0	39,739.2
1994	109,068.9	39,412.8
1995	106,978.6	39,282.5
1996	105,642.8	39,330.6
1997	108,395.0	39,269.2
1998	103,418.9	39,156.7
1999	103,651.4	40,769.7
2000	103,008.6	40,861.7
2001	94,223.9	38,862.5
2002	104,031.7	38,005.0
2003	99,245.8	37,242.5
2004	107,778.1	37,524.2
2005	101,389.4	37,164.4
2006	96,961.1	39,341.4
2007	98,300.0	37,633.6
2008	95,964.7	36,745.0
2009	81,807.8	28,379.7
2010	82,133.6	31,462.2
2011	85,610.3	36,466.9
2012	86,302.2	36,515.3
2013	87,606.9	10,889.4
2014	93,428.3	6,278.9

Gross Ontario Energy Demand, Weather Corrected, in Av MW

	Month											
Year	1	2	3	4	5	6	7	8	9	10	11	12
1970	7946	8005	7521	7205	6789	6795	6617	6691	7012	7324	7800	8268
1971	8513	8582	8105	7557	7198	7239	6939	7149	7422	7669	8334	8773
1972	9095	9083	8630	8041	7810	7839	7498	7543	7889	8213	9014	9493
1973	9821	9914	9341	8655	8364	8406	8081	8171	8365	8821	9555	9766
1974	10415	10350	9856	9199	8798	8781	8720	8732	8822	9249	9985	10454
1975	10966	10877	10087	9527	8934	8968	8768	8844	8895	9191	10028	10738
1976	11230	11225	10907	9855	9318	9642	9334	9518	9683	9919	11061	11732
1977	12201	12079	11318	10240	9659	9847	9571	9797	9835	9964	11090	11697
1978	12454	12214	11422	10578	10080	10183	9749	9836	9939	10236	11259	12029
1979	12885	12684	11915	10782	10220	10353	10211	10341	10348	10791	11724	12238
1980	13104	13027	12272	11013	10355	10273	10159	10373	10454	10755	11783	12609
1981	13175	13380	12382	11371	10507	10842	10743	10644	10744	11089	12015	12823
1982	13860	13567	12734	11496	10671	10782	10293	10559	10511	10617	11732	12476
1983	13417	13410	12648	11457	10909	11286	10849	11418	11314	11584	13001	13966
1984	14782	14601	13739	12434	11646	11829	11562	11982	11681	12262	13408	14107
1985	15196	14995	14031	12834	11990	11939	12067	12228	12286	12641	14084	15086
1986	16083	15943	14795	13413	12498	12450	12512	12542	12805	13290	14526	15626
1987	16406	16411	15379	13944	12898	13466	13468	13484	13475	13925	15480	16546
1988	17669	17600	16436	14444	13651	13956	13833	14398	13781	14213	15992	17303
1989	18413	18313	16904	15271	14065	14634	14739	14756	14555	15144	16730	18071
1990	19082	18754	17165	15417	14319	14471	14548	14632	13970	14397	15878	17223
1991	18565	18043	16571	14928	14292	14888	14540	14874	14189	14623	15913	17227
1992	18408	18185	16835	14971	13743	14122	14179	14513	14191	13940	15904	16896
1993	17861	17712	16307	14905	13514	13950	14244	14661	13785	13830	15622	16438
1994	17733	17606	16343	14905	13470	14418	14544	14865	14282	14205	15627.3	16728
1995	17761	17699	16519	14603	14146	14671	14925	15415	14490	14409	15709	16757
1996	17785	17469	16159	14896	14142	14627	14942	15187	14549	14770	15755	16870
1997	17780	17710	16357	15263	14115	14664	15443	15397	14968	15097	16208	17146
1998	17897	17836	16853	15566	14891	15425	15777	15835	15300	15224	16275	17254
1999	18068	17920	16970	15527	14948	16035	16263	16184	15700	15510	16681	17644
2000	18407	18343	17181	15732	15504	16378	16821	17009	16000	15946	16998	18110
2001	18679	18600	17349	15910	15616	16549	16776	17003	15863	15941	17099	17339
2002	18555	18630	17426	16348	15798	16537	17366	17561	16692	16507	17556	18227
2003	19101	19119	17986	16633	15880	16446	17303	16701	16393	16289	17487	18362
2004	19225	19044	18135	16417	16025	17119	17482	17472	16768	16663	17866	18704
2005	19521	19147	17927	16818	15892	17242	17708	17922	16933	16351	17506	18450
2006	19644	19218	18148	16554	16059	17241	17786	17716	16511	16211	17455	18320
2007	19561	19205	18286	16705	16209	17310	17867	17716	16606	16463	17559	18405
2008	19465	19019	17682	16849	15951	17246	18253	18068	16951	16182	16946	17946
2009	18752	18356	17225	15666	14992	16219	16895	17054	15871	15574	16560	17666
2010	18497	18407	17105	15861	15462	16797	17124	16644	15661	15559	16534	17557
2011	18625	18398	17218	15740	15188	16655	17927	17209	16073	15619	16582	17284
2012	18733	18344	17321	15843	15747	17084	18430	17198	16286	16003	16955	17749
2013	18845	18537	17021	16093	15578	17126	18555	17910	16355	16133	17025	17866
2014	18974	18687	17493	16174	15779	17488	18564	18088	16440	15906	16916	17922
2015	18703	18495	17225	15893	15592	17284	18427	18008	16565	15837	16888	17636
2016	18387	18289										

Energy Prices

Industrial Energy Prices (in dollar per eGWH)

Year	Electricity	Natural Gas	Oil	Coal
1961	25,407.6	10,715.0	12,387.7	2,865.7
1962	25,618.6	10,202.9	8,843.2	2,826.4
1963	25,829.6	10,221.7	8,741.1	2,787.2
1964	25,820.8	10,226.9	8,676.5	2,747.9
1965	26,190.4	10,158.8	8,289.4	3,650.8
1966	26,027.2	10,496.1	7,697.6	4,004.1
1967	26,558.1	9,624.8	7,675.0	4,082.6
1968	27,100.6	9,092.3	7,340.6	4,121.8
1969	29,149.6	8,700.7	6,911.8	2,669.4
1970	30,791.4	8,114.1	6,539.2	3,179.7
1971	32,639.8	8,185.4	8,658.2	3,219.0
1972	31,933.9	7,803.1	8,691.7	3,415.2
1973	32,281.8	7,626.3	8,437.8	3,493.8
1974	31,591.6	8,064.1	11,189.4	7,026.8
1975	33,191.0	10,451.8	16,029.6	9,696.2
1976	37,477.2	14,521.3	15,656.5	9,931.7
1977	45,954.8	15,640.5	17,566.1	9,931.7
1978	43,585.9	17,097.2	19,351.0	10,834.6
1979	43,601.7	17,069.5	17,753.2	7,262.3
1980	45,183.1	17,754.5	17,863.0	10,442.0
1981	44,153.5	20,202.9	20,955.1	10,873.8
1982	45,512.8	22,531.0	20,972.4	10,795.3
1983	45,193.3	23,761.5	21,543.3	9,853.2
1984	45,756.3	22,651.6	22,492.9	10,010.2
1985	47,807.3	21,613.8	22,546.4	10,010.2
1986	47,478.3	20,054.4	13,960.9	9,421.4
1987	47,699.3	17,034.8	13,441.7	8,636.3
1988	48,021.3	14,981.9	11,113.5	8,247.6
1989	47,752.7	12,969.8	10,990.6	6,205.3
1990	48,385.2	12,268.3	13,921.1	8,000.8
1991	50,199.0	12,341.9	11,784.6	7,383.7
1992	54,501.5	12,710.4	12,388.3	6,945.5
1993	53,615.6	12,931.4	12,257.1	7,070.6
1994	53,878.1	14,552.4	12,897.5	6,413.6
1995	52,598.4	13,005.1	13,354.2	6,163.3
1996	51,843.7	12,378.8	17,044.4	6,100.7
1997	50,760.9	13,926.1	15,306.9	5,881.7
1998	50,760.9	15,068.2	12,419.8	6,100.7
1999	50,531.2	17,941.9	15,207.2	6,132.0
2000	49,557.5	23,259.4	22,873.7	5,830.6
2001	51,878.1	25,505.3	19,812.0	6,330.5
2002	54,572.9	29,236.3	20,045.0	6,514.0
2003	53,479.6	35,444.4	20,905.3	5,972.3
2004	45,768.1	34,435.2	25,919.1	5,896.2
2005	52,301.5	35,933.7	31,033.2	6,169.3
2006	46,290.8	39,450.7	34,365.6	5,842.5
2007	42,532.3	38,441.5	34,870.5	6,357.3
2008	42,492.9	34,588.1	47,445.3	6,003.6
2009	48,336.4	35,138.6	31,035.7	4,530.7
2010	47,048.4	32,875.5	33,963.7	4,942.6
2011	47,206.7	31,835.8	40,630.9	5,036.6
2012	46,962.2	32,936.7	39,418.1	5,412.7
2013	52,892.9	35,386.3	38,790.6	4,984.2
2014	56,962.5	36,310.3	37,085.8	5,015.7
2015	60,750.3	23,052.5	21,982.2	5,558.9
2016	61,189.6	23,471.1	15,503.5	6,103.2
2017	61,819.8	25,080.9	19,052.0	5,509.4
2018	62,411.9	24,865.2	20,914.7	4,886.6

Residential Energy Prices (in dollar per eGWH)

Year	Electricity	Natural Gas	Oil
1961	49,569.4	21,234.8	16,432.1
1962	48,981.6	20,983.0	16,237.3
1963	48,162.8	20,307.3	15,754.1
1964	47,311.2	19,788.7	16,640.4
1965	46,157.3	19,306.0	16,599.8
1966	44,510.4	18,316.9	15,655.3
1967	43,343.9	17,825.3	15,753.5
1968	43,504.8	16,861.0	15,910.4
1969	43,030.7	16,135.0	15,990.0
1970	43,307.5	15,604.4	15,464.2
1971	44,102.7	15,179.4	15,697.1
1972	45,180.1	14,470.3	15,712.0
1973	44,821.5	13,645.2	16,483.8
1974	42,894.2	13,240.2	18,564.6
1975	43,027.0	15,041.1	19,132.2
1976	46,615.8	18,189.2	20,854.1
1977	53,849.9	20,135.3	22,378.9
1978	52,461.9	21,219.3	23,625.8
1979	52,112.2	21,446.9	24,083.4
1980	53,198.2	22,076.9	26,272.8
1981	52,089.3	24,242.8	33,899.9
1982	51,747.2	25,718.6	37,428.4
1983	52,547.9	28,040.9	38,886.3
1984	53,622.6	27,034.9	39,592.4
1985	55,229.1	26,136.8	41,619.1
1986	54,839.5	24,779.5	33,339.5
1987	55,081.8	23,285.4	30,748.3
1988	55,201.6	22,027.0	30,947.8
1989	54,621.1	18,920.5	28,261.2
1990	55,576.7	18,350.4	30,573.8
1991	61,832.6	19,319.8	32,700.7
1992	68,331.4	19,386.6	31,238.4
1993	77,908.4	19,754.3	32,634.2
1994	76,351.4	21,091.3	32,866.8
1995	78,995.3	20,021.7	32,900.1
1996	75,881.4	19,654.0	34,894.0
1997	76,087.0	20,823.9	37,320.0
1998	76,087.0	22,495.2	35,425.7
1999	75,749.2	25,436.6	36,954.4
2000	73,626.6	33,912.0	44,249.5
2001	75,775.2	44,160.3	34,160.0
2002	78,053.2	39,392.8	27,645.8
2003	75,900.3	45,413.3	34,909.0
2004	74,498.5	50,303.0	33,933.0
2005	80,706.7	61,854.9	35,703.4
2006	80,706.7	65,583.4	36,906.4
2007	74,498.5	69,586.8	35,703.4
2008	74,498.5	76,698.7	34,455.1
2009	74,498.5	63,000.1	34,999.8
2010	86,914.9	67,138.6	32,435.0
2011	80,706.7	78,099.0	31,368.2
2012	86,914.9	79,003.3	32,253.4
2013	93,123.1	78,618.7	34,461.9
2014	100,754.0	77,035.9	34,791.7
2015	107,851.4	62,443.8	21,984.5
2016	108,740.7	44,822.6	22,281.0
2017	108,648.9	50,178.5	23,629.9
2018	111,591.9	51,198.2	23,267.1

Commercial Energy Prices (in dollar per eGWH)

Year	Electricity	Natural Gas	Oil
1961	29,394.1	18,818.4	11,510.7
1962	29,638.1	18,769.1	14,227.4
1963	29,882.1	17,942.7	13,989.6
1964	29,871.2	17,289.7	13,742.3
1965	30,298.9	16,049.2	13,407.1
1966	30,111.9	14,844.8	12,928.7
1967	30,723.6	14,329.0	12,479.5
1968	31,352.7	13,484.7	11,999.5
1969	33,723.2	12,763.8	11,482.8
1970	35,621.7	11,937.2	11,135.3
1971	36,619.0	11,480.1	11,036.9
1972	36,133.4	10,818.0	11,581.9
1973	38,063.8	10,268.6	11,028.6
1974	36,984.1	10,339.5	11,446.3
1975	37,121.4	12,104.1	12,813.9
1976	39,890.0	15,766.5	13,539.9
1977	46,961.2	16,910.7	14,916.2
1978	44,939.8	18,007.0	15,661.3
1979	44,777.6	18,186.1	16,539.5
1980	45,776.1	18,489.0	16,575.9
1981	44,808.9	20,490.0	18,171.2
1982	44,934.1	22,628.3	23,984.8
1983	45,341.3	24,659.0	26,876.3
1984	46,334.6	23,872.3	27,453.8
1985	47,711.8	22,932.1	29,475.8
1986	47,382.2	21,650.3	20,799.0
1987	47,698.8	20,036.0	17,103.8
1988	47,796.0	18,443.2	16,452.5
1989	47,651.2	16,097.8	16,557.8
1990	48,674.3	15,165.1	18,075.1
1991	50,517.8	15,847.8	17,744.1
1992	55,681.6	16,638.4	17,556.5
1993	58,241.0	16,854.1	18,781.3
1994	59,155.1	18,111.8	18,262.7
1995	58,528.3	17,177.5	18,786.9
1996	59,207.4	16,530.6	22,985.6
1997	58,841.7	17,500.9	21,749.7
1998	58,841.7	18,650.9	16,933.0
1999	58,580.5	21,705.4	19,984.1
2000	56,905.2	30,130.0	33,528.6
2001	55,217.3	30,765.4	28,031.3
2002	60,222.2	27,205.3	28,755.5
2003	57,852.6	35,813.3	30,464.8
2004	47,944.9	34,245.8	10,749.5
2005	53,272.1	34,272.3	11,901.1
2006	53,272.1	34,564.6	11,955.5
2007	53,272.1	33,634.7	12,265.4
2008	47,944.9	33,900.4	13,518.9
2009	53,272.1	34,617.7	11,104.4
2010	53,272.1	32,226.6	11,833.9
2011	58,599.3	31,190.5	13,765.8
2012	63,926.5	32,173.5	13,925.1
2013	69,253.7	34,479.6	13,857.4
2014	74,545.0	34,726.3	13,578.4
2015	77,880.5	21,990.7	11,006.4
2016	79,483.5	22,334.6	7,900.4
2017	81,265.6	23,769.7	8,844.5
2018	83,701.3	23,479.0	9,024.2