Analysis of Ontario's Full Scale Roll-out of TOU Rates – Final Study

PREPARED FOR

Independent Electric System Operator

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This report was prepared for the Independent Electric System Operator (IESO). All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

We acknowledge the valuable contributions of Phil Bosco and Kausar Ashraf of the IESO team to this report and to the underlying analysis as well as independent reviewers Ian Rowlands and Nicholas Rivers. We also acknowledge the valuable efforts of the participating local distribution companies (LDCs) in developing the data required for the study. Finally, this report would not have been possible without the hard work and analytical skills of Chip Russell, Stephen Lagos, Yang Wei Neo, Nicole Irwin, and Abby Ostriker.

Table of Contents

Executive Summary

Besides the country of Italy, the Canadian province of Ontario is the only region in the world to have rolled out smart meters to all its residential customers and to deploy Time-of-Use (TOU) rates for generation charges to all customers who stay with the regulated supply option. TOU rates were deployed as a load shifting measure in Ontario, to persuade customers to curtail electricity usage during the peak period and/or to shift that usage to less expensive mid-peak and off-peak periods, and possibly to reduce overall electricity usage.

This impact evaluation of Ontario's full-scale roll-out of TOU rates is a three-year project with the following objectives: (i) Quantify the change in energy usage by pricing period for the residential and general service customers (defined below) using a few select local distribution companies (LDCs); (ii) Estimate the peak period impacts using the IESO's definition of summer peak demand; (iii) Estimate the elasticity of substitution between the pricing periods and the overall price elasticity of demand.

This report presents the findings from the third and final year of the study, examining impacts from TOU rates from their inception through to the end of 2014.[1] The methodology employed is consistent with the second year study[2] and the only major change is the addition of one extra LDC, PowerStream, as well as one extra year of data for all of the other LDCs in the study.

The LDCs included in the Third Year Study constitute more than 50% of the Ontario population. Although many LDCs were approached to participate in the first and second study years, not all of them had the data required to participate. In particular, LDCs had to have a sufficiently long pre-TOU data record of preferably one year, but at least six months. The five original LDCs selected for the first year study were chosen based on their previous experience with TOU pilots, general size and geographic location.[3] In the second year an additional three LDCs were chosen based on geographic and demographic factors.

In order to implement TOU rates, LDCs had to first install smart meters that recorded electricity usage at different times of the day (interval data). Once they had smart meters installed, they could roll-out the TOU rate to their customers. Each LDC in Ontario managed its TOU rate

1 While all LDCs in the study were offering TOU rates by 2012, they started offering these rates at different points in time from 2009 onwards.

2 See: http://powerauthority.on.ca/sites/default/files/conservation/2013-Evaluation-of-TOU-Rates-Year-Two-Analysis.pdf

3 See the first year study for more details: http://powerauthority.on.ca/sites/default/files/conservation/Preliminary-Report-First-Year-Impact-Evaluation-of-Ontario-TOU-Rates.pdf

deployment independently. Both smart meters and the TOU rate were rolled out at different dates and over different time scales across the LDCs. Participant LDCs were included because they had sufficiently long pre-TOU periods, where customers had interval data, but were not yet on the TOU rate. The deployment of TOU rates in Ontario was not part of an experiment and this posed an analytical challenge for constructing a control group for impact evaluation purposes. However, heterogeneous timing of the TOU deployment worked in our favor as we were able to include customers who were at the tail end of the deployment as a proxy control group in our study (at least through the end of 2012).[3] However, because we have included pre-TOU implementation data for the entire sample, there is a second set of control data across time. Finally, retail customers who are not on TOU rates act as an additional control group.

For each region, we examined two customer classes: residential and general service. Single family homes and individually metered apartment buildings constitute the residential class and general service customers are non-residential customers with demands less than 50 kW. Only customers with a sufficient history of hourly data in the pre-TOU period were able to be included in the study.[4] The final year three sample was comprised of 102,769 residential customers (including 4,038 retail customers) and 29,145 general service customers (including 493 retail customers), out of a total customer population of 2,460,025 residential customers and 147,450 general service customers for the participating LDCs.[5] Due to insufficient pre-TOU data we were unable to include general service customers for Toronto Hydro, Newmarket-Tay Power, and PowerStream.[6]

Methodology

We employ a two-pronged approach to achieve the 1st and 3rd objectives of the TOU study: (i) estimation of an advanced model of consumer behavior called the "Addilog Demand System" to discern load shifting effects that are caused by the TOU rates and to estimate inter-period elasticities of substitution; (ii) estimation of a simple monthly consumption model to understand the overall conservation behavior of the customers and estimate an overall price elasticity of

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4 Sufficient data means at least 6 months, but preferably at least 1 year of pre-TOU data for those LDCs where it was available.

5 These numbers designate the number of retail customers present in the sample in December of 2014. Generally, the number of retail customers in our sample was falling throughout our sample period and particularly in 2014. 10,780 residential and 4,022 general service customers were retail customers at some stage in the study.

6 For each LDC and customer class we required at least 6 months of pre-TOU hourly data. Hourly data were obtained from the installation of smart meters. If the window between smart meter installations and TOU rates was too short (less than 6 months), then adequate pre-TOU data did not exist. This was the case for general service customers for Toronto Hydro, Newmarket-Tay Power, and PowerStream. Residential PowerStream customers also had insufficient pre-TOU data, but were included in the study, since the data had already been collected. The results are not sensitive to their inclusion or exclusion.

demand. By using the parameter estimates from these two models and solving them together, we calculate the impact that TOU rates have had on energy consumption by period and for the month as a whole.

The 2nd objective of the TOU study is to estimate peak period impacts coinciding with the IESO's Evaluation, Metrics, and Valuation (EM&V) Protocols and Requirements definition of peak ("EM&V peak demand") which is defined as the average demand between 1pm – 7pm on weekdays (excluding public holidays) during June, July, and August.[7] It should be noted that the EM&V peak is different from the summer TOU peak that customers see on their electricity bill, which in summer extended from 11am to 5pm. In order to estimate the EM&V peak impacts, we re-estimated the Addilog Demand System model and the Monthly Consumption model over just the peak summer months (June - August) and load-weighted the associated period impacts to infer an average impact for the 1pm- 7pm window.

Results

The analysis is conducted at the regional level, with the province split into four regions, and aggregated to the provincial level. Load shifting impacts are split into four separate calendar periods: pre-2012, 2012, 2013, and 2014. The pre-2012 period reflects all of the years that LDCs within a region were on TOU rates prior to 2012. Some LDCs started TOU as early as 2009, while others only began in 2012, resulting in compositional changes potentially affecting the comparison between pre-2012 and later years. By 2012, all LDCs in the study were on TOU rates.

The key findings are summarized below:

- Residential customers show clear patterns of load shifting behavior across regions and study years, but little evidence of conservation. The magnitude of load shifting appears to diminish over time.
- General service class customers show little evidence of load shifting behavior and are less responsive to the TOU prices than residential customers. However, general service class customers show some mixed evidence of conservation, although this is still marginal.
- The residential load shifting model parameters are generally consistent across regions and years and have magnitudes that have been observed in other pilots.
- There are some unexpected positive elasticities in the conservation models, likely due to little price variation during the study period. None of these elasticities are statistically significant.

7 *See* "EM&V Protocols STG-10: Demand Savings Calculation Guidelines." http://www.cleanairpartnership.org/files/EMV%20Protocols%20and%20Requirements.pdf

Residential Class:

In terms of the *residential class* results, there is significant evidence of load shifting during the EM&V peak demand period across all regions in the pre-2012 and 2012 periods. However, load shifting was substantially lower in 2013 in all regions except the East. In 2014, the load shifting impact decreased further for the Central and East regions and remained low (as compared to pre-2012 and 2012) in the West and North. For the province as a whole there was a statistically significant reduction in usage during the EM&V peak of 2.11 percent in the pre-2012 period, 1.89 percent in 2012, 0.82 percent in 2013, and 0.73 percent in 2014 relative to what usage would have been in the absence of TOU. The EM&V peak demand period is calculated over June, July, and August from 1pm to 7pm. This time period is "invisible" to consumers who only see the Ontario Energy Board ("OEB") TOU periods. The EM&V peak demand period straddles two of these periods - the summer peak from 11am to 5pm and summer mid-peak from 5pm to 7pm, and is a subset of the OEB summer TOU pricing period, which extends from May to October.

Figure ES1 shows the impacts on residential customers for the EM&V peak demand period (1pm to 7pm). The impacts are the percentage change in electricity usage during this period relative to what would have been consumed in the absence of TOU. A negative impact represents curtailment of energy usage in the EM&V peak demand period. The colored bars show the estimated impacts, while the black brackets show a 95 percent confidence interval for the impact. The confidence intervals are narrow relative to the magnitude of the impacts and lie far away from zero, leading us to be highly confident that we can reject the null hypothesis of zero load-shifting, particularly in the earlier years. To understand why this reduction occurred, further research is needed, in particular detailed surveys of customer attitudes and behaviors. In the absence of such research, we can only engage in informed speculation as to the reasons. One possible explanation is that over time customers learnt that their bill savings from engaging in load shifting behaviors was not as large as they had originally imagined (owing to the low peak to off-peak price differential). Alternatively, enthusiasm may have waned after the initial publicity accompanying TOU rates died down. It is unlikely that the decrease is caused by issues in identification because our model has two control groups that don't disappear over time – a customer's own pre-TOU usage as well as that of retail customers. Moving further away from the pre-TOU period could increase noise (larger confidence bands), but should not bias the results downward.

**Figure ES1: EM&V Peak Demand Period (June, July, August, 1pm to 7pm)
Residential Load shifting Results**

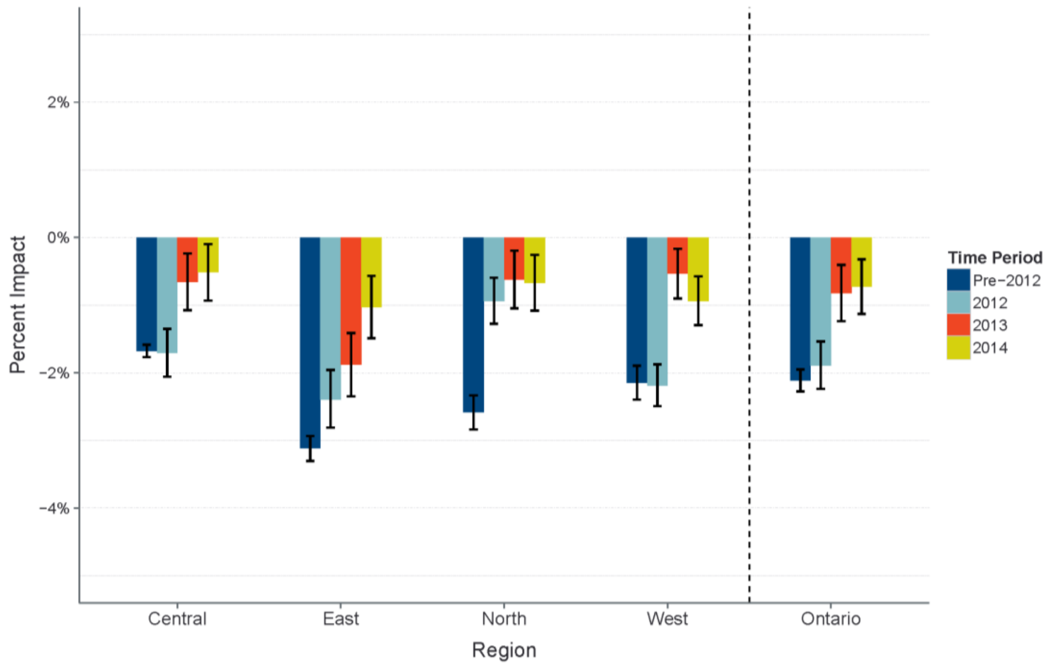
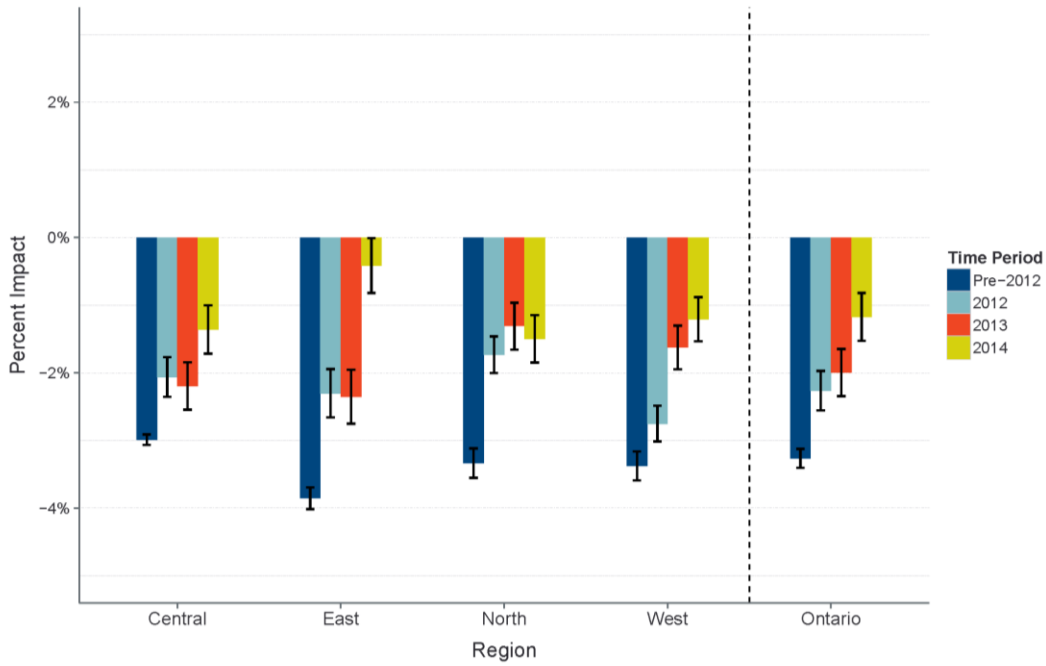


Figure ES2 shows the impacts during the summer peak period (11am to 5pm) across the regions and province as a whole for residential customers. The summer peak reflects the TOU peak prices seen by customers. The impacts are the percentage change in electricity usage during this period relative to what would have been consumed in the absence of TOU. A negative impact represents curtailment of energy usage during the summer peak period. For the province as a whole, TOU reduced usage during the summer peak by 3.26 percent in the pre-2012 period, 2.27 percent in 2012, 2.00 percent in 2013, and 1.18 percent in 2014, relative to what usage would have been in the absence of TOU. The 95 percent confidence intervals on these impacts are narrow relative to the magnitude of the impacts and lie far away from zero, leading us to be highly confident that we can reject the null hypothesis of zero load-shifting in all years and regions.

Figure ES2: Summer TOU Peak Period (11am to 5pm) Residential Load Shifting Results



While we chose to focus on summer results, we also estimate load shifting impacts for the winter. These are generally smaller than in the summer rate period in the earlier years, and have decreased over successive years of the study. More details on winter load-shifting can be found in Appendices 1 through 4.[8] Lastly, there is no evidence of energy conservation. (This is discussed in more detail in section V subsection B.)

General Service Class:

In terms of the *general service class* results, we find no consistent evidence of load shifting for general service customers. In most regions and years, impacts are far smaller than those estimated for the residential customer class, results are not as unambiguous, and there are some odd substitution patterns. This is most likely an artifact of the heterogeneity in the General Service class.

For the province as a whole there was a reduction in usage during the EM&V peak demand period of 0.66 percent in the pre-2012 period, 0.12 percent in 2012, 0.57 percent in 2013, and 0.09 percent in 2014 relative to what usage would have been in the absence of TOU. Only the pre-2012 impact was statistically significant and distinguishable from a zero impact. During the

[8] See the associated tables labeled "Region *X* Winter Residential/General Service TOU Impacts" and "Region *X* Residential/General Service Winter Elasticities," and charts labeled "Load shifting for Region *X* Winter Residential/General Service."

summer TOU peak period, TOU reduced usage by 0.53 percent in the pre-2012 period, 0.08 percent in 2012, 0.49 percent in 2013, and 0.34 percent in 2014 relative to what usage would have been in the absence of TOU. Again, only the pre-2012 impact was statistically significant and distinguishable from a zero impact.

Evidence on energy conservation was limited, with all estimates across the various regions and seasons showing very small (smaller than 0.5 percent) conservation impacts. For the province as a whole, the general service conservation impact decreased over the study period from 0.1 percent in the pre-2012 summer period to 0.02 percent in the 2014 summer period. These impacts were statistically distinguishable from zero. There was no statistically significant winter conservation.

Limitations of the Study

As stated earlier, the TOU roll-out in Ontario was not a randomized control experiment.[9] This posed some unique challenges in study design. We were able to exploit the phased nature of the deployment to approximate a "difference-in-differences" analysis. The amount and quality of the pre-TOU data differed widely across LDCs. By determining an eligible customer list with at least six months of pre-TOU data, we have mitigated this issue to a large extent.[10] We use this variation to estimate four calendar year effects – the pre-2012 year(s), 2012, 2013, and 2014 – at the regional level.

However, little price variation between the pre-TOU and TOU period led to difficulties with conservation equations. We zeroed out implausible (and statistically insignificant) conservation elasticities for impact calculations.

While we correct for serial correlation in the Monthly Consumption model, we did not do so for the Addilog Demand System model. This methodology is correct under certain assumptions.

Lastly, the customer sample has the following limitations. First, the Newmarket-Tay Power sample *may* not be representative of the relevant population.[11] Second, due to data availability and timing issues, we are not able to include general service customers for Toronto Hydro, Newmarket-Tay Power, and PowerStream. Third, 2014 data for Newmarket-Tay Power retail

9 In randomized controlled experiments, eligible customers are randomly allocated into the treatment and control groups. The treatment group customers receive the "treatment" (TOU rates in this context), whereas the control customers do not receive the treatment.

10 Retail customers, who have opted out of the regulated price plan offered by their local LDC, act as an additional control group, since they will not be placed on TOU rates.

11 The Newmarket-Tay Power sample was drawn from a pre-existing study and was not randomly selected by Brattle or selected to be representative of the population. However, in the First Year Study we did test whether the distribution of annual kWh of the population differed from our sample (using a non-parametric chi-square test). We could not reject that they were the same.

customers were not included in the study.[12] Finally, PowerStream residential customers were included in the study, but only have 2-4 months of pre-TOU data.[13]

12 Newmarket-Tay Power was unable to supply this data in time to be included in the study.

13 At least six months' data availability was required for determining the list of eligible customers. This list was used to draw the sample. Once we verified that there were a large number of customers with at least six months of pre-TOU data availability, we selected our sample and requested at least twelve months of pre-TOU data (if available) to be provided to us for the impact evaluation. The only exception is PowerStream, for which only 2-4 months of pre-TOU data were available for most customers. This error was only discovered after final data had been collected and PowerStream was had already been included in the final study.

I. Introduction

Pursuant to the *Electricity Restructuring Act, 2004*, the OEB is mandated to develop a regulated price plan (the RPP), which includes a TOU pricing structure whose purpose is to provide stable and predictable electricity pricing for consumers that more accurately reflects the actual costs of generation.

As part of TOU implementation, each of the 76[1] LDCs in Ontario is accountable for:

- undertaking the installation of smart meters for all residential customers and general service customers under 50 kW;
- enrolling smart meters in the centralized provincial Meter Data Management Repository (MDM/R); and
- activating TOU pricing across its service territory.[2]

LDC progress on TOU implementation is monitored by OEB-mandated monthly reporting obligations, which ended on 30 June of 2012.[3] As of that date, 99 percent of the RPP eligible customers had their smart meters installed; 92 percent were enrolled with MDM/R, and 89 percent were on TOU billing.

TOU prices are set by the OEB and reviewed bi-annually in May and November.[4] The OEB price review is based on an analysis of electricity supply cost forecasts for the year ahead and a true-up between the price paid by consumers and the actual cost of generation in the previous billing period. Consumers may be exempted from TOU pricing by executing a flat-price contract with an electricity retailer for a term generally between three and five years.

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1 In Ontario, there are a total of 76 LDCs, however only 73 of these are subject to OEB regulations. The remaining 3 LDCs are not compelled to install smart meters or to impose TOU rates. These three LDCs are Cornwall Street Railway Light & Power Company Limited, Hydro One Remote Communities, and Dubreuil Forest Products Limited.

2 Full implementation of TOU pricing across all LDC service territories was initially scheduled for June 2011. However, LDCs had the opportunity to apply for full or partial OEB exemption from this compliance deadline due to limitations with existing telecommunications infrastructure and other circumstances.

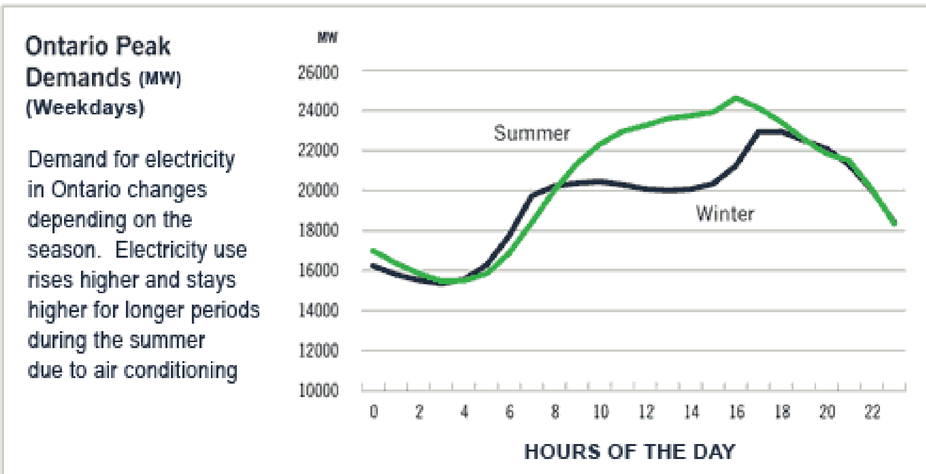
3 OEB Smart Meter Deployment and the Application of Time-of-use Pricing Website: http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Smart+Metering+Initiative+(SMI)/Smart+Meter+Deployment+Reporting

4 OEB Time of Use Pricing Website: www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Smart+Meters/FAQ+-+Time+of+Use+Prices

Besides Italy, Ontario is the only region in the world to roll-out smart meters to all its residential customers and to deploy TOU rates for generation charges to all customers who stay with regulated supply.

The rationale for TOU pricing is clear. Electricity cannot be stored economically in large quantities and the demand for electricity varies throughout the day. On weekdays, demand starts to rise in the morning as people get up and continues to its peak in the late afternoon or evening as people come home. On weekends and holidays, demand is lower overall. This is illustrated in Figure 1.1.

Figure 1.1: Ontario's Load Profile for 2013



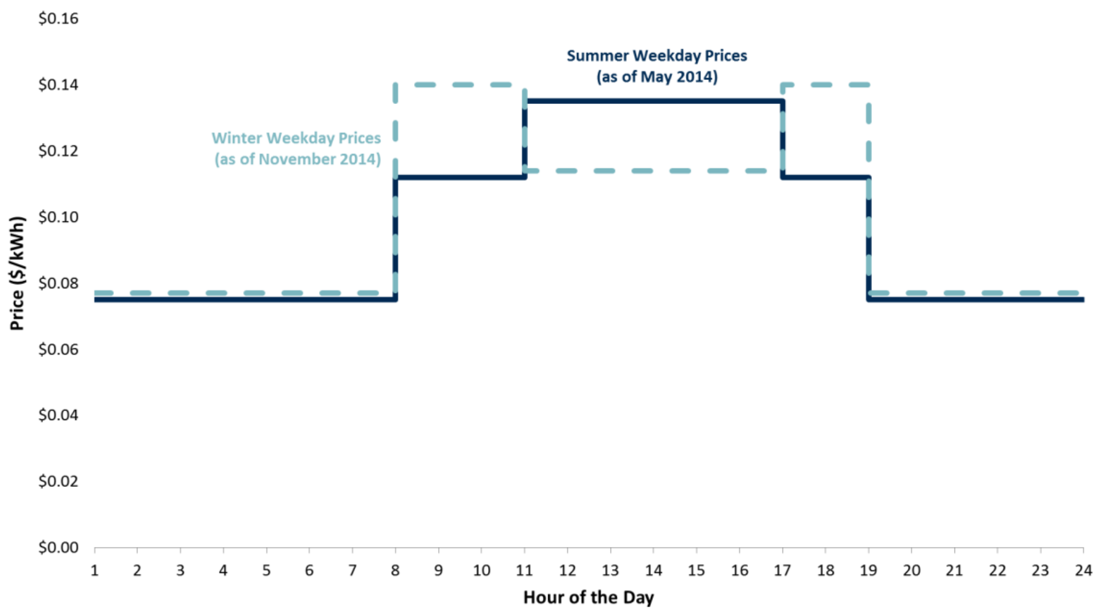
Source: Independent Electricity System Operator at www.ieso.ca.

Weather exercises a very important influence on how much and when Ontarians consume electricity. Over the last few decades, peak demands have become much more pronounced over the summer months as more people install air conditioning in homes and businesses (winter heating is usually fuelled by natural gas). Peaks in the summer usually take place in the mid- to late-afternoon. The amount of daylight also affects peak demand. In the winter, increases in usage typically occur in the morning, when people wake-up in darkness to begin their day and peaks in the afternoon when the sun sets relatively early. TOU rates were deployed as a load shifting measure in Ontario, to incentivize customers to curtail electricity usage during the peak period and/or to shift that usage to less expensive mid-peak and off-peak periods, and possibly to reduce overall electricity usage. By conserving or shifting electricity use during peak periods, consumers can take an active role in the management of Ontario's electricity system.

Ontario's TOU consists of three pricing periods. Only the commodity (generation) prices are time varying. The prices for distribution and transmission are volumetric, but time invariant. The commodity prices are determined by the OEB and are seasonal and may be adjusted every six months to reflect changes in system conditions and market prices. An illustration of the relevant

TOU periods and commodity prices (effective November 2014, the most recent rate change) is shown in Figure 1.2.[5] It should be noted that these TOU prices account for roughly only half of the average customer's bill; other charges that the customers face are not time-varying.

Figure 1.2: Electricity Prices across a Day (effective in 2014)[6]



Historically, these prices have risen over time. See Figure 1.3 below for the historical all-in[7] peak price across the four regions used in the study. These regions are used to separate Ontario into four distinct climate zones, with each region analyzed separately. The climate zones are shown graphically in the accompanying appendix. Figure 1.3 shows that the West region has had consistently higher prices than the other regions. The all-in price includes the TOU price for generation as well as other prices that don't vary by time of day (but do vary across LDCs) such as distribution costs, uplift factors, network charges, connection charges, wholesale market charge, etc. All-in prices also include the generalized or harmonized sales tax and the Ontario Clean Energy Benefit, which after September 2012 entered in as a tiered rate.[8]

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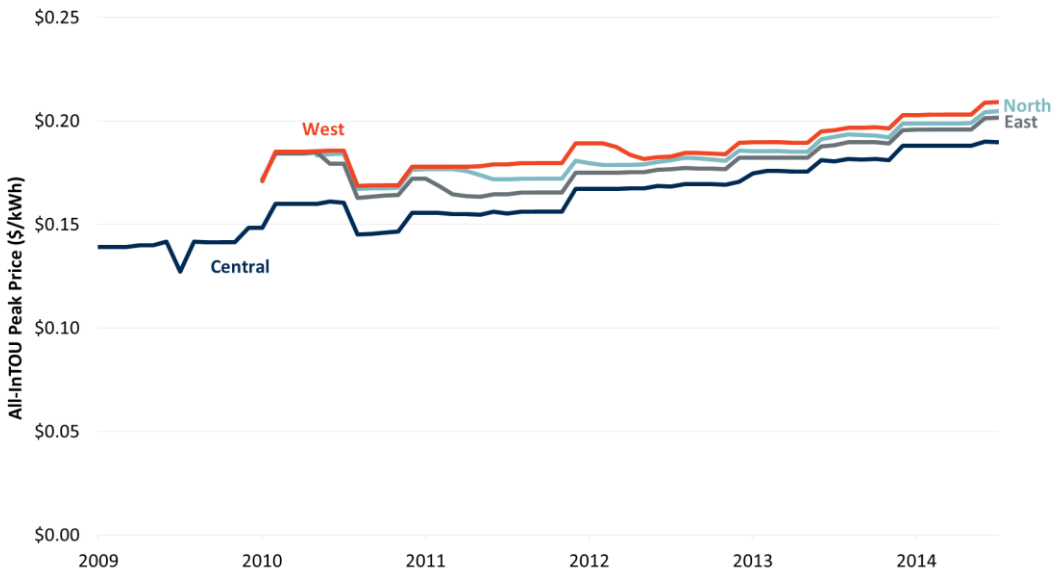
5 Source: Ontario Energy Board website. http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity+Prices

6 Data is shown as "hour ending", so 1 is the hour starting at midnight and ending at 1am.

7 The all-in rate is the sum of generation, transmission and distribution.

8 The clean energy rebate originally affected rates for all customers when it was introduced in January 2011. However, in September 2012, the clean energy rebate was confined to the first 3000 kWh of consumption.

Figure 1.3: All-In TOU Peak Price by Region 2009 – 2014[9]



Differentials between the peak and off-peak prices have remained relatively stable since 2010. As of November 2014, the peak to off-peak price ratio is 1.8 for the generation component only. When other non-volumetric bill components are included (excluding customer charges) to result in an "all-in" rate, the peak to off-peak price ratio is roughly 1.5.

Now that TOU rates have been deployed for three or more years at most LDCs, the data exist to measure the changes in customer usage patterns that have occurred in response to the TOU rates. The measurements have been carried out over a three year period. This report contains the Third Year Impact Evaluation of the TOU rates in Ontario by carrying out an econometric analysis at the regional and provincial levels.

II. Study Objectives

The Third Year Study has three primary objectives:

1. Quantify the change in energy usage by pricing period for the residential and general service customers for each of the four Ontario regions, containing eight LDCs in total;
2. Estimate the peak period impacts using the IESO's peak demand period definition (EM&V peak);
3. Estimate the elasticity of substitution between the pricing periods and the overall price elasticity of demand;

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9 Peak prices are a simple mean of all participating TOU customers in our sample for the designated region during the designated time period.

In the Third Year Study, we analyze hourly customer data from four regions in eight LDCs as follows:

- East: Hydro One East, Hydro Ottawa
- Central: Hydro One Central, Toronto Hydro, Newmarket-Tay Power, PowerStream
- West: Hydro One West, Cambridge and North Dumfries Hydro
- North: Hydro One North, Thunder Bay Hydro, Sudbury Hydro

Owing to insufficient pre-TOU interval data, the general service analysis excludes general service customers from Toronto Hydro, Newmarket-Tay Power, and PowerStream. Due to data availability issues, Newmarket-Tay Power retail customers are not included for calendar year 2014.[10] Retail customers, who have opted out of the regulated price plan offered by their local LDC, act as additional control group, since they will not be placed on TOU rates.

The LDCs included in the Third Year Study constitute more than 50% of the Ontario population. Although many LDCs were approached to participate in the First and Second study years, not all of them had the data required to participate. In particular, LDCs had to have a sufficiently long pre-TOU data record of preferably one year, but at least six months. The five original LDCs selected for the first year study were chosen based on their previous experience with TOU pilots, general size and geographic location.[11] In the second year an additional three LDCs were chosen based on geographic and demographic factors.

In order to implement TOU rates, LDCs had to first install smart meters that recorded electricity usage at different times of the day (interval data). Once they had smart meters installed, they could roll-out the TOU rate to their customers. Each LDC in Ontario managed its TOU rate deployment independently. Both smart meters and the TOU rate were rolled out at different dates and over different time scales across the LDCs. Participant LDCs were included because they had sufficiently long pre-TOU periods, where customers had interval data, but were not yet on the TOU rate. Even though the TOU roll-out was not a randomized control experiment, we were able to exploit the phased nature of the deployment to approximate a "difference-in-differences" analysis.[12] Moreover, we relied on the data for customers who are at the tail end of the deployment as well as retail customers who aren't on TOU rates to constitute the control

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10 The Newmarket-Tay Power sample was drawn from a pre-existing study and was not randomly selected by Brattle or selected to be representative of the population. However, in the First Year Study we did test whether the distribution of annual kWh of the population differed from our sample (using a non-parametric chi-square test). We could not reject that they were the same.

11 See the first year study for more details: http://powerauthority.on.ca/sites/default/files/conservation/Preliminary-Report-First-Year-Impact-Evaluation-of-Ontario-TOU-Rates.pdf

12 Difference-in-differences is a conceptual technique for ensuring that TOU impact measurements do not include any changes that would have occurred in the absence of TOU. It does this by netting off any changes that occur between the pre-TOU and post-TOU periods for customers who never received TOU from those who did.

group. PowerStream is included in the study, although their data did not meet the 6 months of pre-TOU data eligibility requirement. This was only discovered after the data had already been supplied and with 2-4 months of pre-TOU data, it still provides valuable information. The results are not sensitive to their inclusion or omission.

For each region, we examined two customer classes: residential and general service. Single family homes and individually metered apartment buildings constitute the residential class and general service customers are non-residential with demands less than 50 kW. Only customers with a sufficient history of hourly data in the pre-TOU period were able to be included in the study.[13] The final year three sample was comprised of 102,769 residential customers (including 4,038 retail customers) and 29,145 general service customers (including 493 retail customers), out of a total customer population of 2,460,025 residential customers and 147,450 general service customers for the participating LDCs.[14]

III. Methodology

We employ a two-pronged approach to achieve the first and second objectives of the TOU study: (1) estimate an advanced model of consumer behavior called the Addilog Demand System model to discern load shifting effects that are triggered by the TOU rates and to estimate inter-period elasticities of substitution; the Addilog Demand System model is estimated over six pricing periods (described later); (2) estimate a simple Monthly Consumption model to understand the overall conservation behavior of the customers and to estimate an overall price elasticity of demand.[15] By using the parameter estimates from these two models and solving them together,

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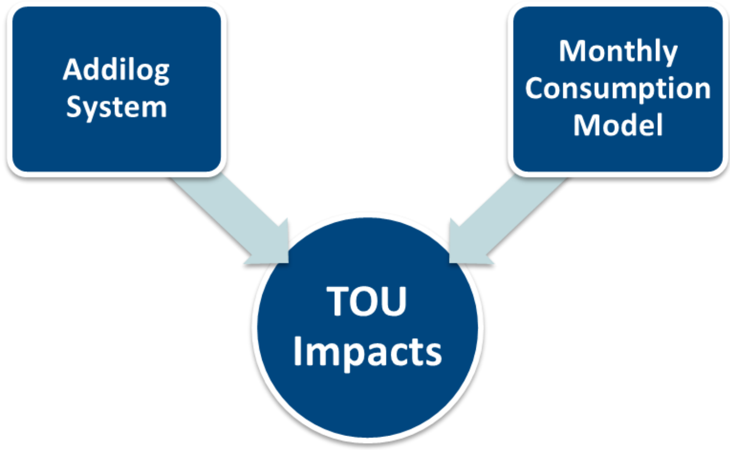
13 Sufficient data means at least 6 months, but preferably at least 1 year of pre-TOU data for those LDCs who where it was available.

14 These numbers designate the number of retail customers present in the sample in December of 2014. Generally the number of retail customers in our sample was falling throughout our sample period and particularly in 2014. 10,780 residential and 4,022 general service customers were retail customers at some stage in the study.

15 In this study, we estimate two types of elasticities. The first one is the “substitution elasticity” which indicates the percent change in the ratio of peak -to-off-peak consumption due to a 1 percent change in the peak-to-off-peak price ratio (of the all-in price). For instance, a substitution elasticity of -0.10 implies that, when the peak-to-off-peak price ratio increases by 1%, the usage ratio decreases by 0.10%. In the economics literature, the negative sign is removed from the substitution elasticity. However, consistent with our prior papers on the subject, we have kept it in, since it is mathematically correct and easier to interpret. The second one is the “overall conservation elasticity” which indicates the percent change in the average monthly consumption due to a 1% change in the average monthly all-in price. For instance, an overall conservation elasticity of -0.05 implies that, when the average monthly price increases by 1%, the average monthly usage decreases by 0.05%.

we calculate the impact that TOU rates have had on energy consumption by period and for the month as a whole.[16]

Figure 3.1: Two-Pronged Approach to Estimating the TOU impacts



The third objective of the TOU study is to estimate peak period impacts as defined by the IESO's EM&V Protocol definition. The EM&V peak demand is defined as the average demand between 1pm – 7pm on non-holiday weekdays during June, July, and August. To achieve this objective, we re-estimate the Addilog Demand System model and the Monthly Consumption model over just the peak summer months (June - August) and reweight the peak and evening mid-peak impacts to infer an average impact for the 1pm- 7pm window.[17]

Below, we describe each of the estimated models in detail.

A. Addilog Demand System Estimation

As indicated above, we estimate an advanced model of consumer behavior called the "Addilog Demand System" to discern load shifting effects that are triggered by the TOU rates and to estimate inter-period elasticities of substitution.

The Addilog Demand System model, first formulated by Houthakker (1960, *Econometrica*) and more recently extended by Conniffe (2006, *Canadian Journal of Economics*) and Jensen, et al. (2011, *Journal of Economics*), is a well-behaved demand system, which is capable of estimating

16 Originally, we had planned to survey the customers included in the sample and use the survey data to be able to report the impacts for different customer characteristics. However, due to limitations in customer privacy, whereby customer identities were strictly anonymized, we were not able to survey the customers analyzed in this study.

17 Period 4 covers the 11am – 5pm window (peak in summer) and period 5 covers the 5pm – 7pm window (mid-peak in summer). The period definitions are introduced later in the report.

small elasticities of substitution.[18] Unlike more flexible demand systems, the Addilog Demand System, like the Constant Elasticity of Substitution (CES) demand system, is known to satisfy regularity conditions (*e.g.,* concavity) globally. As noted in Mountain and Hsiao (1989, *Journal of the American Statistical Association*), even though the intent of flexible functional forms is to permit testing of hypotheses about elasticities of substitution over a wide range of possible data points, the available Monte Carlo studies (*e.g.,* Gallant (1981, *Journal of Econometrics*) and Guilkey, Lovell, and Sickles (1983, *International Economic Review*) and the results of Caves and Christensen (1980, *American Economic Review*) suggest that the available flexible functional forms cannot totally serve the purposes for which they were originally produced. Consequently, the CES was also used in earlier work by Caves and Christensen (*The Energy Journal,* 1980) who analyzed data from the Wisconsin TOU experiment and later in a meta-analysis of data from five TOU experiments (*Journal of Econometrics,* 1983).[19]

We estimated the Addilog Demand System model separately for summer and winter seasons over six pricing periods.

Figure 3.2 TOU Study Period Definitions

Period	Hours	Summer TOU Window (May - October)	Winter TOU Window (January - April, November & December)
1	-	Weekends & Holidays	Weekends & Holidays
2	9 pm - 7 am	Off-peak	Off-peak
3	7 am - 11 am	Mid-peak	Peak
4	11 am - 5 pm	Peak	Mid-peak
5	5 pm - 7 pm	Mid-peak	Peak
6 (*)	7 pm - 9 pm	Off-peak	Off-peak

(*) Before May 2011, period 6 was a summer mid-peak and winter peak period.

18 Unlike more flexible functional forms, which can violate the second-order conditions for utility maximization, the Addilog Demand System model is globally concave and always satisfies those conditions. This property is not only valuable for estimating theoretically consistent elasticities, but also essential for estimating out-of-sample province-wide impacts. (This is a reason Addilog Demand System models are often used in Computable General Equilibrium models for long-term simulations.)

19 Moreover, as a reflection of the advantages of these more parsimonious demand systems for estimating the impact of dynamic pricing, many recently published papers in applied energy journals have used the CES demand system. For example, see the published papers of Faruqui and Sergici (2011, *Journal of Regulatory Economics*), Faruqui and George (2005, *The Electricity Journal*), Faruqui, Sergici and Akaba (*The Energy Journal*, 2014) and Faruqui, Sergici and Akaba (*Energy Efficiency*, 2013), in their analyses of the pricing experiments in Baltimore, California, Connecticut, and Michigan, respectively.

Following is a generalized Addilog System for the six TOU periods, with period 1 acting as base:

$$\ln\left(\frac{q_{2ht}}{q_{1ht}}\right)-\ln\left(\frac{q_{2ht-12}}{q_{1ht-12}}\right)=\beta_2\left(\ln\left(\frac{P_{2ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{2ht-12}}{Y_{ht-12}}\right)\right)-\beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right)+\sum_{k=1}^{K}\gamma_{k2}\left(X_{k2ht}-X_{k2ht-12}\right)+\nu_{2ht}$$

$$\ln\left(\frac{q_{3ht}}{q_{1ht}}\right)-\ln\left(\frac{q_{3ht-12}}{q_{1ht-12}}\right)=\beta_3\left(\ln\left(\frac{P_{3ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{3ht-12}}{Y_{ht-12}}\right)\right)-\beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right)+\sum_{k=1}^{K}\gamma_{k3}\left(X_{k3ht}-X_{k3ht-12}\right)+\nu_{3ht}$$

$$\ln\left(\frac{q_{4ht}}{q_{1ht}}\right)-\ln\left(\frac{q_{4ht-12}}{q_{1ht-12}}\right)=\beta_4\left(\ln\left(\frac{P_{4ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{4ht-12}}{Y_{ht-12}}\right)\right)-\beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right)+\sum_{k=1}^{K}\gamma_{k4}\left(X_{k4ht}-X_{k4ht-12}\right)+\nu_{4ht}$$

$$\ln\left(\frac{q_{5ht}}{q_{1ht}}\right)-\ln\left(\frac{q_{5ht-12}}{q_{1ht-12}}\right)=\beta_5\left(\ln\left(\frac{P_{5ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{5ht-12}}{Y_{ht-12}}\right)\right)-\beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right)+\sum_{k=1}^{K}\gamma_{k5}\left(X_{k5ht}-X_{k5ht-12}\right)+\nu_{5ht}$$

$$\ln\left(\frac{q_{6ht}}{q_{1ht}}\right)-\ln\left(\frac{q_{6ht-12}}{q_{1ht-12}}\right)=\beta_6\left(\ln\left(\frac{P_{6ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{6ht-12}}{Y_{ht-12}}\right)\right)-\beta_1\left(\ln\left(\frac{P_{1ht}}{Y_{ht}}\right)-\ln\left(\frac{P_{1ht-12}}{Y_{ht-12}}\right)\right)+\sum_{k=1}^{K}\gamma_{k6}\left(X_{k6ht}-X_{k6ht-12}\right)+\nu_{6ht}$$

Where:

X refers to non-TOU variables such as weather characteristics; h refers to customer; t refers to month; q and P refer to the consumption and prices in the specific time period, respectively; Y refers to overall electricity expenditure, and ν is a random disturbance.

The price and weather terms are implemented as vectors of parameters that allow us to obtain:

1) Separate impacts estimates for pre-2012, 2012, 2013, and 2014 periods
2) Heterogeneous responses to prices and weather based on postal code level demographics.

To this end we have

$$\beta_i = \beta_{i\,pre-2012} + \beta_{i\,2012} * I(2012) + \beta_{i\,2013} * I(2013) + \beta_{i\,2014} * I(2014) + \beta_{ic1}PCX1 + \beta_{ic2}PCX2$$

And

$$\gamma_{ki} = \gamma_{ki0} + \gamma_{kic1}PCZ1 + \gamma_{kic2}PCZ2$$

Where:

- $I(2012)$ is an indicator if the calendar year is greater than or equal to 2012
- $I(2013)$ is an indicator if the calendar year is greater than or equal to 2013
- $I(2014)$ is an indicator if the calendar year is greater than or equal to 2014
- PCX1 and PCX2 are the first two principal components of census variables that would influence price responsiveness
- PCZ1 and PCZ2 are the first two principal components of census variables that would influence weather responsiveness

More details on the principal components are available in Section III part D.

The above system of equations was estimated using the "Seemingly Unrelated Regression" (SUR) estimation routine. Even though the set of equations seem unrelated to each other, they are actually related through the correlation in their error. This routine also allows us to enforce cross-equation restrictions, *i.e.,* the coefficient of the period 1 price will take the same coefficient in all five equations, etc. SUR employs random effects estimator in the context of unbalanced panels (time-invariant fixed effects are accounted for using first differences). This systems estimation is consistent with the procedure used by Ham, Mountain, and Chan (1997, *Rand Journal of Economics*) where household specific effects (for which we have very little information) are differenced out to avoid possible selection biases regarding those who opted for not choosing a retail rate. Separate systems were estimated for the summer and winter. Here are the overall steps followed in estimating the Addilog Demand System:[20]

1. Based on the census data for each region, construct principal components to capture sensitivity to price and weather;
2. Construct monthly average consumption levels for six time periods corresponding to the TOU periods on weekdays and weekends;
3. Normalize each period's price by the monthly expenditure for the corresponding month;
4. Take the natural logarithm of the price and quantity variables (but not the logarithm of the weather variables, as all the observations with 0 values would be lost with the logarithms);
5. Assign period 1 as the baseline period relative to which we represent quantities, prices, and weather variables of all other five periods;
6. Take the first differences of each of the regression variables by subtracting the previous year's values from the current year's values. First differencing will account for self-selection bias concerns related to specific fixed customer attributes that may prompt them to select into retail rates;
7. Parameter estimates from the Addilog Demand System readily yield elasticity of substitution for all five periods relative to the first period.[21] Other elasticities (such as own price and cross price elasticities) can also be derived from the estimated Addilog Demand System model.

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20 While we correct for serial correlation of the error term in the monthly consumption model, we were unable to do so for the Addilog Demand System, which estimates the load shifting impacts because of time constraints. Under a certain set of assumptions, we have correctly estimated the standard errors.

21 The above Addilog Demand System encompasses the CES formulation $(\beta_1 = \beta_2 = ... = \beta_6)$ and is known to be very robust in detecting small elasticities, customarily encountered in TOU implementation. Furthermore, the Addilog Demand System is globally concave. Another nice feature of the Addilog Demand System is that it does not constrain the commodity expenditure elasticities to be 1 (homotheticity). This implies that the overall conservation coming from TOU would not necessarily correspond to equiproportional decreases in all time periods.

It is important to note that the demand systems approach is needed not only to predict the impact of the TOU rates that have actually been deployed, but also to predict the impact of alternative TOU rates in the future.

B. Monthly Consumption Model

The Addilog Demand System model and the load shifting behavior is only one piece of the puzzle. The other piece is the Monthly Consumption model, which looks at changes in overall monthly electricity consumption. We estimate a Monthly Consumption model to estimate the overall price elasticity of demand and the conservation impact. Our model takes the following generalized form:

$$\ln Q_{ht} - \ln Q_{ht-12} = \theta\left(\ln\left(\frac{PE_{ht}}{CPI_t}\right) - \ln\left(\frac{PE_{ht-12}}{CPI_{t-12}}\right)\right) + \sum_{k=1}^{K}\tau_k\left(X_{hkt} - X_{hkt-12}\right) + e_{ht}$$

Where:

X refers to non-TOU variables such as weather; h refers to customer; t refers to month; PE is the overall monthly price of electricity; CPI is the consumer price index; Q is the monthly consumption of electricity; and e is a random disturbance.

As with the Addilog Demand System model we allow for heterogeneous reactions to price and weather. Price terms are interacted with pricing principal components

$$\theta = \theta_1 + \theta_{2c1}PCX1 + \theta_{2c2}PCX2$$

Weather terms are interacted with weather principal components and vary by season

$$\tau_k = \begin{array}{l}\tau_{k1S}I(summer) + \tau_{k1c1S}I(summer)PCZ1 + \tau_{k1c2S}I(summer)PCZ2 \\ + \tau_{k1W}I(winter) + \tau_{k1c1W}I(winter)PCZ1 + \tau_{k1c2W}I(winter)PCZ2\end{array}$$

As before, PCX1 and PCX2 are the first two principal components of census variables that would influence price responsiveness and PCZ1 and PCZ2 are the first two principal components of census variables that would influence weather responsiveness. More details on the principal components are available in Section D below.

Here are the steps followed in estimating the Monthly Consumption model:

1. Construct monthly consumption variable by multiplying the average usage and the number of hours in each period and aggregating over all six periods;

2. Construct average monthly price by dividing the monthly expenditure by monthly usage and convert to real prices using the LDC-specific CPI series;[22]
3. Construct monthly CDH and HDW variables by summing up the period totals and calculating a monthly average;
4. Take the natural logarithm for monthly consumption and price (do not take logarithm for the weather variables);
5. Take the first differences.

We estimate the Monthly Consumption model using fixed effects estimation corrected for the 1st order autocorrelation. Parameter estimates from this equation yield the overall price elasticity of demand.

After estimating the Addilog Demand System model and Monthly Consumption models for summer and winter seasons by class, we then solve these equations together and calculate the impacts by period. These impacts are summarized in Section V.

C. EM&V Peak Model

The IESO defines their peak (EM&V peak) as the average demand between 1pm and 7pm on non-holiday weekdays during June, July, and August. The EM&V peak demand window, 1pm-7pm, is not a standalone time period from the customer perspective, or in our modeling framework, but it is a combination of peak and mid-peak periods. As the EM&V peak period covers the time window from 1pm to 7pm, our estimate of impact for that period has to be consistent with the impacts in the peak and mid-peak periods that overlap extensively with the EM&V peak period. To be able to achieve that consistency, we have adapted the methodology described above to account for the EM&V peak demand definition. Here are the steps followed in estimating the EM&V peak demand model:

1. Estimate the Addilog Demand System and Monthly Consumption models for the EM&V peak demand months of June, July, and August;
2. Calculate the impacts for each of the six periods;
3. Calculate a weighted average impact for the peak period by aggregating the results of Period 4 (11am – 5pm) and Period 5 (5pm – 7pm) impacts. We use the non-TOU period loads for Periods 4 and 5 as the weights.

The results are summarized in Section V.

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22 CPI data was obtained from Statistics Canada for Thunder Bay, Toronto & Ottawa. LDCs were then matched to the nearest city that had such data.

D. VARIATION IN CUSTOMER RESPONSES

To capture variation in how customers responded to TOU rates within each region, we interacted the price and weather impacts with census variables. This allows for customers in different census areas with different characteristics to respond differently to both prices and weather. These heterogeneous responses were then used to move from our sample impacts to a representative impact for the population of each region. This was done by re-weighting impacts, which are a function of customer characteristics, by the correct proportion of characteristics for the population of the region. For example, let's say that the impact was a function of household size such that the impact was 0.1*household size. If the average household size in the sample was 2, but the average household size in the region was 3, we can move from the sample impact to a representative regional impact by inserting 3, the region's average household size, into the equation.

While the idea of interacting impacts with census variable is theoretically attractive, there are many census variables of interest and if we interacted all of them with price and/or weather, the model would "explode" due to the large number of parameters to estimate. We therefore collapse census variables into principal components. Principal component analysis is a relatively common statistical procedure that converts a set of observations of possibly correlated variables into a smaller set of values of uncorrelated variables called principal components. Put differently, principal components capture the maximum amount of variation in explanatory variables with a small number of scores, which are weighted averages of the underlying variables.

We selected seven census variables that we thought would influence price responsiveness and four to explain weather responsiveness. By collapsing these census variables into two principal components for price and two principal components for weather we could capture most of the variation in these census variables. The two price principal components capture 85.9 to 92.3 percent of the variation in the seven price sensitive census variables, depending on the region. The two weather principal components capture 82.5 to 86.8 percent of the variation in the four weather sensitive census variables, depending on the region.[23]

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[23] In choosing the number of variables represented in the principal components, our objective was to confine the number of principal components to two or less. The reason was that each additional principal component used in the system of equations added an additional 18 coefficients. We did try constructing principal components using all 11 variables, but we would have had to use at least three principal components to capture the amount of variation we are now capturing with two principal components associated with price sensitivity and weather sensitivity coefficients. In dividing up the original variables that would influence price sensitivity versus weather sensitivity we made use of variables found to affect price or weather sensitivity in other studies. Variables more likely to influence price sensitivity are demographic and income characteristics. On the other hand, variables more likely to influence weather sensitivity (which ultimately affects electricity used for air conditioning and electric heating) are characterizations of the dwelling type. Also, the variables we used were limited to those collected by Statistics Canada's census by postal code.

Continued on next page

Below are the seven variables that could influence price responsiveness:

1) Average number of persons in private households relative to Ontario average;
2) Median after-tax household income relative to Ontario average;
3) Proportion of population between ages 0 and 14;
4) Proportion of population with ages 65 and over;
5) Proportion of households with after-tax income less than $20,000;
6) Proportion of households with after-tax income greater than $90,000;
7) Proportion of owner-occupied private dwellings

And the four variables that could influence weather responsiveness:

1) Proportion of occupied private dwellings built before 1985;
2) Proportion of occupied private dwellings built after 1995;
3) Average number of rooms per dwelling relative to Ontario average;
4) Proportion of private single-detached private dwellings

IV. Data

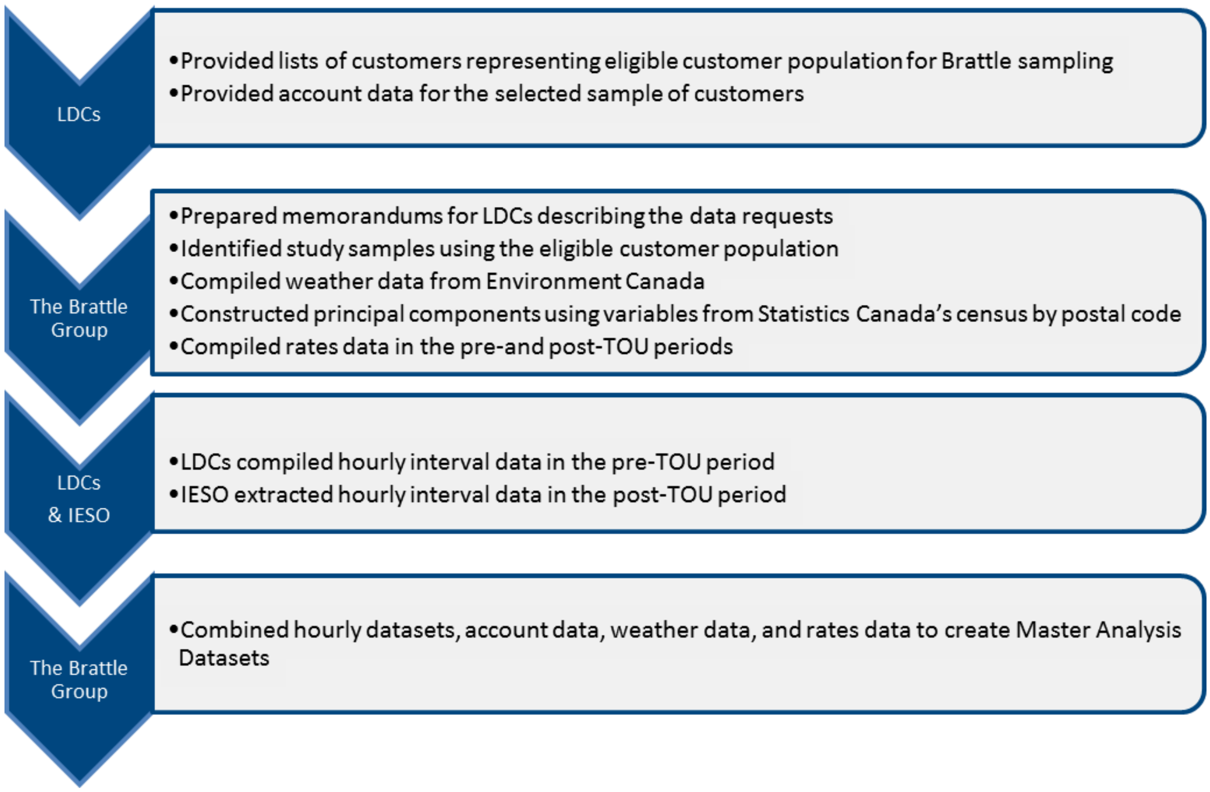
A. Data Compilation

The data compilation process for the TOU study was the largest EM&V data collection process to date carried out by the IESO and the partner LDCs. The first year study was also the first time that large volumes of data were extracted from the MDM/R for evaluation purposes.

The process started in the first year of the study with the development of privacy and data collection protocols by the IESO and Brattle. The IESO oversaw the entire data collection process, ensuring IESO's privacy and data collection protocols were respected by all parties involved. Throughout the data compilation process, Brattle provided technical guidance and supported the LDCs and the IESO. While the LDCs provided data required for the sample size calculations and the hourly interval data for the pre-TOU period, the IESO extracted the hourly interval data for the post-TOU period from the MDM/R. eMeter provided the data extraction templates and the virtual platform for data transfer between the LDCs and Brattle. This protocol was followed in the second and third years of the study with some simplifications in how sample customers were selected from the LDCs. Figure 4.1 provides an overview of the data compilation process for the second and third years of the study.

Continued from previous page

Figure 4.1: Data Compilation Process for the Third Study Year



B. Determining Sample Sizes

In studies with repeated measurements taken at points preceding and following a treatment, it is possible to achieve a substantial increase in efficiency (variance reduction) due to the correlation between measurements at different time points as compared to studies with single measurements. The increased efficiency in measurements implies that it is possible to meet a given statistical reliability criteria with a smaller sample size. This study will utilize repeated measurements for study participants (*i.e.*, a panel data structure). Therefore, it will be possible to measure a given impact with desired precision by using a smaller sample size.

In the first year study, we conducted "statistical power calculations" in order to determine the minimum sample sizes required to achieve a pre-determined statistical precision level. As the peak to off-peak ratio is relatively low (roughly 1.5), based on our work on 34 pilots from around the world summarized in the Arcturus database,[24] we expected the peak and conservation impacts flowing from the TOU rates to be small. This implied that we would need larger sample sizes to be able to detect a statistically significant impact than other studies that had used higher price ratios.

[24] The Arcturus database is a comprehensive collection of the impacts from various pilots, experiments and roll-outs of Time Varying Rates from across the world, including TOU rates.

In the second and third years of the study, we elected to take the sample size for new LDCs using the maximum percentage of the population chosen for the sample from the first year study by customer class. First year study sample sizes showed some consistency within customer class. This eliminated the need for gathering sampling data from the new LDCs. The sample sizes this year are shown below in Figure 4.2.

Figure 4.2: Population and Sample Customer Counts for Each LDC and Region

Population and Sample Counts

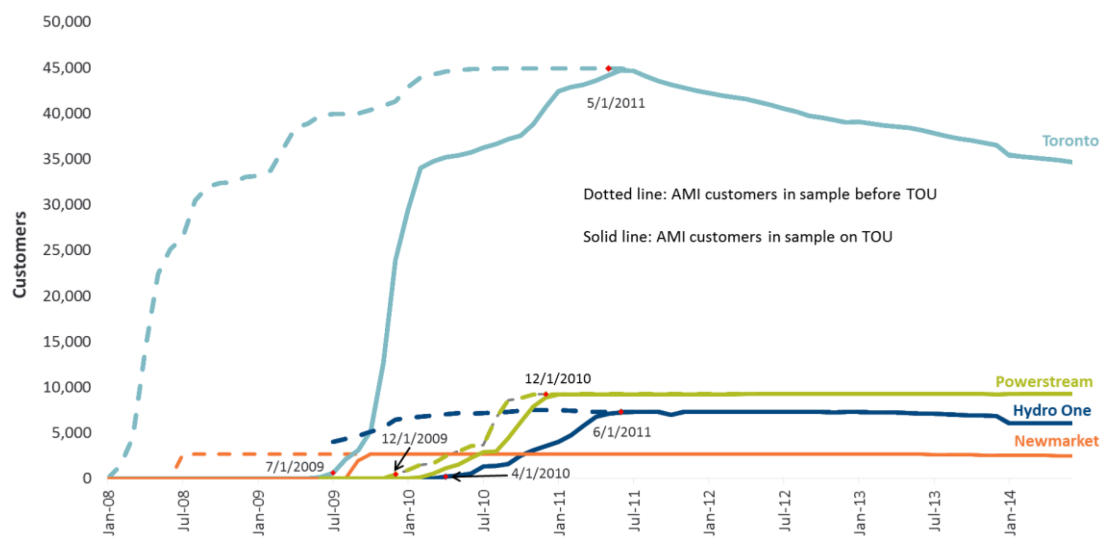
Region	LDC	Residential (# Accounts)		General Service (# Accounts)	
		Sample Size	Population	Sample Size	Population
Central	Hydro One Central	6,766	365,798	6,275	32,905
	Toronto Hydro	34,881	629,049	-	-
	Newmarket-Tay Power	2,630	29,873	-	-
	Powerstream	11,031	297,962	-	-
North	Hydro One North	7,479	161,606	4,665	20,207
	Thunder Bay Hydro	3,047	44,749	820	4,485
	Sudbury Hydro	1,875	42,279	607	3,940
West	Hydro One West	7,459	224,939	6,346	26,280
	Cambridge North Dumfries Hydro	4,500	46,122	1,510	4,691
East	Hydro One East	6,361	339,592	5,813	31,208
	Hydro Ottawa	16,740	278,056	3,109	23,734
Central	Subtotal for participating LDCs	44,277	1,024,720	6,275	32,905
North		12,401	248,634	6,092	28,632
West		11,959	271,061	7,856	30,971
East		23,101	617,648	8,922	54,942
Total		**102,769**	**2,460,025**	**29,145**	**147,450**

Note: Retail customers are included in these counts. The final year three sample included 4,038 residential retail customers 493 general service retail customers. These numbers designate the number of retail customers present in the sample in December of 2014. Generally the number of retail customers in our sample was falling throughout our sample period and particularly in 2014. 10,780 residential and 4,022 general service customers were retail customers at some stage in the study.

For a customer to be eligible for the study, they needed at least six months of pre-TOU and one year of post-TOU hourly billing data. Each utility varied in when they started and ended installing both AMI meters and when they started and ended their TOU roll-out. This leads to substantial variation in the amount of pre- and post-TOU data available for our study.

The total sample size for each LDC was not reached simultaneously because not all smart meters were rolled out simultaneously and neither was the TOU rate. Customers can be on one of three rate types at any point in type: the regulated non-TOU rate (before TOU was rolled out), the regulated TOU rate, or a non-TOU retail rate. There is substantial variation in when each LDC initially received interval data (smart meter data) and how long until we reached the maximum sample size. For example, in the central region, data for Toronto Hydro begin in January of 2008, but we do not reach the maximum sample size until the middle of 2011. By contrast, data for Newmarket-Tay Power begin in July of 2008 and is available almost immediately for the full sample. Figures 4.3 through Figure 4.6 show how many residential customers were on TOU and were not on TOU at any given point in time. These figures show how the residential sample size changes over the study period for each region. The dotted lines indicate the total number of AMI customers in the sample before TOU; the solid line indicates the total number of AMI customers in the sample on TOU. Decreases in the most recent years are due to attrition in the sample (for example a premise is no longer included in the sample once the customer residing there changes).[25] For simplicity of exposition we exclude retail customers and general service customers from the graphical depictions below.

Figure 4.3: Central Region Residential TOU Roll-Out by Month



25 Attrition was not evident in results presented in the second year of the study. This year, adjustments were made based on clarification that data were being provided at the premise level rather than at the individual account level. Attrition in the sample sizes is one result of these adjustments.

Figure 4.4: East Region Residential TOU Roll-Out by Month

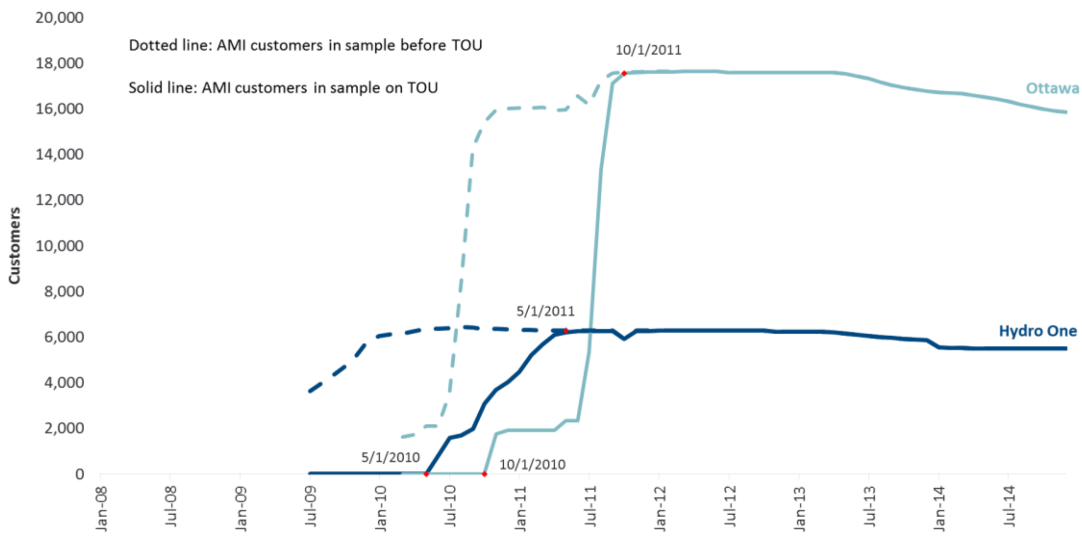


Figure 4.5: West Region Residential TOU Roll-Out by Month

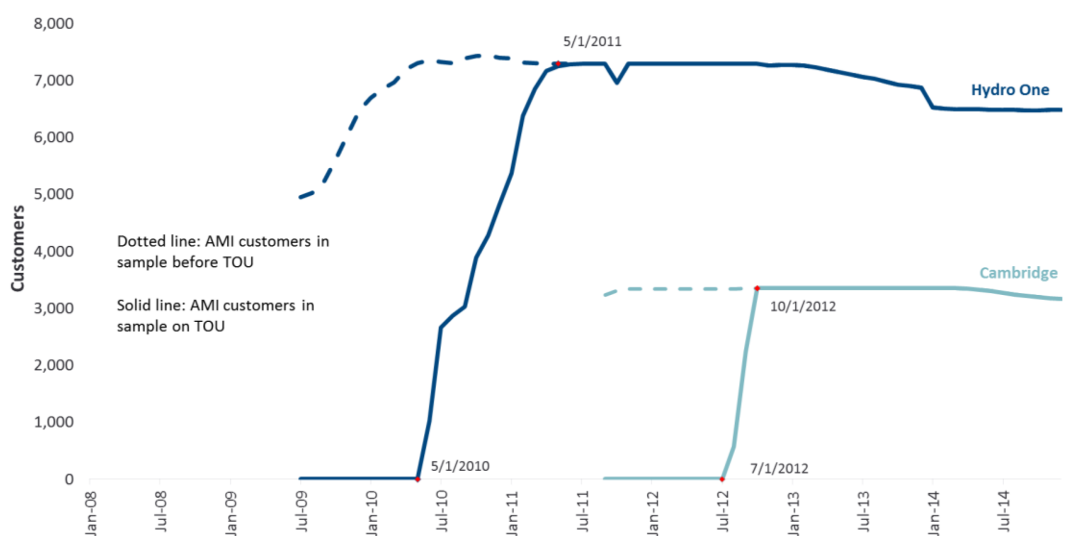
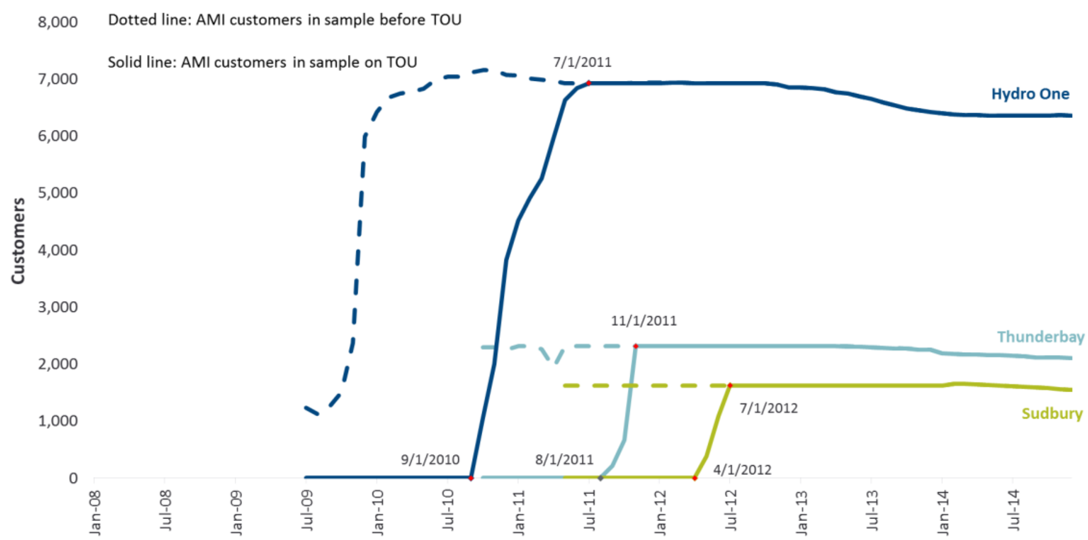


Figure 4.6: North Region Residential TOU Roll-Out by Month



There may be concerns with whether customers who "self-select" into retail rates are different from other customers and whether customers opted in to retail rates as a direct consequence of TOU rates. We analyzed self-selection among retail customers in the first year of the study and found that it was not a significant concern. In addition, we account for self-selection by first differencing observations, thereby removing any fixed differences between customers.[26] In all LDCs in the study, fewer than 10 percent of the residential population are on retail rates.

C. Moving from Theory to Application

The Addilog Demand System model is run separately for each region and each season (summer, winter and EM&V peak). The Monthly Consumption model is run separately for each region, but captures seasonal variation in its parameters.

To obtain elasticities from both models that are representative of the region's population rather than the sample, we estimate price elasticities that are dependent on socio-demographic factors, captured through our price principal components. To get the population elasticity we simply need to substitute in the price principal components that are representative of the population of the region. This allows us to obtain representative price (and weather elasticities) for each of the four regions. To obtain the provincial elasticities we then use the customer count weighted averages of the regional impacts.

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[26] We are assuming that self-selection is occurring due to unchanging customer factors. Time variable factors that influence self-selection will not be accounted for here.

To move from elasticities to impact measures, we need to apply those elasticities to a model that has pre-TOU baseline usage and TOU and non-TOU prices for all years. Since the Addilog Demand System and Monthly Consumption models are run at the regional level, these quantities need to also be calculated at the regional level. Since each LDC started TOU at a different point in time, each LDC has a different pre-TOU baseline period. These are shown in Figure 4.7.

To get average regional pre-TOU baseline usage we need to take a weighted average of usage for each LDC in the region. Since each LDC has a different baseline year, we wanted to standardize the pre-TOU usage as much as possible. To this end, we use our regression coefficients for weather to remove baseline year weather impacts and replace them with 2011 weather impacts for all LDCs. The year 2011 was selected since it was the first year for which all LDCs had data and was also before the IESO's main period of interest for the study – calendar years 2012, 2013 and 2014.

Figure 4.7: Pre-TOU Base Year Time Periods

	Pre TOU Period	
LDC	**From**	**To**
Central		
Toronto Hydro	January-09	December-09
Newmarket-Tay Power	July-08	August-09
Hydro One	July-09	June-10
Powerstream	January-10	December-10
West		
Hydro One	July-09	June-10
Cambridge North Dumfries Hydro	September-11	August-12
East		
Hydro Ottawa	March-10	February-11
Hydro One	July-09	June-10
North		
Thunder Bay Hydro	October-10	September-11
Hydro One	July-09	September-10
Sudbury Hydro	January-10	December-10

V. Results

A. Overview

The analysis is conducted at the regional level and aggregated to the provincial level. Load shifting impacts are split into four separate periods: pre-2012, 2012, 2013, and 2014. The pre-2012 period reflects all of the years that LDCs within a region were on TOU rates prior to 2012. Some LDCs started TOU as early as 2009, while others only began in 2012, resulting in compositional changes potentially affecting the comparison between pre-2012 and later years. By the end of 2012, all LDCs in the study were on TOU rates.

For each of the regions we estimated load shifting impacts, energy conservation impacts, and conservation and substitution elasticities. This was done separately for the summer, winter and EM&V peak demand months (June, July, and August). Overall, the load shifting model parameters have the expected signs and have magnitudes that have been observed in previous pilots. We find that residential customers show more consistent patterns of load shifting behavior than general service customers and that general service customers are less responsive to the TOU prices than residential customers. These results are consistent with findings from other studies.[27] There are however some unexpected positive elasticities in the Monthly Consumption models. None of these are statistically significant. This is most likely due to the little variation in the overall average monthly prices that customers face from month-to-month.

B. Residential Results

Overall, we find that there is significant evidence of load shifting across all LDCs for residential customers, with reductions in usage in the peak period and increases in usage in the off-peak periods. Results from the mid-peak periods are mixed. In general the magnitude of all load shifting impacts diminish over time.

Figure 5.1 summarizes the impacts and substitution elasticities for the summer and winter rate periods, as well as the EM&V peak demand period. The figure also shows the 95 percent confidence interval (C.I.) for the impacts. A 95 percent confidence interval for the estimated impact means that if random samples are drawn repeatedly, the unknown population value for the estimated impact would lie between the lower and upper bound interval for 95 percent of the samples.

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27 For a review of similar studies see Faruqui A, & S Sergici (2010): "Household Response to Dynamic Pricing of Electricity: A Survey of 15 Experiments," *Journal of Regulatory Economics*, Vol.38, pp.193-225.

For each region load shifting is more pronounced in the summer rates period than in the winter rates period. The summer rates period extends from the start of May until the end of October, with the peak being from 11am until 5pm. The winter rates period extends from the start of November through to the end of April with peaks at 7am-11am and 5pm-7pm. The EM&V peak period occurs in the months of June, July, and August between 1pm and 7pm. Holidays and weekends are off-peak in both seasons. During the summer TOU peak period, we estimated that TOU rates induced regional impacts of -0.4% to -3.9%, depending on the year. Winter TOU peak regional impacts ranged from 0.44% to -3.3%. During the EM&V peak, regional impacts ranged from -0.51% to -3.1%. There was no evidence of conservation, with all estimates showing conservation elasticities that were statistically indistinguishable from zero. The impacts are the percentage change in electricity usage during this period relative to what would have been consumed in the absence of TOU. A negative impact represents curtailment of energy usage during the period in question.

Figure 5.1: Residential Substitution Impacts

	Pre 2012				2012				2013				2014			
	Impact	95% C.I. for Impact Lower Bound	95% C.I. for Impact Upper Bound	Substitution Elasticity	Impact	95% C.I. for Impact Lower Bound	95% C.I. for Impact Upper Bound	Substitution Elasticity	Impact	95% C.I. for Impact Lower Bound	95% C.I. for Impact Upper Bound	Substitution Elasticity	Impact	95% C.I. for Impact Lower Bound	95% C.I. for Impact Upper Bound	Substitution Elasticity
EM&V Peak Period (June, July, August 1-7pm)																
North	-2.59%	-2.84%	-2.33%	-0.16	-0.94%	-1.27%	-0.59%	-0.07	-0.62%	-1.05%	-0.20%	-0.06	-0.67%	-1.08%	-0.26%	-0.06
Central	-1.68%	-1.77%	-1.58%	-0.13	-1.71%	-2.06%	-1.35%	-0.13	-0.66%	-1.08%	-0.24%	-0.08	-0.51%	-0.93%	-0.10%	-0.07
East	-3.12%	-3.30%	-2.93%	-0.20	-2.39%	-2.81%	-1.96%	-0.16	-1.88%	-2.35%	-1.41%	-0.13	-1.03%	-1.49%	-0.57%	-0.09
West	-2.15%	-2.40%	-1.90%	-0.15	-2.19%	-2.49%	-1.88%	-0.15	-0.53%	-0.90%	-0.17%	-0.06	-0.94%	-1.29%	-0.57%	-0.08
Province	**-2.11%**	-2.28%	-1.95%	-0.15	**-1.89%**	-2.24%	-1.54%	-0.13	**-0.82%**	-1.24%	-0.41%	-0.08	**-0.73%**	-1.13%	-0.32%	-0.08
Summer TOU Peak Period (11am - 5pm)																
North	-3.33%	-3.55%	-3.12%	-0.16	-1.73%	-2.00%	-1.46%	-0.09	-1.31%	-1.66%	-0.96%	-0.07	-1.50%	-1.85%	-1.15%	-0.08
Central	-2.99%	-3.06%	-2.91%	-0.15	-2.07%	-2.35%	-1.77%	-0.11	-2.20%	-2.55%	-1.84%	-0.11	-1.36%	-1.72%	-1.00%	-0.08
East	-3.85%	-4.02%	-3.69%	-0.19	-2.31%	-2.66%	-1.94%	-0.13	-2.36%	-2.75%	-1.96%	-0.12	-0.42%	-0.82%	-0.01%	-0.05
West	-3.38%	-3.59%	-3.16%	-0.17	-2.75%	-3.01%	-2.49%	-0.14	-1.62%	-1.95%	-1.30%	-0.09	-1.21%	-1.53%	-0.88%	-0.07
Province	**-3.26%**	-3.40%	-3.12%	-0.16	**-2.27%**	-2.55%	-1.97%	-0.12	**-2.00%**	-2.34%	-1.65%	-0.10	**-1.18%**	-1.53%	-0.82%	-0.08
Winter TOU Morning Peak Period (7 - 11am)																
North	-2.55%	-2.68%	-2.42%	-0.12	-1.03%	-1.20%	-0.84%	-0.05	-0.91%	-1.13%	-0.68%	-0.04	-0.97%	-1.21%	-0.74%	-0.04
Central	-1.70%	-1.75%	-1.64%	-0.08	-0.40%	-0.58%	-0.22%	-0.03	0.35%	0.12%	0.59%	0.00	0.44%	0.21%	0.67%	0.00
East	-3.26%	-3.36%	-3.16%	-0.16	-1.64%	-1.86%	-1.42%	-0.08	-0.94%	-1.19%	-0.67%	-0.05	-0.72%	-0.99%	-0.46%	-0.04
West	-2.42%	-2.57%	-2.28%	-0.12	-1.44%	-1.62%	-1.26%	-0.07	-0.90%	-1.12%	-0.67%	-0.05	-0.76%	-0.99%	-0.53%	-0.04
Province	**-2.22%**	-2.31%	-2.13%	-0.11	**-0.94%**	-1.12%	-0.75%	-0.05	**-0.30%**	-0.53%	-0.07%	-0.02	**-0.19%**	-0.43%	0.05%	-0.02
Winter TOU Afternoon Peak Period (5 - 7pm)																
North	-2.17%	-2.30%	-2.04%	-0.10	-0.60%	-0.78%	-0.43%	-0.03	-0.44%	-0.67%	-0.21%	-0.02	-0.50%	-0.72%	-0.26%	-0.02
Central	-2.14%	-2.19%	-2.09%	-0.10	-0.85%	-1.03%	-0.67%	-0.05	-0.11%	-0.34%	0.12%	-0.02	0.02%	-0.21%	0.25%	-0.01
East	-2.40%	-2.50%	-2.30%	-0.12	-0.73%	-0.95%	-0.51%	-0.04	0.06%	-0.21%	0.32%	-0.01	0.28%	0.02%	0.54%	0.00
West	-1.83%	-1.97%	-1.69%	-0.09	-0.80%	-0.97%	-0.63%	-0.04	-0.19%	-0.42%	0.03%	-0.02	-0.02%	-0.25%	0.20%	-0.01
Province	**-2.10%**	-2.19%	-2.01%	-0.10	**-0.80%**	-0.98%	-0.62%	-0.04	**-0.13%**	-0.36%	0.10%	-0.02	**0.01%**	-0.22%	0.25%	-0.01

Figure 5.2 shows the impacts for the EM&V peak demand period (which is not the same as the TOU period seen by consumers), which is calculated over June, July, and August from 1pm to 7pm. The colored bars show the estimated impacts, while the black brackets show a 95 percent confidence interval for the impact.

In the pre-2012 and 2012 periods the confidence intervals are narrow relative to the magnitude of the impacts and lie far away from zero, leading us to be confident that we can reject the null hypothesis of zero-load shifting in these years. However, load shifting was substantially lower in 2013 in all regions except the East. In 2014, the load shifting impact decreased further for the Central and East regions and remained low (as compared to pre-2012 and 2012) in the West and North. For the province as a whole there was a statistically significant reduction in usage during the EM&V peak of 2.11 percent in the pre-2012 period, 1.89 percent in 2012, 0.82 percent in 2013, and 0.73 percent in 2014 relative to what usage would have been in the absence of TOU.

Figure 5.2: EM&V Peak Demand Period (June, July, August, 1PM – 7PM)
Residential Load Shifting Results

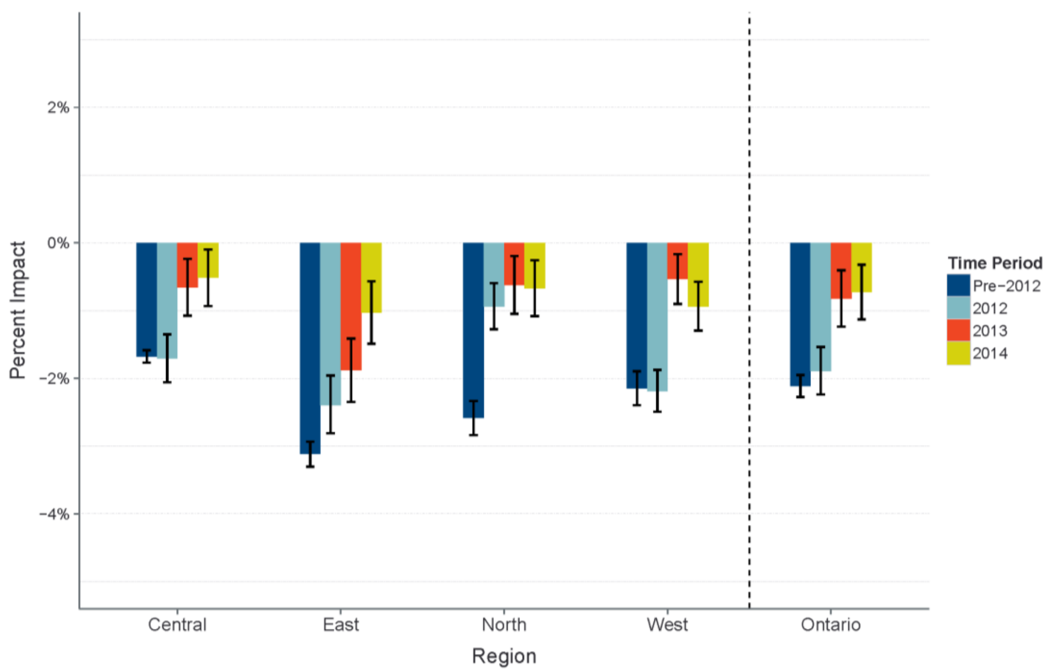
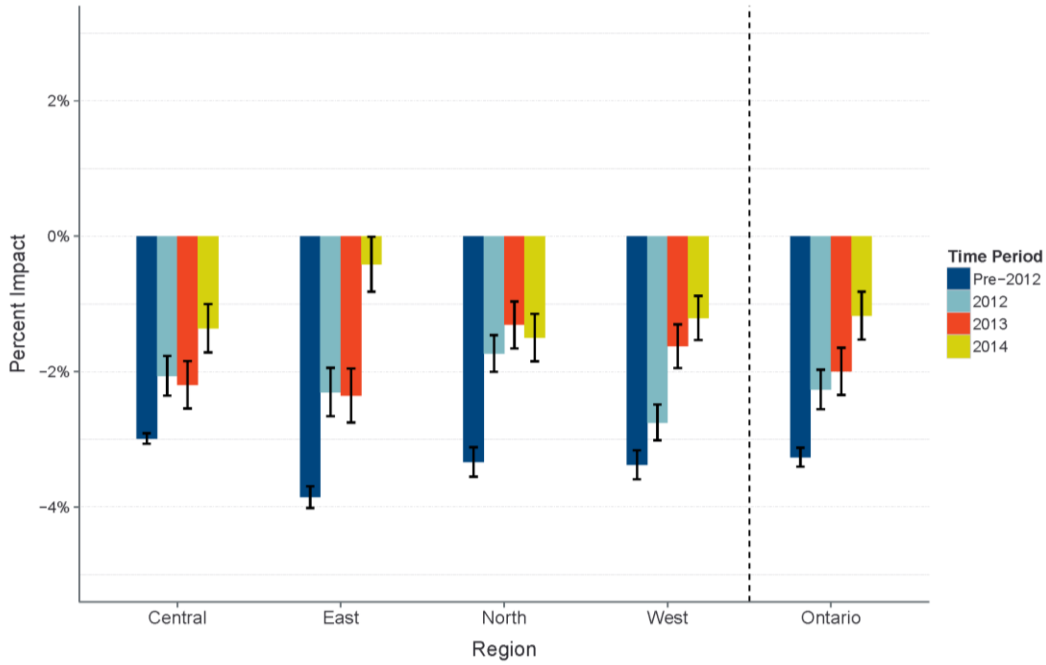


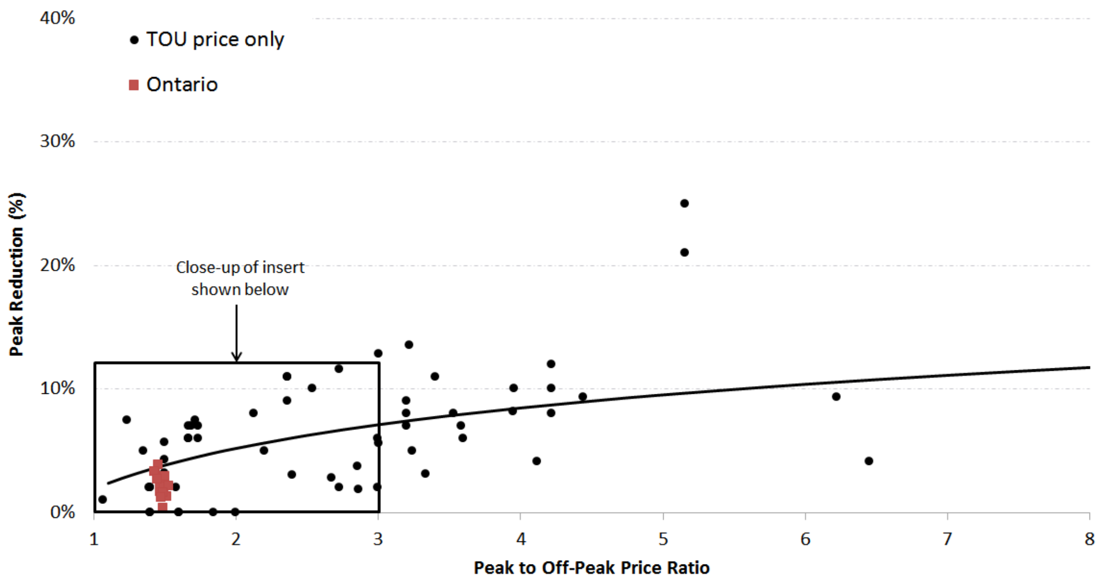
Figure 5.3 shows the impacts during the summer TOU peak period across the regions and province for residential customers. Most confidence intervals are narrow relative to the magnitude of the impacts and lie far away from zero, leading us to be confident that we can reject the null hypothesis of zero load-shifting in all years and regions. Impacts are lower in 2014, but still statistically significant for all regions. For the province as a whole, TOU reduced usage during the summer peak period by 3.26 percent in the pre-2012 period, 2.27 percent in 2012, 2.00 percent in 2013, and 1.18 percent in 2014, relative to what usage would have been in the absence of TOU.

Figure 5.3: Summer TOU Peak Period (11am – 5pm)
Residential Load Shifting Results



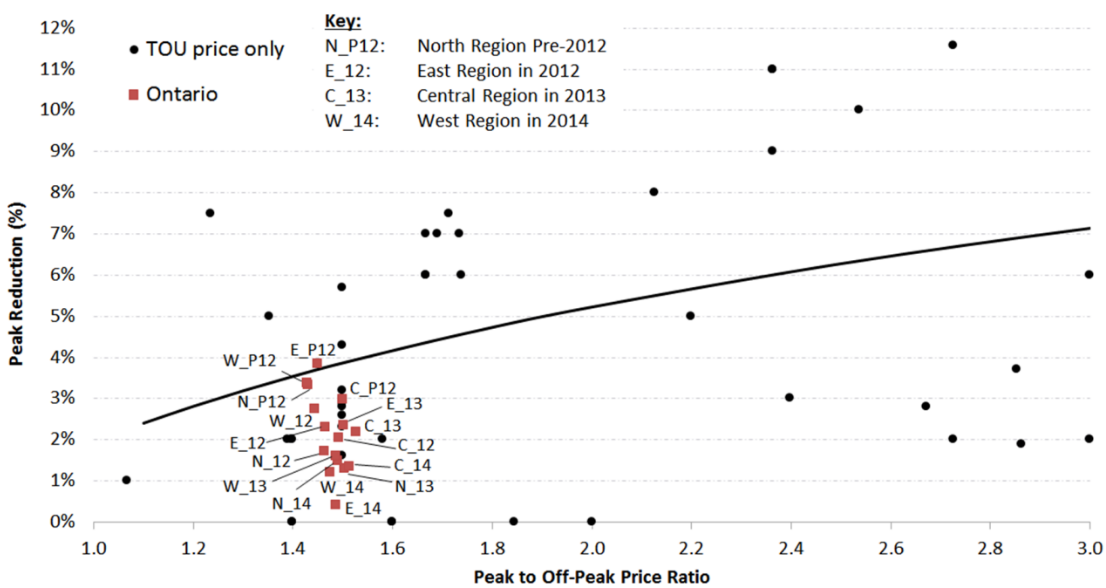
Figures 5.4a and 5.4b compare the Ontario residential summer TOU peak period results to results collected from 77 pilots around the world using Brattle's Arcturus database. The IESO impacts are the only impacts reported in both figures obtained from a full scale roll-out rather than a pilot. On the y-axis is the percentage peak reduction, while the x-axis shows the peak-to-off-peak price ratio. The blue curve is Brattle's Arc of price responsiveness, which is an econometric estimation of the curve that best fits the data. The Arc can be used to make predictions of peak reductions for various peak-to-off peak price ratios. In Ontario the peak-to-off peak price ratio for all of the LDCs was approximately 1.5. This would correspond to a 3 percent reduction in peak usage, which is slightly lower than the provincial estimate for pre-2012, but higher than the provincial estimates in 2012, 2013, and 2014. The lower bounds of the 95 percent confidence bound on the summer TOU peak period impacts for these years were 2.55, 2.34, and 1.53 percent, respectively.

Figure 5.4a: Ontario Residential TOU Summer Impacts Compared to TOU Pilots from around the World



Source: Faruqui, Ahmad. "Arcturus." The Brattle Group.

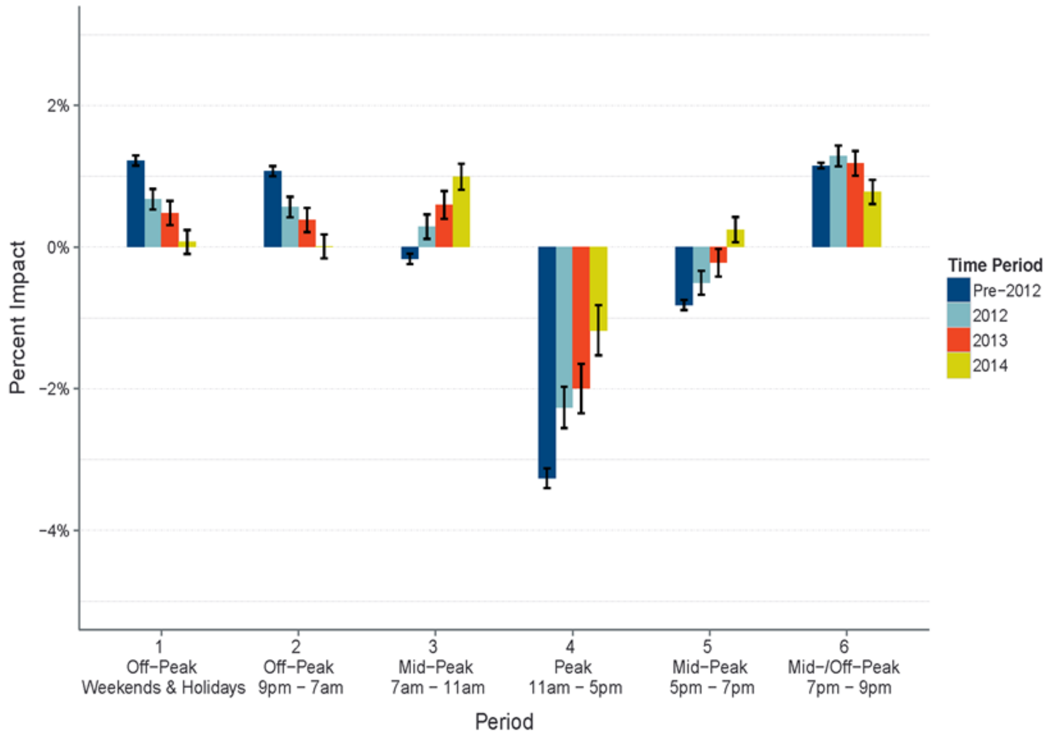
Figure 5.4b: Close-up of Ontario Residential TOU Summer Impacts Compared to TOU Pilots from around the World



Source: Faruqui, Ahmad. "Arcturus." The Brattle Group.

Figure 5.5 shows residential load shifting across all periods in the summer for the whole province. Period 1 is weekends and holidays which are off-peak. Period 2 is from 9pm to 7am and is also off-peak. Period 3 is from 7am to 11am and is mid-peak. Period 4 is the peak period from 11am to 5pm. Period 5 is the second mid-peak from 5pm to 7pm. Period 6 from 7pm to 9pm is currently off-peak, but was mid-peak before May of 2011.[41] Load is shifted from the peak and evening mid-peak period to the off-peak periods. In 2014, there is evidence of increasing load shifting into the mid-peak periods (additional shifting into the morning mid-peak period relative to prior years, and shifting into the evening mid-peak period, for which negative impacts were previously observed).

Figure 5.5: Province-Level Load Shifting
Summer Residential



Finally, we estimated substitution and overall conservation elasticities. A substitution elasticity indicates the percent change in the ratio of peak-to-off-peak consumption due to 1 percent change in the peak-to-off-peak price ratio. For instance, a substitution elasticity of -0.10 implies that, when the peak-to-off-peak price ratio increases by 1 percent, the usage ratio decreases by 0.10 percent. Overall conservation elasticities indicate the percent change in the average monthly consumption due to a 1 percent change in the average monthly price.[42] For instance, an overall conservation elasticity of -0.05 implies that, when the average monthly price increases by 1 percent, the average monthly usage decreases by 0.05 percent.

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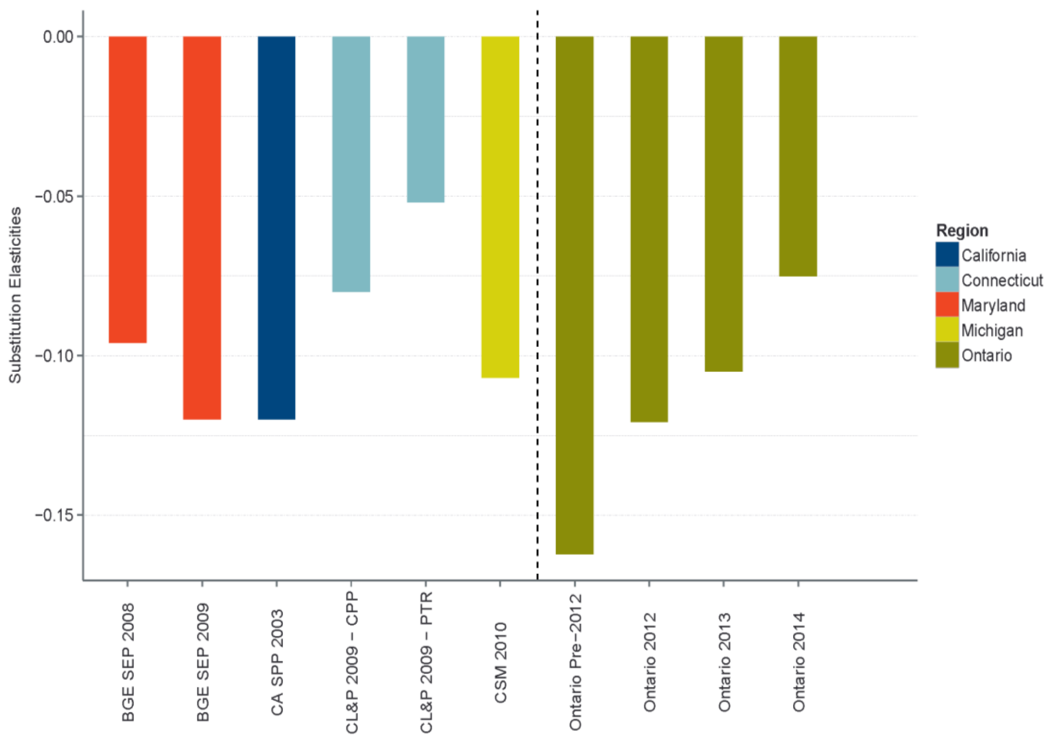
41 Note that the assignment of the peak and mid-peak periods change in the winter months.

42 This is the average "all-in" price including generation, distribution and transmission, with the TOU generation charge weighted by usage in each period.

Figure 5.6 shows substitution elasticities from several other studies alongside the provincial residential summer peak elasticities. The provincial elasticities, which lie between -0.1 and -0.15, are shown on the right. Altogether, they are very similar in magnitude to elasticities observed in other studies.

Figure 5.6: Residential Substitution Elasticities Compared to Other Pilots (Summer TOU Peak Period)[43]



We did not find any statistically significant evidence of conservation in the residential class across all regions and thus do not report a conservation elasticity for the residential class. Figure

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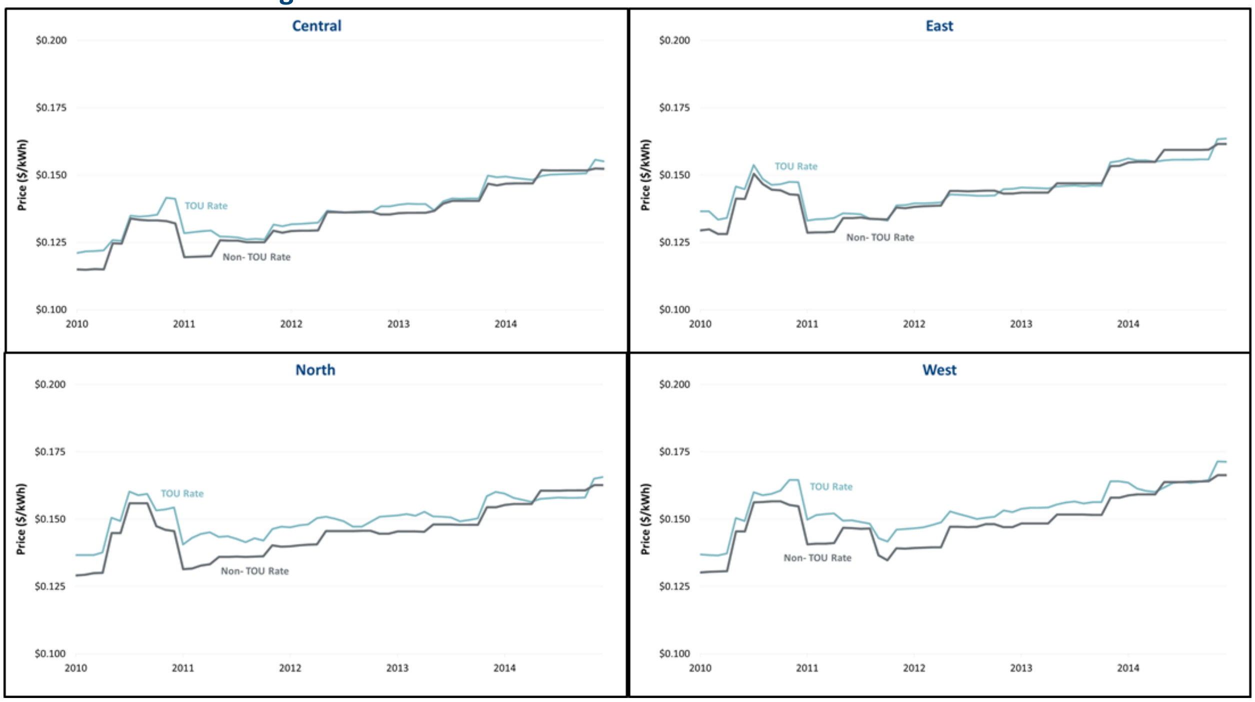
43 Data drawn from several studies; see respectively:

1) Faruqui, A. & S. Sergici (2009): "Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment," *Journal of Regulatory Economics*, Vol. 40(1), pp. 82-109
2) Faruqui, A. and S. George (2005)"Quantifying Customer Response to Dynamic Pricing," *The Energy Journal,* Vol. 18(4), pp. 53–63
3) Faruqui, A, Sergici, S. and L. Akaba (2014): "The Impact of Dynamic Pricing on Residential and Small Commercial and Industrial Usage: New Experimental Evidence from Connecticut," *The Energy Journal"* Vol. 35(1), pp.137-161
4) Faruqui, A, Sergici, S. and L. Akaba (2013): "Dynamic pricing of electricity for residential customers: the evidence from Michigan," *Energy Efficiency,* Vol. 6(3), pp. 571-584

5.7 shows the average monthly TOU and non-TOU all-in prices that consumers faced from 2010 to 2014 divided by region. Both TOU and non-TOU prices are from the province's regulated price plan (RPP). Within each region the TOU and non-TOU prices track each other closely and prices have been on a slight upward trend since 2011.

Figure 5.7 Residential TOU and Non-TOU Prices 2010-2014



Detailed information and impact estimates for each region can be found in the Appendix to this report.

C. General Service Results

Overall we find no consistent evidence of load shifting for general service customers. In most regions and years, impacts are far smaller than those estimated for the residential customer class, results are not as unambiguous, and there are some odd substitution patterns. This is most likely an artifact of the heterogeneity in the general service class.

During the EM&V peak demand period across all regions and years, we estimated that TOU rates induced impacts ranging from 1.38% to -1.35%. During the TOU summer peak period, we estimated that TOU rates induced impacts of 1.68% to -0.83% percent, depending on the region and year. Winter peak impacts ranged from 0.74% to -0.52%, again varying by region and year. Evidence on conservation was limited, with all estimates showing very small (less than 0.5%) conservation impacts.

Figure 5.8 summarizes the impacts and substitution elasticities for the summer and winter rates period, as well as the EM&V peak period for the general service class. Unlike for the residential class, there is no clear pattern of winter versus summer load shifting impacts.

Figure 5.8: General Service Substitution Impacts

	Pre 2012				2012				2013				2014			
	Impact	95% C.I. for Impact Lower Bound	95% C.I. for Impact Upper Bound	Substitution Elasticity	Impact	95% C.I. for Impact Lower Bound	95% C.I. for Impact Upper Bound	Substitution Elasticity	Impact	95% C.I. for Impact Lower Bound	95% C.I. for Impact Upper Bound	Substitution Elasticity	Impact	95% C.I. for Impact Lower Bound	95% C.I. for Impact Upper Bound	Substitution Elasticity
EM&V Peak Period (June, July, August 1-7pm)																
North	-0.13%	-0.61%	0.33%	-0.01	-0.73%	-1.42%	-0.04%	-0.06	-0.68%	-1.56%	0.18%	-0.05	1.38%	0.52%	2.24%	0.05
Central	-1.07%	-1.63%	-0.51%	-0.08	0.03%	-0.87%	0.92%	-0.02	-0.83%	-1.90%	0.22%	-0.06	0.11%	-0.93%	1.14%	-0.02
East	-0.36%	-0.74%	0.02%	-0.05	-0.01%	-0.69%	0.69%	-0.03	-0.53%	-1.34%	0.29%	-0.05	-1.35%	-2.16%	-0.54%	-0.09
West	-0.31%	-0.76%	0.13%	-0.03	-0.20%	-0.80%	0.39%	0.00	-0.12%	-0.81%	0.56%	-0.02	-0.22%	-0.89%	0.43%	-0.02
Province	**-0.66%**	-1.17%	-0.18%	-0.05	**-0.12%**	-0.77%	0.56%	-0.02	**-0.57%**	-1.35%	0.20%	-0.05	**-0.09%**	-0.87%	0.63%	-0.03
Summer TOU Peak Period (11am - 5pm)																
North	-0.07%	-0.46%	0.32%	-0.01	-0.56%	-1.10%	-0.02%	-0.04	0.17%	-0.54%	0.86%	0.00	1.68%	0.98%	2.36%	0.06
Central	-0.83%	-1.29%	-0.37%	-0.06	0.05%	-0.68%	0.77%	-0.02	-0.71%	-1.58%	0.15%	-0.05	0.22%	-0.64%	1.07%	-0.01
East	-0.23%	-0.53%	0.08%	-0.03	0.00%	-0.55%	0.56%	-0.02	-0.80%	-1.45%	-0.12%	-0.05	-0.51%	-1.19%	0.16%	-0.04
West	-0.36%	-0.73%	0.02%	-0.02	-0.19%	-0.70%	0.31%	-0.01	-0.17%	-0.76%	0.41%	-0.02	0.57%	-0.01%	1.15%	0.01
Province	**-0.53%**	-0.94%	-0.14%	-0.04	**-0.08%**	-0.61%	0.46%	-0.02	**-0.49%**	-1.15%	0.13%	-0.04	**0.34%**	-0.32%	0.94%	0.00
Winter TOU Morning Peak Period (7 - 11am)																
North	-0.47%	-0.67%	-0.26%	-0.01	-0.32%	-0.61%	-0.02%	-0.02	0.16%	-0.22%	0.54%	0.00	0.20%	-0.19%	0.59%	0.00
Central	-0.28%	-0.53%	-0.04%	-0.01	0.13%	-0.27%	0.55%	0.00	-0.17%	-0.64%	0.30%	-0.02	0.65%	0.16%	1.12%	0.02
East	-0.45%	-0.60%	-0.30%	-0.03	-0.36%	-0.66%	-0.05%	-0.02	-0.50%	-0.87%	-0.13%	-0.03	0.10%	-0.28%	0.48%	0.00
West	-0.30%	-0.54%	-0.06%	0.00	-0.38%	-0.67%	-0.08%	-0.02	0.04%	-0.31%	0.39%	-0.01	0.32%	-0.04%	0.67%	0.00
Province	**-0.33%**	-0.53%	-0.13%	-0.01	**-0.13%**	-0.46%	0.23%	-0.01	**-0.13%**	-0.56%	0.28%	-0.02	**0.43%**	0.01%	0.85%	0.01
Winter TOU Afternoon Peak Period (5 - 7pm)																
North	-0.52%	-0.72%	-0.32%	-0.01	-0.38%	-0.66%	-0.09%	-0.02	0.03%	-0.35%	0.42%	-0.01	0.06%	-0.32%	0.45%	0.00
Central	-0.17%	-0.40%	0.07%	-0.01	0.24%	-0.15%	0.65%	0.00	-0.07%	-0.54%	0.41%	-0.01	0.74%	0.27%	1.22%	0.02
East	-0.06%	-0.21%	0.09%	-0.01	0.03%	-0.27%	0.34%	-0.01	-0.08%	-0.45%	0.29%	-0.01	0.54%	0.16%	0.91%	0.02
West	-0.22%	-0.45%	0.01%	0.00	-0.29%	-0.58%	0.00%	-0.01	0.12%	-0.23%	0.47%	-0.01	0.40%	0.05%	0.75%	0.01
Province	**-0.20%**	-0.39%	0.01%	-0.01	**0.00%**	-0.33%	0.35%	-0.01	**-0.01%**	-0.42%	0.40%	-0.01	**0.55%**	0.15%	0.98%	0.02

Figure 5.9 shows general service impacts during the EM&V peak demand period across all regions and years. The confidence bands are wide relative to the magnitude of the impacts and we cannot confidently reject the null hypothesis of no load shifting in most of the regions and years. For the province as a whole, only the pre-2012 impact is statistically distinguishable from zero.

**Figure 5.9: EM&V Peak Demand Period (June, July, August, 1PM – 7PM)
General Service Load Shifting Results**

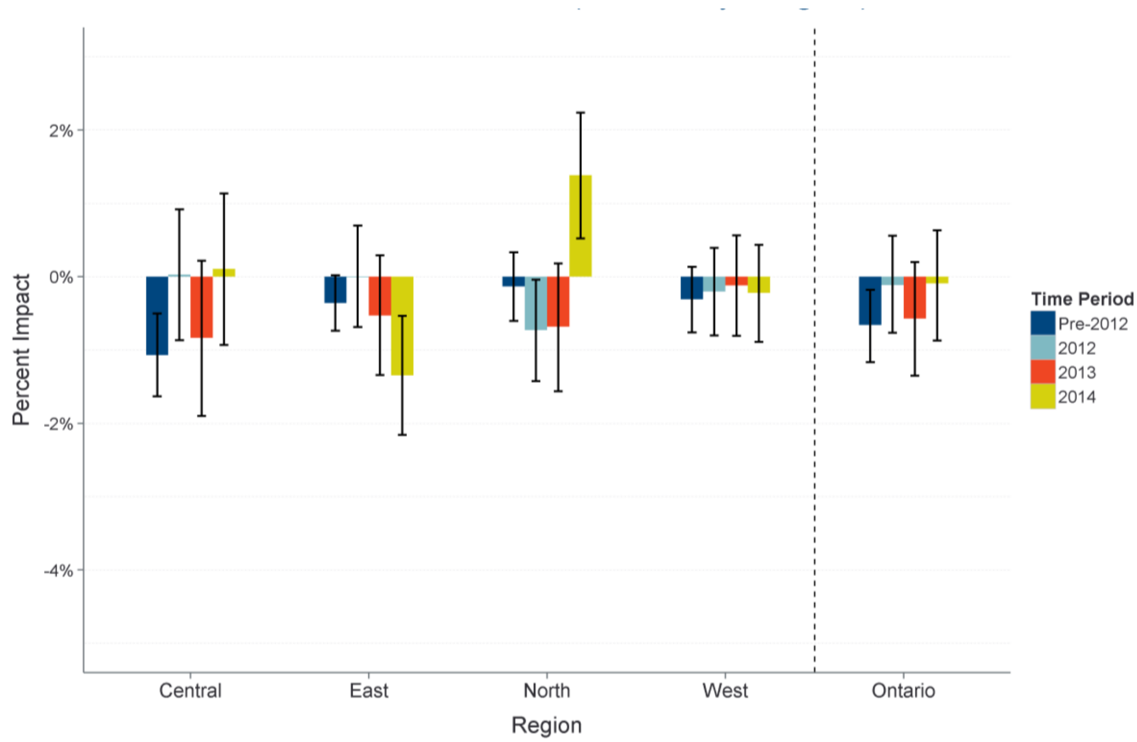


Figure 5.10 shows general service impacts during the summer TOU peak period across all regions and years. Again, confidence bands are wide relative to the magnitude of the impacts and we cannot confidently reject the null hypothesis of no load shifting in most of the regions and years. For the province as a whole, only the pre-2012 impact is statistically distinguishable from zero.

Figure 5.10: Summer TOU Peak Period (11am – 5pm)
General Service Load Shifting Results

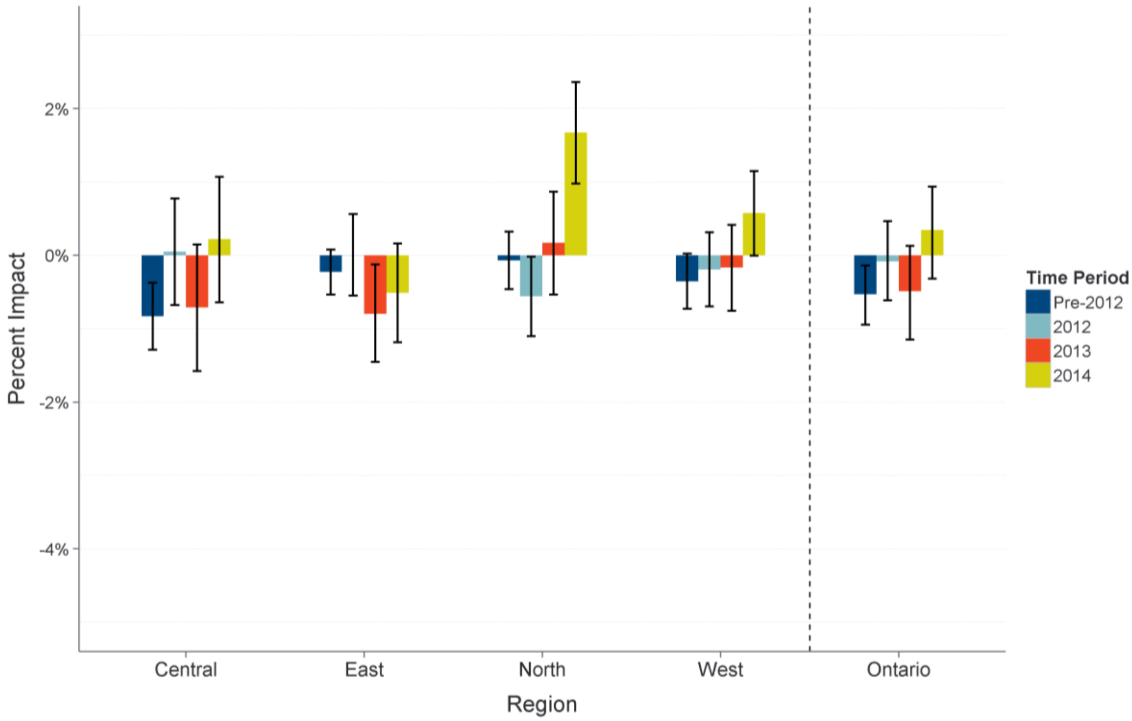
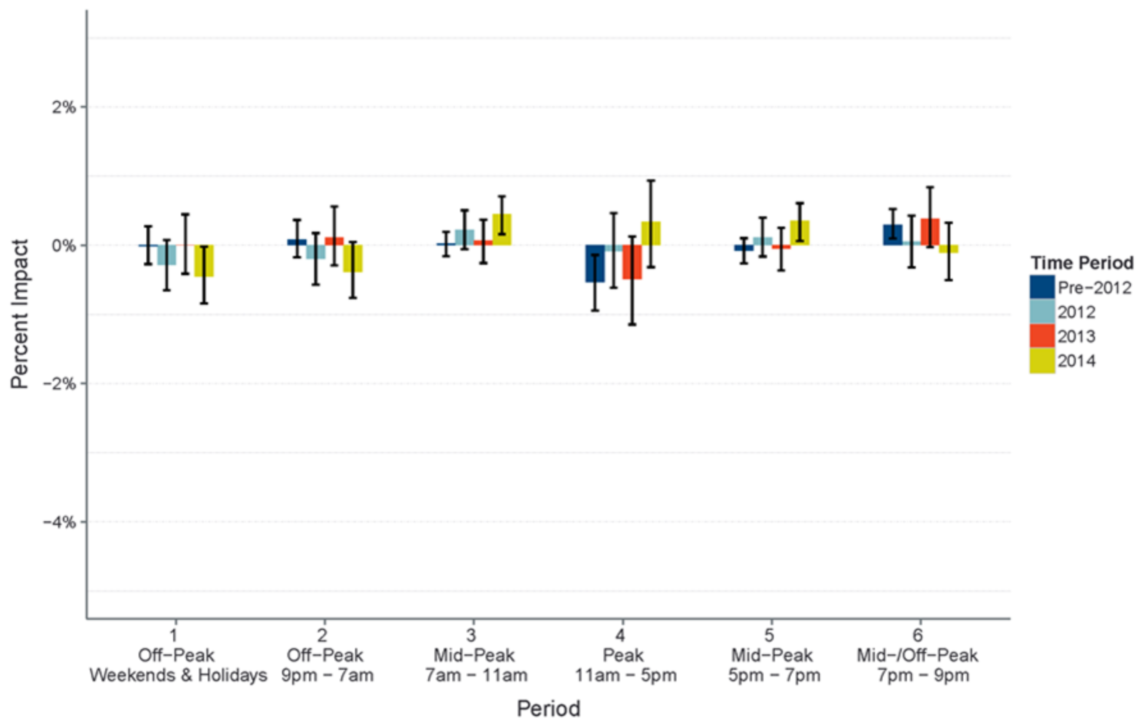


Figure 5.11 shows general service load shifting across all periods in the summer for the whole province. Period 1 is weekends and holidays which are off-peak. Period 2 is from 9pm to 7am and is also off-peak. Period 3 is from 7am to 11am and is mid-peak. Period 4 is the peak period from 11am to 5pm. Period 5 is the second mid-peak from 5pm to 7pm. Period 6 from 7pm to 9pm is currently off-peak, but was mid-peak before May of 2011. There is no clear pattern of load shifting from peak to off-peak periods.

Figure 5.11: Province-Level Load Shifting
Summer General Service



Detailed information and impact estimates for each region can be found in the Appendix to this report.

VI. Challenges and Limitations

In this section, we describe the challenges and limitations of this study and our approach to overcoming them, where feasible.

1. Full-scale deployment of TOU rates poses two challenges for the impact evaluation:
    a. The TOU roll-out was not designed as a randomized controlled experiment and there is no control group. In the first year of the study, we were able to exploit the phased nature of the deployment within the LDCs to construct a proxy control group. We allocated the eligible customer lists into two groups using the median TOU start date. Customers who got the TOU rates after the median date were classified in the "potential control group" bucket, whereas the customers who got the rates before this date were placed in the "potential treatment group" bucket. After determining the sample sizes, we randomly selected the control and treatment groups from these two buckets. In the Third Year Study we examine impacts in 2012, 2013, and 2014, when almost all customers are on TOU rates. Fortunately, there is still a small pool of retail customers to act as a control group.

In addition, we have the pre-2012 results to act as a check on the later results, since these results are calculated as incremental divergences from the pre-2012 results.

b. For some LDCs, the TOU rates were deployed very shortly after the AMI deployment. This implies that there is a very short window with pre-TOU data available. We address this issue in the sample design process by defining eligible customers to be included in the study as those who have at least 6 months of pre-TOU and at least 12 months of post-TOU data. However, PowerStream's data did not include 6 months of pre-TOU data for most customers (the average was 2-4 months). The sensitivity of our results to the inclusion of PowerStream proved to be very low. We therefore included PowerStream's data in the study so as to benefit from the increased overall sample size (*e.g.,* tighter confidence bands).

2. We use a small group of retail customers as an additional control group. As of December 2014 this group comprised 3.9 percent of the residential customer sample and 1.7 percent of the general service customer sample. However, over the course of the study 10.5 percent of the residential customer sample were retail customers at some point, with general service ratial customers constituting a higher share of the general service customer sample at 13.8 percent. There may be a concern that those customers who "self-select" into the retail rates may be different from other customers, particularly if they do so as a reaction to TOU rates. In order to account for this potential self-selection bias, we run our regressions using first differences ($year_t - year_{t-1}$) to remove any customer specific characteristics that do not change over time. If there is a specific customer attribute that prompts them to select into the retail rate, this attribute will be removed by taking the first differences. For example, if customers have higher than average usage in the peak periods, this usage pattern will be removed by taking the difference between the current and previous year. Moreover, if customers opted out of TOU because they anticipated their usage becoming peakier, we would find larger negative elasticities than we should and in such a case we would be overstating the TOU impacts. In the First Year Study, we tested whether self-selection by retail customers biased our results downward and found no evidence to support this.

3. Little overall price variation led to difficulties with conservation equations and resulted in implausible (*i.e.* positive) conservation elasticities primarily for residential customers. None of these elasticities are statistically distinguishable from zero. We therefore zeroed out these implausible conservation elasticities for impact calculations.

4. Due to data availability issues, we were not able to include general service class customers from Toronto Hydro, Newmarket-Tay Power, and PowerStream.

5. The Newmarket-Tay Power sample was drawn from a pre-existing study and was not randomly selected by Brattle or selected to be representative of the population. However,

in the First Year Study we did test whether the distribution of annual kWh of the population differed from our sample (using a non-parametric chi-square test). We could not reject that they were the same.

6. We were unable to include 2014 data for Newmarket-Tay Power retail customers due to timing and data availability issues.

7. While we correct for serial correlation of the error term in the Monthly Consumption model, we were unable to do so for the Addilog Demand System model which estimates the load shifting impacts because of time constraints. Under a certain set of assumptions, we have correctly estimated the standard errors.

VII. Conclusions

The Third Year Study of Ontario's Full-Scale TOU Program revealed that the residential customers responded to the TOU rates by shifting their usage from peak to off-peak and mid-peak periods, at magnitudes similar to those that have been observed in pilots. Load shifting during the EM&V peak demand period and summer TOU on peak period were lower in 2014 than in previous years. The load shifting impacts for general service customers were generally much smaller than those estimated for the residential customer class and results are not as evident, with some odd substitution patterns. This is most likely an artifact of large variability in customers that comprise the general service class. Evidence on energy conservation was non-existent for residential customers, and negligible for the general service class.

GLOSSARY

Addilog Demand System: is a well-behaved demand system which is capable of estimating small elasticities of substitution. Unlike more flexible demand systems, the Addilog Demand System satisfies regularity conditions (*e.g.,* concavity) globally.

Constant Elasticity of Substitution System: is a well-behaved demand system which allows the elasticity of substitution to take any value. The Constant Elasticity of Substitution System model has been found to be well-suited to TOU pricing studies involving electricity since there is strong prior evidence suggesting that these elasticities are going to be small.

Cooling Degree Humidex Index: is a warm weather indicator defined as follows,

$$CDHM_t = \max[HM_t - 22{,}0]$$

$$where \quad HM_t = \max[H_t \cdot d_t, T_t] \quad with \quad d_t = \begin{cases} 1 \; if \;\; H_t \; is \; reported \\ \quad 0 \; otherwise \end{cases}$$

T_t is hourly outdoor air temperature at hour t.

H_t is the hourly humidex statistic reported by Environment Canada.

Difference-in-Differences Estimation: is a technique to measure the effect of a treatment by first calculating the difference between pre- and post-treatment periods for the treatment group and then netting it off by the difference between these two periods for the control group.

EM&V Peak: The IESO's Evaluation, Metrics, and Valuation (EM&V) Protocols and Requirements definition of peak ("EM&V peak demand") which is defined as the average demand between 1pm – 7pm on weekdays (excluding public holidays) during June, July, and August.[1] It should be noted that the EM&V peak is different from the summer TOU peak that customers see on their electricity bill, which in summer extended from 11am to 5pm.

General Service Customers: are non-residential customers with demands less than 50 kW

Heating Degree Wind-Chill Index: is a cold weather indicator defined as follows,

$$HDW_t = max[18 - W_t, 0]$$

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1 *See* "EM&V Protocols STG-10: Demand Savings Calculation Guidelines." http://www.cleanairpartnership.org/files/EMV%20Protocols%20and%20Requirements.pdf

with $W_t = min[T_{wct} \cdot v_t, T_t]$ with $v_t = \begin{cases} 1 \text{ } if \text{ } T_{wct} \text{ } is \text{ } reported \\ 0 \text{ } otherwise \end{cases}$

T_t is hourly outdoor air temperature at hour t, and

T_{wct} is the wind chill statistic reported by Environment Canada.

Price Elasticity of Demand: represents the percentage change in quantity demanded in response to a one percent change in price holding constant all the other determinants of demand.

Randomized Control Experiment: in randomized controlled experiments, eligible customers are randomly allocated into the treatment and control groups. The treatment customers receive the treatment (TOU rates in this context), whereas the control customers do not receive the treatment.

Residential Service Customers: refer to single family homes and individually-metered apartment buildings. When the metering takes place at the building level, they are classified as general service customers.

Seemingly Unrelated Regression: is a generalization of a linear regression model that consists of several regression equations, each having its own dependent variable and potentially different sets of exogenous explanatory variables. Each equation is a valid linear regression on its own and can be estimated separately, which is why the system is called *seemingly unrelated*, although some authors suggest that the term *seemingly related* would be more appropriate, since the errors are assumed to be correlated across the equations.

Summer Mid-Peak: 7am – 11 am and 5pm – 7 pm on weekdays (excluding public holidays) during the months of May – October.

Summer Off-Peak: 7pm – 7am on weekdays (excluding public holidays) during the months of May – October. All weekends and public holidays during the months of May – October.

Summer Peak: 11am – 5pm on weekdays (excluding public holidays) during the months of May – October.

Substitution Elasticity: indicates the percent change in the ratio of peak -to-off-peak consumption that occurs due to a one percent change in the peak -to-off-peak price ratio. For instance, a substitution elasticity of -0.10 implies that, when the peak -to-off-peak price ratio increases by 1%, the corresponding peak -to-off-peak usage ratio decreases by 0.10%. Or put another way, if the peak -to-off-peak price ratio was to be doubled, the corresponding usage ratio would fall by 10%.

Winter Mid-Peak: 11am – 5pm on weekdays (excluding public holidays) during the months of November – April.

Winter Off-Peak: 7pm – 7am on weekdays (excluding public holidays) during the months of November – April. All weekends and public holidays during the months of November – April.

Winter Peak: 7am – 11am and 5pm – 7 pm on weekdays (excluding public holidays) during the months of November – April.

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