CENTRAL TORONTO AREA
INTEGRATED REGIONAL RESOURCE PLAN - APPENDICES

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

ieso

Independent Electricity System Operator

Metro Toronto – Central IRRP

Appendix A: Single Line Diagram of the Central Toronto Transmission System

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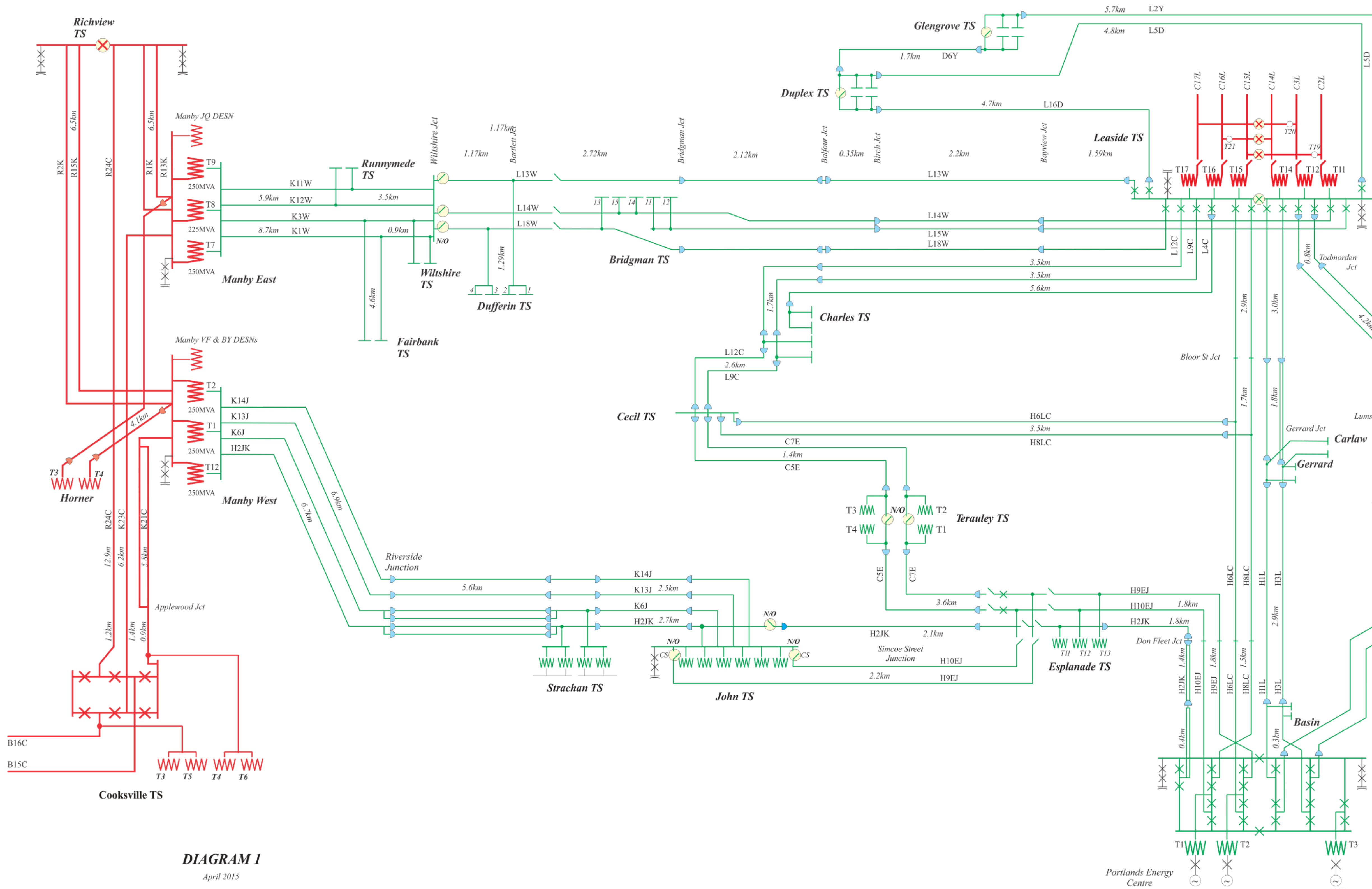

DIAGRAM 1

April 2015

Metro Toronto – Central IRRP

Appendix B: Toronto Hydro Spatial Load Forecast Methodology

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NAVIGANT

Memorandum

To:	Angelo Boschetti, Capacity Planning, THESL
From:	Glen Wood, Navigant Peter Steele-Mosey, Navigant
CC:	Chun Hung Ngai, Capacity Planning , THESL Anna Tubina, Rates and Treasury, THESL Todd Williams, Navigant Amanda Bond, Navigant
Date:	31 July 2012 (Revised 13 Nov 2012)
Attachment:	***Annual Forecast Peak Demand 30 July 2012 - THESL.xlsx***
Re:	**Forecast of THESL System-Wide Gross Peak Demand - 2012 to 2036.**

1. Purpose and Summary of Approach:

The purpose of this memo is to document the methods, data sources, and assumptions used in the development of the forecast of the ***System-Wide Gross Peak Demand Forecast*** for the THESL system. This projection has been completed as the first step in the development of a ***Spatial Peak Demand Forecast*** for the THESL system. While the System-Wide Gross Peak Demand Forecast projects demand for the system as a whole, the Spatial Peak Demand Forecast (SPDF) will project demand for specific areas within THESL's service territory.

This memorandum presents Navigant's projection of peak demand for THESL's total service territory under four different scenarios:

1. "Normal" (i.e., 1-in-2) weather,
2. "Extreme" weather,
3. "Climate Change" scenario, which assumes that "Normal" weather conditions are affected by an average temperatures rise of 2.3 degrees from current "normal" over the next 25 years, and,
4. A "net" demand scenario in which demand reductions as a result of Conservation and Demand Management (CDM) and distributed generation (DG) are subtracted from the extreme weather scenario.

The definitions of "normal" and "extreme" will be discussed in greater detail below.

The memorandum is divided into the following sections:

1. Purpose and Summary of Approach (this section).
2. Data Description:
   - This data includes both:
     a. Historic estimation data (used to estimate the regression model), and,
     b. Forecast input data (not including weather).
3. Econometric modeling:
   a. Regression specification and parameter estimates.
   b. Model diagnostics and validation.
4. Weather scenarios.
5. THESL peak demand forecast.
6. Summary of results.

We have presented the discussion of the data used in the analysis prior to the discussion of the econometric modeling since the outcomes of the regression process are dependent on the data underlying the analysis.

One of the key challenges in projecting future demand for electricity lies in quantifying the future contributions of Conservation and Demand Management (CDM) and Distributed Generation (DG). The level of future demand reduction arising from CDM and DG will be influenced by policy decisions and are therefore subject to uncertainty. After reviewing alternative approaches to addressing these impacts as part of the projection, Navigant recommended and employed an approach in which the effects of CDM were identified and removed from demand during the historic period[1]. This approach allowed the development of a projection of demand as it would have been without the impact of CDM and assuming only current levels of DG. The resulting projection, without the impact of CDM or DG is referred to as the "gross" forecast. The future impacts of CDM and DG can then be treated explicitly over the projection period.

A forecast of gross peak demand was developed for a "normal" weather scenario, an "extreme" weather scenario and a weather scenario in which average and peak temperatures increase as a result of climate change. In addition, a "net" scenario was developed to show the level of peak demand that would be expected under the "extreme" weather scenario if the same level of distributed generation now operating within the THESL system is maintained and CDM programs currently in place continue to operate. This "net" scenario will be referred to as Scenario 1.

[1] Existing DG was assumed to continue operating in the projection period, so no adjustment was made for DG over the historic period.

The project team met with representatives of the IESO and OPA on March 27th to discuss methods for normalizing historic demand for the effects of weather. At that meeting, both the IESO and OPA discussed their forecast methods and the IESO described the processes used for weather normalization. After discussing the objectives of the THESL forecast, the consensus of the group was that the most appropriate weather normalization approach for THESL to follow would be to use the IESO monthly weather normal and extreme scenarios used in their Transmission Planning Analysis.

2. Data Description

The data used in this analysis can neatly be divided into two types: that used to estimate the regression equation (historical data), and that used as an input to the forecast peak demand. Both types are described below.

Historical data

Weather Data

Weather data were obtained from Environment Canada (EC) for Toronto's Pearson International airport (station ID #5097).

The variables considered in the development of this analysis included:

- Temperature (˚C)
- Dew point (˚C)
- Wind speed (km/h)
- Cloud opacity (in tenths)

Missing values were estimated as the simple average of the value observed in the hour before the missing value and the hour after. For cloud opacity, such averages were rounded to the nearest integer.

Population Data

Monthly historical population data for Toronto residents over the age of 15 was provided by the Strategic Growth and Sector Development department of the City of Toronto. This data can be obtained by request through the City of Toronto Economic Indicators webpage[2].

[2] City of Toronto Economic Indicators, http://www.toronto.ca/business_publications/indicators.htm

Employment Data

Employment data for 2002-2010 were obtained from Toronto's annual publication entitled "Profile Toronto, Toronto Employment Surveys" ("the Toronto survey") published by Urban Development Services Policy and Research Division.

The annual figures by sector of the economy were used without change where they were provided. In some cases sectoral figures had to be derived based on percentages of total employment provided in the Toronto survey, and in other cases sectoral figures were derived based on the indicated year-over-year change.

Employment figures are provided for following categories listed below. For the purposes of this analysis, employment figures were aggregated into two sectoral categories as indicated below: "Industrial" employment and "Commercial" employment":

- Manufacturing/Warehouse (Industrial)
- Retail (Commercial)
- Service (Commercial)
- Office (Commercial)
- Institutional (Commercial)
- Other (Commercial)

Demand Data

THESL provided Navigant with hourly demand billing demand data (in kW) from the IESO for its system[3], from May, 2002 to December, 2011.

CDM Data

The data used to remove the impacts of CDM from the historic hourly demand data are described in Navigant's CDM memo, most recently updated on July 23, 2012.

DG Data

DG impacts were not considered as part of the demand modeling, which assumed that existing DG would continue operation during the projection period. Projections of future DG impacts, discussed later in Scenario 1, were provided by THESL.

[3] Hourly billing demand did not include IESO market participants. Market participants represent < 1% of load on THESL system.

Forecast data

Weather Data

As per IESO guidelines[4], and with guidance from the IESO, Navigant created three different types of peak demand weather scenarios for May through September: "Normal" weather, "Normal with climate change" weather (which is simply the "Normal" scenario assuming an average maximum temperature increase of 2.3 ˚C phasing in over thirty years beginning in 2011[5]) and "Extreme" weather. Details of how these scenarios were developed may be found below. For the "normal" and "extreme" weather scenario, the weather input values for a given month's peak demand estimate remain constant across all years of the forecast. Input weather values for a given month's peak demand estimate change gradually for the "normal with climate change" scenario, as noted above.

Population Data

Population projections for the city of Toronto were obtained from the City's "*Flashforward*" publications which describe Toronto's Official Plan. Specifically, projected growth rates from "*Flashforward: Projecting Population and Employment to 2031 in a Mature Urban Area, How Many People Will There be in Toronto?*"[6] were used as the basis for population and employment projections. Population projections are given for every 5th year from 1996-2031.

Understanding that the data in the "*Flashforward*" projection doesn't reflect actual changes in population and employment since its publication, more recent data was obtained from the City for the historic period up to 2011. The growth rates for each 5-year period projected in the "*Flashforward*" document were applied to the actual historic population data. For our dataset, we were able to obtain annual population projections for 2011, 2016, 2021, 2026, and 2031. The base for our population projection was taken as December 2011 based on the monthly series from the City of Toronto, which was used as our starting point for January 2012. In order to derive

[4] Independent Electricity System Operator, *Methodology to Perform Long Term Assessments*, June 2012. http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2012jun.pdf

[5] Climate Change Research Report (CCRR16) – Current and Projected Future Climatic Conditions for Ecoregions and Select Natural Heritage Areas in Ontario. Ontario Ministry of Natural Resources, 2010. The MNR projection indicates that over the period from 2011-2040, the maximum temperature in warmest month is expected to increase by between 1.8 to 3°C. For the sensitivity analysis we have assumed the mean increase in projected maximum temperatures of 2.3°C.

[6] City of Toronto, *Flashforward: Projecting Population and Employment to 2031 in a Mature Urban Area, How Many People Will There be in Toronto?*, 2001 http://www.toronto.ca/planning/flashforward.htm

monthly population projections from the annual series, the data was linearly interpolated across each year. Note that since the population projection is based on the historical population data, it is consistent in reflecting residents aged 15 years and older.

Forecast Toronto population for December of milestone years is shown in Table 1, below.

Employment Data

Projected employment for the City of Toronto, from the beginning of 2011 to the end of 2037, was obtained from the city of Toronto, in its "*Flashforward*" publications[7]. Select years are published in which projections are given. In cases where no employment projection was provided for a given year, it was estimated by linear interpolation. For years falling after the final year of the City of Toronto's employment forecast, data were extrapolated based on the growth rate observed between the final two years forecast by the City of Toronto.

As with the population data, the City of Toronto forecast was updated to reflect current levels of employment but maintaining the original implicit growth rates. Forecast average levels of employment for milestone years, by sector, is shown in Table 1, below.

[7] City of Toronto, *Flashforward: : Projecting Population and Employment to 2031 in a Mature Urban Area, Where Are We Going to Work?* http://www.toronto.ca/planning/flashforward.htm

Table 1: Projected Population and Employment - Milestone Years

Population and Employment (Thousands)			
Year	Population(1)	Industrial Employment	Commercial Employment
2012	2,179	129	1,185
2013	2,200	128	1,197
2014	2,220	128	1,208
2016	2,262	127	1,231
2018	2,275	128	1,253
2021	2,291	128	1,287
2031	2,352	126	1,400
2036	2,395	125	1,460

(1) for December of given year

Source: City of Toronto, Navigant analysis

3. Econometric Modeling

Forecast data

The basic functional form of the regression equation was determined by the need to adhere to the IESO's established method for developing weather scenarios for long-term forecasts. Which regressors (independent variables) were to be included in the model was determined using a specification search, with competing models ranked by the Schwartz-Bayesian Criterion (SBC) and adjusted R^2. Of the model specifications tested, that with the lowest SBC and highest adjusted R^2 was used[8].

Note that since THESL is summer-peaking and is expected to remain so, only summer months (May through September) were used in the regression. Likewise, since peak demand is not expected to occur on a weekend or holiday[9], all observations on these days are dropped from the sample.

The model estimated by Navigant was:

$$\begin{aligned} y_t &= \alpha + \beta_1 Cool\_THI_t + \beta_2 Heat\_THI_t + \beta_3 Cloud_t + \\ &\beta_4 Pop_t + \beta_5 Ind\_Jobs_t + \beta_6 Com\_Jobs_t + \beta_7 \left(Pop_t \times Cool\_THI_t \right) \\ &+ \vec{\gamma}\,\overrightarrow{Day_t} + \vec{\omega}\,\overrightarrow{Month_t} + errors \end{aligned}$$

[8] Where the two criteria disagreed as to the relative rank of model specification, priority was given to the SBC.
[9] Peak monthly demand has not occurred on any weekend or holiday previously.

Where:

y_t	=	THESL's peak observed demand, as it would have been without any CDM impacts (but assuming continued DG operation), day *t*.
$Cool\_THI_t$	=	Is the cooling temperature-humidity index (THI) observed on day *t*. THI is calculated in the following manner[10]: $$THI_s = 17.5 + 0.55 \times DryBulb_s + 0.2 \times Dew_s$$ Where *DryBulb* is the dry bulb temperature (˚C) observed in hour *s* and *Dew* is the dew point temperature (˚C) observed in hour *s*. The daily THI to be used for the analysis is then calculated as the average of: the minimum THI between 7am and noon, the maximum THI between noon and 5pm and minimum THI between 5pm and 10pm (all times EST). *Cool_THI* is calculated as the daily THI minus 30 or the number zero, whichever is greater.
Heat_THI	=	Is calculated as 25 minus the daily THI (see above) or the number zero, whichever is greater.
Cloud	=	Is the maximum cloud opacity (in tenths) observed on day *t* between 11am and 4pm (EST).
Pop	=	Is the cumulative change in Toronto's population over the age of 15 since January of 2002 for the month in which day *t* falls.
Ind_Jobs	=	Is the cumulative change in the number of Toronto's industrial jobs since 2001 for the year in which day *t* falls.
Com_Jobs	=	Is the cumulative change in the number of Toronto's commercial jobs since 2001 for the year in which day *t* falls.
$\overrightarrow{Day}$	=	Is a vector of three dummy variables capturing the impact on peak daily demand if day *t* is a Tuesday, Wednesday or Thursday.[11]

[10] Equations and method for calculating hourly and daily THI and cooling and heating THI were provided by the IESO.

[11] The impact on peak daily demand due to day *t* being a Monday or Tuesday is implicitly captured by the intercept term.

$\overrightarrow{Month}$ = Is a vector of four dummy variables capturing the impact on peak demand if day *t* occurs in June, July, August and September..[12]

The model was estimated in SAS[13] using the PROC REG and PROC MODEL procedures. Parameter estimates, HAC standard errors and p-values are shown in, below. The R-squared of this model is 0.9048 and the adjusted R-squared is 0.9035 indicating a very good fit of the model to the data.

Table 2: Regression Model Parameter Estimates, SEs, t-stats and P-values

Variable	Parameter Estimate	HAC Standard Error	t statistic	P Value
Intercept	3,519.73	28.41510	123.87	<.0001
Cool_THI	158.48	5.57790	28.41	<.0001
Heat_THI	-20.75	5.73750	-3.62	0.0003
Cloud	-9.96	1.54410	-6.45	<.0001
Pop	0.0017	0.00042	3.98	<.0001
Ind_Jobs	0.0080	0.00125	6.39	<.0001
Com_Jobs	0.0018	0.00054	3.35	0.0008
Pop × Cool_THI	0.0002	0.00009	2.47	0.0137
Tue Dummy	33.60	10.07470	3.33	0.0009
Wed Dummy	49.81	11.22920	4.44	<.0001
Thurs Dummy	46.53	10.60340	4.39	<.0001
June Dummy	235.26	16.12160	14.59	<.0001
July Dummy	249.51	18.88670	13.21	<.0001
Aug Dummy	241.34	18.97630	12.72	<.0001
Sept Dummy	187.91	17.37200	10.82	<.0001

Source: Navigant Analysis

Model Diagnostics and Validation

Stationarity

The standard test for stationarity in a data series is the Dickey-Fuller test. Generally, the Dickey-Fuller test for stationarity is conducted by estimating the three equations shown in

[12] The impact on peak daily demand due to day *t* being in May is implicitly captured by the intercept term.
[13] SAS (Statistical Analysis Software) version 9.2 (http://www.sas.com/software/sas9/).

Table 3, below and testing the null hypothesis that gamma is zero (that is, that there exists a unit root).

Table 3: Dickey-Fuller Test Equations

Model	Description	Specification
A	Random walk	$\Delta y_t = \gamma y_{t-1} + \varepsilon_t$
B	Random walk with drift	$\Delta y_t = \alpha_0 + \gamma y_{t-1} + \varepsilon_t$
C	Random walk with drift and trend	$\Delta y_t = \alpha_0 + \gamma y_{t-1} + \alpha_1 t + \varepsilon_t$

Where "y_t" is the variable which is being tested for stationarity, in this case the peak daily demand experienced by THESL. The three models above were estimated using the PROC ARIMA procedure in SAS and produced the results shown in Table 4, below.

Table 4: Dickey-Fuller Test Statistics

Model	Tau Statistic	Pr < Tau	F Statistic	Pr > F
A	-1.09	0.2488		
B	-10.47	<.0001	54.78	0.001
C	-10.46	<.0001	54.73	0.001

Source: Navigant analysis

Although the null hypothesis of a unit root cannot be rejected for model A, this is clearly not the appropriate model – any plot of changes in peak daily demands will clearly show that this value fluctuates around a non-zero mean due to seasonal shifts, or around a non-zero mean and a deterministic trend (models B and C, respectively). The tau statistics for these two models allow the null hypothesis of a unit root to be rejected, indicating that the data is either mean- or trend- stationary.

Residual Serial Correlation and Heteroskedasticity

Residual serial correlation was tested for using the Durbin-Watson statistic (using the PROC REG procedure). The Durbin-Watson statistic returned was 1.298 meaning the hypothesis that the residuals are serially independent must be rejected – that is, it is highly likely that the residuals are serially correlated. For confirmation, the Breusch-Godfrey/Lagrange Multiplier test for serial correlation was conducted and confirmed the result of the Durbin-Watson test.

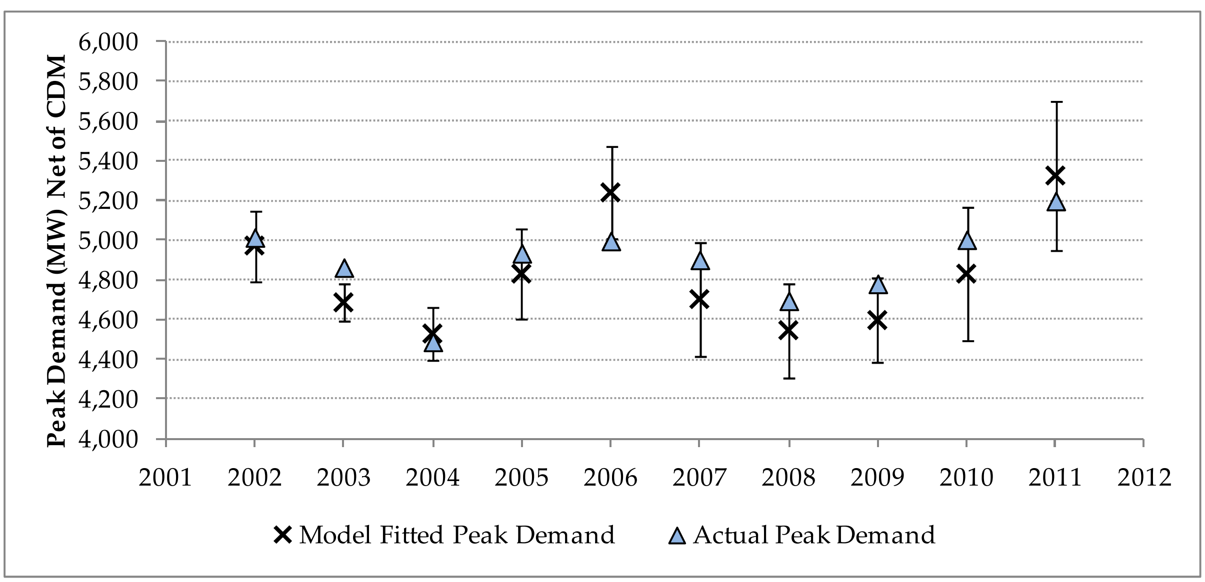
Residual heteroskedasticity was tested using the White test, which delivered the Chi-squared distributed statistic of 125.69, meaning that the null hypothesis that the residuals are homoskedastic must be rejected at the 95% level[14] (p-value of 0.0363) – that is, it is likely that the residuals are heteroskedastic.

Fortunately, neither serial correlation not heteroskedasticity biases the coefficient estimates when no lagged dependent variable is included in the model specification, although both violations of the classic assumptions result in bias of estimates of the coefficient standard errors. This results in inaccurate t-values and may lead to significant estimates being rejected as not significant or vice versa. To correct for this, heteroskedasticity and autocorrelation consistent (HAC) standard errors were estimated using the PROC MODEL procedure. Confidence intervals and statistical testing of parameter estimates was conducted using these standard errors.

Accuracy of Fitted Peak Demands

One of the most important tests of model validity (certainly the most accessible for readers less familiar with econometrics) is simply to compare the model fitted values and the actual historical values. This comparison is made in Table 5, below. For convenience we have used the term "absent CDM" in this memo to refer to demand as it would have been without the impacts of CDM and assuming the continued operation of existing levels of DG.

Table 5: Historic Peak Demand (Absent CDM) vs. Fitted Peak Demand (Absent CDM).



[14] Although not at the 99% level of significance.

Source: THESL demand data, Environment Canada weather data, City of Toronto population and employment data and Navigant analysis.

The error bars shown in Table 5 represent the fitted values obtained using the upper and lower 95% confidence intervals for all of the estimated parameters, calculated using (HAC) standard errors.

Note that Navigant's point estimates of historic peak demand (absent CDM) all fall very close to the observed actual historic peak demand, absent the impacts of CDM[15]. In only one case does the historic value fall outside the 95% confidence interval, and even in that case it remains very close to the point estimate. Note too that Navigant's estimates do not always either over-estimate or under-estimate the true impact but fluctuate, sometimes higher and sometimes lower than the true peak demand. The average absolute deviation of Navigant's estimates from the true values shown in Table 11 is less than 3%.

4. Weather Scenarios

Weather scenarios used in the forecast were generated in a manner consistent with the method outlined by the IESO in its "*Methodology to Perform Long Term Assessments*" document[16] and further expanded on in a slide deck presented to both Navigant and THESL in March of 2012.

"Normal" Weather Scenario

Step 1:

Calculate the peak daily demand absent CDM which may be ascribed purely to weather for every day in May, June, July, August and September from 1981 through to the end of 2011. This is done by multiplying the purely weather coefficients by the corresponding variable values on each day and summing them up.

Step 2:

Collect the highest peak demand for each month of each year as calculated in Step 1. This will result in a data set of 155 values, 31 for each of the five months. Each row of this data set will contain the weather observations corresponding to the highest peak daily demand observed in each month of each year.

[15] Note that the relative position of the observations on this chart would not change were CDM to be included – both fitted and actual observations would simply shift downward by the same amount of peak demand attributable to CDM in a given year.

[16] Independent Electricity System Operator, *Methodology to Perform Long Term Assessments*, June 2012. http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2012jun.pdf

Step 3:

Extract the median row for each month. The corresponding weather observations are the weather values that will be used for as the 1-in-2 weather for forecasting the peak demand of each month (i.e., May through September). For each year of the forecast, these values will be used, along with the forecast economic and demographic factors for that year, to estimate the peak monthly demand.

A summary of the temperature and other weather variables drawn from the days used for the "normal" weather scenario is presented in Table 6, below.

Table 6: Summary Statistics From "Normal" Weather Scenario Days, 11am – 5pm EST

Month	Date	Avg. Temperature	Max. Temperature	Avg. Dew Point	Avg. Cloud Opacity
May	22-May-94	26.6	27.8	13.1	0
June	15-Jun-01	28.0	29.1	20.4	0
July	8-Jul-81	30.7	32.0	21.2	4
August	15-Aug-03	30.6	31.0	20.1	5
September	1-Sep-81	24.7	25.6	19.8	9

Source: Environment Canada

"Normal" Weather Scenario with Climate Change

Climate change is already affecting temperatures and hence electricity demand in Ontario: *"Between 1948 and 2008 the average temperature in Ontario has increased by up to 1.4°C"*[17].

The Ontario Ministry of Natural Resources (MNR) has developed projections of the impacts of future climate change for different eco-regions and areas in Ontario based on the outputs from two emission scenarios and using results from four different climate models[18] or GCMs (general circulation models). *"Projections of monthly temperature and precipitation were generated for each year over the period 2011-2100"*[19].

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17 Province of Ontario, "Climate Ready: Ontario's Adaptation and Strategy and Action Plan – 2011 – 2014", 2011, page 10.

[18] The four models used included: 1) the Canadian GCM, 2) the UK-based Hadley GCM, 3) the Australian-based Commonwealth Scientific and Industrial Research Organization (CSIRO) GCM and 4)the US-based National Center for Atmospheric Research (NCAR).

[19] Climate Change Research Report (CCRR16) – Current and Projected Future Climatic Conditions for Ecoregions and Select Natural Heritage Areas in Ontario, Ontario Ministry of Natural Resources, 2010.

The outputs of these models indicate that the impacts of climate change will become significant over the time period being considered for this forecast. *"For people living in an A2 world, most of southern Ontario will have summers that are 2 to 3°C warmer by mid-century and 4 to 5°C warmer by 2071"*[20].

The results project the impacts of climate change under two different emissions scenarios:

(1) Scenario A2, which "*assumes a higher human population, less-forested land, greater pollution, and higher carbon dioxide (CO2) emissions*", and

(2) Scenario B2 which "*assumes an acceleration of energy and resource conservation efforts during the early decades of this century, such that CO2 emissions will decline by mid-century*".

For the purposes of the sensitivity analysis, Navigant has used the conditions projected under Scenario A2 and the change projected for the period from 2011 to 2040 to calculate the potential impact of climate change over the 25-year forecast period. Scenario A2 was selected as being the most conservative in terms of estimating the potential impacts of climate change on the THESL system and as being more representative of the actual trajectory of emissions in the period since the report was issued.

The table below shows the results for six climate variables for the eco-region that includes Toronto (7E). These values were projected by the MNR for each of Ontario's eco-regions under scenario A2. The projections show projected temperature and precipitation impacts over three 30-year future periods compared to average conditions over the period from 1971 to 2000.

Table 7: Projected Change in Climate Variables for Toronto

	1971 200			2011 2040			2041 2070			2071 2100		
Description	**Min**	**Max**	**Mean**	**Min**	**Max**	**Mean**	**Min**	**Max**	**Mean**	**Min**	**Max**	**Mean**
Annual Mean temperature (AMT)	7.3	10	8.6	8.5	11.1	9.9	10	12.6	11.5	12.2	14.8	13.7
Maximum Temperature of the Warmest Month	25.8	28.8	27.1	28.8	30.6	29.4	29.9	32	30.7	32.5	34.8	33.3
Min. Temperature in Coldest Month (all minus/ -)	11.2	8	9.1	10.5	7.1	8.7	8.5	5.1	6.5	6.1	2.8	4.2

[20] Climate Change Research Report (CCRR-05) – Climate Change Projections for Ontario: Practical Information for Policymakers and Planners, Ontario Ministry of Natural Resources, 2007,

	1971 200			2011 2040			2041 2070			2071 2100		
Annual Precipitation	776	1012	911	777.5	1022	908	810.3	1067	940	809	1052	933.8
Precipitation in the Warmest Quarter	216	275	249	221	279	251.8	221	278	248.8	204	262	235.5
Precipitation in the Coldest Quarter	154	229	192	160	228	192.5	168	241	202.3	173	252	211.3
Change in Maximum Temperature	***-***	***--***	***-***	***3***	***1.8***	***2.3***	***1.1***	***1.4***	***1.3***	***2.6***	***2.8***	***2.6***

Source: Ontario MNR, CCRR-16 Appendix 1.

The MNR projection indicates that over the period from 2011-2040, the maximum temperature in warmest month is expected to increase by between 1.8 to 3°C. For the sensitivity analysis we have assumed the mean increase in projected maximum temperatures of 2.3°C.

As noted previously, temperature contributes to the peak demand forecast through the value of the THI. Also as noted earlier, the average temperature has been assumed to increase at a constant rate from 2011 to 2040 when it is assumed to be 2.3 degrees Celsius higher than under the “normal” scenario. Therefore, under the normal weather scenario with climate change, in any given year, the THI variable is increased by the number of degrees above normal that temperature is expected to be in that year, times 0.55 as indicated by the equation for calculating THI (see model specification discussion above for more detail).

“Extreme” Weather Scenario

Selection of the extreme weather scenario for each month proceeds in the same manner as selection of the normal weather scenario for steps 1 and 2. For step 3, however, rather than taking the median value within each month, the highest value is selected.

A summary of the temperature and other weather variables drawn from the days used for the “extreme” weather scenario is presented in Table 8, below.

Table 8: Summary Statistics From "Extreme" Weather Scenario Days, 11am – 5pm EST

Month	Date	Avg. Temperature	Max. Temperature	Avg. Dew Point	Avg. Cloud Opacity
May	30-May-06	31.8	32.8	21.3	4
June	19-Jun-95	33.9	35.1	20.0	0
July	21-Jul-11	36.6	37.5	23.9	5
August	1-Aug-06	35.4	36.4	23.4	3
September	10-Sep-83	32.1	33.3	18.9	3

Source: Environment Canada

5. THESL Peak Demand Forecast

Gross Forecast

The System Wide Gross Peak Demand Forecast for 2012 through 2036 is presented in the attached MS Excel spreadsheet. A summary of the forecast peak demand for Toronto Hydro's milestone years is summarized in Table 9 below. For each year, peak monthly demand for May, June, July, August and September was calculated, and the highest of these was selected as the peak summer demand. Given the parameter estimates in Table 2, and the monthly weather scenarios, the peak demand for each July became the peak annual value.

Table 9: System Wide Gross Peak Demand Forecast (MW) for THESL

	Normal Weather	Normal Weather w/ Climate Change	Extreme Weather
2012	4,815	4,830	5,433
2013	4,897	4,921	5,531
2014	4,980	5,012	5,630
2016	5,145	5,195	5,826
2018	5,246	5,314	5,942
2021	5,359	5,454	6,068
2031	5,739	5,932	6,493
2036	5,968	6,218	6,755

Source: THESL demand data, Environment Canada weather data,
City of Toronto population and employment data and Navigant analysis.

Note that the values shown above are for the gross peak demand, as it would occur without the demand reductions resulting from codes and standards put in place in 2006 or later, time-of-use rates, energy efficiency and demand response (both residential and otherwise) CDM programs or distributed generation.

Net Forecast

As described in section 1, Navigant used a method in which the demand reductions attributed to CDM and DG were removed from demand in the historic period in order to project a CDM/DG free "gross" forecast. This approach allows the projected impacts of CDM and DG to be treated explicitly over the forecast period.

Table 10 below shows the system-wide gross peak demand forecast presented above as well as the results for the "net" scenario we have named Scenario 1. This scenario is based on the extreme weather projection, but assumes current levels of DG and current approved CDM programs are continued. It should be noted that Scenario 1 also includes the on-going demand reductions projected to result from "historic" CDM programs operated prior to the forecast period. All of the projections of future CDM and DG impacts were provided to Navigant by THESL.

Table 10: System Wide Gross and Net Demand Forecasts for THESL

	Gross Demand			Net Demand
	Normal Weather	Normal Weather w/ Climate Change	Extreme Weather	**Scenario 1** *Extreme Weather Existing DG Current CDM*
2012	4,815	4,830	5,433	5,047
2013	4,897	4,921	5,531	5,071
2014	4,980	5,012	5,630	5,057
2016	5,145	5,195	5,826	5,344
2018	5,246	5,314	5,942	5,457
2021	5,359	5,454	6,068	5,607
2031	5,739	5,932	6,493	5,832
2036	5,968	6,218	6,755	6,078

Source: THESL demand data, Environment Canada weather data, City of Toronto population and employment data and Navigant analysis.

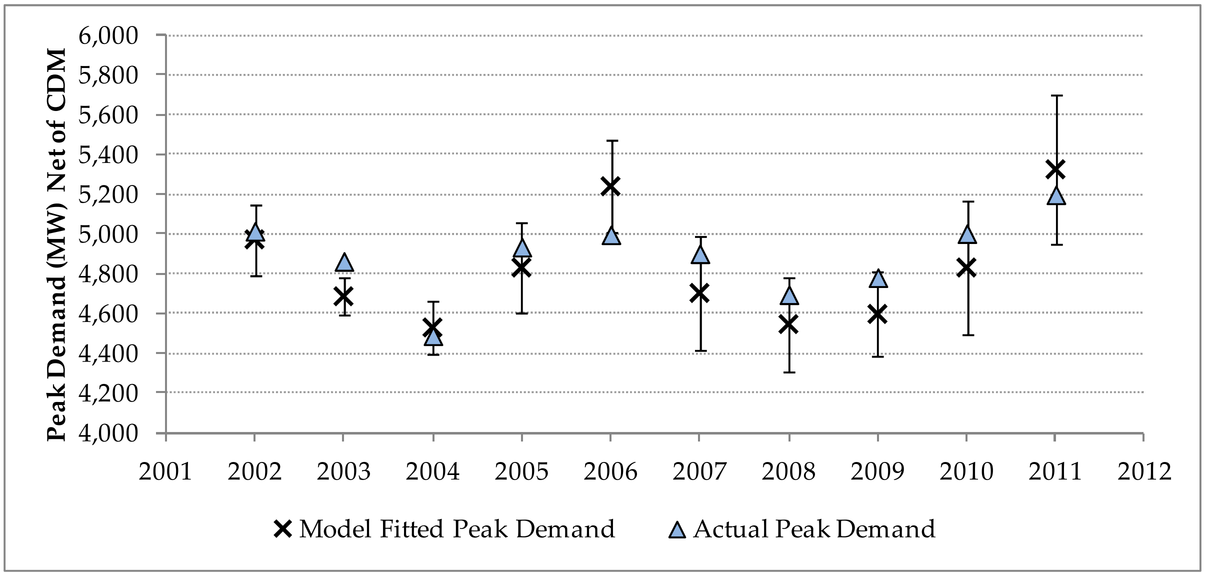
6. Summary of Results

Peak demand absent CDM was forecast based on the historic relationships between daily summer peak demand (absent the impacts of historic CDM) in the THESL system and: weather, levels of employment (in commercial and industrial sectors), population, the day of the week and the month of the year. These estimated relationships were then applied to three types of weather scenarios shown in Table 10. These weather scenarios were generated using the method outlined by the Independent Electricity System Operator (IESO) in its "Methodology to Perform Long Term Assessments" document[21] and through discussion between Navigant analysts and IESO staff.

The principal analytic tool used to generate the estimated forecast is a regression model that estimates the degree to which peak daily demand absent CDM is driven by a variety of economic, meteorological and other factors. This regression model was arrived at after a comparison of a number of possible model specifications and was subjected to a standard battery of statistical diagnostic tests to ensure its validity. These tests are all discussed in the body of this memorandum, below. One of the most important tests of model validity (certainly the most accessible for readers less familiar with econometrics) is simply to compare the model fitted values and the actual historical values. This comparison is made in Table 11, below.

[21] Independent Electricity System Operator, *Methodology to Perform Long Term Assessments*, June 2012. http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2012jun.pdf

Table 11: Historic Peak Demand (Absent CDM) vs. Fitted Peak Demand (Absent CDM).



Source: THESL demand data, Environment Canada weather data, City of Toronto population and employment data and Navigant analysis.

The error bars shown in Table 11 represent the fitted values obtained using the upper and lower 95% confidence intervals for all of the estimated parameters, calculated using heteroskedasticity and autocorrelation consistent (HAC) standard errors.

Note that Navigant's point estimates of historic peak demand (absent CDM) all fall very close to the observed actual historic peak demand, absent the impacts of CDM[22]. In only one case does the historic value fall outside the 95% confidence interval, and even in that case it remains very close to the point estimate. Note too that Navigant's estimates do not always either over-estimate or under-estimate the true impact but fluctuate, sometimes higher and sometimes lower than the true peak demand. The average absolute deviation of Navigant's estimates from the true values shown in Table 11 is less than 3%.

Again, the resulting projection of "gross" and "net" peak demand for the THESL service territory are shown in the table below.

[22] Note that the relative position of the observations on this chart would not change were CDM to be included – both fitted and actual observations would simply shift downward by the same amount of peak demand attributable to CDM in a given year.

Table 12: System Wide Gross and Net Demand Forecasts for THESL

	Gross Demand			Net Demand
	Normal Weather	Normal Weather w/ Climate Change	Extreme Weather	**Scenario 1** *Extreme Weather* *Existing DG* *Current CDM*
2012	4,815	4,830	5,433	5,047
2013	4,897	4,921	5,531	5,071
2014	4,980	5,012	5,630	5,057
2016	5,145	5,195	5,826	5,344
2018	5,246	5,314	5,942	5,457
2021	5,359	5,454	6,068	5,607
2031	5,739	5,932	6,493	5,832
2036	5,968	6,218	6,755	6,078

Source: THESL demand data, Environment Canada weather data, City of Toronto population and employment data and Navigant analysis.

Metro Toronto – Central IRRP

Appendix C: Conservation and Demand Management and Distributed Generation Forecast

Appendix C: Conservation and Demand Management Forecast

C.1 Toronto Hydro-Electric System Limited ("THESL") Station CDM Forecast

Table C-1: THESL CDM Forecast by Station (MW) – High Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	3.4	4.1	5.2	4.3	4.4	4.1	3.7	3.7	4.1
BRIDGMAN (115KV/13.8KV) TS	5.8	7.1	9.0	7.4	7.5	7.1	6.3	6.3	7.0
CARLAW (115KV/13.8KV) TS	8.4	10.2	12.9	10.7	10.8	10.2	9.1	9.1	10.1
CECIL (115KV/13.8KV) TS	7.9	9.6	12.1	10.1	10.1	9.6	8.5	8.6	9.5
CHARLES (115KV/13.8KV) TS	7.3	8.8	11.2	9.3	9.3	8.8	7.9	7.9	8.7
DUFFERIN (115KV/13.8KV) TS	7.8	9.4	11.9	9.9	10.0	9.4	8.4	8.4	9.3
DUPLEX (115KV/13.8KV) TS	10.4	12.7	16.0	13.3	13.4	12.7	11.3	11.3	12.5
ESPLANADE (115KV/13.8KV) TS	10.0	12.1	15.3	12.7	12.8	12.1	10.8	10.8	12.0
FAIRBANK (115KV/27.6KV) TS	18.9	22.9	29.0	24.1	24.2	22.9	20.5	20.5	22.6
GERRARD (115KV/13.8KV) TS	4.4	5.4	6.8	5.6	5.7	5.4	4.8	4.8	5.3
GLENGROVE (115KV/13.8KV) TS	6.2	7.6	9.6	7.9	8.0	7.6	6.7	6.7	7.5
HORNER (230KV/27.6KV) TS	8.6	10.5	13.2	11.0	11.1	10.5	9.3	9.3	10.3
LEASIDE (230KV/27.6-13.8KV) TS	13.1	15.9	20.2	16.7	16.8	15.9	14.2	14.2	15.7
MAIN (115KV/13.8KV) TS	5.6	6.8	8.6	7.2	7.2	6.8	6.1	6.1	6.7
MANBY (230KV/27.6KV) TS	11.7	14.3	18.0	15.0	15.1	14.2	12.7	12.7	14.1
RUNNYMEDE (115KV/27.6KV) TS	5.4	6.5	8.3	6.9	6.9	6.5	5.8	5.8	6.5
STRACHAN (115KV/13.8KV) TS	12.6	15.4	19.4	16.1	16.2	15.3	13.7	13.7	15.2
TERAULEY (115KV/13.8KV) TS	33.9	41.2	52.1	43.2	43.5	41.1	36.7	36.7	40.6
WILTSHIRE (115KV/13.8KV) TS	3.2	3.9	4.9	4.0	4.1	3.8	3.4	3.4	3.8
WINDSOR (115KV/13.8KV) TS	13.9	16.9	21.4	17.8	17.9	16.9	15.1	15.1	16.7
Copeland (Bremner) TS	0	0	0	0	0	0	0	0	0
Total 115 kV Stations	**165**	**201**	**254**	**211**	**212**	**200**	**179**	**179**	**198**
Total 230 kV Stations	**33**	**41**	**51**	**43**	**43**	**41**	**36**	**36**	**40**
Area Total	**199**	**241**	**305**	**253**	**255**	**241**	**215**	**215**	**238**

Note: Windsor TS is also referred to as "John TS"

The CDM forecast under a high demand scenario assumes the peak demand savings from all Conservation programs up to and including the end of 2014, persistence resulting from continued savings from all installed Conservation measures associated with these programs, and savings from present and future Codes and Standards.

Table C-2: THESL CDM Forecast by Station (MW) – Low Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	3.4	4.1	5.2	6.5	7.1	8.0	10.1	12.9	13.6
BRIDGMAN (115KV/13.8KV) TS	5.8	7.1	9.0	12.2	13.6	15.4	19.7	24.7	25.6
CARLAW (115KV/13.8KV) TS	8.4	10.2	12.9	12.7	13.4	13.8	14.4	16.8	18.1
CECIL (115KV/13.8KV) TS	7.9	9.6	12.1	15.4	17.1	19.2	24.4	30.7	31.9
CHARLES (115KV/13.8KV) TS	7.3	8.8	11.2	14.4	16.2	18.6	24.1	30.4	31.9
DUFFERIN (115KV/13.8KV) TS	7.8	9.4	11.9	12.7	13.5	14.0	15.6	18.1	19.1
DUPLEX (115KV/13.8KV) TS	10.4	12.7	16.0	16.2	17.1	17.6	19.2	22.3	23.8
ESPLANADE (115KV/13.8KV) TS	10.0	12.1	15.3	19.9	22.5	26.0	34.6	45.1	47.3
FAIRBANK (115KV/27.6KV) TS	18.9	22.9	29.0	29.0	30.4	31.2	33.4	38.0	40.4
GERRARD (115KV/13.8KV) TS	4.4	5.4	6.8	7.0	7.5	8.0	11.7	14.6	15.3
GLENGROVE (115KV/13.8KV) TS	6.2	7.6	9.6	9.8	10.4	10.8	12.0	14.1	14.9
HORNER (230KV/27.6KV) TS	8.6	10.5	13.2	14.8	15.8	16.7	19.1	21.9	23.1
LEASIDE (230KV/27.6-13.8KV) TS	13.1	15.9	20.2	21.2	22.5	23.7	26.8	31.7	33.3
MAIN (115KV/13.8KV) TS	5.6	6.8	8.6	8.6	9.0	9.2	9.7	11.3	12.3
MANBY (230KV/27.6KV) TS	11.7	14.3	18.0	20.2	21.6	23.0	26.7	32.7	34.3
RUNNYMEDE (115KV/27.6KV) TS	5.4	6.5	8.3	8.9	9.4	9.7	10.8	12.5	13.2
STRACHAN (115KV/13.8KV) TS	12.6	15.4	19.4	21.6	23.5	25.6	30.5	37.3	38.9
TERAULEY (115KV/13.8KV) TS	33.9	41.2	52.1	53.8	58.0	62.4	72.0	87.3	92.7
WILTSHIRE (115KV/13.8KV) TS	3.2	3.9	4.9	5.6	6.0	6.4	7.4	8.8	9.2
WINDSOR (115KV/13.8KV) TS	13.9	16.9	21.4	30.4	35.1	42.3	58.2	76.5	79.3
Copeland (Bremner) TS	-	-	-	5.0	6.7	9.5	17.2	23.4	22.8
Total 115 kV Stations	**165**	**201**	**254**	**290**	**316**	**348**	**425**	**525**	**550**
Total 230 kV Stations	**33**	**41**	**51**	**56**	**60**	**63**	**73**	**86**	**91**
Area Total	**199**	**241**	**305**	**346**	**376**	**411**	**497**	**611**	**641**

Note: Windsor TS is also referred to as "John TS"

The CDM forecast under a low demand scenario assumes the peak demand savings from all Conservation programs up to and including the end of 2014, the assumed peak demand reductions associated with all future planned Conservation, persistence resulting from continued savings from all installed Conservation measures associated with these programs, and savings from present and future Codes and Standards.

Table C-3: THESL CDM Forecast by Station (MW) – Median Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	3.4	4.1	5.2	4.3	4.4	5.1	7.1	7.9	8.5
BRIDGMAN (115KV/13.8KV) TS	5.8	7.1	9.0	7.4	7.5	9.2	13.5	14.9	15.7
CARLAW (115KV/13.8KV) TS	8.4	10.2	12.9	10.7	10.8	11.1	12.0	12.7	13.9
CECIL (115KV/13.8KV) TS	7.9	9.6	12.1	10.1	10.1	12.0	17.0	18.7	19.8
CHARLES (115KV/13.8KV) TS	7.3	8.8	11.2	9.3	9.3	11.2	16.4	18.0	19.2
DUFFERIN (115KV/13.8KV) TS	7.8	9.4	11.9	9.9	10.0	10.6	12.5	13.2	14.2
DUPLEX (115KV/13.8KV) TS	10.4	12.7	16.0	13.3	13.4	13.9	15.7	16.6	17.9
ESPLANADE (115KV/13.8KV) TS	10.0	12.1	15.3	12.7	12.8	15.5	23.3	26.1	27.8
FAIRBANK (115KV/27.6KV) TS	18.9	22.9	29.0	24.1	24.2	25.1	27.7	28.9	31.3
GERRARD (115KV/13.8KV) TS	4.4	5.4	6.8	5.6	5.7	6.0	8.4	9.2	9.7
GLENGROVE (115KV/13.8KV) TS	6.2	7.6	9.6	7.9	8.0	8.4	9.6	10.2	11.0
HORNER (230KV/27.6KV) TS	8.6	10.5	13.2	11.0	11.1	12.1	14.9	15.5	16.7
LEASIDE (230KV/27.6-13.8KV) TS	13.1	15.9	20.2	16.7	16.8	17.9	21.1	22.5	24.1
MAIN (115KV/13.8KV) TS	5.6	6.8	8.6	7.2	7.2	7.5	8.1	8.7	9.5
MANBY (230KV/27.6KV) TS	11.7	14.3	18.0	15.0	15.1	16.5	20.5	22.3	24.0
RUNNYMEDE (115KV/27.6KV) TS	5.4	6.5	8.3	6.9	6.9	7.4	8.7	9.1	9.8
STRACHAN (115KV/13.8KV) TS	12.6	15.4	19.4	16.1	16.2	17.9	22.6	24.4	25.9
TERAULEY (115KV/13.8KV) TS	33.9	41.2	52.1	43.2	43.5	46.3	54.9	59.0	63.5
WILTSHIRE (115KV/13.8KV) TS	3.2	3.9	4.9	4.0	4.1	4.5	5.7	6.1	6.5
WINDSOR (115KV/13.8KV) TS	13.9	16.9	21.4	17.8	17.9	23.0	37.3	42.0	44.1
Copeland (Bremner) TS	-	-	-	-	-	2.3	8.8	10.3	10.0
Total 115 kV Stations	**165**	**201**	**254**	**211**	**212**	**237**	**309**	**336**	**358**
Total 230 kV Stations	**33**	**41**	**51**	**43**	**43**	**47**	**56**	**60**	**65**
Area Total	**199**	**241**	**305**	**253**	**255**	**284**	**366**	**396**	**423**

Note: Windsor TS is also referred to as "John TS"

The CDM forecast under a median demand scenario assumes the peak demand savings from all Conservation programs up to and including the end of 2014, half of the assumed peak demand reductions associated with all future planned Conservation, persistence resulting from continued savings from all installed Conservation measures associated with these programs, and savings from present and future Codes and Standards.

C.2 THESL Distributed Generation Forecast by Station

Table C-4: THESL DG Forecast by Station (MW)

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
BRIDGMAN (115KV/13.8KV) TS	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
CARLAW (115KV/13.8KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CECIL (115KV/13.8KV) TS	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
CHARLES (115KV/13.8KV) TS	-	-	-	-	-	-	-	-	-
DUFFERIN (115KV/13.8KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
DUPLEX (115KV/13.8KV) TS	-	-	-	-	-	-	-	-	-
ESPLANADE (115KV/13.8KV) TS	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
FAIRBANK (115KV/27.6KV) TS	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
GERRARD (115KV/13.8KV) TS	-	-	-	-	-	-	-	-	-
GLENGROVE (115KV/13.8KV) TS	-	-	-	-	-	-	-	-	-
HORNER (230KV/27.6KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LEASIDE (230KV/27.6 - 13.8KV) TS	-	-	-	-	-	-	-	-	-
MAIN (115KV/13.8KV) TS	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
MANBY (230KV/27.6KV) TS	-	-	-	-	-	-	-	-	-
RUNNYMEDE (115KV/27.6KV) TS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
STRACHAN (115KV/13.8KV) TS	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
TERAULEY (115KV/13.8KV) TS	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
WILTSHIRE (115KV/13.8KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
WINDSOR (115KV/13.8KV) TS	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**	**21.5**

Note: Windsor TS is also referred to as "John TS"

Metro Toronto – Central IRRP

Appendix D: Detailed Load Forecast and Forecast Scenarios

Appendix D: Demand Forecast Scenarios

D.1 High Demand Forecast Scenario

High Demand Scenario (The THESL Station Forecast includes conservation program savings to 2015, codes and standards changes, and persistence of pre-2015 program savings thereafter).

Table D-1: THESL High Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	53	54	54	72	74	77	81	87	92
BRIDGMAN (115KV/13.8KV) TS	155	157	158	164	167	170	173	178	184
CARLAW (115KV/13.8KV) TS	67	67	65	71	74	78	74	82	88
CECIL (115KV/13.8KV) TS	157	157	157	164	166	171	177	185	192
CHARLES (115KV/13.8KV) TS	127	127	127	132	136	139	145	149	157
DUFFERIN (115KV/13.8KV) TS	122	123	122	128	132	133	137	141	145
DUPLEX (115KV/13.8KV) TS	103	103	103	110	113	116	121	128	133
ESPLANADE (115KV/13.8KV) TS	173	174	174	171	177	184	197	210	222
FAIRBANK (115KV/27.6KV) TS	184	184	182	196	199	203	209	215	220
GERRARD (115KV/13.8KV) TS	26	25	25	27	28	30	51	54	56
GLENGROVE (115KV/13.8KV) TS	60	60	59	64	66	68	71	75	77
HORNER (230KV/27.6KV) TS	140	167	167	175	178	182	188	184	190
LEASIDE (230KV/27.6-13.8KV) TS	152	153	153	164	168	175	183	191	196
MAIN (115KV/13.8KV) TS	71	71	71	61	63	67	66	74	80
MANBY (230KV/27.6KV) TS	231	207	208	220	225	231	240	260	269
RUNNYMEDE (115KV/27.6KV) TS	85	86	86	91	93	94	97	100	102
STRACHAN (115KV/13.8KV) TS	133	131	129	138	141	146	151	158	162
TERAULEY (115KV/13.8KV) TS	183	178	170	184	190	202	210	223	234
WILTSHIRE (115KV/13.8KV) TS	70	70	70	74	75	77	77	80	82
WINDSOR (115KV/13.8KV) TS	311	314	253	238	244	256	268	281	293
Copeland (Bremner) TS	0	0	63	102	102	102	113	113	113
Total 115 kV Stations	**2080**	**2081**	**2068**	**2187**	**2240**	**2313**	**2418**	**2533**	**2632**
Total 230 kV Stations	**523**	**527**	**528**	**559**	**571**	**588**	**611**	**635**	**655**
Area Total	**2603**	**2608**	**2596**	**2746**	**2811**	**2901**	**3029**	**3168**	**3287**

Notes: The Eglinton LRT project is expected to add an additional 18 MW of demand to Runnymede TS in the years after 2018.

Toronto Hydro estimates that an additional 90 MW of demand will materialize within the downtown area (in the vicinity of Copeland TS and Esplanade TS) in the near and medium-term, based on approvals for new buildings and developments.

Windsor TS is also referred to as "John TS"

D.2 Low Demand Forecast Scenario

Low Demand Forecast Scenario (includes conservation savings in the High Demand Scenario, and assumed peak demand savings resulting from the Province's commitment to long-term savings achievement under the Long Term Energy Plan).

Table D-2: THESL Low Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	53	54	54	70	71	73	75	78	83
BRIDGMAN (115KV/13.8KV) TS	155	157	158	159	161	162	160	160	165
CARLAW (115KV/13.8KV) TS	67	67	65	69	71	74	69	74	80
CECIL (115KV/13.8KV) TS	157	157	157	159	159	161	161	163	170
CHARLES (115KV/13.8KV) TS	127	127	127	127	129	129	129	126	134
DUFFERIN (115KV/13.8KV) TS	122	123	122	125	128	128	130	131	135
DUPLEX (115KV/13.8KV) TS	103	103	103	107	109	111	113	117	122
ESPLANADE (115KV/13.8KV) TS	173	174	174	164	167	170	173	176	187
FAIRBANK (115KV/27.6KV) TS	184	184	182	191	193	195	196	197	202
GERRARD (115KV/13.8KV) TS	26	25	25	26	26	27	44	44	46
GLENGROVE (115KV/13.8KV) TS	60	60	59	62	64	65	66	68	70
HORNER (230KV/27.6KV) TS	140	167	167	171	173	176	178	171	177
LEASIDE (230KV/27.6-13.8KV) TS	152	153	153	160	162	167	170	174	178
MAIN (115KV/13.8KV) TS	71	71	71	60	61	65	62	69	74
MANBY (230KV/27.6KV) TS	231	207	208	215	218	222	226	240	249
RUNNYMEDE (115KV/27.6KV) TS	85	86	86	89	91	91	92	93	95
STRACHAN (115KV/13.8KV) TS	133	131	129	133	134	136	134	134	138
TERAULEY (115KV/13.8KV) TS	183	178	170	173	175	181	175	172	182
WILTSHIRE (115KV/13.8KV) TS	70	70	70	72	73	74	73	75	77
WINDSOR (115KV/13.8KV) TS	311	314	253	226	227	231	225	220	230
Copeland (Bremner) TS	0	0	63	97	95	93	96	90	90
Total 115 kV Stations	**2080**	**2081**	**2068**	**2108**	**2136**	**2166**	**2172**	**2187**	**2280**
Total 230 kV Stations	**523**	**527**	**528**	**546**	**554**	**565**	**575**	**585**	**604**
Area Total	**2603**	**2608**	**2596**	**2654**	**2690**	**2731**	**2747**	**2772**	**2884**

Notes: The Eglinton LRT project is expected to add an additional 18 MW of demand to Runnymede TS in the years after 2018.
Toronto Hydro estimates that an additional 90 MW of demand will materialize within the downtown area (in the vicinity of Copeland TS and Esplanade TS) in the near and medium-term, based on approvals for new buildings and developments.
Windsor TS is also referred to as "John TS"

D.3 Median Demand Forecast Scenario

Median Demand Forecast Scenario (includes conservation savings in the High Demand Scenario, and half of the assumed peak demand savings resulting from the Province's commitment to long-term savings achievement under the Long Term Energy Plan).

Table D-3: THESL Median Demand Forecast Scenario

Station	2012	2013	2014	2016	2018	2021	2026	2031	2036
BASIN (115KV/13.8KV) TS	53	54	54	72	74	76	78	83	88
BRIDGMAN (115KV/13.8KV) TS	155	157	158	164	167	168	166	169	175
CARLAW (115KV/13.8KV) TS	67	67	65	71	74	77	71	78	84
CECIL (115KV/13.8KV) TS	157	157	157	164	166	169	169	175	182
CHARLES (115KV/13.8KV) TS	127	127	127	132	136	137	136	139	147
DUFFERIN (115KV/13.8KV) TS	122	123	122	128	132	132	133	136	140
DUPLEX (115KV/13.8KV) TS	103	103	103	110	113	115	117	123	128
ESPLANADE (115KV/13.8KV) TS	173	174	174	171	177	181	185	195	206
FAIRBANK (115KV/27.6KV) TS	184	184	182	196	199	201	202	207	211
GERRARD (115KV/13.8KV) TS	26	25	25	27	28	29	47	50	52
GLENGROVE (115KV/13.8KV) TS	60	60	59	64	66	67	68	72	73
HORNER (230KV/27.6KV) TS	140	167	167	175	178	180	182	178	184
LEASIDE (230KV/27.6-13.8KV) TS	152	153	153	164	168	173	176	183	188
MAIN (115KV/13.8KV) TS	71	71	71	61	63	66	64	71	77
MANBY (230KV/27.6KV) TS	231	207	208	220	225	229	232	250	259
RUNNYMEDE (115KV/27.6KV) TS	85	86	86	91	93	93	94	97	99
STRACHAN (115KV/13.8KV) TS	133	131	129	138	141	143	142	147	151
TERAULEY (115KV/13.8KV) TS	183	178	170	184	190	197	192	201	211
WILTSHIRE (115KV/13.8KV) TS	70	70	70	74	75	76	75	77	79
WINDSOR (115KV/13.8KV) TS	311	314	253	238	244	250	246	254	266
Copeland (Bremner) TS	0	0	63	102	102	100	104	103	103
Total 115 kV Stations	**2080**	**2081**	**2068**	**2187**	**2240**	**2276**	**2288**	**2376**	**2472**
Total 230 kV Stations	**523**	**527**	**528**	**559**	**571**	**582**	**591**	**611**	**630**
Area Total	**2603**	**2608**	**2596**	**2746**	**2811**	**2858**	**2878**	**2987**	**3102**

Notes: The Eglinton LRT project is expected to add an additional 18 MW of demand to Runnymede TS in the years after 2018.
Toronto Hydro estimates that an additional 90 MW of demand will materialize within the downtown area (in the vicinity of Copeland TS and Esplanade TS) in the near and medium-term, based on approvals for new buildings and developments.
Windsor TS is also referred to as "John TS"

Metro Toronto – Central IRRP

Appendix E: Technical Results – Deterministic and Probabilistic Assessments

Appendix E: Technical Assessment Results

The following tables present the detailed technical results of the assessments completed for the Central Toronto Integrated Regional Resource Plan.

Electrical system needs were assessed through tests defined in the IESO document Ontario Resource and Transmission Assessment Criteria ("ORTAC"), which establishes the planning criteria and assumptions to be used for assessing the adequacy and security of Ontario's electricity system.

In accordance with the ORTAC, the transmission system must be able to provide continuous supply following defined transmission and generation outage scenarios, as well as limit the amount of load loss and restoration time following the occurrence of multiple element outages. The defined outage scenarios are referred to as "contingencies." These contingency-based tests are deterministic in that they are assessed independent of the probability of their occurrence.

In addition to the ORTAC defined tests, a supplemental Probabilistic Reliability Assessment ("PRA") was conducted to test higher-order contingencies beyond those specified in the ORTAC.

All system tests were performed assuming summertime peak demand conditions under various load forecast scenarios that accounted for City of Toronto growth projections and different levels of achievement of CDM, including efficiency programs, pricing, building codes and efficiency standards.

The assessments were conducted using the software based modeling tool *Power System Simulator for Engineering* ("PSS®E") for deterministic AC contingency analysis. The PRA within PSS®E was used to estimate the risk related to higher-order contingencies up to the simultaneous loss of up to three system elements.

For the contingency-based tests, instances of criteria violations are shaded in Red. Other assessment results which have been highlighted, but that do not represent criteria violations, are shaded in Yellow.

Table E-1: Pre-contingency Conditions: All Transmission Elements In-service and Portlands Energy Centre In-service (@ 550 MW)

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby H1H4	Manby T1	N/A	2013	2013	2013	Load Curtailment	105 MW	Manby West 115 kV	118.7% 15-min LTR	*Short-term Emergency ratings ("STE")*	*Operational measures as solution for STE violation*
Manby A1H4	Manby T2	N/A	2013	2013	2013	Load Curtailment	95 MW	Manby West 115 kV	138.7% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
Manby H2H3	Manby T9	N/A	2013	2013	2013	Open Disconnects and restore unfaulted element(s)	N/A	Manby East 115 kV	91.7% 15-min LTR	*Flag Only: Does not violate Criteria*	
R15K	R2K	Richview x Manby	2018	2018	2026	N/A	N/A	N/A		*Long-term Emergency ratings ("LTE")*	
Manby H2H3	Manby T9	N/A	2018	2018	2036	Open Disconnects and restore unfaulted element(s)	N/A	Manby East 115 kV	100.7% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
C16L/C17L	Leaside T15	N/A	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Leaside 115 kV	73.4% 30-min LTR	*Flag Only: Does not violate Criteria*	
H9EJ	H2JK	Don Fleet x Esplanade	2026	2036	Beyond 2036	None	N/A	N/A	97.2% Loading in 2021	*LTE*	*Mitigated through load transfers*
H2JK	K13J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	99.3% Loading in 2026	*LTE*	
H2JK	K14J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	99.3% Loading in 2026	*LTE*	
H2JK	K6J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.6% Loading in 2026	*LTE*	
K6J	K13J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.8% Loading in 2026	*LTE*	
K6J	K14J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.8% Loading in 2026	*LTE*	
K6J	H2JK	Manby x Riverside	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.3% Loading in 2026	*LTE*	
Manby T1	Manby T12	N/A	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	98.0% Loading in 2026	*LTE*	
Manby T2	Manby T12	N/A	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	96.8% Loading in 2026	*LTE*	
C5E	H9EJ	Hearn x Esplanade	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	92.7% Loading in 2026	*LTE*	
K13J	K14J	Manby x Riverside	2036	Beyond 2036	Beyond 2036	None	N/A	N/A	97.7% Loading in 2031	*LTE*	
K14J	K13J	Manby x Riverside	2036	Beyond 2036	Beyond 2036	None	N/A	N/A	97.7% Loading in 2031	*LTE*	
H10EJ	H2JK	Don Fleet x Esplanade	2036	Beyond 2036	Beyond 2036	None	N/A	N/A	99.6% Loading in 2031	*LTE*	

Table E-2: Pre-contingency Conditions: All Transmission Elements In-service and Steam Turbine Generator Outage at Portlands Energy Centre (@ 160 MW), Dufferin TS on Leaside Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
C16L/C17L	Leaside T15	N/A	2013	2013	2013	Load Curtailment	110 MW	Leaside 115 kV	80.6% 30-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
C16L/C17L	H3L	Gerrard x Basin	2016	2016	2016	Load Curtailment Initiated	0 MW	Leaside 115 kV	50.5% 15-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
C16L/C17L	H1L	Gerrard x Basin	2016	2016	2016	Load Curtailment Initiated	0 MW	Leaside 115 kV	53.9% 15-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
C2L/C3L	Leaside T14	N/A	2016	2016	2016	Load Curtailment Initiated	0 MW	Leaside 115 kV	72.5% 30-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
C14L/C15L	Leaside T16	N/A	2018	2018	2018	Load Curtailment Initiated	0 MW	Leaside 115 kV	71.6% 30-min LTR	*Flag Only: Does not violate Criteria*	*Can be mitigated by transferring Dufferin TS*
None	Leaside T15	N/A	2026	2036	Beyond 2036	None	N/A	N/A	98.5 % Loading in 2021	*Continuous equipment ratings*	*Can be mitigated by transferring Dufferin TS*
C16L/C17L	Voltage Instability	Leaside 115 kV	2018+	2021	2031	None	N/A	N/A	N/A	*Voltage Criteria*	

Notes:
*Flagged Items are only changes to "All Elements In-service Precontingency and PEC @ 550 MW"
*No Flags beyond pre-contingency violation

Table E-3: Pre-contingency Conditions: All Transmission Elements In-service and Steam Turbine Generator Outage at Portlands Energy Centre (@ 160 MW), Dufferin TS on Manby Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby H2H3	Manby T9	N/A	2013	2013	2013	Load Curtailment	160 MW	Manby East 115 kV	133.5% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
C16L/C17L	Leaside T15	N/A	2016	2016	2016	Load Curtailment Initiated	0 MW	Leaside 115 kV	75.3% 30-min LTR	*Flag Only: Does not violate Criteria*	
K12W	K11W	Manby x Runnymede	2016	2016	2016	Load Curtailment Initiated	0 MW	Runnymede TS	81.4% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K11W	K12W	Manby x Runnymede	2016	2016	2016	Load Curtailment Initiated	0 MW	Runnymede TS	81.4% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K1W	K11W	Manby x Runnymede	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.2% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K1W	K12W	Manby x Runnymede	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.2% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K1W	K3W	Manby x St. Clair	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.7% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K3W	K11W	Manby x Runnymede	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.1% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K3W	K12W	Manby x Runnymede	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.1% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
K3W	K1W	Manby x St. Clair	2026	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	82.7% 15-min LTR	*Flag Only: Does not violate Criteria*	*Open LV breakers pre-contingency*
C14L/C15L	Leaside T16	N/A	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Leaside 115 kV	71.2% 30-min LTR	*Flag Only: Does not violate Criteria*	
None	Leaside T15	N/A	2031	Beyond 2036	Beyond 2036	None	N/A	N/A	93.2% Loading in 2026	*Continuous ratings*	
C16L/C17L	Voltage Instability	Leaside 115 kV	2026+	2031	Beyond 2036	None	N/A	N/A	N/A	*Voltage Criteria*	

Table E-4: Pre-contingency Conditions: Manby Transformer T1 Out-of-service Portlands Energy Centre In-service (@ 550 MW)

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby T2	Manby T12	N/A	2013	2013	2013	Load Curtailment	155 MW	Manby West 115 kV	140.5% 15-min LTR	*STE and Load loss*	*Can be mitigated by transferring loads*

Table E-5: Pre-contingency Conditions: Manby Transformer T1 Out-of-service , Portlands Energy Centre In-service (@ 550 MW), Copeland TS and half of Strachan TS on Leaside Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby T2	Manby T12	N/A	2013	2013	2013	Load Curtailment	105 MW	Manby West 115 kV	125.5% 15-min LTR	*STE*	*Load transfer once Copeland TS in-service*
Manby T2	Manby T12	N/A	2016	2016	2031	Load Curtailment	25 MW	Manby West 115 kV	92.7% 15-min LTR	*Flag Only: Does not violate Criteria*	
Manby T2	Manby T12	N/A	2021	2031	Beyond 2036	Load Curtailment	45 MW	Manby West 115 kV	101.2% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
Manby T2	Manby T12	N/A	2036	Beyond 2036	Beyond 2036	Load Curtailment	90 MW	Manby West 115 kV	141.9% 15-min LTR	*STE*	*Operational measures would satisfy ORTAC beyond study period*

Table E-6: Pre-contingency Conditions: Manby Transformer T1 Out-of-service , Portlands Energy Centre In-service (@ 550 MW), John TS and Copeland TS on Leaside Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
H10EJ	H9EJ	Hearn x Esplanade	2013	2013	2013	Load Curtailment	80 MW	John TS	94.6% 15-min LTR	*Flag Only: Does not violate Criteria*	
H10EJ	H9EJ	Hearn x Esplanade	2018	2018	Beyond 2036	Load Curtailment	120 MW	John TS	103.6% 15-min LTR	*STE*	*Operational measures as solution for STE violation*
H10EJ	H9EJ	Hearn x Esplanade	2021	2031	Beyond 2036	Load Curtailment	150 MW	John TS	108.0% 15-min LTR	*STE and Load Loss*	

Table E-7: Pre-contingency Conditions: Leaside Transformer T14 Out-of-service and Portlands Energy Centre In-service (@ 550 MW)

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
C16L/C17L	Leaside T15	N/A	2021	2031	Beyond 2036	Load Curtailment Initiated	0 MW	Leaside 115 kV	73.7% 30-min LTR	*Flag Only: Does not violate Criteria*	

Note: This scenario was determined to be far less limiting than considering PEC outages and was not pursued further for establishing needs

Table E-8: Pre-contingency Conditions: Manby Transformer T8 Out-of-service, Portlands Energy Centre In-service (@ 550 MW), Wiltshire TS on Leaside Supply

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
Manby T9	Manby T7	N/A	2013	2013	2013	Load Curtailment Initiated	0 MW	Manby East 115 kV	73.3% 15-min LTR	*Flag Only: Does not violate Criteria*	
Manby T9	Manby T7	N/A	2036	Beyond 2036	Beyond 2036	Load Curtailment	55 MW	Manby East 115 kV	91.9% 15-min LTR	*Flag Only: Does not violate Criteria*	

Table E-9: Additional Pre-contingency Outage Conditions Assessed with Portlands Energy Centre In-service (@ 550 MW)

Pre-contingency Outage	System Adjustment	Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
					High	Median	Low				1) Loading	2) Violation	3) Mitigation
L14W	Open breaker T11YH*	LxW (new)	L15W	Bayview x Bridgman	2013	2013	2013	None	47 MW	Bridgman (Conf)	83.7% 50-hr LTR	*Flag Only: Requires System Adjustment*	
L14W	Open breaker T11YH*	LxW (new)	L15W	Bayview x Bridgman	2036	Beyond 2036	Beyond 2036	Load Curtailment	55 + 10 MW	Bridgman (Conf)+further L/R	73.3% of 15-min LTR	*Flag Only: Requires System Adjustment + Control Action*	*Could open T12XH as well to drop load automatically following the second contingency*
L13W or L14W	None	L14W or L13W	L15W	Bayview x Bridgman	2036	Beyond 2036	Beyond 2036	Load Curtailment Initiated	0 MW	Bridgman	92.4% of 15-min LTR	*Flag Only: Requires Control Action*	
L9C or L12C	None	L12C or L9C	L4C	Leaside x Charles	2036	Beyond 2036	Beyond 2036	Load Curtailment Initiated	0 MW	Bridgman	84.3% 15-min LTR	*Flag Only: Requires Control Action*	
K1W or K3W	None	K11W or K12W	K1W or K3W	Manby x St Clair	2036	Beyond 2036	Beyond 2036	Load Curtailment Initiated	0 MW	Manby East 115 kV	80.2% 15-min LTR	*Flag Only: Requires Control Action*	
K6J or H2JK	Transfer Bremner to Leaside.	K13J or K14J**	K14J or K13J	Manby x Riverside	2018	2018	Beyond 2036	Load Curtailment Initiated	0 MW	Manby West 115 kV	84.5% 15-min LTR	*Flag Only: Requires System Adjustment + Control Action*	
K6J or H2JK	Transfer Bremner to Leaside.	K13J or K14J**	K14J or K13J	Manby x Riverside	2031	Beyond 2036	Beyond 2036	Load Curtailment	55 MW	Manby West 115 kV	101.0% 15-min LTR	*STE*	*Below 150 MW Operational measures as solution*

Notes:
*This system adjustment is required to allow load to be lost by configuration post-contingency.
**This scenarios was most limiting for Manby West 1+1 because Strachan is not able to be transferred to Leaside supply. Note - this state is more limited by N-1.

Application of Bulk Electric System Criteria

Table E-10: All Elements In-service Pre-contingency and PEC @ 550 MW

Contingency	Limiting Element	Limiting Section	Need Forecast Year Growth Scenarios			Control Action Required	Load Reduction Required	Load Reduction Station(s)	Notes:		
			High	Median	Low				1) Loading	2) Violation	3) Mitigation
H9EJ/H10EJ	H2JK	Don Fleet x Esplanade	2013	2013	2013	Load Curtailment	15 MW	Esplanade TS	55.9% 15-min LTR	*Flag Only: Does not violate criteria*	
Leaside L14L15	Bridgman HL12 HL78 + Bridgman T13	ΔV post-ULTC = 0.11 & 0.13 p.u. (Criteria = 0.05p.u.) + Bridgman T13	2013	2013	2013	Load Curtailment	35 MW	Bridgman TS	121.5% 15-min LTR	*Voltage Criteria, STE*	*Trip Breaker T13XH or T13YH to shed 50% load. Open Breaker Disconnect Switches to restore unfaulted element and restore load*
H6LC/H9EJ	H8LC	Cecil x Gerrard	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Cecil TS	66.4% 15-min LTR	*Flag Only: Does not violate Criteria*	
H6LC/H10EJ	H8LC	Cecil x Gerrard	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Cecil TS	62.4% 15-min LTR	*Flag Only: Does not violate Criteria*	
H8LC/H10EJ	H6LC	Cecil x Gerrard	2026	2036	Beyond 2036	Load Curtailment Initiated	0 MW	Cecil TS	62.4% 15-min LTR	*Flag Only: Does not violate Criteria*	
Cecil L8L12	H6LC	Cecil x Gerrard	2036	Beyond 2036	Beyond 2036	Load Curtailment Initiated	0 MW	Cecil TS	64.1% 15-min LTR	*Flag Only: Does not violate Criteria*	

Probabilistic Reliability Assessment Results (PRA)

- 65% Load Factor assumed at all busses
- 100 hours per year at peak loading conditions (when system is most at risk to post-contingency load shedding)
- Value of Lost Load (Value of Customer Reliability) assumed at $30 per kWh not supplied
- Probabilistic Input Data:
    - 115 kV circuits:
        - frequency of outages: 0.036 occurrences per km per year
        - average duration of outages: 1760 minutes per occurrence
    - 230 kV circuits:
        - frequency of outages: 0.018 occurrences per km per year
        - average duration of outages: 1275 minutes per occurrence
    - Step Down transformers (115 kV/13.8/27.6 kV):
        - frequency of outages: 0.36 occurrences per year
        - average duration of outages: 3735 minutes per occurrence
    - Autotransformers (230 kV/115 kV):
        - frequency of outages: 0.14 occurrences per year
        - average duration of outages: 3180 minutes per occurrence
- Shedding load is assumed to occur only following the contingency (not in preparation for the contingency)
- Shedding load is the only measure assumed to be available to relieve overloads
- System adjustments are not made to outage states as a mitigation measure
- Load is not restored until (coincident) outages are resolved
- Annualized Transmission Costs for the monetary estimates represent 7% of Capital Investment

PRA Summary Results

System Total Monetized Risk Over The Study Period (All values expressed in $millions)	
Total Capital Risk	83.5
Annual Average	5.85

SUB-SYSTEM BREAKDOWN

Leaside West		
	Expected Energy Lost by Configuration	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**1.31**	**0.00**
Capital Risk (M$)	**18.72**	**0.01**
Leaside East		
	Expected Energy Lost by Configuration	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**0.93**	**0.00**
Capital Risk (M$)	**13.33**	**0.00**
Leaside Radial - Bridgman, Dufferin, Duplex, Glengrove		
	Expected Energy Lost by Configuration	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**0.91**	**0.00**
Capital Risk (M$)	**12.95**	**0.01**
Manby West		
	Expected Energy Lost by Configuration	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**1.06**	**0.40**
Capital Risk (M$)	**15.16**	**5.69**
Manby East		
Buses	**Expected Energy Lost by Configuration**	**Expected Energy Lost by Shedding**
Annual (M$ @ 30$/kWh)	**1.02**	**0.22**
Capital Risk (M$)	**14.54**	**3.11**

PRA Detailed Station-by-Station Results

Leaside West		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, (MWh/a)**	**Expected Energy Lost by Shedding Evaluated At Peak, (MWh/a)**
Charles A1A2	3.67	0
Charels A3A4	3.78	0
Charles A5A6	4.97	0
Charles A7A8	4.02	0
Terauley A12	5.35	0
Terauley A34	4.83	0
Terauley A56	6.13	0.02
Terauley A78	4.6	0
Cecil A12	1.72	0
Cecil A34	1.9	0
Cecil A56	3.08	0
Cecil A78	3.44	0
Esplanade J12	7.28	0.00
Esplanade Q12	7.28	2.21
Esplanade A12	5.15	0.00
Total	67.2	2.23
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	1.3104	0.000763699
Capital Risk (M$)	**18.72**	**0.01**

Leaside East		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, MWh/a**	**Expected Energy Lost by Shedding Evaluated At Peak, MWh/a**
Basin A56	8.07	0
Basin A78	7.46	0
Carlaw A1A2	7.86	0
Carlaw A4A5	5.65	0
Carlaw A6A7	2.22	0
Gerrard A1A2	6.05	0
Main A1A2	5.98	0
Main A3A4	4.56	0
Total	47.85	0
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	0.933075	0
Capital Risk (M$)	**13.33**	**0.00**

Leaside Radial - Bridgman, Dufferin, Duplex, Glengrove		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, MWh/a**	**Expected Energy Lost by Shedding Evaluated At Peak, MWh/a**
Bridgman A12	5.14	0.01
Bridgman HL12	0.03	0.51
Bridgman HL56	1.77	0
Bridgman HL78	0.01	1.09
Dufferin A12	5.31	0.28
Dufferin A34	3.54	0.1
Dufferin A56	6.35	0.37
Dufferin A78	4.43	0.12
Duplex A1A2	3.37	0
Duplex A3A4	3.01	0
Duplex A5A6	4.19	0
Glengrove 12	2.37	0
Glengrove 34	3.17	0
Glengrove 56	3.79	0
Total	46.48	2.48
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	0.90636	0.000849315
Capital Risk (M$)	**12.95**	**0.01**

Manby West		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, MWh/a**	**Expected Energy Lost by Shedding Evaluated At Peak, MWh/a**
John AB	3.29	166.48
John B1	3.29	164.6
John A1112	1.54	0
John A13	2.07	1.52
John A1516	2.49	164.22
John A1718	2.49	154.56
Strachan A12	9.62	3.16
Strachan A34	7.39	0
Strachan A56	7.83	0.02
Strachan A78	7.83	0.02
Bremner A	4.06	342.38
Bremner B	2.51	166.38
Total	54.41	1163.34
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	1.060995	0.39840411
Capital Risk (M$)	**12.95**	**5.69**

Manby East		
Buses	**Expected Energy Lost by Configuration Evaluated At Peak, MWh/a**	**Expected Energy Lost by Shedding Evaluated At Peak, MWh/a**
WILTSHIR_A12	1.85	0
WILTSHIR_A34	2.02	0
WILTSHIR_A56	2.89	0
Fairbank BQ	16.63	0.41
Fairbank YZ	17.47	635.09
Runnymede	11.34	0.29
Total	52.2	635.79
Load Factor/ Percent of Time	***0.65 (100 hours/year at peak loading)***	0.011415525
Annual Risk (M$ @ 30$/kWh)	1.0179	0.217736301
Capital Risk (M$)	**14.54**	**3.11**

Metro Toronto – Central IRRP

Appendix F: Review of Power System Reliability Standards in Major Metropolitan Areas

Appendix F: Review of Power System Reliability Standard for Major Metropolitan Areas

F.1 Introduction and Background

In recognition of the potential high consequences of electricity service interruptions in high density urban areas, the IESO undertook a review of power system planning standards used by utilities in other jurisdictions, to determine if special consideration was given to supply standards in these areas.

The review focused specifically on:

a. whether other jurisdictions apply higher standards in high density urban areas, as compared to the rest of the electricity system, and
b. where higher standards are applied in these urban areas, how is the higher standard achieved?

The purpose of this review was to:

- Identify if planning to achieve higher levels of electricity service reliability is a common utility practice for densely populated urban areas within other jurisdictions, and
- Inform the Central Toronto Integrated Regional Resource Plan ("IRRP") assessments of needs and options.

Early discussions of the Central Toronto IRRP Working Group were focused on determining whether there are reasonable grounds for adopting higher reliability standards for the Central Toronto area. Within the context of a regional planning study, higher reliability standards would require applying power system planning criteria which are more stringent than those typically used in Ontario. Since the Central Toronto area is an economic centre with high density commercial and residential development, government and institutional customers, a review of electricity industry practices used in by utilities in other high density urban areas was considered a prudent course of action in supporting the IRRP analysis.

In Ontario, the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") specifies the specific contingencies to be applied in planning studies for the power system. Sections 2 through 7 of ORTAC provide details on the types of technical studies which must be carried out to assess the adequacy of the grid and to ensure reliability of the electric system.

ORTAC also addresses load security and restoration capability of the system. It should be noted that the power system serving the Central Toronto area is composed of both Bulk Power System facilities (as described in Section 2.7.1 of ORTAC) and Local Area facilities (as described in Section 2.7.2 of ORTAC). In general, Bulk Power needs are determined based on the occurrence of double element contingencies, whereas Local Area needs are typically assessed under single element contingencies. This higher standard for the Bulk Power system is in part related to the greater system-wide consequences and the need to avoid impacts on neighbouring jurisdictions.[1]

The sections that follow present a summary of findings of the review of other jurisdictions, and the resulting considerations for the Central Toronto IRRP assessment.

F.2 Summary of Reliability Planning Standards for Urban Areas

The IESO reviewed several utility industry professional papers and published reliability standards associated with planning practices used by utilities in other regulatory jurisdictions around the world. The focus of this review was to establish the extent to which other utilities plan to higher reliability standards in metropolitan areas. Specific details on planning standards and/or practices for urban areas were not found for many jurisdictions.

Some jurisdictions were found to give explicit consideration to planning for higher reliability in the Central Business Districts ("CBD") than in other parts of their electric power systems. Across the literature, high density urban areas are commonly referred to as the "Central Business District," and they are typically a part of larger metropolitan area. A small number of examples were also found for electricity infrastructure projects that obtained regulatory approval based on the rationale of providing better service to customers in urban areas.

Finding 1: Some jurisdictions conduct planning to meet higher reliability standards in large urban areas; however, the majority of jurisdictions reviewed do not

A survey completed by Cigré[2] entitled Maintenance of Acceptable Reliability in an Uncertain Environment (2007) reported that 36% of respondents indicated that the reliability standards

[1] Due to security concerns, in recent years many jurisdictions have not published specific technical information related to the makeup of their electric power systems.
[2]International Council on Large Electric Systems (Cigré) is an international not for profit association for promoting collaboration with a network of 3,500 electricity experts working to improve electric power systems of today and tomorrow.

were higher for CBDs in urban areas than for the rest of the system. The following table summarizes the responses.

Country	**Central Business District (CBD)**	**Responded that CBD planned to higher reliability than rest of system?**
France	Paris	Yes
USA	unspecified	Yes
Japan	Osaka, Kyoto, Tokyo	Yes
Portugal	Lisbon	Yes
Canada	Ottawa	No
Hungary	unspecified	No
Russia	Moscow	No
Northern Ireland	unspecified	No
South Africa	Pretoria	No
Belgium	unspecified	No
Switzerland	unspecified	No

In addition to the nations surveyed for the Cigré report, a small number of other jurisdictions have given consideration to planning for higher levels of reliability service in urban areas. In New York City, for example, Consolidated Edision specifically plans for better reliability in the inner urban areas, such as for transmission load areas in lower Manhattan and surrounding boroughs. This is accomplished by designating the transmission load areas that are planned to a double contingency standard as opposed to a single contingency standard. This practice is intended to reflect the sensitivity and density of customers in these areas.

In Canada, no jurisdictions have been found that plan for higher load security in CBDs than in other areas. An exception to this rule is a project that was developed in downtown Vancouver (Cathedral Square Substation), which was cost justified based on the risk of extended electricity service disruption within the urban area. This project is discussed in the next section.

Additional notes on planning standards applied in other jurisdictions are provided in Table F-1. While some jurisdictions explicitly define higher standards in CBDs, the evidence indicates that this is not a common utility practice.

Finding 2: Jurisdictions that plan for higher reliability in urban areas do not typically rely solely on deterministic reliability criteria; rather, probabilistic assessments are used to compare the economic costs and benefits

Several Australian jurisdictions also plan for better load security in CBDs. This is typically done through a combination of deterministic and probabilistic approaches. In the State of Victoria, this planning practice is based primarily on probabilistic economic analyses. This process is described in greater detail by the Australian Energy Regulator:

> "There are no pre-determined reliability criteria for planning done on an economic basis. In these cases the economic costs and benefits are assessed and an investment only proceeds if the benefits outweigh the costs. Victoria currently uses this approach. The Value of Customer Reliability metric[3] ("VCR") is therefore critical to this planning approach, since the estimated value of a reliability improvement is pitted directly against its cost to determine whether or not an augmentation will be carried out. Victoria is the only jurisdiction undertaking purely economic assessment of transmission investments. Victoria does not rely on deterministic standards for transmission investments that are primarily intended to deliver reliability outcomes. Therefore Victoria has the greatest reliance on an accurate regional estimate of VCR. Arguably it already has existing estimates that meet this criterion (see CRA, 2002 and 2008)."[4]

An example project that was assessed on this probabilistic basis is the Regional Victorian Thermal Capacity Upgrade.[5] The consequence of the "do nothing" scenario was initially calculated by considering the amount of energy which would have to be rejected to meet thermal limits over the course of a year, which was monetized using the VCR metric. This cost increased each year, commensurate with the affected area's demand forecast. A detailed assessment was carried out on all credible options, including a Net Present Value analysis to determine net market benefit under different sensitivity scenarios. The final recommendation included a new and upgraded circuit. The new circuit was approved, and the second upgraded circuit was placed on hold pending further assessment.

[3] $61,960/MWh in 2013-14 $AUS

[4] http://www.aemo.com.au/planning/0400-0032.pdf

[5] http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Regional-Victorian-Thermal-Capacity-Upgrade

In the City of Vancouver, the rationale used to justify the business case for the Cathedral Square substation, which supplies about one-third of downtown Vancouver's load, was based on an economic evaluation of the incremental reliability benefits to affected customers.[6] The original transformer station consisted of two parallel transformers in an underground facility. Studies indicated that following the outage of one transformer, the remaining unit could still supply the area. However the loss of both would interrupt supply until one could be repaired or replaced. Given the age and configuration of this station, the repair/replacement time was estimated at up to 2 years, depending on the type of failure. Since deterministic planning did not require consideration of a contingency this severe, probabilistic planning was applied, given the potential consequences to customers.

Based on the probabilistic analysis, BC Hydro determined it to be cost effective from a societal perspective to invest in a third transformer, thereby reducing the probability of simultaneous loss of all transformers. The British Columbia Utilities Commission approved the expenditure and the probabilistic analysis was integral to the business case submitted to the regulator.

As mentioned earlier, the deterministic standards typically used by BC Hydro were supplemented by using probabilistic planning to support rationale for expansion of the Cathedral Square Substation.

Finding 3: Jurisdictions that plan for higher reliability in urban areas tend to plan transmission and distribution systems in a highly coordinated fashion

In the Cigré study, all of the jurisdictions that planned for higher reliability for CBDs, and several that did not, indicated that the transmission standards for CBDs are coordinated with those for distribution systems to achieve better overall system performance. The responses indicated that coordination of transmission and distribution system development results in better overall system reliability.

Of the countries that indicated CBD standards were higher than for the rest of the system, France explained that planning to an N-2 security standard is specific to Paris, and that in case of loss of supply to any "C-type" substation (225kV/20kV step-down station), while the nearest one is under maintenance, the system has been designed so that the whole load of both substations can be supplied via the distribution network. This level of security is made possible

[6] http://transmission.bchydro.com/nr/rdonlyres/86da00e7-105f-4f72-8d3c-342c06919b8e/0/oorareliabilityassessmentofcathedralsquaresubstation.pdf

only by distribution ties between step-down stations. The distribution network between transmission stations provides security of supply for any substation from the nearest one. This N-2 security standard is quite specific to Paris. Further, like in most jurisdictions, it is recognized that some load will be lost in the event of multiple element contingencies. In Paris, 40% of the lost load must be restored within 30 minutes after the N-2 incident.

Finding 4: Planning entities rely on a range of options to achieve higher reliability service levels in urban areas

In the Cigré study, 55% of respondents indicated that Special Protection Systems ("SPS") are a part of normal system planning. This indicates that it is generally good utility practice to implement SPSs designed to take corrective action in the event of low probability system contingencies. Schemes of this nature minimize the risk to customers and represent a cost effective alternative to additional infrastructure. SPSs can be implemented quickly and are generally much more cost effective than infrastructure for addressing the impact of contingencies that have a low probability of occurrence.

Other jurisdictions have policies to target location of generation resources in close proximity to, or within, major urban centres. An example is New York City, where an internal generation of 80% of the load is targeted.

Finding 5: It is generally cost prohibitive to achieve load security to ensure full redundancy to withstand a double element contingency without load loss

Where higher standards have been applied, such as N-2 security (e.g., two power system elements out of service simultaneously), the rationale typically employs an economic cost – benefit component. This is accomplished by establishing the incremental cost of investments to achieve better reliability, and comparing these costs to the economic benefit of the change from the status quo. This recognizes that (a) modern power systems planned to N-1 security provide generally high levels of reliability, (b) achieving full N-2 security would come at a very high cost, and (c) 100% reliability is unachievable at any cost. Since the likelihood of N-2 contingencies occurring is low, probabilistic planning methods and value to customer concepts are used to rationalize expenditures which cover these contingencies.

Typical planning studies considering higher reliability levels for specific areas are based on the consideration of a greater number of contingencies than are required to be assessed in other areas served by the utility. Since these additional contingencies (for example, N-2) tend to have a much lower probability of occurring, planning techniques which account for the probability of occurrence (probabilistic methods) are used in addition to the more traditional deterministic studies. The document *TransGrid FINAL REPORT - Review of the MetroGrid Project: Context and Conceptual Design,* (2004) provides a good example of the concept of Cost / Benefit Analysis and network reliability standards within the electric utility industry. The report identifies steps that a prudent operator would have completed in applying a network reliability standard in the Sydney inner metropolitan area. In this report, a prudent operator would have:

- monitored compliance with existing standards;
- assessed the implications (economic and otherwise) of a loss of supply;
- reviewed existing network reliability standards against the above, mindful of international practice;
- if appropriate, recommended and implemented an increase to the standard;
- selected an appropriate option to meet any increase in (or maintain compliance with existing) the standard; and
- put in place a long term plan to maintain reliability and cover any extra contingencies.

F.3 Summary of Assessment Method Used in the Central Toronto IRRP

Based on the above international review of good utility practices for planning large urban areas, the IESO applied the following methodological enhancement for the Central Toronto IRRP. This was developed in consultation with the members of the Working Group, including Toronto Hydro and Hydro One.

1. Assess system performance as per the applicable minimum standards (e.g., ORTAC)
2. Identify where the current system design exceeds the standard, and instances in which the current system performance would degrade given future loadings
3. Review the reasonableness of strict application of the criteria across the study area and make any additional assessments that ensure that all downtown customers are considered equitably, for example, by applying bulk power system standards to certain facilities classified as local area supply
4. Conduct a probabilistic reliability assessment considering up to N-3 element outages and using best available information on outage rates, duration, and value of customer reliability
5. Assess the impact of specifically identified extreme contingencies. These low-probability high-impact events are unlikely to occur, however given that they would result in widespread and / or long-duration outages they have been investigated

including in detail including the time required to restore service given the current operational flexibility within the system.

Table F-1: Transmission Planning Standards in Select Major Metropolitan Areas

Jurisdiction	Planning standard for the urban centre / Central business district	Notes on criteria generally applied in the urban centre
France - Paris	N-2 standard is specific to Paris, and is achieved through coordination with distribution, N-2 is achieved through ability to transfer loads via distribution between substations	N-2 for transmission and distribution together, restoration requirement for 40% of lost load to be resupplied within 30 minutes after the incident
USA – New York City	In addition to the NPCC Regional standards, ConEdison has specified some Manhattan and area transmission load areas (stations, u/g cables) that are planned to a double contingency	N-2 for designated parts of the system which are non-bulk; No additional information regarding use of SPSs or restoration standards; New York City has also had strong policies supporting an 80% supply from in-city generation
Great Britain - London	Demand connection criteria specify the amount of allowable load loss and restoration requirements for an unplanned single element outage or an unplanned outage while an element is out for maintenance; Lower levels of load loss and immediate restoration required for larger demand groups, regardless of the type of demand	Switching / transfers allowable responses, immediate restoration for larger demand groups; criteria allow for higher criteria to be applied subject to an economic assessment
Japan - Osaka, Kyoto, Tokyo	No interruption permitted for N-1. N-2 is taken into consideration for large cities with temporary interruption allowable and resumption of service as soon as possible	SPSs normal part of system planning but must also be backed up to meet the N-2 condition (e.g., backup for protection devices); Allowable interruption time in central part of big cities is set within 30 minutes to 2.5 hours depending on the demand density and demand importance
Canada - Vancouver	Same as in rest of the province	N-1 is the standard applied; investments for higher reliability have been successfully rationalized with economic Cost / Benefit using probabilistic studies
Australia – Sydney	"Modified N-2" standard applied only to the Central Business District; Operator plans to N-2 subject to an economic Cost / Benefit where the benefits must outweigh the costs	N-2 unless the cost of achieving N-2 reliability exceedingly high

Metro Toronto – Central IRRP

Appendix G: Summary of Asset Condition and Sustainment Plans

9 October 2012

Summary of Asset Condition and Sustainment Plans for the Leaside and Manby 115kV System

Prepared by:
Transmission System Development

With input from:
Station and Line Sustainment

Hydro One Networks

1. Introduction:

This filing memorandum provides a summary of aging profile of major facilities in the Leaside TS and the Manby TS 115kV system and identifies any planned refurbishment work over the next five years (2013-2017). Asset condition assessment and Information on refurbishment plans was provided by Stations and Line Sustainment Departments.

The previous memorandum on the subject (issued in 2007) had indicated that a significant number of HV circuit breakers and underground cables were approaching end of useful life and required refurbishment. The memorandum also identified 115kV cables requiring replacement. Since then Hydro One has initiated significant capital replacement/refurbishment work in the Toronto Area and most of the previously identified work is expected to be completed by the end of 2014.

2. Facilities Considered:

The following facilities were considered:

1. 230/115V Autotransformers
2. 230kV and 115kV Breakers
3. Switchyard insulators and other bus work
4. 115kV switches
5. 115kV overhead lines
6. 115kV underground cables

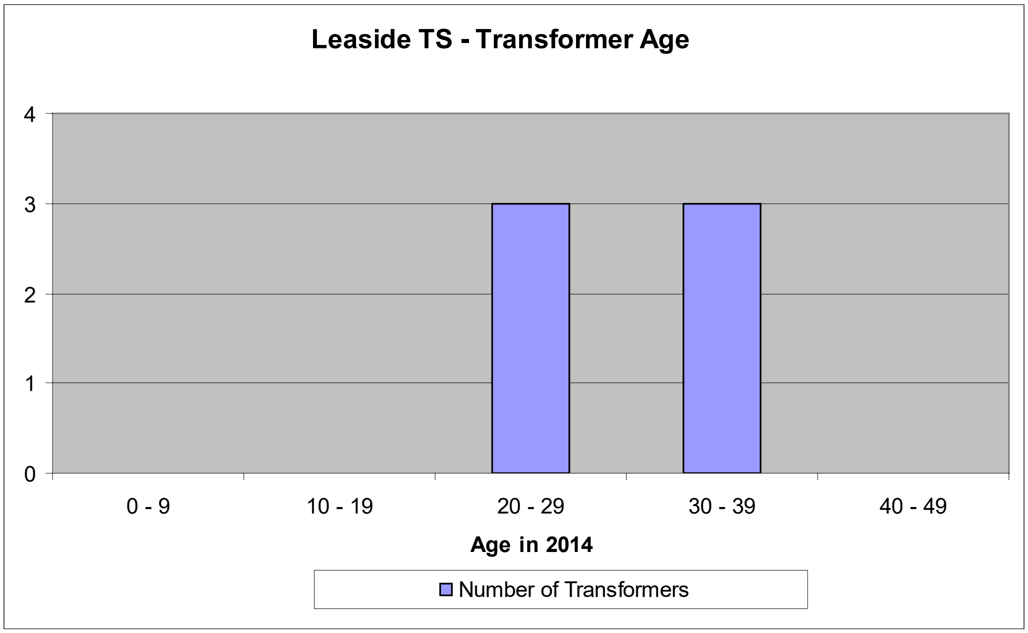
Other facilities such as P&C systems, grounding systems, station civil facilities, station service facilities etc. were not considered since the work can be scheduled without having a critical impact on the system. DESN station transformers and low voltage switchgear were also not covered since the impact is local.

3.0 Stations

3.1 Leaside TS:

Autotransformers:

Leaside TS has six autotransformers with an age distribution as shown in the chart below.

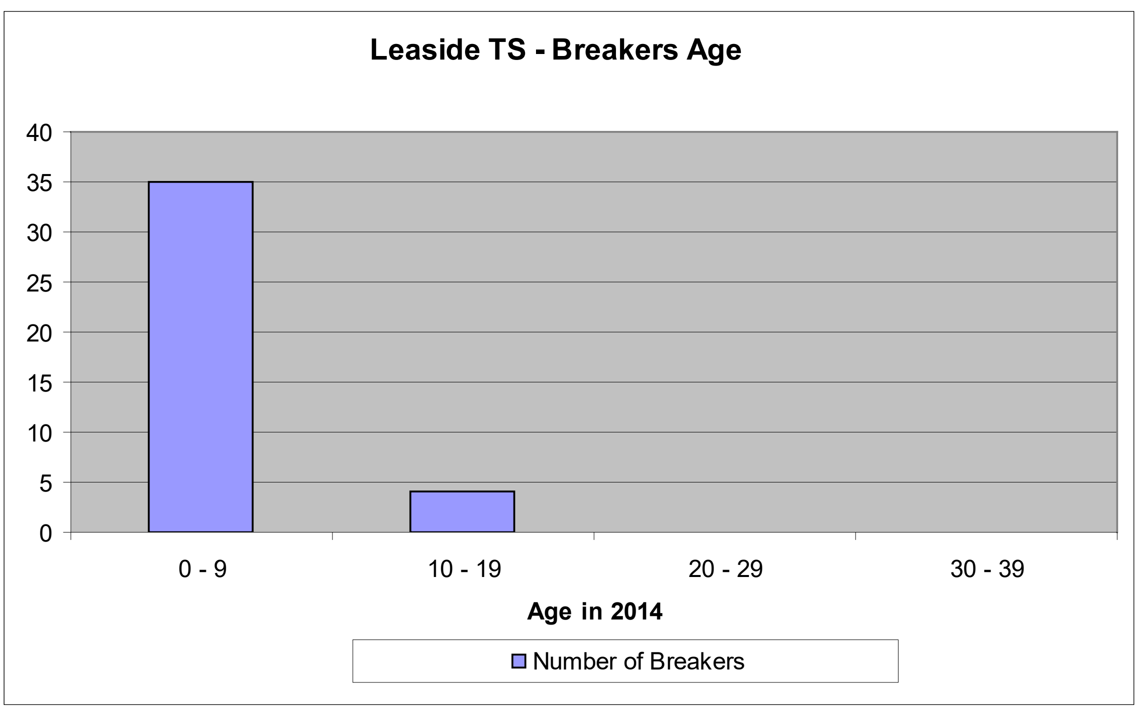


There are no current plans to carry out any major transformer refurbishment work over the next 5 years. However, work may be scheduled beyond that period.

Circuit Breakers – 230 kV and 115kV:

Leaside TS has 3 x 230kV breakers and 36 x 115kV breakers. Eight of the 115kV breakers (used for cap bank switching) and the 230kV breakers have been replaced since 2003. Work is now underway on replacement of all the remaining 115kV breakers by December 2014.

The expected 2014 age profile of Leaside TS breakers is illustrated in the following graph.



Switchyard Insulators, Bus work etc.

The bus work and insulators in the 115kV yard have been reviewed and will be replaced or upgraded as required along with the 115kV breaker upgrade work.

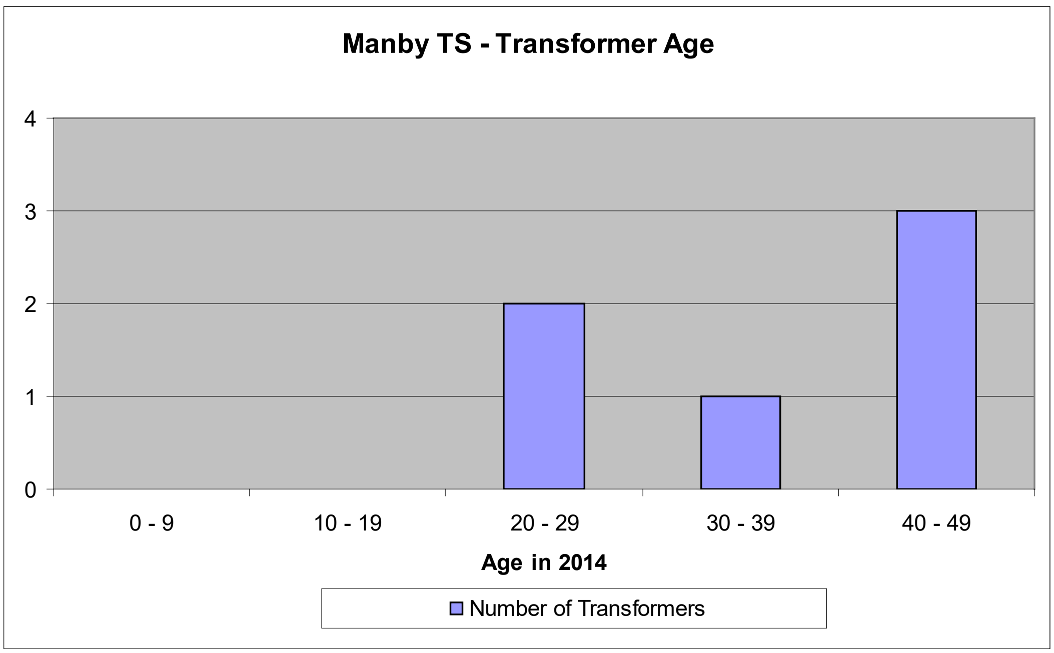
Line and Disconnect Switches – 230kV and 115kV

There are a total of 121 switches at both 230kV and 115kV level, the majority of them over 40 years old. However, the switches are in fair shape and there are no plans to carry out any refurbishment over the next five years.

3.2 Manby TS

Autotransformers:

Manby TS has six autotransformers with an age distribution as shown in the following chart.

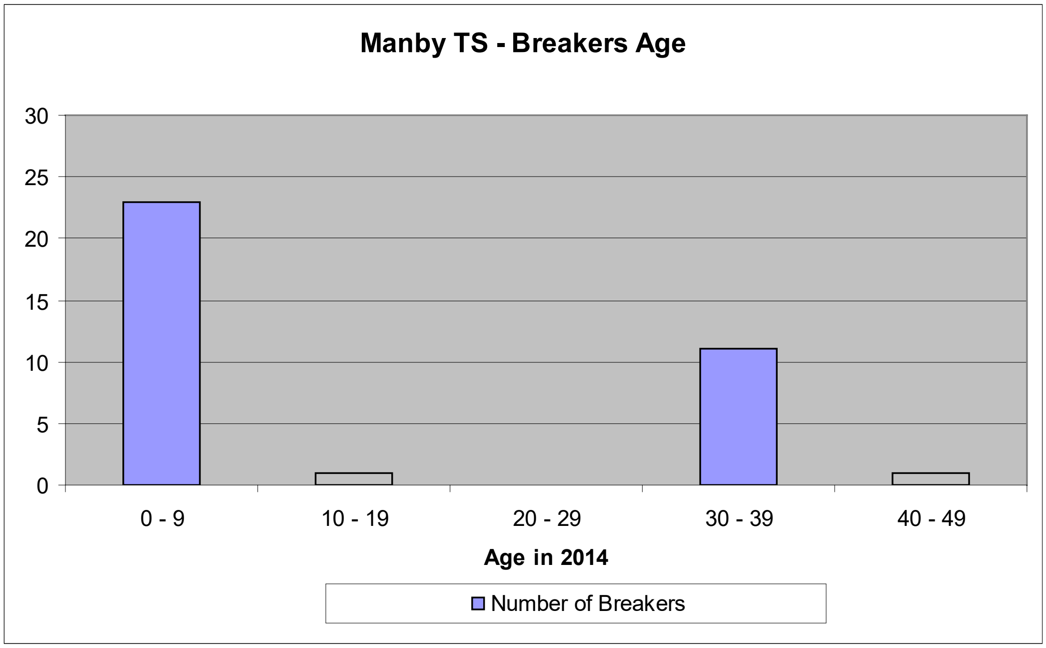


There are no current plans to carry out any major transformer refurbishment work over the next 5 years. However, work may be scheduled beyond that period.

Circuit Breakers – 230 kV and 115kV:

Manby has 18 x 230kV breakers and 18 x 115kV breakers. All except two of the 115kV breakers are oil breakers and these are being replaced under the Manby TS 115kV switchyard upgrade project. The expected date for the Manby breaker replacement work is Dec. 2014.

The expected 2014 age profile of Manby TS breakers is illustrated in the following graph.



Switchyard Insulators, Bus work etc.

There are cap and pin insulators at Manby TS that require replacement. These are being replaced along with the breaker replacement work at the station.

Line and Disconnect Switches – 230kV and 115kV

There are a total of 129 switches at both 230kV and 115kV level, the majority of them over 45 year old. All 115kV switches will be replaced at Manby TS.

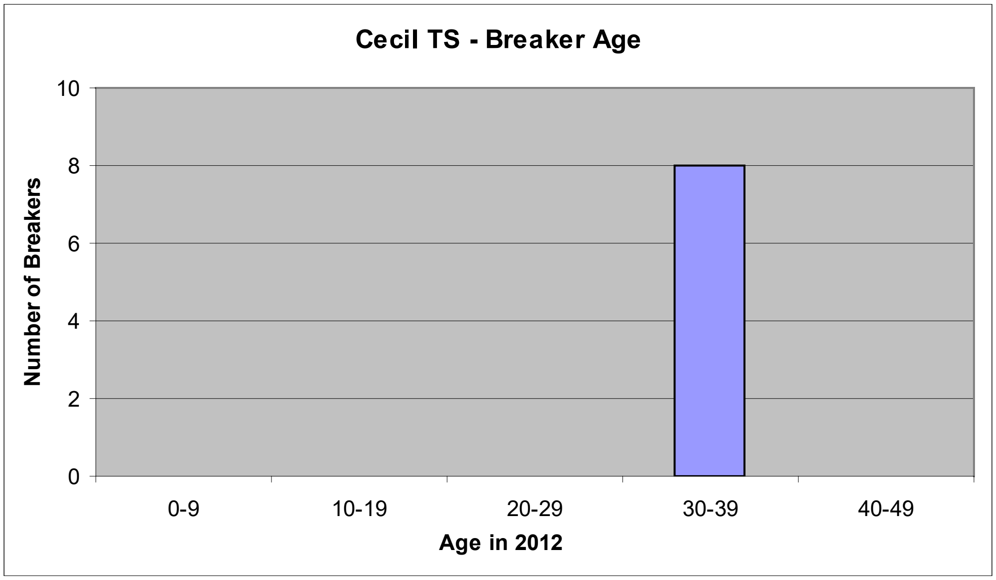
3.3 Hearn TS

Circuit Breakers – 115kV, Line and Disconnect switches, Switchyard Insulators, Bus work etc.

The entire existing 115kV switchyard – including breakers, switches, insulators and bus work - is being replaced with a new GIS indoor switchyard. The expected in-service date is Feb. 2014.

4.0 Cecil TS

Cecil TS is an indoor station and has 8 x 115kV GIS breakers and a 115kV GIS duct ring bus. The age distribution of these breakers is shown in the following graph.



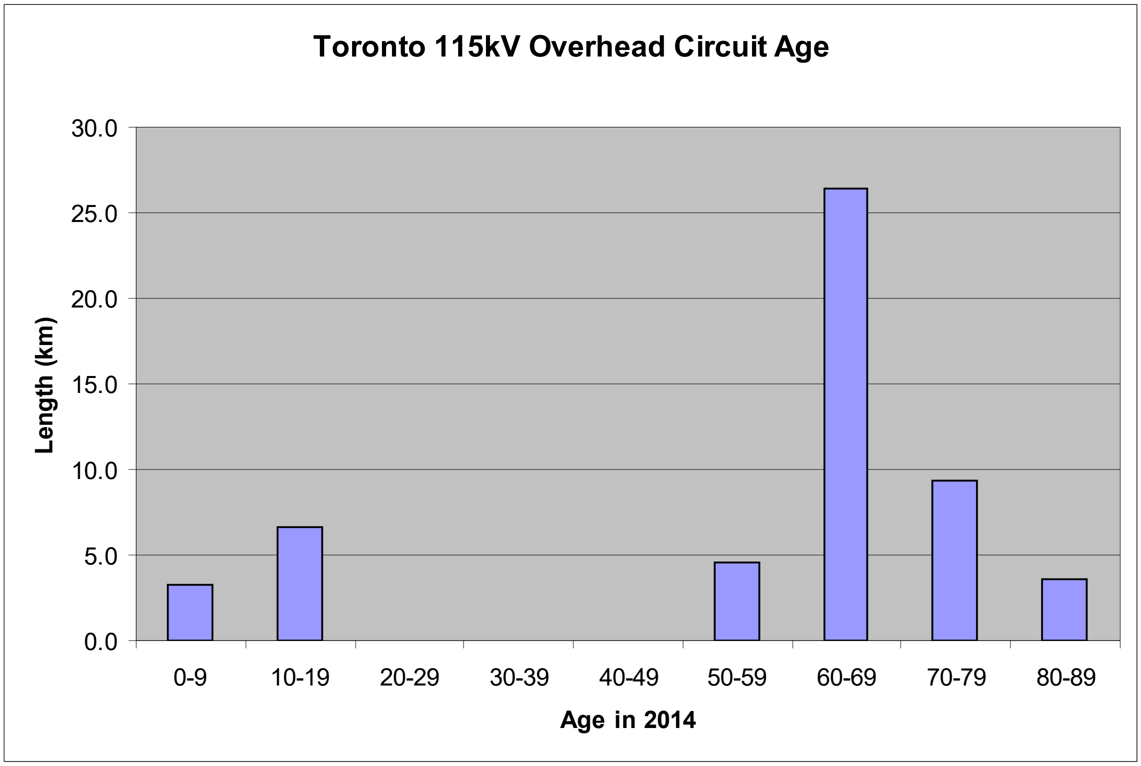
There is no major refurbishment work contemplated at Cecil TS in the next five years.

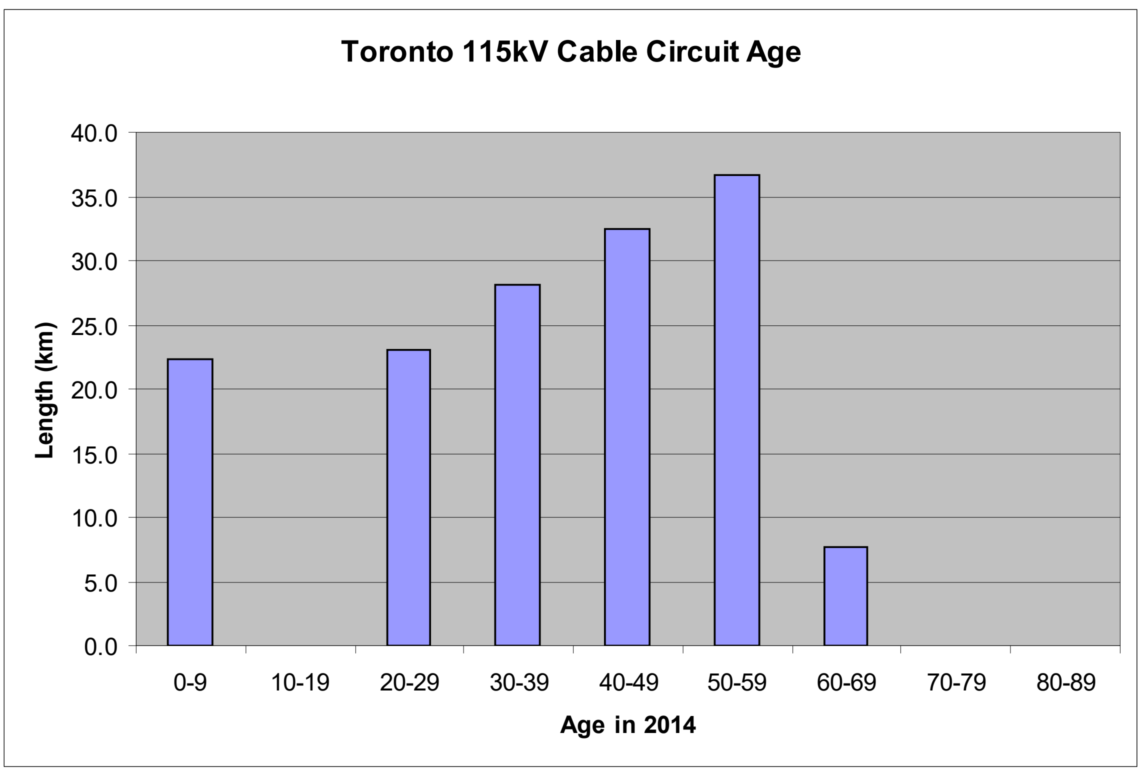
6.0 Leaside TS and Manby TS 115kV Lines

The Leaside TS x Manby TS 115kV network is shown in Figure 1. The overhead lines are over 50 years old except for the overhead section of the circuit H2JK/K6J between Manby TS and Riverside Jct. which was refurbished in 1998 and the Leaside TS x Bayview Jct. section of the line L14W/L15W which is currently being rebuilt to carry a new circuit and to reinforce the Leaside TS x Bridgman TS transmission corridor. Hydro One monitors the conditions of the lines and based on current assessment no overhead transmission line refurbishment work is planned for the next ten years.

The cable network is somewhat newer, but there are some cables circuits over fifty year old. Work is underway on replacing the Leaside TS x Bridgman TS circuit L14W and the Riverside Jct x Strachan TS circuits K6K/H2JK. Both cable replacements are expected to be complete by end 2014.

The age profiles for both overhead and underground circuits are shown in the charts below:





The timeline for the refurbishment of some of the older 115kV cables is also given in Figure 1. This is based on surveys of the cable health carried out over the last several years.

7.0 Conclusions

This filing memorandum summarises the aging profile of the main components of the Toronto area 115kV network and current planned refurbishment work over the next 5 years.

Significant work is currently under way – Hearn TS is being rebuilt and the 115kV oil breakers are being replaced at Leaside and Manby TS. Work is also underway on the Leaside TS x Bridgman TS and the Riverside Jct. x Strachan TS cable circuits.

Hydro One's challenge for the refurbishment and replacement of the underground and overhead lines over the next 10-20 years will be managing outages to carry out the work while continuing to supply the area load.

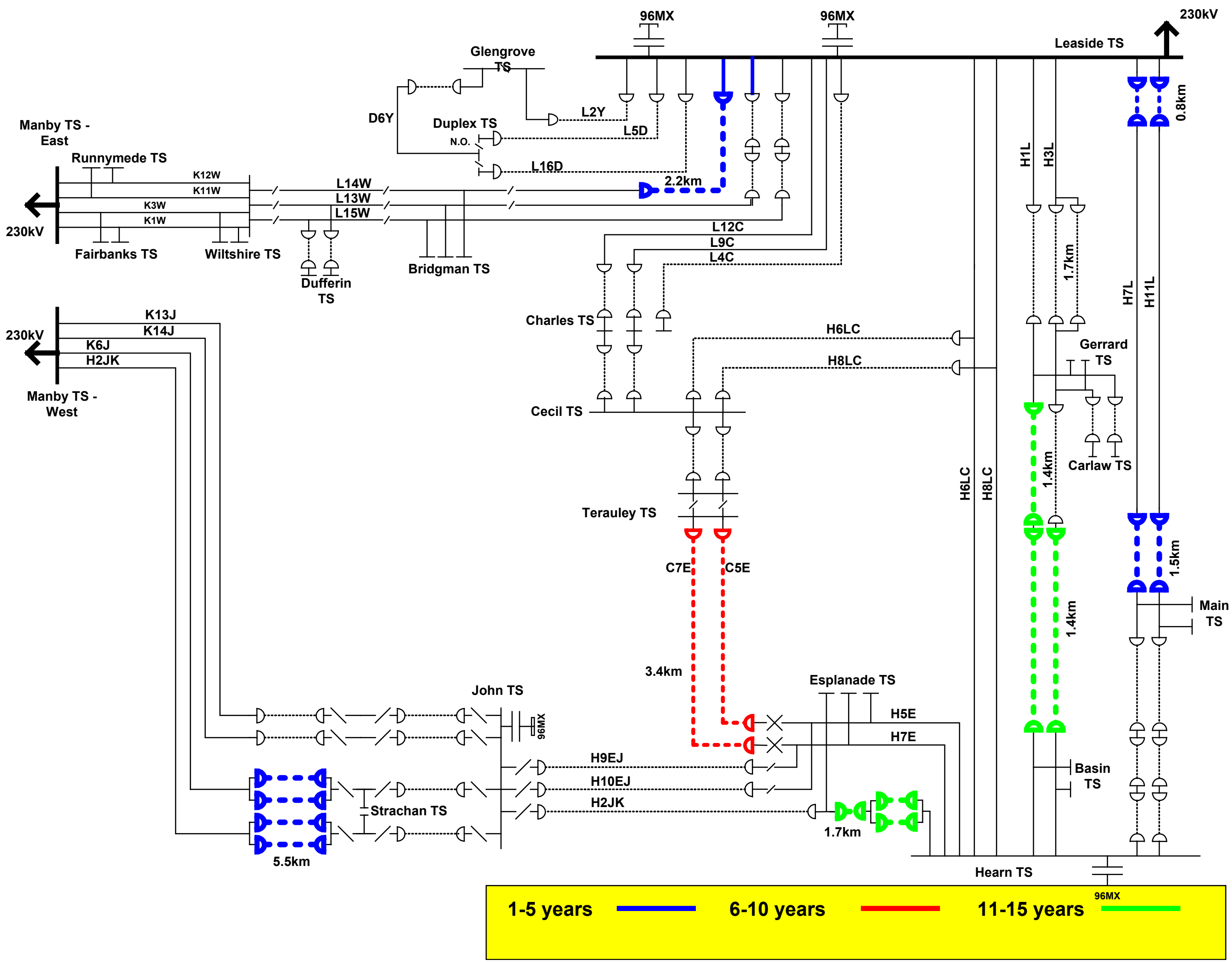


Figure 1. Leaside TS and Manby TS – 115 KV area Transmission Network. Timeline for Refurbishment/Replacement of Overhead lines and Underground Cable

The End

Metro Toronto – Central IRRP

Appendix H: Estimates of Conservation Achievable Potential

Appendix H: Conservation Potential Estimates

The following estimates of conservation potential for Central Toronto are adapted from the analysis and findings presented in the report *Achievable Potential: Estimated Range of Electricity Savings from Energy Efficiency and Energy Management* (ICF Marbek, March 2014).[7]

The conservation Achievable Potential Study estimated energy efficiency electricity savings potential as a function of building and end-use stock, technology electricity intensity, and technology adoption rates. The study included electrical conservation technology measures expected to be available by 2022. Energy efficiency and energy management/customer behaviour measures and district energy were included in the analysis but demand response, lifestyle changes and other customer-based generation resources were excluded.

The study estimated the technical energy savings potential at the provincial level, as well as a range of achievable potential based on different program designs for the Province and each IESO Zone. The varying levels of potential were defined as follows:

- Technical potential: estimated potential savings for all measures that pass an economic screen.
- Upper achievable potential: based on programs with incentives sufficient to reduce customer payback to one year and aggressive support through education, training, marketing.
- Lower achievable potential: based on less aggressive programs with incentives sufficient to reduce customer payback to two years.

Using the estimates of technical potential and range of achievable potential for the Toronto IESO Zone, the energy efficiency savings potential for Central Toronto was estimated by accounting for local building stock and floor space data from the Municipal Property Assessment Corporation (MPAC) and local electricity consumption data from Toronto Hydro.

These steps were followed to develop the conservation potential estimates for Central Toronto.

1. The estimates of technical potential and range of achievable potential for the Toronto IESO Zone were disaggregated by sub-sector (e.g., single family homes, offices, manufacturing, etc). These saving estimates were provided at 5-year intervals from

[7] http://powerauthority.on.ca/news/conservation-achievable-potential-study

which intermediate years were interpolated to develop an annual potential savings forecast.

2. The sub-sector potential savings estimates for the Toronto IESO Zone were then allocated to Central Toronto using the ratio of growth drivers (residential housing stock, commercial floor space, and industrial consumption) for each sub-sector for the technical and two achievable potential levels.

   For example, if the technical potential for large offices in the Toronto IESO zone is 1,000 GWh, the floor space for large offices in the Toronto IESO zone is 5,000 ft sq, and the floorspace for large offices in Central Toronto is 200 ft sq, then the Central Toronto Office Savings Potential = IESO Toronto Zone Office savings x (Toronto Office Floorspace/IESO Toronto Zone office floor space = 1,000 GWh x (200 ft sq/5,000 ft sq) = 40 GWh office technical potential in Central Toronto. This is equivalent to assuming that the sub-sector energy savings intensity (e.g., per unit household or floor space) at the local level is equivalent to that at the Zone level. To allocate the Toronto IESO Zone level savings to Central Toronto, data from the following sources were used. Housing stock data was obtained from Environics, commercial floorspace data was obtained from MPAC, and institutional and industrial consumption was obtained from Toronto Hydro.

3. The energy savings estimates by sub-sector allocated to Central Toronto were then converted to peak demand savings potential using the sub-sector load shapes derived from hourly end use load profiles. Summing up the demand savings across all sub-sectors provided the total savings potential for the Central Toronto area. Note that these savings are reflective of a 2005 base year and are inclusive of persisting savings from existing conservation programs and savings from codes and standards.
4. To develop estimates of the "remaining" program savings potential for comparison to the planned program savings included in the IRRP, the persisting savings from existing conservation programs in the region and from existing codes and standards were subtracted. The existing savings for 2005-2013 were taken from the IESO's Evaluation, Measurement, and Verification reports which include an estimate of the persistence effect of implemented programs. The Codes and Standards savings were assumed to be the same proportion, by sector, as that assumed in the Provincial study. The savings remaining represent the remaining potential for conservation savings.

Table H-1: Summary of Remaining Conservation Potential and Supply Needs for Central Toronto

Need Area	Supply Need/ Conservation Potential (MW)	2014	2016	2018	2021	2026	2031
Manby TS (West + East)	***Supply Need (MW)***	***90***	***123***	***134***	***158***	***195***	***227***
	Technical Conservation Potential	48	79	113	143	139	130
	Upper Achievable Potential	4	15	36	53	47	49
	Lower Achievable Potential	3	5	15	18	12	13
Leaside TS - Bridgman TS	***Supply Need (MW)***	***13***	***17***	***19***	***21***	***23***	***26***
	Technical Conservation Potential	18	27	35	42	41	38
	Upper Achievable Potential	2	5	9	14	12	12
	Lower Achievable Potential	2	2	4	4	3	3
Richview – Manby 230 kV Corridor	***Supply Need (MW)***	***0***	***15***	***28***	***15***	***9***	***4***
	Technical Conservation Potential	78	123	168	209	203	190
	Upper Achievable Potential	8	23	50	74	64	65
	Lower Achievable Potential	6	8	21	24	16	18
Manby TS (230 - 27.6 kV)	***Supply Need (MW)***	***30***	***30***	***30***	***30***	***30***	***40***
	Technical Conservation Potential	19	26	32	38	37	34
	Upper Achievable Potential	3	5	8	11	9	9
	Lower Achievable Potential	2	2	3	3	2	3
Fairbank TS	***Supply Need (MW)***	***0***	***30***	***30***	***30***	***30***	***30***
	Technical Conservation Potential	15	21	27	32	31	29
	Upper Achievable Potential	2	4	6	10	8	7
	Lower Achievable Potential	1	2	2	3	2	2
Esplanade TS	***Supply Need (MW)***	***0***	***10***	***10***	***10****	***30***	***30***
	Technical Conservation Potential	5	10	16	21	20	19
	Upper Achievable Potential	0	2	6	9	8	9
	Lower Achievable Potential	0	0	3	3	2	2

* Notes: The following forecast new customer demand is not accounted for in the above table (Supply Need)
1. The Eglinton LRT demand is forecast to result in an additional 18 MW of demand in the Fairbank TS service area by 2019, and is in addition to the supply need identified in Table H-1.
2. Toronto Hydro estimates that an additional 90 MW of demand will materialize within the downtown area in the near and medium-term, based on approvals for new buildings and developments.

Metro Toronto – Central IRRP

Appendix I: Letter to Toronto Hydro on Load Stations Planning

ONTARIO POWER AUTHORITY

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April 4, 2014

Mr. Jack Simpson
Director, Generation and Capacity Planning
Toronto Hydro-Electric System Limited
500 Commissioners Street
Toronto, Ontario M4M 3N7

RE: Request for Continued Distribution Planning and Development Work for Near Term Infrastructure Projects in Central Toronto

Dear Jack:

This letter is to thank you and your Toronto Hydro team for the support provided to date in progressing the Central Toronto Integrated Regional Resource Planning ("IRRP") and to request your continued support in developing the work scope, cost and timing requirements for the distribution infrastructure options required for meeting the near-term needs identified the by the IRRP Working Group ("Working Group").

The Working Group (consisting of staff from the Ontario Power Authority ("OPA"), Toronto Hydro-Electric System Limited, the Independent Electricity System Operator and Hydro One Networks Inc.) has established that there are certain near term-needs that require action by Toronto Hydro to ensure that distribution infrastructure options are identified and appropriately represented within the study. Of particular concern is the understanding of the lead time that some of these infrastructure options may have as well as their costs, at a planning level of certainty. We understand that some of these options developed by Toronto Hydro may require the coordination and/or participation of Hydro One.

The OPA therefore requests that Toronto Hydro continue with detailed studies and development work for the distribution infrastructure related near-term components of the IRRP as outlined below:

- Develop the distribution infrastructure components of the integrated plan that may be required to meet near-term capacity and/or reliability of the Central Toronto area. These options may be required in the event that planned conservation and demand management (CDM), distributed generation, or other electricity system initiatives are insufficient or are determined to be technically and / or economically infeasible for providing the necessary near-term relief by the Working Group.

- Continue to work with the OPA to ensure that CDM, distributed generation, and other electricity system initiatives are fully and appropraitely accounted for in developing the near-term and longer-term elements of the integrated plan.

In addition to the distribution infrastructure options, alternative or complementary approaches for addressing these near-term needs and issues may include CDM, distributed generation, or other non-wires based electricity system initiatives. These along with recommended solutions will be investigated further by the Working Group through the IRRP process.

Supporting Information for Central and Downtown Toronto Near-Term Projects:

The near-term needs and issues identified by the Working Group which require action by Toronto Hydro are summarized in Attachment 1.

To facilitate the implementation of further planning and development activities, the OPA will provide Toronto Hydro with the following information established by the Working Group:

- Conservation and distributed generation forecasts
- Preliminary assessments of other non-wires based options
- Other relevant information upon request by Toronto Hydro.

I look forward to discussing a timeline for the requested information at our next Working Group meeting.

Thanks again for your support to date and I look forward to continuing to work together and supporting Toronto Hydro on the further development and implementation of solutions.

Best Regards,

Joe Toneguzzo
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

Copied: Central Toronto IRRP Working Group

Attachment 1

Near-Term Needs Requiring Initiation of Planning and Development Work

A. West-Central Toronto Step-down Capacity Relief

Load forecast information provided by Toronto Hydro indicates strong near-term growth pressures in the West-Central Toronto area. This requires the development of distribution infrastructure options for providing step-down station capacity relief. This relief is required to supply growth in demand from existing customers, enable the connection new customers and manage the risk of outages under certain contingencies.

Distribution infrastructure options to address the West-Central Toronto Step-down Capacity relief have not been explored in detail by the Working Group. However, based on preliminary discussions these options should include, as determined appropriate by Toronto Hydro:

- Permanently transferring load from the step-down stations requiring relief to Richview TS or other nearby step-down stations, which are not fully utilized. This may include incorporating feeder-ties between stations where feasible and economic.
- Building an new step-down transformer station to offload the step-down stations requiring relief. This may include incorporating feeder-ties between stations where feasible and economic.
- Providing, where it is feasible and economic to do so, inter-station transfer capability in order to enhance restoration of the West-Central Toronto step-down stations for normal design contingencies as well as extreme contingency events. These stations include, but are not limited to: Manby 230/27.6 kV DESNs, Richview 230/27.6 kV DESNs, Fairbank TS, and Horner TS.

B. Downtown Toronto Step-down Capacity Relief

The load forecast provided by Toronto Hydro indicates that continued strong near-term growth pressure in the downtown Toronto area requires the development of distribution infrastructure options for providing step-down station capacity relief. This relief is required to supply growth in demand from existing customers, enable the connection new customers and manage the risk of outages under certain contingencies.

Distribution infrastructure options to address the downtown Toronto Step-down Capacity relief have not been explored in detail by the Working Group. Based on preliminary discussions within the Working Group these options should include, as determined appropriate by Toronto Hydro:

- Developing Phase II of Copeland TS.
- Expanding Esplanade TS.

- Permenently transferring load to other adjacent step-down stations which are not fully utilized.
- Providing, where it is feasible and economic to do so, inter-station transfer capability in order to enhance restoration and the optimization of station loading.

The information provided should include:

1. A summary of the expected scope of work.
2. The time required to implement specific distribution infrastructure options from the planning phase through to in-service. This should include identifying approval and other requirements such as the need for environmental assessments, the acquisition of property, etc.
3. Planning level capital cost estimates.
4. Rationale for not including options, where Toronto Hydro believes this is not technically feasible.
5. Concerns Toronto Hydro has regarding use of the CDM and/or distributed generation as an interim measure or as alternatives to the distribution infrastructure option.

Depending on the findings from the investigations from 1 and 2 above, it may be possible for CDM, local generation, or other electricity system initiatives to defer the need for wires-based options. This includes the Local Demand Management Pilot Study that Toronto Hydro is conducting with financial support from the OPA's Conservation Fund that is intended to specifically target local areas of high constraint. This determination will be investigated further by the Working Group though the IRRP once the nature, timing and cost of these options are better understood and any concerns expressed by Toronto Hydro are documented.

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END of LETTER

Metro Toronto – Central IRRP

Appendix J: Stakeholder Engagement Summary Reports

Innovative Research Group, Inc.

Toronto • Vancouver

Customer Consultation Report

Central Toronto IRRP

January 2015

Prepared for:

Central Toronto Integrated Regional Resource Plan Study Partners

Customer Consultation Report

Central Toronto IRRP

January 2015

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro-Electric System Limited (THESL), Hydro One Networks Inc. (HONI), the Independent Electricity System Operator (IESO) and the Ontario Power Authority (OPA).

The conclusions drawn and opinions expressed are those of the authors.

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Contents

Introduction

About this Consultation

INNOVATIVE has been commissioned by the Central Toronto Integrated Regional Resource Plan (IRRP) study partners – made up of Toronto Hydro, Hydro One, the Independent Electricity System Operator, and the former Ontario Power Authority – to help design, collect feedback and document its customer engagement and consultation process as part of the development of the Central Toronto IRRP.

The Central Toronto IRRP is a key element in shaping how energy needs will be met in the Central Toronto for the next 25 years. The outcome of this plan will set the context and basis for the preferred options to meet the growing demand in the region.

In developing the Central Toronto IRRP, the study partners, alongside INNOVATIVE, conducted a comprehensive consultation that obtained input from affected stakeholders to ensure that the preferences of the impacted communities are accounted for. This consultation included a two-way dialogue with stakeholders about regional electricity needs and the related options over the medium and long term. The objectives of this consultation included:

- increasing public understanding of the area's electricity needs and options for the future;
- obtaining feedback on the options developed to address the medium- and long-term needs;
- highlighting the importance of electricity as a driver for economic and community development; and
- explaining and promoting the role of CDM, DG and transmission and distribution solutions in helping meet both current and future needs.

Approach to Meaningful Customer Engagement

It is our experience at INNOVATIVE that engaging customers in meaningful consultation can be a challenge. The reality of most consultation processes is they start out aiming to collect the views of the average person, but end up collecting the views of organized advocacy groups.

Many customers feel they do not know enough to contribute to a public consultation. Others fear the combative nature of some public processes or prefer not to risk offending friends and neighbours by taking firm positions on issues that are sometimes controversial. Moreover, many customers are simply not aware that public consultations of interest are taking place.

Running a consultation on a complex IRRP has additional challenges – mainly a lack of awareness regarding how the system operates, is funded and the regulatory frameworks. This process is intended to bridge these gaps and educate customers about the electricity system.

Considering both the challenge of engaging a representative group of customers and the challenge of lack of awareness, we built a process built on six key principles:

1. Ensure customers from across Central Toronto have an opportunity to be heard.
2. Use random-sampling research elements to ensure a representative sample of customers are engaged.

3. Create open voluntary processes to allow anyone who wants to be heard to be heard.
4. Focus on fundamental value choices. Look for questions that ask people to choose between key outcomes rather than focus on the technical questions of how to reach those outcomes.
5. Create an opportunity for the public to learn the basics of the distribution system so they can provide a more informed point of view.
6. Test the consultation material ahead of time for clarity of language, appropriateness of questions, ability to respond to questions, and the right balance between comprehensiveness and simplicity.

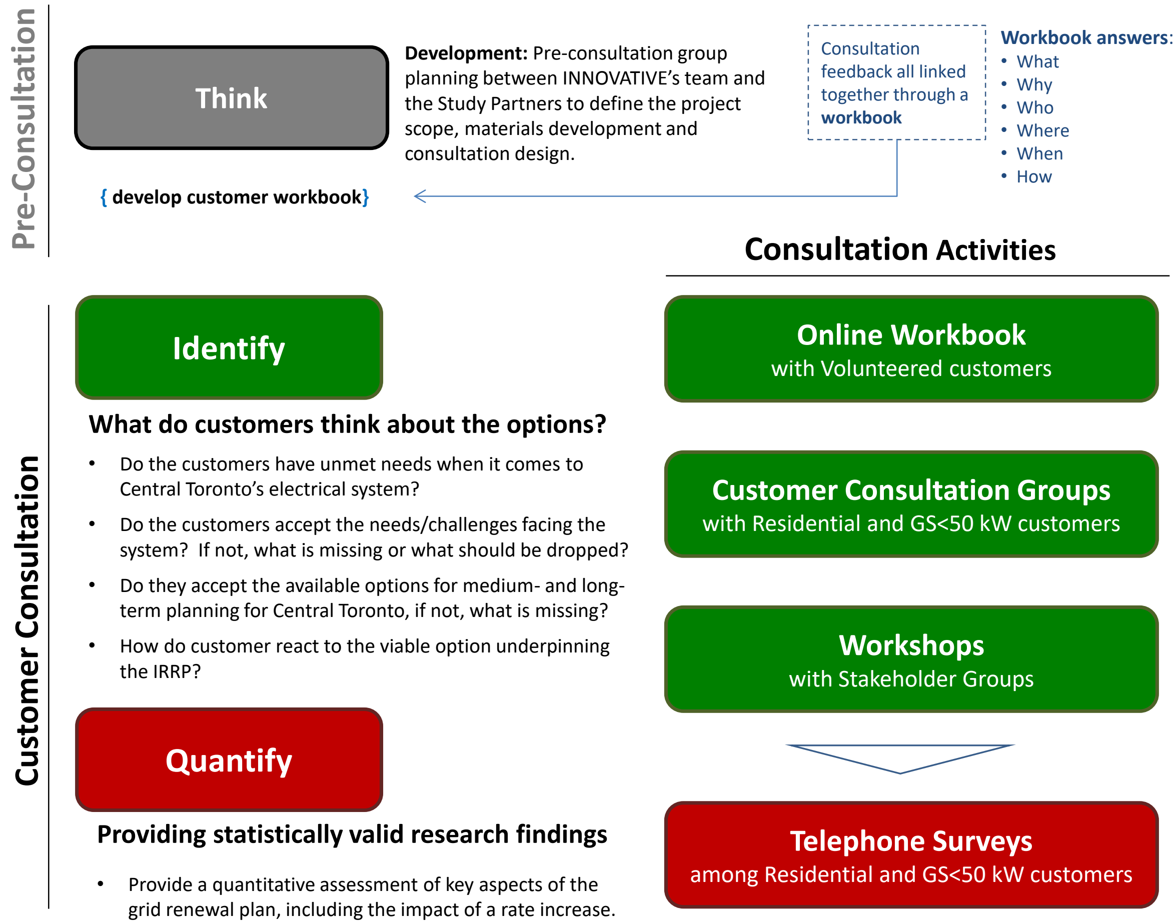
Since this was the first time the IRRP study partners so explicitly engaged customers in the development of their plan, a specific effort was made to collect participant comments on the process itself. While most customers felt this approach to engagement was effective at soliciting their feedback on the Central Toronto IRRP, other ideas on how to improve upon the process were collected throughout the consultation. This is discussed throughout the body of this report.

Customer Consultation Overview

Based on the principles outlined above, INNOVATIVE worked with the Central Toronto IRRP study partners to design a multi-faceted customer engagement program, which included a combination of traditional consultation services, as well as qualitative and quantitative research elements. This comprehensive consultation was designed to engage various rate classes and stakeholder groups and collect feedback on preferences and priorities as they relate to the Central Toronto IRRP.

There were three stages in developing and implementing this consultation:

- **Think**: The first step was developing the core background material and key questions for the workbook. INNOVATIVE and the IRRP study partners worked together to identify potential questions that would allow customers to share their needs and preferences and then to develop a workbook that would provide the information needed to allow customers with different levels of initial knowledge to find answers to those questions.
- **Identify**: The second step in the customer consultation were the qualitative research element. These elements consisted of: a volunteered online workbook that was completed by customers across Central Toronto; customer consultation groups to help identify the needs and preferences of customers as related to the IRRP; and stakeholder workshops to help gauge planning priorities for Central Toronto.
- **Quantify**: The final step included gathering final thoughts on the planning options for Central Toronto through a random recruited telephone surveys of residential and general service customers in the study area. Randomly recruited surveys allow us to draw generalizable conclusions that can be applied to the broader Central Toronto population. The surveys were developed based on the feedback gathered from the subsequent consultation phase of the research.



The consultation encompassed five core elements of customer engagement.

1. **Testing Focus Groups**: Testing groups were used to determine the effectiveness of the workbook. These groups helped determine where improvements could be made to the narrative developed by the IRRP study partners and INNOVATIVE.

2. **Online Workbook**: The online workbook was promoted through both traditional and online media by the four members of the IRRP study partners. This first phase of the consultation was available to all Ontario residents who wanted to participate.

3. **General Service and Residential Consultation Groups:** The general service and residential customer phase of Central Toronto's IRRP multi-faceted customer consultation was used as an engagement tool to educate customers, access customer preferences and priorities, as well as inform subsequent phases of the consultation. The groups were randomly recruited and held in a central location in downtown Toronto. A workbook was used to provide the participants with core information about the Ontario electricity system and the growing demand on Central

Toronto's electricity system. They were provided incentives in recognition of their time commitment.

4. **Stakeholder Workshops**: Key stakeholders were engaged through a series of randomly recruited workshops. More than 300 stakeholders were invited to attend one of the three workshop sessions.
5. **Random Telephone Surveys**: INNOVATIVE conducted telephone surveys with residential and general service (GS < 50kW) customers to provide a quantitative assessment of key aspects of the Central Toronto IRRP. Customer lists for both respondent groups were provided by Toronto Hydro and the sample was randomly-selected by INNOVATIVE.

The consultation was designed so anyone who was interested would have an opportunity to participate in the process through the online workbook. However, in our approach, we distinguished between responses from the opinion research discipline (random recruits and scientific polls) and responses from an "open invitation" consultation discipline.

The small group results are presented as numeric counts to help readers remember that qualitative research only identifies points of view, it does not project the incidence of that point of view in the broader public.

The results from the workbook and random surveys are presented as percentages due to the larger numbers involved.

- Readers are cautioned that the workbook results represent the views of volunteers. The workbook sample is not randomly selected and cannot be generalised to the broader Central Toronto customer-base.
- The telephone surveys are based on random samples so we can reliable project the incidence to the broader population of Central Toronto.
- In some instances, the quantitative total may be greater than 100% due to rounding. This is in keeping with standard research practice.

Workbook Development

As noted earlier, a key challenge in getting public feedback on the Central Toronto IRRP is the lack of awareness concerning Ontario's electricity system. Our challenge was to briefly cover the key issues and to frame meaningful questions around preference as it pertains to electricity needs and options for the future of Central Toronto's electricity system.

The process of developing the consultation workbook began in the fall of 2013 and continued into the spring of 2014. The draft workbook was tested among Toronto Hydro's Central Toronto residential and general service customers in November and December 2013. Based on feedback from testing, the workbook was divided into key sections that explained the IRRP process, the challenges facing Central

Toronto's the electricity system, and how challenges related to capacity, reliability and security could be met in the medium- and long-term.

The final consultation workbook had six distinct chapters:

1. **What is this Consultation about?** This section explains the purpose of the customer engagement and where this consultation fits within the broader scope of electricity planning in Ontario.
2. **Where Does Electricity Come From?** This section explains how electricity is generated, transmitted and distributed to the city of Toronto.
3. **An Overview of the Central Toronto Electricity System Today**: This section provides an overview of Central Toronto's electricity system and how it has grown and changed to meet demand over the past century.
4. **Planning to Meet Customer Expectations**: This section provides a context for the various issues system planners consider when planning for medium- and long-term electricity needs: peak demand, capacity, reliability and security.
5. **Options for Meeting Central Toronto Demands**: This final question provide an overview of potential medium- and long-term planning options for Central Toronto's electricity system.

Although the sophistication of customers varied, the same basic workbook was used in all qualitative engagements – the online workbook, the residential and general service discussion groups and the stakeholder workshops. As the customer went through the consultation workbook – either independently or through a facilitated session – they were prompted with questions related to system reliability, system challenges, and preferences on options for meeting of Central Toronto's demands.

Another key element of the workbook were the questions. In developing the questions, we looked for questions that could work also on telephone without all the information in the workbook.

The workbook began with reliability experience and expectation questions. These questions asked whether the current number and length of outages are acceptable. These questions were followed by an open-ended question about how these outages affected both your business (for general service customers) and you personally (for residential customers). This series of questions then continued to ask the dollar value of any expenses that were incurred as a result of these power outages. Finally, customers were given the opportunity to voice if there was a certain amount of time without power that the costs and consequences of an outage would become more serious. Questions on reliability were then followed with questions related to security (how the electricity performs during major events) and willingness to pay for greater security.

Preference questions were a bit more difficult to design, as we were looking for value choices rather than technical issues. Most customers are not engineers, so additional efforts were required to provide adequate information on conservation and demand management (CDM), distributed generation (DG), and transmission and distribution options. Key topics for preference included:

- Likelihood to participate in various types of CDM programs;
- Preferences on electrical infrastructure build including transmission, distribution and DG; and
- Comparison questions between all the options available to system planners as they plan to meet Central Toronto's electricity needs in the future.

The workbooks can be found in the **Appendix** of this report.

Executive Summary

This section outlines the findings of the two-part customer consultation: both the qualitative research from the online workbook, general service and residential consultation groups, and stakeholder workshops and also the quantitative research from the telephone survey of residential and general service customers in Central Toronto.

Customer Familiarity, Satisfaction and System Reliability

Most Central Toronto customers say they are familiar with the electricity system and satisfied with their current service.

Familiarity: Directional vs. Quantitative

	Directional	Quantitative (Telephone)	
	Online Workbook	**Residential Survey**	**GS Survey**
Familiar	60%	62%	46%
Not Familiar	40%	38%	54%

- About 6-in-10 respondents in both the Online Workbook (60%) and the Telephone Survey (62% Residential) are familiar with the electricity system.

Across all levels of consultation, respondents were quite satisfied with the service they received:

- The participants in the fall 2014 Stakeholder Workshops felt the system works reasonably well, albeit there's always room for improvement.
- In the Telephone Survey, more than 8-in-10 Residential (86%) and GS (82%) are satisfied with their service.
- The Online Workbook satisfaction question focused on service during unusual weather- a bit different, but the results are similarly positive: nearly 6-in-10 (58%) were satisfied with the service during major events.

Cost is the key issue for customers: they want lower rates and better service.

When asked what the electricity system could do to improve service, far-and-away the leading answer was "reduce rates"- 40% of telephone respondents mentioned this in an open-ended question. For many, paying their electricity bill is a financial hardship: about half (46%) of residential and 3-in-4 (77%) general service customers say their electricity bill has a "major impact" on their finances.

The drive to reduce cost is also paired with a preference for increased reliability. In the past twelve months, half of residential and general service customers experienced an outage of some kind, either during a major weather event (50%) or under normal circumstances (51%).

This "more for less" contradiction is something explored through every step of the consultation. The September 2014 focus groups clearly understood the need to replace aging infrastructure, but suggested the system look within for savings and to rein in "waste" before asking customers for a price increase. In the Workbook, those against increased infrastructure spending say primarily "we should use existing infrastructure first".

Outage length is another major concern. Cutting down the time of outages is crucial.

The problem of outages - particularly the summer flooding and December 2013 ice storm - is top of mind for residential and general service customers. Much of the consultation process focused on how reliability issues affected customers in their day-to-day.

The qualitative consultation in particular examined the impacts of outages, acceptable timelines and frequencies of outages and customer preferences on frequency versus duration.

With this qualitative feedback in mind, the telephone survey examined customer preferences between cost and reliability.

Number of Hours when Cost and Consequence of Outage Becomes More Serious:

Directional vs. Quantitative

	Directional	Quantitative (Telephone)	
	Online Workbook	Residential Survey	GS Survey
<1 hour	9%	19%	62%
1-6 hours	28%	42%	23%
6+ hours	28%	29%	13%
*When food spoilage occurs	19%	--	--
*Any amount of time	11%	--	--

- By more than a six-to-one margin, customers in the telephone poll feel more inconvenienced by the length of outages (77%) than the number (12%).
- According to the Online Workbook, the median customer experienced two outages over the last two years and spent roughly two hours each time without power. When asked an open-ended question on how the outages affected their place of business, most responded with issues of minor inconvenience such as "resetting clocks" and "spoiled food".
- In the Workbook, three-quarters said that "yes", there was a certain length of time at which the costs and consequences of an outage became more serious for them. In that small sample the amount of time varied widely, but the telephone survey clarified how fast they wanted power restored: more than 6-in-10 (62%) general service customers say an hour or less outage makes things difficult; a third (32%) say 15 minutes or less is a problem for their organization.

Challenges, Solutions and Customer Preferences for the Future

The three options presented are not well-known to customers.

Throughout the process, customers weighed in on the three capacity solutions: "Conservation and Demand Management", "Distributed Generation" and "Transmission and Distribution Infrastructure".

- In the telephone survey, unaided awareness of the three solutions is rather low: about as many customers are familiar as unfamiliar with "Transmission and Distribution Infrastructure" (+10) and "Conservation and Demand Management" (+2).

- “Distributed Generation” is the least known to customers in both the qualitative and quantitative research. Both of the September 2014 focus groups requested more information on this “relative unknown”. And more than 6-in-10 (62%) customers in the Telephone Survey are not familiar with “Distributed Generation”.

Customers in Central Toronto are conflicted when it comes to “Conservation and Demand Management”:

- In the 2014 focus groups, a majority (17/28) of participants choose CDM as their first choice.
- And they are more likely than not to participate in Demand Response Programs that allow managers to cycle off their home equipment (62% likely).
- But in the quantitative telephone survey when asked if they would agree to the option of “Conservation and Demand Management”, customers were split roughly evenly: a third (34%) of customers said they were likely to do so and 4-in-10 (40%) said they would not agree to it.

Overall though, customers are supportive of energy conservation and concerned about environmental issues.

In general terms, customers in both the qualitative and quantitative research appear to embrace the idea of energy conservation.

- A majority in the Workbook claim to participate in conservation activities such as using “LED lightbulbs” or “energy efficient appliances”.
- “Solar” and “combined heat and power” are the two options Online Workbook respondents felt most appropriate for use in the Central Toronto region. Almost all the consulted customers would use solar and combined heat and power “all of the time” or “some of the time”. “Bioenergy” and “using emergency generators” are seen as less viable options, but still received net support.
- Finally, there’s strong concern among customers regarding the environmental effects of the electricity system: 9-in-10 (89%) in the Telephone Survey think “reducing impacts that contribute to climate change” is an important consideration in electricity planning.

When push comes to shove, they will pay more and they think they’re getting good value for money.

In every part of the consultation, from focus group to telephone survey, once the critical issue of aging infrastructure was explained a majority of customers gave their support to increase rates.

- A slight majority (52%) in the Online Workbook supported a potential rate increase to improve the system’s reaction to major events.
- When asked about how much they would be willing to add to their monthly bill for better service, the average customer in the Workbook would be willing to pay about 5% more (median: 3%).
- As for value-for-money, nearly 6-in-10 (58%) residential customers think they are getting a reasonable or good deal on their electricity.

Given the difficult choice between “increased rates” and “reduced reliability”, customers have shown throughout the consultation that they will, rather reluctantly, accept higher rates for better service in Central Toronto.

Online Workbook

Online Workbook
with Volunteered customers

PURPOSE: To inform customers on the details of the Central Toronto IRRP and obtain feedback on the proposed planning options

Summary

This summary underlines key findings from residential and business customer feedback collected through the Online Workbook.

Familiarity, System Reliability and Rates

- Around 6-in-10 (n=49) respondents are generally familiar with Toronto Hydro's electricity distribution system. Of those 49 people, about 32 can explain the details of the system to others.
- A majority of customers think that both the average *number* (n=66 out of 83) and *length* (n=59 out of 83) of outages is acceptable. On average, customers surveyed experienced an average of just under four outages over the last two years (median: two outages) and during these outages, on average they spent a bit over 12 hours (median: two hours) each time without power.
- When asked an open-ended question on how the outages affected their place of business, most responded with issues of minor inconvenience such as "resetting clocks" and "spoiled food". In another follow-up asking customers to estimate their expenses during the outages, 4-in-10 (n=26) did not incur any expenses. The median customer lost about $12.50 from their last power outage.
- While a majority think the current length of outages is acceptable, there's a ceiling to this support. Nearly three-quarters (n=57) felt that "yes", there was a certain length of time at which the costs and consequences of an outage became more serious for them. When those "yes" respondents were asked a follow-up to describe that length of time in detail, timelines varied widely. Specific concerns mentioned include "food spoilage", "home heating and cooling affected" and "access to internet".
- It is important for customers surveyed that the regional electricity system is reliable beyond the bare minimum. About half (n=36) said it is "extremely important" to be reliable beyond the minimum standards and roughly a third (n=27) think it is somewhat important.
- When asked about how much they would be willing to add to their monthly bill for better service, the average customer surveyed would be willing to pay about 5% more (median: 3%). The range of per cent customers would be willing to pay for better service varied widely, from as little as nothing to as high as 25%
- The 11 business respondents who filled out the workbook appear to follow the trends in the larger sample on familiarity, reliability and price.

Security of the Electricity System: Satisfaction and Permission

- The 79 customers surveyed are more satisfied than not with the Central Toronto region's system performance during major events. Forty-six of 79 said they were satisfied with the service during major events and 33 claimed they were dissatisfied with the service.
- That being said, there's always room for improvement and customers appear to understand the need for long-term infrastructure development. A majority (n=41) of customers supported a potential rate increase to improve the system's reaction to major events while 26 of 79 said "no" to the increase. The remaining 12 did not know either way.
- Asking permission for a rate increase could be perceived as more successful when explained in the language of "major events". The average respondent would be willing to pay about 6% more for better service during major events, compared to less than 5% when asked previously about more general infrastructure improvements.
- Again, the eleven business respondents follow a similar trend to the larger sample on satisfaction and permission questions.

Conservation and Long-term Solutions

- About 3-in-4 (n=56) claim to have participated in energy conservation activities. Of the remaining 11 business customers, nine of them state they have participated in conservation.
- Out of the 56 respondents who do participate in conservation activities, 49 explained their actions in a follow-up open-ended question. Some of the conservation activities listed include "LED lightbulbs" (n=17), "*peaksaver* PLUS program" (n=9) and "use of energy efficient appliances" (n=7).
- Most customers (n=48 out of 78) state they would participate in "Demand Response" programs and 29 out of 78 would be "very likely" to participate. The small group of 11 business customers were also net likely to participate in these programs (n=7 to n=4 likely/unlikely).
- Most respondents (n=46) agree that system planners should forge long-term investments in infrastructure to improve reliability and security, compared with about 4-in-10 (n=31) who feel that system planners should manage the issues with the current infrastructure in place.
- In an open-ended follow-up question answered by 53 customers, those against infrastructure investment cited "we should use existing infrastructure" (n=15) as their main reason, followed by "it's more cost-effective" (n=2) and "we should reduce consumption" (n=2). Customers in support of additional infrastructure investment listed "build new infrastructure to improve reliability" (n=12), "plan for the future" (n=11) and "build to improve efficiency" (n=3) as their key reasons for the investment.
- When it comes to electricity generation, "solar" and "combined heat and power" are the two options respondents felt most appropriate for use in the Central Toronto region. Almost all the consulted customers would use solar and combined heat and power "all of the time" (n=45 and n=41, respectively) or "some of the time" (n=28 and 31). 'Bioenergy" (n=28: "all of the time"; n=37: "some of the time) and "using emergency generators" (n=16: "all of the time"; n=41 "some of the time") were seen as less viable options in the region, but still received net support. The small sample of 11 business customers mirrored the results of the larger sample for this and all subsequent questions.

- For demand solutions, customers consulted felt all three possibilities offered –“Conservation and Demand Management”, “Transmission and Distribution” and “Distributed Generation”- were appropriate for the problem at hand.
- Customers considered “Conservation and Demand Management” the most appropriate solution (“all the time” n=48; “some of the time”: n=20), followed by “Transmission Distribution” (appropriate “all of the time”: n=42; “some of the time”: n=29) and “Distributed Generation” (“all of the time”: n=32; “some of the time”: n=39).
- Customers’ first choice of demand solutions is “Conservation and Demand Management” (n=31). When asked for their second choice, consulted customers chose “Distributed Generation” (n=35).
- In the open-ended explanations of their first and second choices of electricity solutions, the answers customers gave focused on cost, improved supply, reduced reliance and environmental concerns.

Methodology

About the Online Workbook

In the fall of 2014, the IRRP Study Partners and INNOVATIVE staff started to develop an online customer workbook which would help the IRRP Study Partners to consult and inform customers about a 25-year plan for electricity service.

The Online Workbook was divided into five key sections:

1. What is this Consultation About?
2. Where Does Electricity Come From?
3. An Overview of the Central Toronto Electricity System Today
4. Planning to Meet Customer Expectations
5. Options for Meeting Central Toronto Demands

The first section informed the respondent about the geography and organizational responsibilities of the IRRP Study Partners, explained why the customer was consulted, and asked for basic demographic information.

The second and third sections were informative only: they explained electricity generation, how electricity is transmitted and distributed in the city of Toronto as well as a brief overview of the current system.

In the next section “Planning to Meet Customer Expectations”, the key analysis started. First, the IRRP Study Partners informed customers about each of the key questions to forecast electricity:

- How much electricity will customers likely demand in the future?
- All things being equal, how much electricity can the system supply?
- When things go wrong outside of major events, how reliable is the system?
- And how does the system cope with major storms or disasters?

Respondents then were prompted with questions on system reliability and the perceived financial costs to the customers personally during outages, followed by questions on system security during major events and electricity pricing. Open-ended responses were included (ex: “How did the power outage affect your business?”) to provide additional opportunities for customers to give more specific feedback.

(In part because of the small n-sizes of the open-ended responses, the results of these questions should be considered exploratory research and not a definitive quantitative analysis).

The final section of the workbook provided detailed explanations on the three main solutions to capacity concerns (“CDM”, “DG” and “Transmission or Distribution Expansion”) and then asked customers to choose between a variety of options. Again, open-ended responses were included such as “why do you prefer the one view over the other?” to provide additional engagement opportunities for customers.

In total, the Online Workbook contained a total of 23 survey questions and six demographic questions. All responses were anonymous and kept strictly confidential.

This workbook was an opportunity to engage customers and inform them about the IRRP as well as share their feedback. The ultimate goal was to ensure the IRRP accurately reflects the regional customers’ preferences and priorities.

Field Dates:

The Online Workbook was available online to access for Central Toronto residents and businesses for just over six weeks, between September 3, 2014 and October 20, 2014.

Promoting the Online Workbook:

The Online Workbook was promoted by the IRRP Study Partners through traditional print advertising as well as the various organizational web sites and social media accounts of the member organizations, including Facebook and Twitter.

Hosting the Online Workbook:

The Online Workbook was hosted by INNOVATIVE under the URL: *www.centraltorontoplan.ca*.

The IRRP Study Partners and INNOVATIVE designed the workbook to prevent respondents from completing questions multiple times and to save the progress of respondents in case they leave prematurely.

When respondents reached the final webpage, the survey was considered complete and the site was no longer accessible to the internet protocol (IP) address used to complete the Online Workbook. Cookies were used in the design of the Online Workbook ensure that respondents only complete the Online Workbook once. (Cookies are small pieces of data that identify users and prepare customized Web pages for them).

At the same time, the site saved answers if respondents left the Online Workbook part-way through the process. When respondents returned to the Online Workbook, all previously entered answered re-appeared linked to the user’s IP address.

We do not link the information stored in cookies to any personal information submitted on our site.

Respondent feedback data was only ever available to INNOVATIVE staff through a secure data retrieval portal.

Validating Customer Responses:

Respondents were asked to identify themselves as either a residential or business customer of Toronto Hydro and also to provide the postal code that corresponded to either their residence or business. All further questions tagged them with an individual identification number based on this information.

Toronto Hydro provided INNOVATIVE with a list of all valid customer postal codes which were cross-referenced against responses to these questions in this workbook. Invalid postal codes were removed from the final sample.

Sample Characteristics:

The breakdown of Online Workbook responses are as follows:

- 753 unique visitors came to the Online Workbook's landing page.
- 257 unique visitors answered at least one question.
- 71 customers completed the entire Online Workbook by answering all questions.

NOTE: Results contained within this report are based on a limited and non-representative sample of volunteered respondents and should be interpreted as directional research only. Depending on user response error and completes, n-sizes may vary slightly from question to question. Because there was no mechanism in place to force users to answer specific questions, customers sometimes 'cherry-picked' which follow-up they decided to answer. This is reflected in the n-size, particularly on the open-ended questions.

Customer answers for each question were grouped together in tables anonymously and the information provided was used for statistical analysis only.

Out of 257 initial respondents who answered at least one question, 71 completed the entire workbook.

The 60 residential and 11 business customers who completed all questions are the focus of the *Respondent Feedback* section of this report.

As for business respondents, 28 identified as a business customer initially. While the n-size of residential customers experienced a significant drop-off over the course of the survey, the business customers tended to finish what they started. Eleven of the 12 business customers who completed the profiling section of the Online Workbook completed the entire survey from start to finish.

Responses provided by business customers are included in most of the following charts as footnotes because of the small sample size.

Respondent Profile

Figure A1: Residential Customer Profile

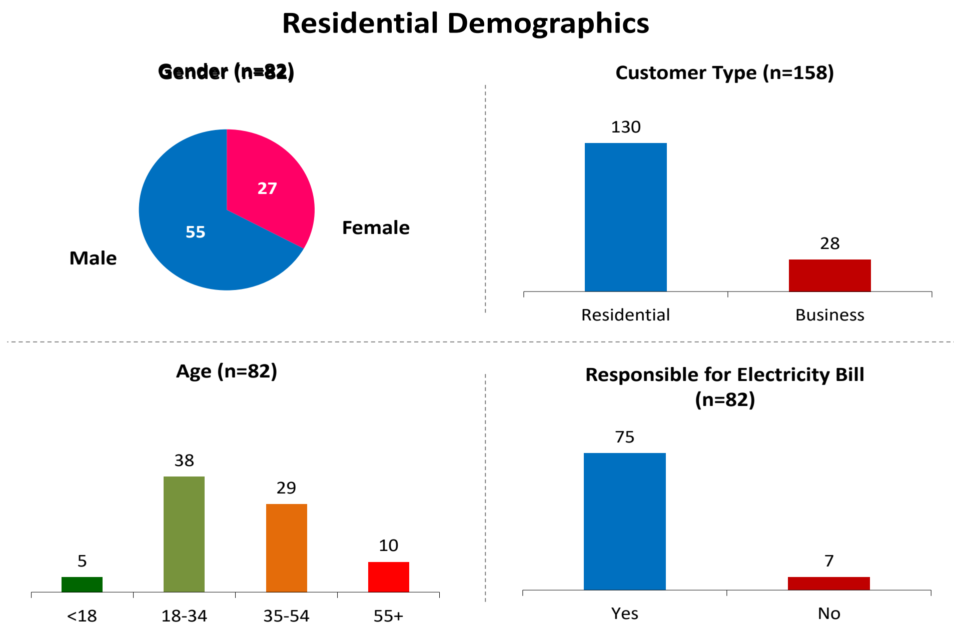


Figure A2: Residential Customer Profile

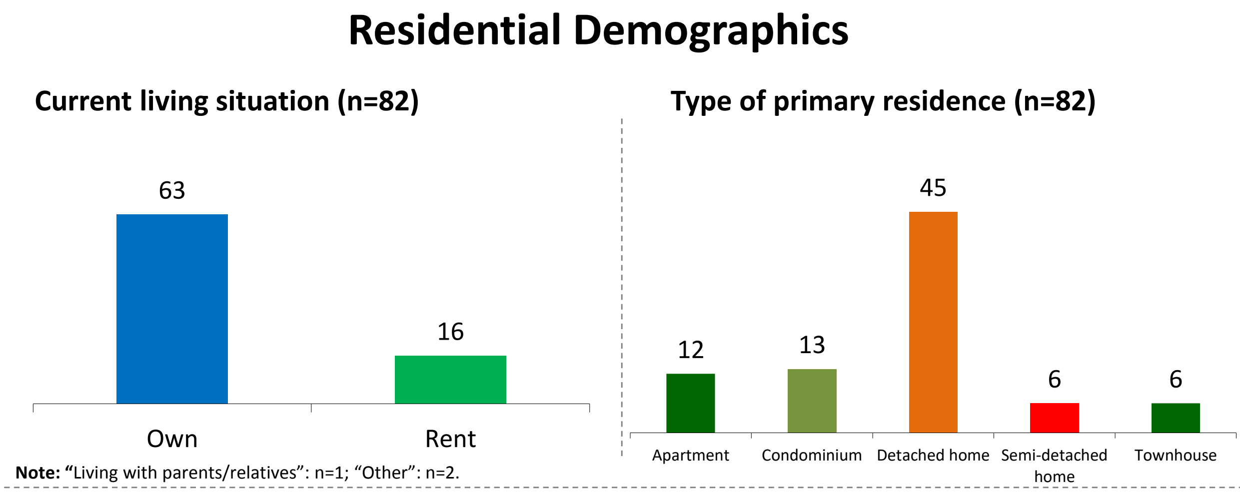
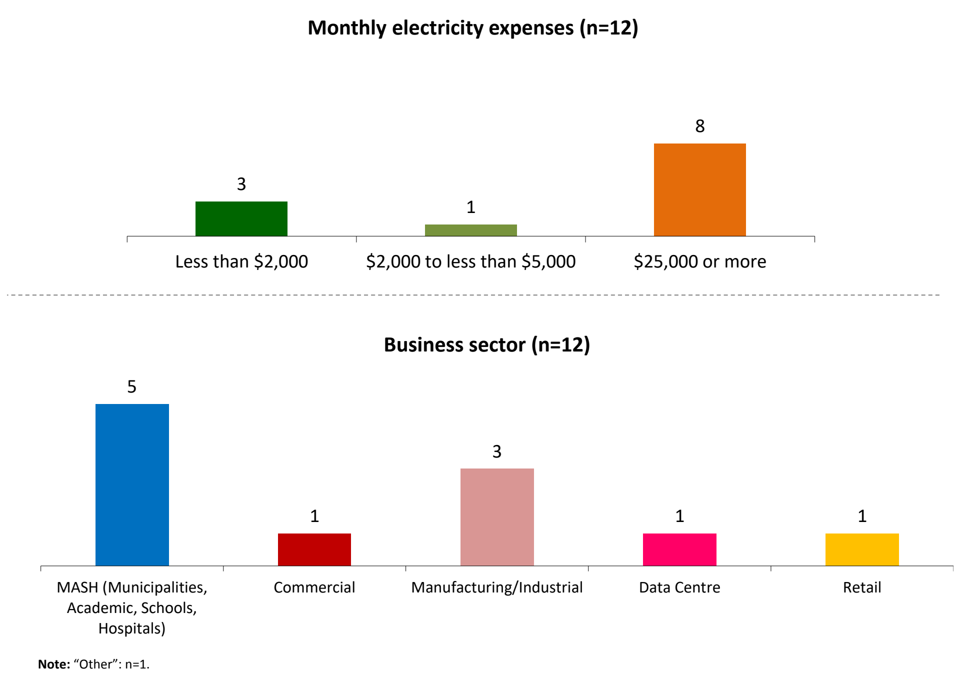
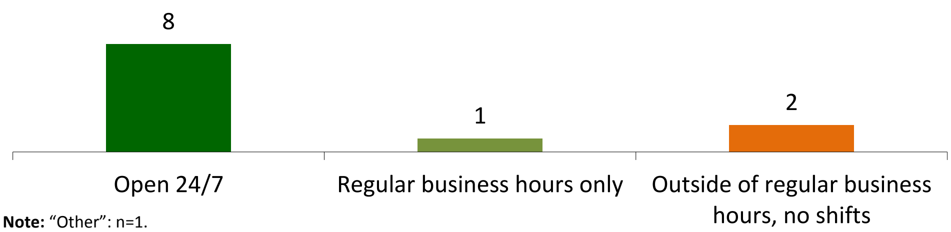


Figure B: Business Customer Profile

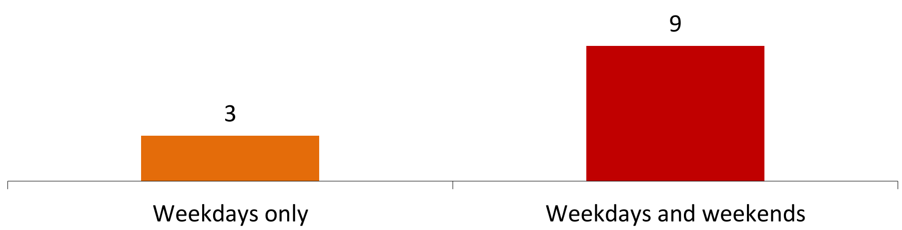


Hours of operation (n=12)



Note: "Other": n=1.

Business sector (n=12)



Respondent Feedback

As mentioned in the previous section, 60 residential and 11 business respondents completed the IRPP's Online Workbook. However, number of completes from question to question vary and are a bit higher at the start.

Familiarity, System Reliability and Price

This first section examines how familiar respondents are with the electricity system, reliability of the electricity system in terms of number, length and overall seriousness of outages and, finally, attitudes on price.

Familiarity with the System

- About 6-in-10 respondents (n=49) state they are "familiar" with Toronto Hydro's electricity distribution system. Of those 49 people, 32 can explain the details of the system to others.

System Reliability: Number, Length and Seriousness of Outages

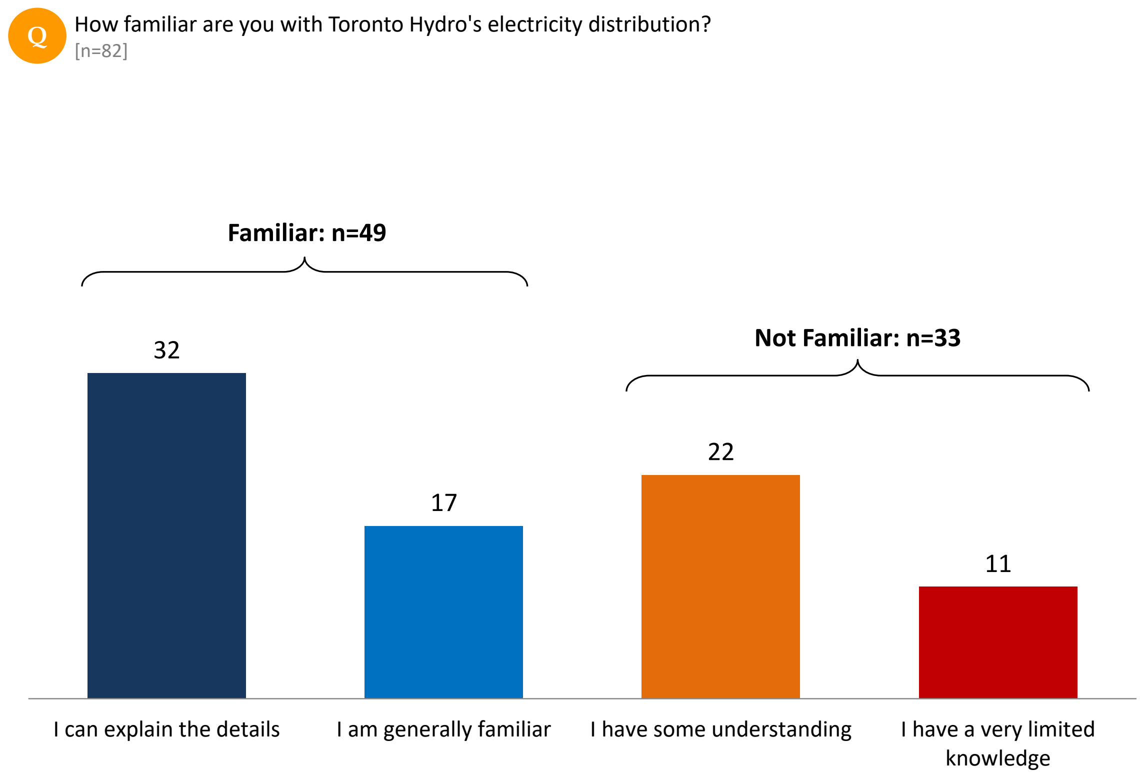
- A strong majority of respondents (n=66 out of n=83) think that the average *number* of outages in Central Toronto is "acceptable". Only 17 out of the 83 respondents on this question consider the number of outages "unacceptable".
- Again, a majority of respondents (n=59 out of n=83) find the average *length* of outages "acceptable" with roughly 3-in-10 (n=24) who find it "unacceptable".
- Sixty-one consulted customers also answered an open-ended question on 'number of outages' and 47 answered the follow-up on 'outage length'. The average *number* of outages for customers was a bit less than four (3.72). But the median or mid-point customer experienced outages much less frequently: two outages over the last two years. This difference can be explained by a few frequent outliers ("20" and "30" outages in the past two years) that skewed the average higher.
- The average outage *length* for customers who experienced one was 12.39 hours; again, the average skewed a bit higher from six possible outliers who experienced an outage of "48 hours or more". The median customer or half-way point in the sample was just two hours; and one in five (n=10) customers experienced an outage of 15 minutes or less.
- When customers were asked an open-ended question on how the outages affected their place of business, 56 people responded. The leading effect was a "minor inconvenience" (n=19) such as resetting clocks, followed by "spoiled food/disrupted holidays" (n=11) and "negatively affected living conditions" (n=11).
- In another open-ended follow-up, 65 customers gave a response estimating the dollar cost of expenses incurred during the power outage. About 4-in-10 (n=26) did not incur any expenses. The median customer experienced a loss of about $12.50 during this time. The average is much higher (almost $100k) due to a $5 million outlier response.
- Nearly three-quarters of respondents (n=57) stated "yes", that there was a certain length of time at which the costs and consequences of an outage became more serious for them.
- When those "yes" respondents were asked a follow-up to describe that length of time in detail, 57 responded. Anywhere from less than 30 minutes (n=5) to 48 hours or more (n=5) were timelines that caused serious consequences to consumers. Specific concerns mentioned include "food spoilage", "home heating and cooling affected" and "access to internet".

- Almost half of respondents (n=36) feel it is "extremely important" for the Central Toronto system to be reliable beyond the minimum standards and roughly a third (n=27) think it is somewhat important.

Reliability and Price

- When asked about how much they would be willing to add to their monthly bill for better service, every single person responded for a total of 83 customers. The average customer surveyed would be willing to pay about 5% more (median: 3%). The range of per cent customers would be willing to pay for better service varied widely, from as little as nothing to as high as 25%

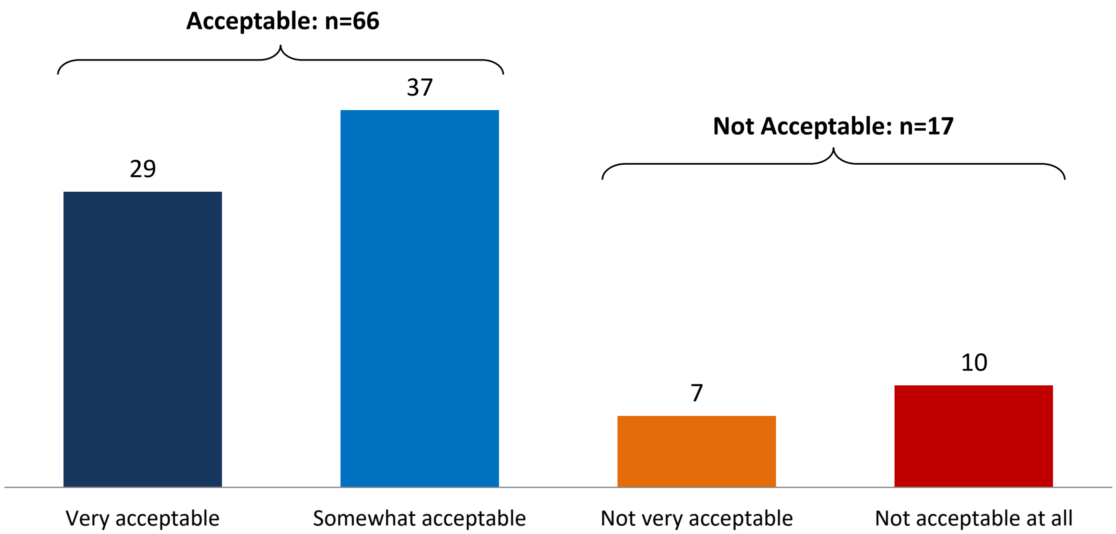
Figure 1: Familiarity with Electricity Distribution System



Roughly 6-in-10 (n=49) respondents are familiar with Toronto Hydro's electricity distribution. Among the 82 people who responded on this question, 32 can explain the details of distribution and 17 say they are generally familiar. About 4-in-10 (n=33) respondents are not familiar. Of these, 22 have some understanding of the system while 11 claim very limited knowledge of Toronto's electricity distribution.

Figure 2: Reliability of System: Number of Outages

Q Do you feel the current average number of electricity outages in the Central Toronto electricity system is acceptable or not acceptable?
[n=83]



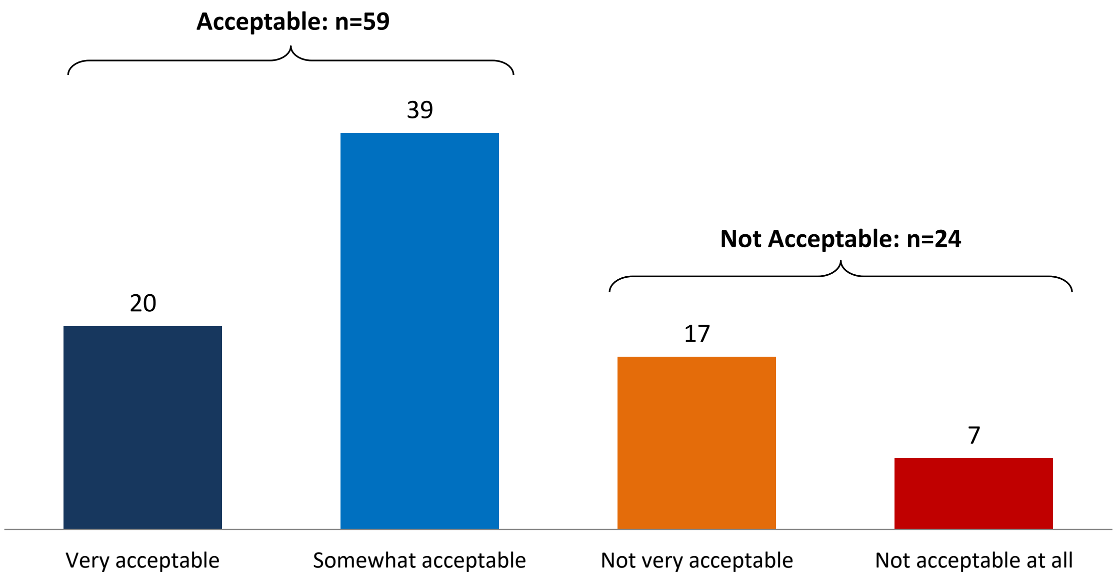
Note: Residential: n=72; Business: n=11. For business: "very acceptable" (4), "somewhat acceptable" (3), "not very acceptable" (1), "not acceptable at all" (3)

A strong majority of respondents (n=66) think that the number of outages in Central Toronto is "acceptable". Of the 83 who responded to this question, 29 stated the average number of outages are "very acceptable" and 37 thought it was "somewhat acceptable". Just 17 of the respondents think the number of outages is "not acceptable" with 10 who think it is "not acceptable at all".

Of the 11 business respondents who answered, four think the current level is "very acceptable", three find it "somewhat acceptable", just one finds it "not very acceptable", and the remaining three find it "not acceptable at all".

Figure 3: Reliability of System: Length of Outages

Q Do you feel the average length of an outage in the Central Toronto electricity system is acceptable or not acceptable?
[n=83]



Note: Residential: n=72; Business: n=11. For business: "very acceptable" (4), "somewhat acceptable" (2), "not very acceptable" (4), "not acceptable at all" (1)

A majority of respondents (n=59) also find the average length of an outage in Central Toronto "acceptable", although agreement is less strong here. Twenty out of the 83 respondents find average outage length "very acceptable" and 39 find it "somewhat acceptable". Roughly 3-in-10 respondents (n=24) find average length of outages in Central Toronto "unacceptable". Seventeen of the 83 think it is "not very acceptable" and the remaining seven believe the average length is "not acceptable at all".

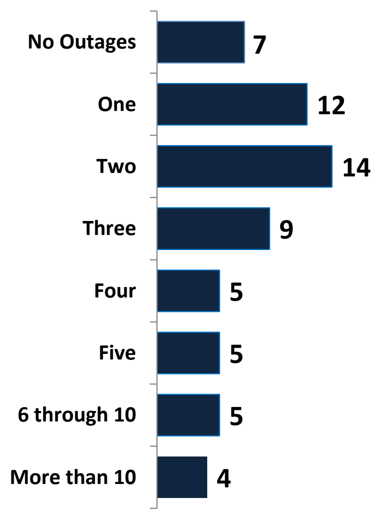
For the 11 business respondents who answered, four think the current level is "very acceptable", two believe it "somewhat acceptable", four find it "not very acceptable", and the remaining person finds it "not acceptable at all".

Figure 4: Open-ended on Number and Length of Outages

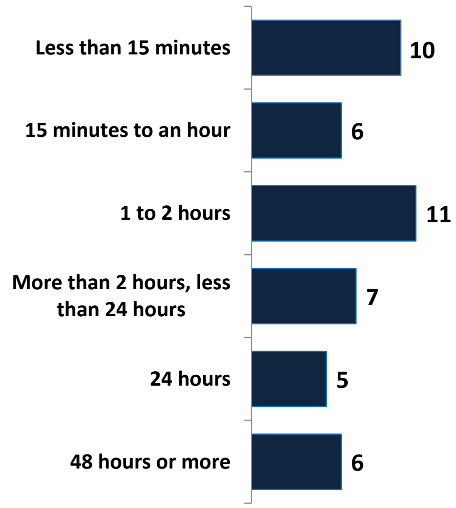
Q How many outages have you experienced over the last two years? [OPEN]
[n=61]

Q [If 1 or more] How long was the power out during your most recent outage? Please describe in hours. [OPEN]
[n=47]

"Number of outages"



"Number of hours without power"



Sixty-one consulted customers also answered an open-ended question on 'number of outages' and 47 answered the follow-up on 'outage length'.

When asked the number of outages they had experienced over the last two years, customer response varied widely from zero to as high as 30 outages. On average, the number of outages among respondents was less than four (3.72). However, because of the wide spread on these numbers (20 and 30 as a possible outlier), it may be more useful to look at the median or mid-way point between all the numbers. The median customer experienced two outages over the last two years.

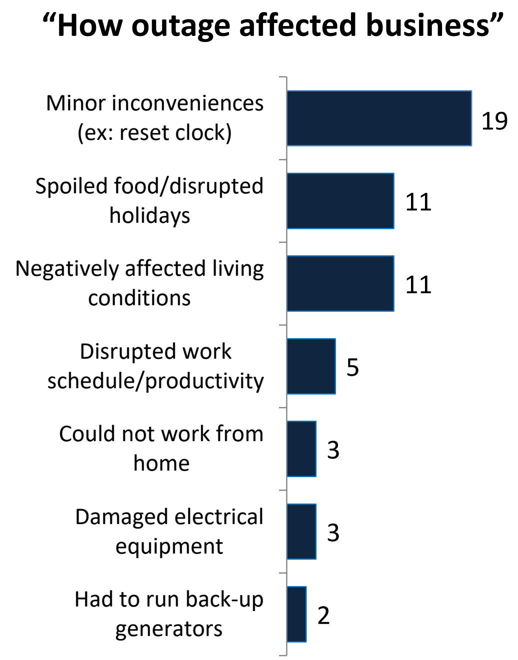
For those who experienced an outage, they were asked a follow-up question: "how long was the power out during your most recent outage in hours"? Ten of the 47 who responded stated their power was out for "less than 15 minutes"; 6 said "15 minutes to an hour" and 11 said between "one and two hours". On the higher end, seven customers said "more than two hours but less than 24 hours", 5 said "24 hours" and the final six suffered outages of "48 hours or more".

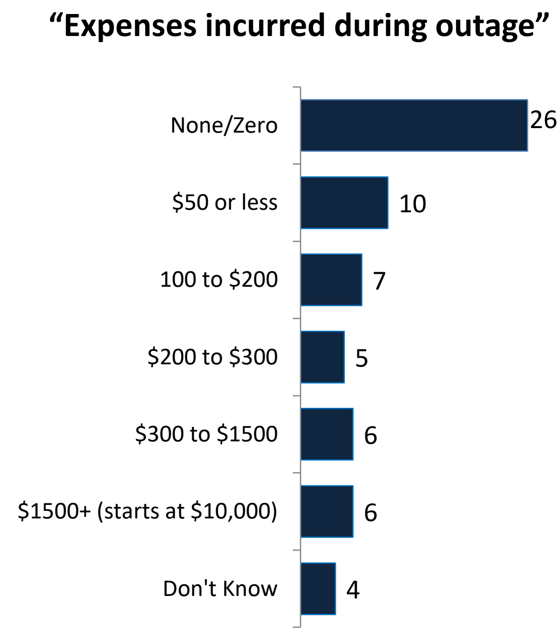
The range on this question varied widely, from just a few moments to a high of 96 hours. Again, because of this wide spread and the outlier of "96 hours" we see a strong difference between the median customer of just two hours and the average customer of 12.39 hours without power.

Figure 5: Open-ended on Outages for Business Respondents

Q [If 1 or more] How did the power outage affect your business? [OPEN]
[n=56]

Q [If 1 or more] Can you estimate the dollar value of any expenses you incurred as a result of the power outage? [OPEN]
[n=65]





Asked of all respondents. "Other" (n=1) and "No effect" (n=1) not shown.

"Refused" (n=1).

If customers experienced an outage, they were asked an additional follow-up on how it affected their place of business. Fifty-six customers responded to this open-ended question.

The leading effect for consulted customers was a "minor inconvenience" such as resetting clocks (n=19), followed by "spoiled food/disrupted holidays" (n=11) and "negatively affected living conditions" (n=11). Other effects of the outage on businesses include: "disrupted work schedule/productivity" (n=5), "could not work from home" (n=3", "damaged electrical equipment" (n=3) and "had to run back-up generators" (n=2).

One final follow-up was asked on the dollar estimate of any expenses incurred during the power outage; 65 customers responded.

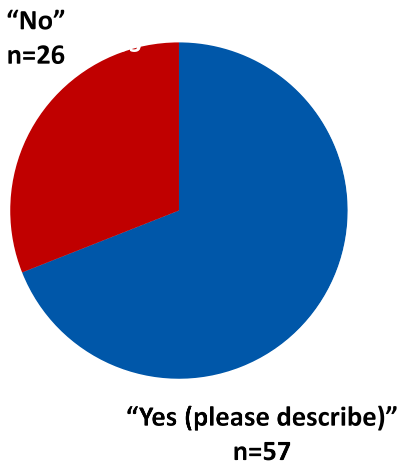
About 4-in-10 (n=26) did not incur any expenses during the outage and ten customers incurred $50 or less in damages. A smaller number of customers incurred $100 to $200 (n=7), $200 to $300 (n=5) and $300 to $1500 (n=6) in damages during the outages. The six remaining customers experienced $10,000 or more in damages with the highest range of cost up to an estimated $5 million.

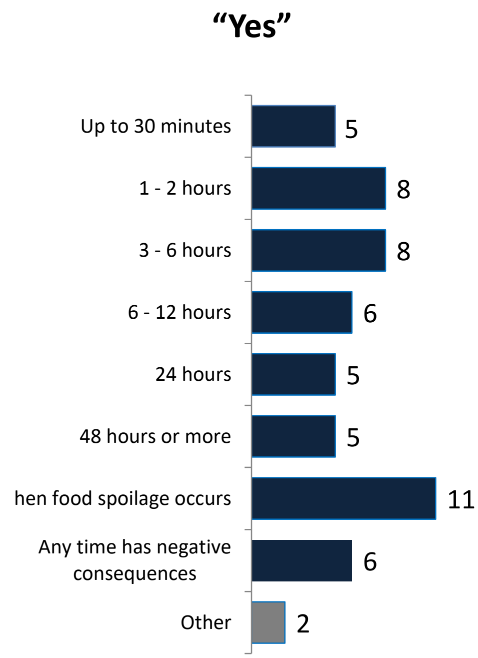
Again, because the range is so high (mostly zero with a $5 million outlier) the average customer loss on this response is going to be much higher than the median or mid-point customer. That being said, the average loss during outages was almost $100,000 ($97,543.88) because of this outlier while the median customer experienced a loss of about the price of dinner at 'Hero Burger': $12.50.

Figure 6: Seriousness of Outage Length

Q Is there a certain length of time at which the costs and consequences of an outage become more serious for you?
[n=83]

Q Yes, please describe [OPEN-ENDED]
[n=57]



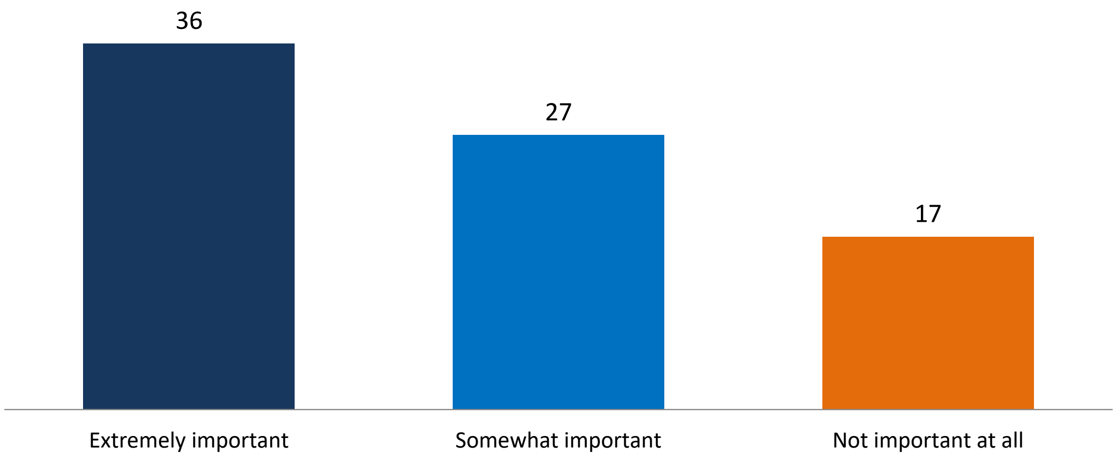


When asked if there was a certain length of time at which the costs and consequences of an outage become more serious, most of the respondents said "Yes" (n=57). Just 26 surveyed said "no", that there was no length of time when the costs and consequences would be serious.

Those that said "yes" were also asked an open-ended follow-up question to describe that length of time and 57 customers responded. A plurality were concerned about food spoilages (n=11 and also mentioned often in multiple time categories). Anywhere from up to 30 minutes (n=5) to 48 hours or more (n=5) were lengths of times that caused serious costs and consequences to consumers. Other concerns mentioned in the open-ended included "home heating and cooling affected", "access to internet" and other specific medical concerns.

Figure 7: Standards for Reliability

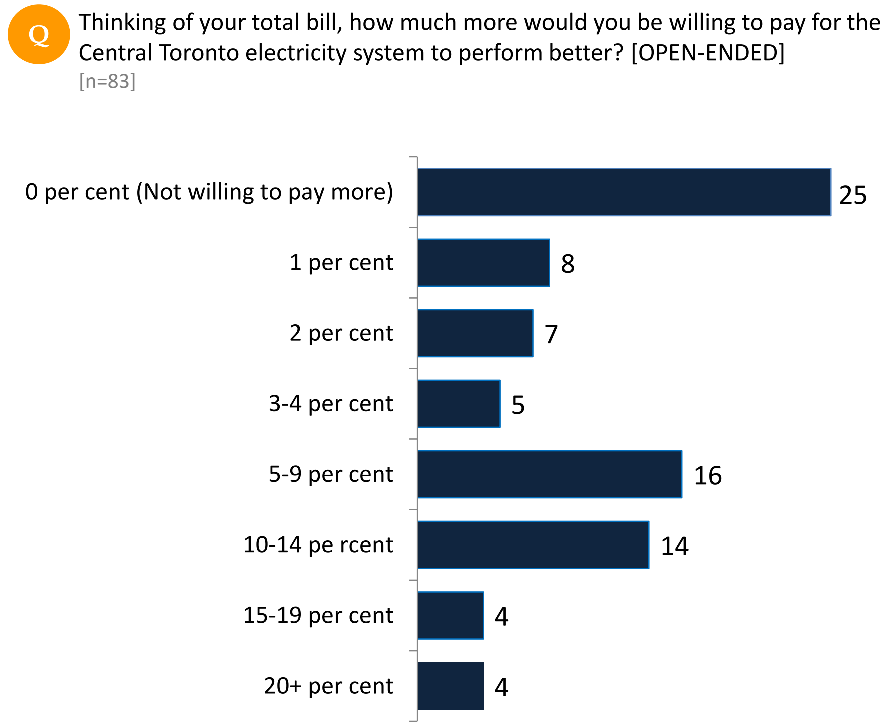
Q How important is it is for the Central Toronto electricity system to be reliable beyond the minimum standard?
[n=81]



Note: "Don't know": n=1. Residential: n=70; Business: n=11.
For business: "extremely important" (9), "somewhat important" (2)

Just under half of respondents (n=36) stated that it is "extremely important" for the Central Toronto electricity system to be reliable beyond the minimum standards. About a third (n=27) think that it is "somewhat important" to be reliable beyond the minimum standard. The remaining 17 people do not think it is important at all to be reliable beyond the minimum.

Figure 8: Reliability and Economic Development



For the open-ended question on billing and how much more they would be willing to pay for better service, every single person still taking the survey responded: a total of 83 customers.

A plurality of customers said they were not willing to pay any more than they currently do (n=25). About a quarter of the customers said they were willing to pay between 1-4% more (1%: n=8; 2%: n=7; 3-4%: n=5). Fifteen customers said they were willing to pay 5-9% more and 14 customers said they would pay between 10-14%. Four customers said they were willing to pay between 15-19% more and the remaining four customers offered to pay 20% or more for better service.

The average customer surveyed would pay roughly 5% (4.89%) more and the median or mid-point customer would pay about 3%. The range of per cent customers would be willing to pay for better service started at nothing and went as high as 25%

Security of the Electricity System: Satisfaction and Permission

This section of the workbook focuses on customer satisfaction with their electricity during major event interruptions and gauges how comfortable customers would be raising rates to address security during major events.

Satisfaction with Service during Major Events

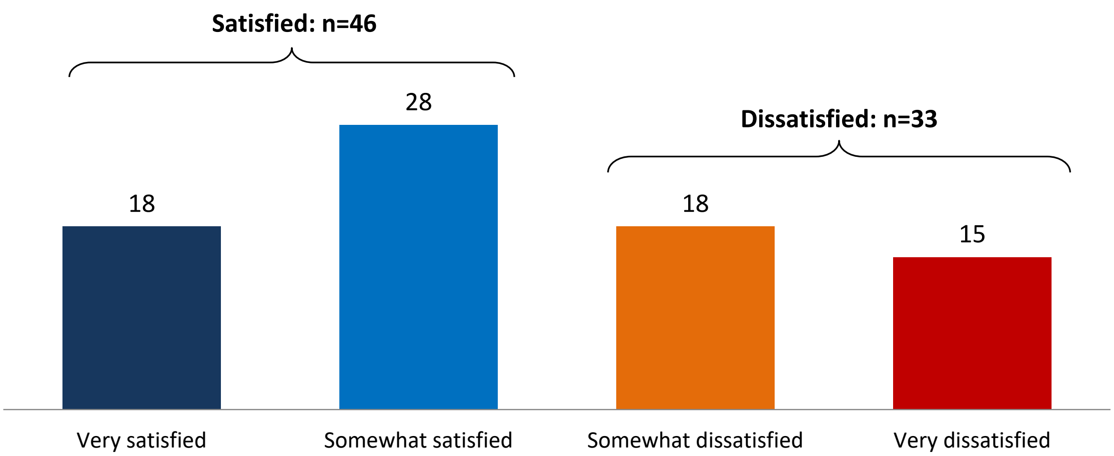
- Satisfaction with electricity system performance during major events is net positive. Forty-six of the 79 who answered the question "how satisfied are you with the way the Central Toronto electricity system has performed during major events" say they are satisfied and 33 of the 79 claim dissatisfaction.
- Of the 11 business customers surveyed, there is a 6-5 split on satisfied/unsatisfied.

Permission for Rate Increase to Address Security

- When asked about a potential rate increase to improve the system during major events, a majority (n=41) of customers supported the idea. Twenty-six of 79 said "no" and the remaining 12 did not know the answer.
- As for the 11 business customers, seven stated "yes", one "no" and the last three did not know how to respond.
- Those who gave permission on a rate increase (n=41) were asked a follow-up: "how much more would they be willing to pay as a percentage of their total bill to improve responses to major events"? (Eleven additional people replied to this despite the "if yes" shown in the question for a total of 52 respondents). The average customer would be willing to pay about 6% more for better service during major events, compared to less than 5% when asked previously about more general infrastructure improvements.

Figure 9: Satisfaction with Service during Major Events

Q From what you have read here and considering your own experience, how satisfied are you with the way the Central Toronto electricity system has performed during major events?
[n=79]



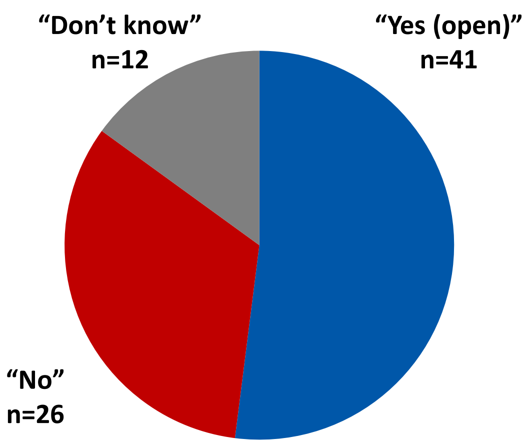
Note: Residential: n=68; Business: n=11. For business: "very satisfied" (4), "somewhat satisfied" (2), "somewhat dissatisfied" (3), "very dissatisfied" (2)

When asked about the performance of the Central Toronto electricity system during major events such as a natural disaster, satisfaction is net positive. Among those surveyed, 46 were satisfied and 33 were dissatisfied with the performance of the electricity system during major events. About one-in-five (n=18) were very satisfied and one-in-three (n=28) respondents were somewhat satisfied. Of those dissatisfied customers, 18 were somewhat dissatisfied and 15 stated they were very dissatisfied.

As for the 11 business respondents who answered, four stated they were "very satisfied", two were "somewhat satisfied", three think it "not very acceptable", and the remaining two people were "very dissatisfied" with the performance during major events.

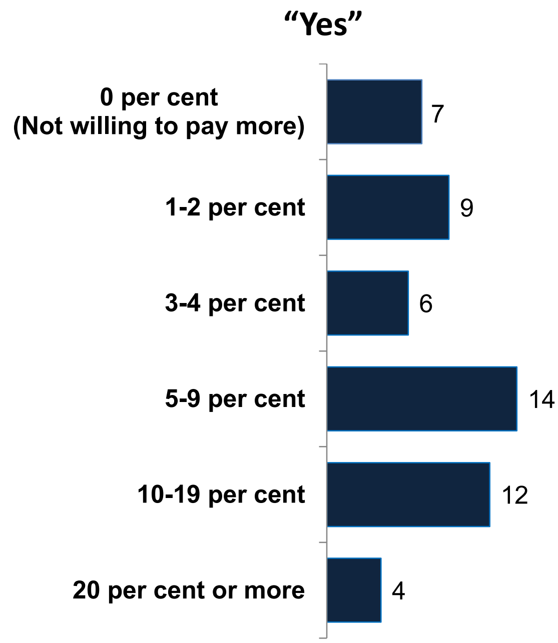
Figure 10: Permission for Rate Increase to Address Security

Q To improve the ability of the Central Toronto electricity system to respond to major events beyond our current standards will require spending more money. Are you willing to pay more on your electricity bill so the Toronto electricity system can improve its ability to respond to major events?
[n=79]



Note: Residential: n=68; Business: n=11. For business: "yes" (7), "no" (1), "don't know" (3)

Q (If Yes) And thinking of a percentage of your bill, how much more would you be willing to pay for the Central Toronto electricity system to improve its ability to respond to major events?
[n=52]



A slight majority of customers (n=41) give permission for a rate increase to improve the system's response to major events. More than a third (n=26) of customers say "no" to a rate increase directed to better service during major events. The remaining 12 people out of 79 just "don't know".

Of the 11 business customers who answered the permission question, seven responded "yes", just one stated "no" and the remaining three did not know the answer.

Those who gave permission (n=41) were asked a follow-up: "how much more would they be willing to pay as a percentage of their total bill to improve responses to major events"? (11 additional people replied to this despite the "if yes" shown in the question for a total of 52 respondents).

With a focus on improving system response to major events, customers were much more willing to pay a higher percentage than the previous, more general question on billing. Just 7 out of 52 respondents were not willing to pay any more, nine were willing to pay 1-2% more and 6 were willing to pay 3-4% more. A plurality of customers (n=14) were willing to pay between 5-9% more and 12 were willing to pay between 10-19% more. The remaining four customers surveyed were willing to pay 20% or more for better service during major events.

The average customer would be willing to pay 6%more for better service during major events, compared to an average of less than 5% more when asked previously about more general improvements. Similarly, the median customer would pay 5% more for better service during major events, compared to just 3%on the previous more general question. Both questions had the same range of responses (0-25%) but the billing question on major events skewed to a slightly higher percentage with less people saying “0%”.

Conservation and Long-term Solutions

This last section examines the customer consultation on long-term solutions, participation in conservation, attitudes on infrastructure investment and also preferences for various demand and generation solutions for regional electricity.

Participation in Energy Conservation

- Roughly three-in-four (n=56) respondents claim they participated in energy conservation activities. Of the 78 respondents left, eleven are business customers. Nine of these 11 business customers say "yes", they have participated in conservation activities.
- Of the 56 respondents who said “yes”, 49 explained their activities in the follow-up questions. Some of the conservation activities listed include “LED light bulbs” (n=17), “*peaksaver* PLUS program” (n=9) and “use of energy efficient appliances” (n=7).
- When asked about “Demand Response” programs, around 6-in-10 (n=48) would participate in them. Of the four categories, a plurality (n=29) of respondents chose “very likely” to participate. Business customers were split about evenly with five “likely” and six “not likely” to participate.

Infrastructure Investment

- Around 6-in-10 (n=46) respondents agree that system planners should look to new long-term investments in infrastructure to improve reliability and security, compared with 4-in-10 (n=31) who feel that system planners should use what they have already first. Slightly more business customers (n=7) than not (n=4) chose the statement on long-term infrastructure investment.
- When customers were asked their reasons for agreeing or disagreeing with the statement supporting infrastructure investment, 53 responded to the follow-up. Those who were against infrastructure investment cited “we should use existing infrastructure” (n=15) as the main reason, followed by “more cost-effective” (n=2) and “should reduce consumption” (n=2). Customers in support of additional infrastructure investment listed “build new infrastructure to improve reliability” (n=12), “plan for the future” (n=11) and “build to improve efficiency” (n=3) as their key reasons for support.

Generation Solutions

- When asked which generation options would be appropriate to Central Toronto "all of the time, some of the time or none of the time", the most popular two options were "solar" and "combined heat and power". Almost all the respondents would use solar and combined heat and power "all of the time (n=45 and n=41, respectively) or "some of the time" (n=28 and 31).
- "Bioenergy" (n=28: "all of the time"; n=37: "some of the time) and "using emergency generators" (n=16: "all of the time"; n=41 "some of the time") were deemed less appropriate generation solutions but still had wide support among those consulted.
- These preferences are largely mirrored in the 11 business customers.

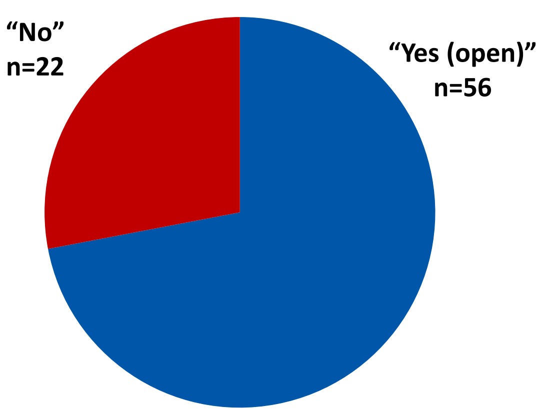
Demand Solutions

- Customers consulted on regional demand solutions felt all three demand solutions were "appropriate" ones. The 11 business customers surveyed also support all three options in similar strength.
- "Conservation and Demand Management" was considered the most "appropriate" demand solution with about two-thirds of customers who think it is a solution that should be used "all the time" (n=48) and a quarter (n=20) who feel it is appropriate "some of the time".
- "Transmission and Distribution" are also considered an "appropriate" demand solution among the 72 surveyed. Roughly 6-in-10 (n=42) think it is appropriate "all of the time" and 4-in-10 (n=29) feel it is appropriate "some of the time".
- The last option "Distributed Generation" also has general support with 32 of 72 customers who feel it is appropriate "all of the time" and 39 who think it should be used "some of the time".
- When asked to rank their first choice of demand solutions, a plurality (n=31) of customers chose "Conservation and Demand Management". Close behind was "Transmission and Distribution" (n=26) and the least popular first choice was "Distributed Generation" (n=15).
- For their second choice of demand solution, "Distributed Generation" (n=35) was the clear winner.
- In the customer explanations of their first and second choices, the main reasons given focused on cost, improved supply, reduced reliance and environmental concerns.

Figure 11: Participation in Energy Conservation

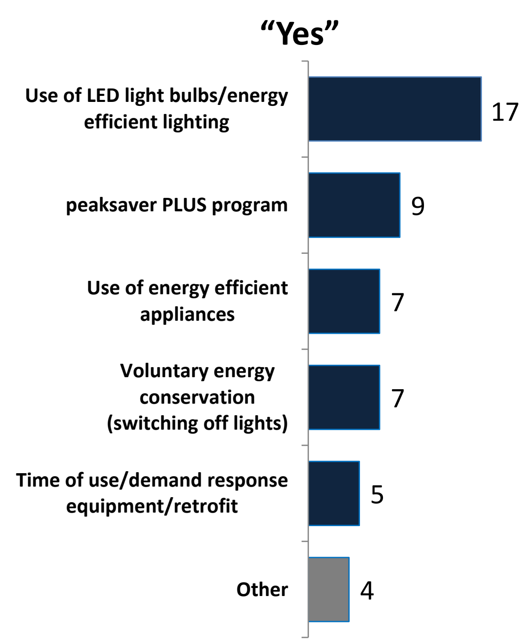
Q For each question, please either check the box for the options that best represents your view or write your response in the space provided.

Have you participated in any conservation activities?
[n=78]



Note: Residential: n=67; Business: n=11. For business: "yes" (9), "no" (2)

Q (If Yes) Please describe some of them? [OPEN]
[n=49]



About three-quarters (n=56) of customers surveyed have participated in energy conservation activities. The remaining 22 out of 78 respondents say "no", they have not participated in any conservation.

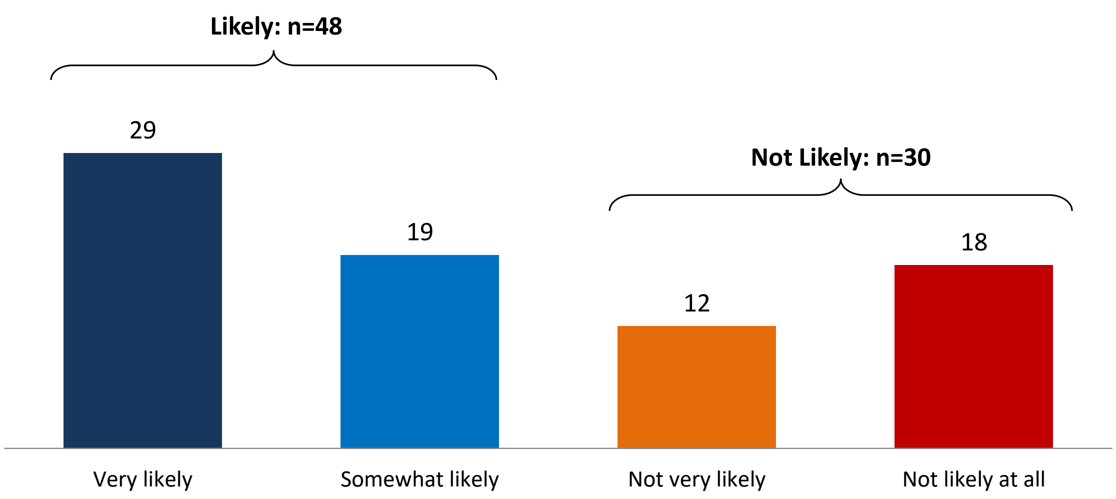
As for the 11 business respondents, nine say "yes", they have participated in conservation activities and the remaining two state the opposite.

Of the 56 respondents who say "yes", they do participate, 49 respondents chose to fill out the next questions describing those activities:

- About 3-in-10 (n=17) respondents cited "use of LED lightbulbs/energy efficient lighting" as their conservation activity.
- The "*peaksaver* PLUS program" (n=9) was the second leading conservation activity for customers.
- Other conservation activities mentioned include "use of energy efficient appliances" (n=7), "voluntary energy conservation" such as switching unused lights off more (n=7) and "time of use/demand response equipment retrofit" (n=5).

Figure 12: Likely Participation in Demand Response Programs

Q For CDM to provide an alternative to DG or transmission/distribution, it must provide an acceptable level of certainty as compared to DG or transmission. **How likely is it that you will participate in Demand Response programs that will allow electricity system managers to cycle equipment you are using?** For residences, this would involve automated devices that turn off your pool heater and air conditioner for short periods at time of peak demand. For commercial or industrial users, this would be an agreement to shut down specific agreed upon equipment on request.
[n=78]



Note: Residential: n=67; Business: n=11. For business: "very likely" (3), "somewhat likely" (2), "not very likely" (1), "not likely at all" (5)

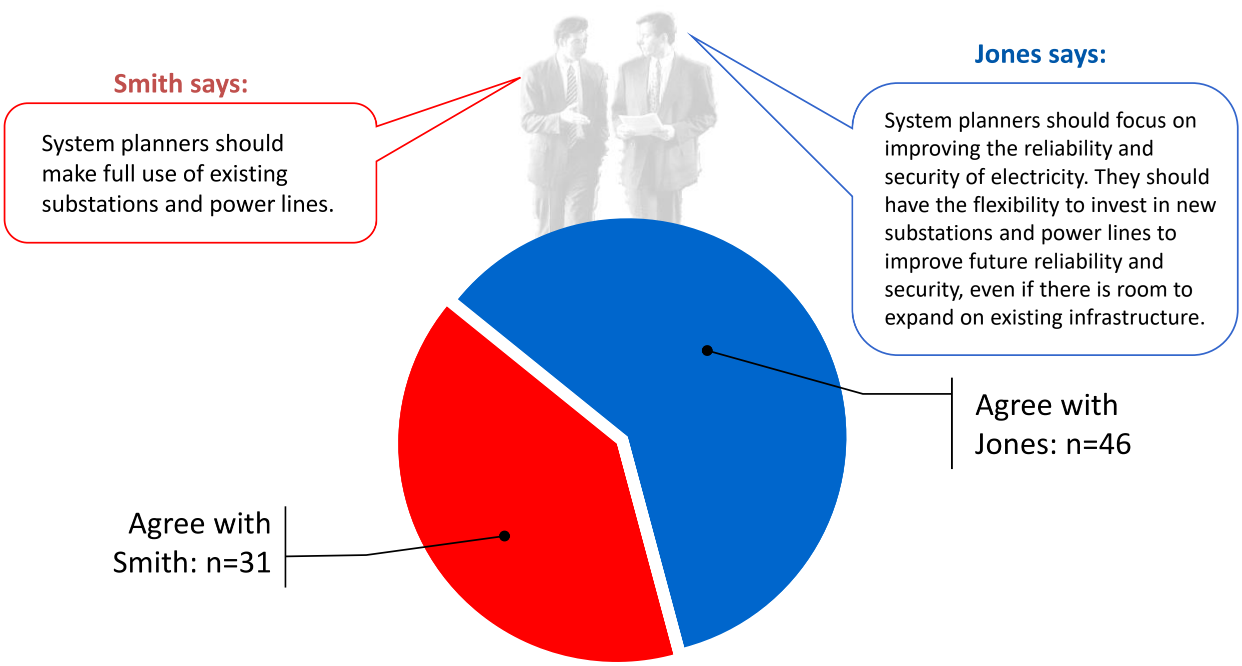
Roughly 6-in-10 (n=48) of the respondents would participate in "Demand Response" programs that would cycle equipment. Of those, 29 out of the 78 are "very likely" to participate and 19 are "somewhat likely" to do so. Roughly 4-in-10 respondents (n=30) are not likely to participate in these programs, with 12 "not very likely" and the remaining 18 "not likely at all" to participate in this type of response.

The 11 business customers responded as follows: three "very likely", two "somewhat likely", one person "not very likely" and five business customers "not likely at all".

Figure 13a: Investments in Infrastructure

Q For each question, please either check the box for the options that best represents your view or write your response in the space provided.

Sometimes planners have tough choices to make when it comes to balancing the need for capacity, reliability, and security. Below you will see two choices. Please indicate which choice you would make and why?
[n=77]



Note: Residential: n=66; Business: n=11. For business: "Smith" (4), "Jones" (7).

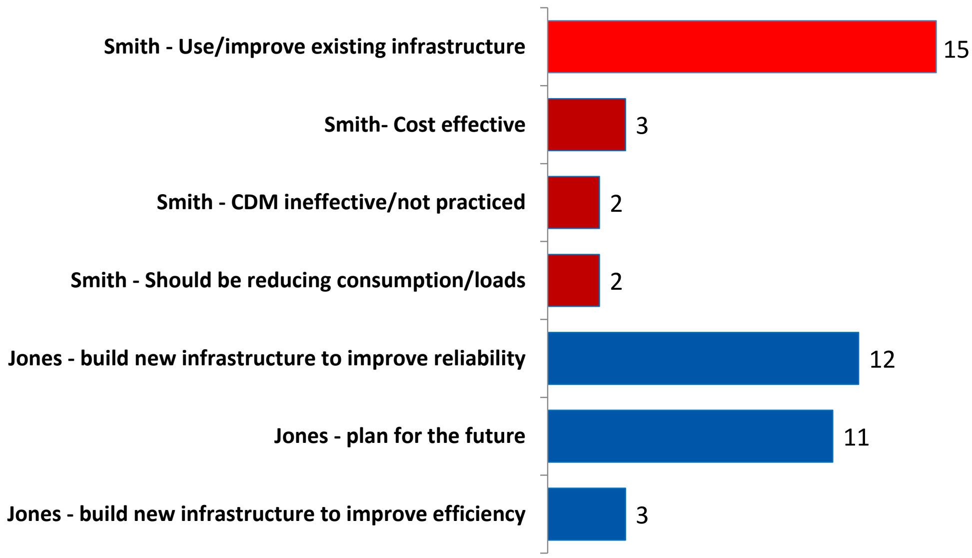
The next question asked respondents to choose between two strong opinions on balancing the need for capacity, reliability and security. One side argues that "system planners should make full use of existing substations and power lines" while the other states that "system planners should focus on improving the reliability and security of electricity…and invest in new substations and power lines to improve future reliability and security, even if there is room to expand on existing infrastructure".

About 4-in-10 (n=31) agree with the first opinion, that system planners should use what they have first. Around 6-in-10 (n=46) agreed with the second option, that system planners should look to new investments in infrastructure to improve future reliability and security.

Of the 11 business respondents, slightly more agree with the second statement on increased infrastructure investment (n=7) than the first statement that system planners should use what they have (n=4).

Figure 13b: Open-ended Response to Investments in Infrastructure

Q Sometimes planners have tough choices to make when it comes to balancing the need for capacity, reliability, and security…Why do you prefer the one view over the other? [OPEN-ENDED]
[n=53]



Note: "Other" [n=4], "Don't know" [n=1]

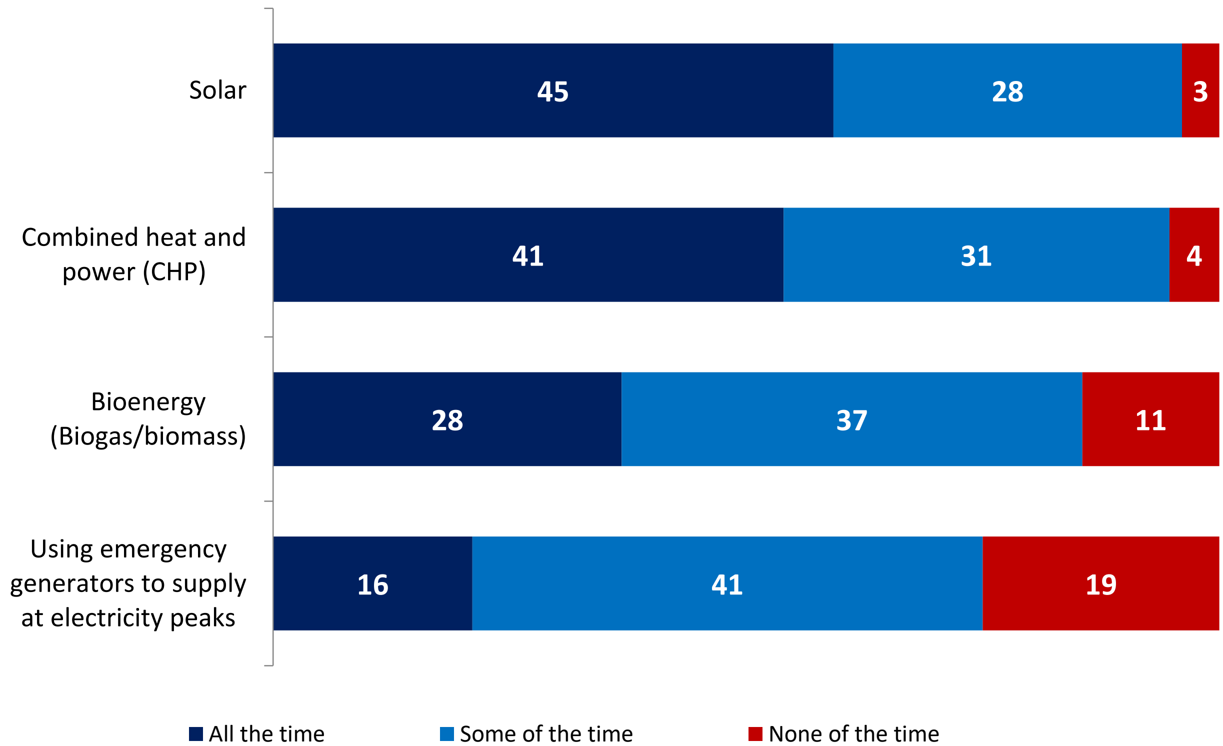
Respondents were then asked an open-ended question on why they preferred one of these arguments to the other- 53 customers answered.

For those that supported "Smith", the argument against infrastructure investment, the number one reason given is that "we should use/improve existing infrastructure" (n=15). Other reasons include "more cost-effective" (n=3), "CDM ineffective/not practiced" (n=2) and "should be reducing consumption/loads" (n=2).

And of those that supported new infrastructure investment or "Jones'" argument, 12 stated "build new infrastructure to improve reliability" (n=12), 11 said to "plan for the future" and the final three respondents stated we should "build new infrastructure to improve efficiency".

Figure 14: Generation Solutions for Central Toronto Area

Q For each of the following types of generation, please tell us what type of generation is appropriate in the Central Toronto area all of time, some of the time or none of the time:
[n=76 for all four questions]



Notes: Residential: n=65; Business: n=11. For business- "Solar" ("all the time": 8; "some of the time": 3), "Combined heat and power" ("all the time": 9; "some of the time": 2), "bioenergy" ("all the time": 7; "some of the time": 1; "none of the time": 3), "generators" ("all the time": 5; "some of the time": 4; "none of the time": 2)

Customers were then asked which of the following four different generation solutions are appropriate in the region "all of the time", "some of the time" or "none of the time": "solar", "combined heat and power (CHP)", "bioenergy" and "using emergency generators to supply at electricity peaks".

Solar proved the most popular option among the 76 remaining respondents with about six-in-ten (n=45) preferring to use this source "all of the time". Twenty-eight of the 76 customers would use it "some of the time" and the remaining three people would not use it at all.

A majority of customers (n=41) also would use combined heat and power 100% of the time. About 4-in-10 (n=31) customers would use this generation solution "some of the time" and just four people would not use it at any time.

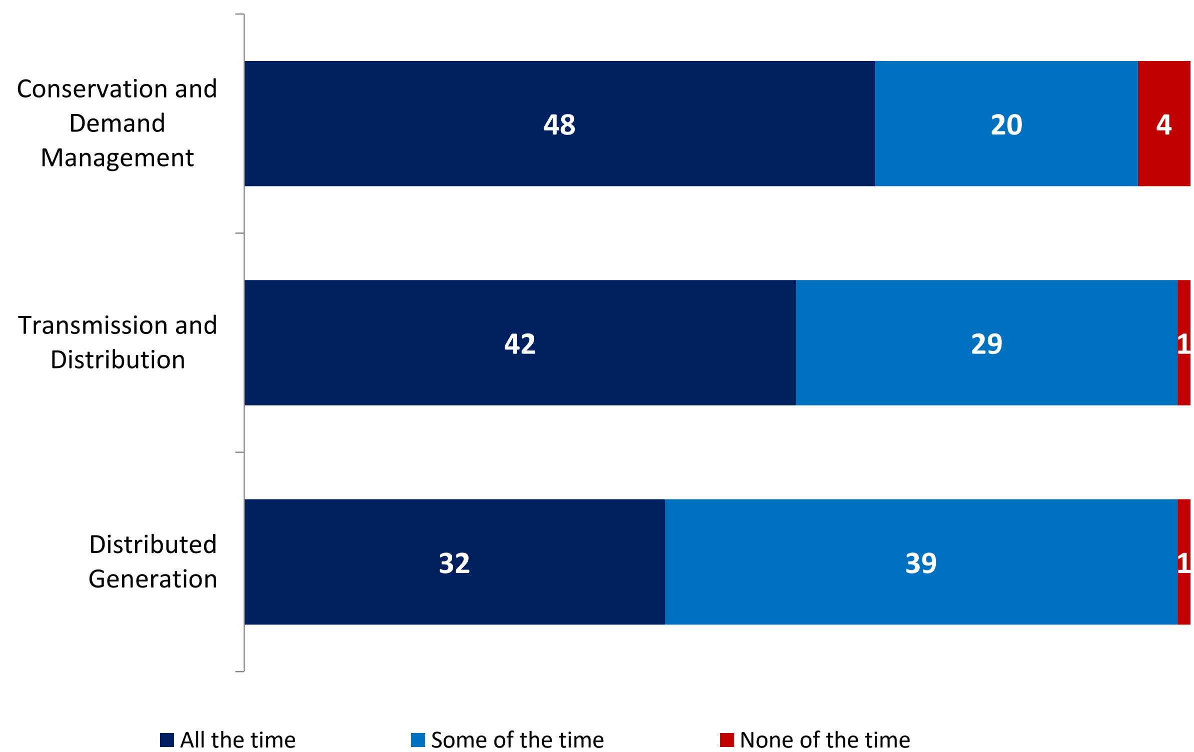
More than a third (n=28) of customers would prefer to use bioenergy at all times and just under half (n=37) would use this solution "some of the time". The remaining 11 people state they would use bioenergy "none of the time".

The least popular generation solution among customers is "emergency generator use at electricity peaks". Of every five respondents, one of them (n=16) would prefer this option "all the time" and more than half (n=41) think it is appropriate "some of the time". The remaining quarter (n=19) of customers think it is never appropriate to use.

Of the 11 business respondents, all of them support "solar" (n=8: "all of the time"; n=3: "some of the time") and "combined heat and power" (n=9: "all of the time"; n=2: "some of the time"). The two remaining options, "bioenergy" (n=7: "all the time"; n=1: "some of the time": n=3: "none of the time") and "generators" (n=5: "all the time"; n=4: "some of the time"; n=2: "none of the time") are less popular among business customers.

Figure 15: Demand Solutions for Central Toronto Area

Q For each of the following types of demand solutions, please tell me if you feel that solution is appropriate in the Central Toronto area all of time, some of the time or none of the time.
[n=72 for all four questions]



Notes: Residential: n=61; Business: n=11. For business- "Conservation and Demand" ("all the time": 10; "some of the time": 1), "Transmission and Distribution" ("all the time": 9; "some of the time": 2), "Distributed Generation" ("all the time": 7; "some of the time": 4)

When consulted about demand solutions for the region, customers proved widely supportive of all three options.

"Conservation and Demand Management" was considered the most "appropriate" demand solution with about two-thirds of customers who think it is a solution that should be used "all the time" (n=48). About a quarter (n=20) of respondents would use this solution "some of the time" and the remaining four people do not think it is an appropriate solution at any time.

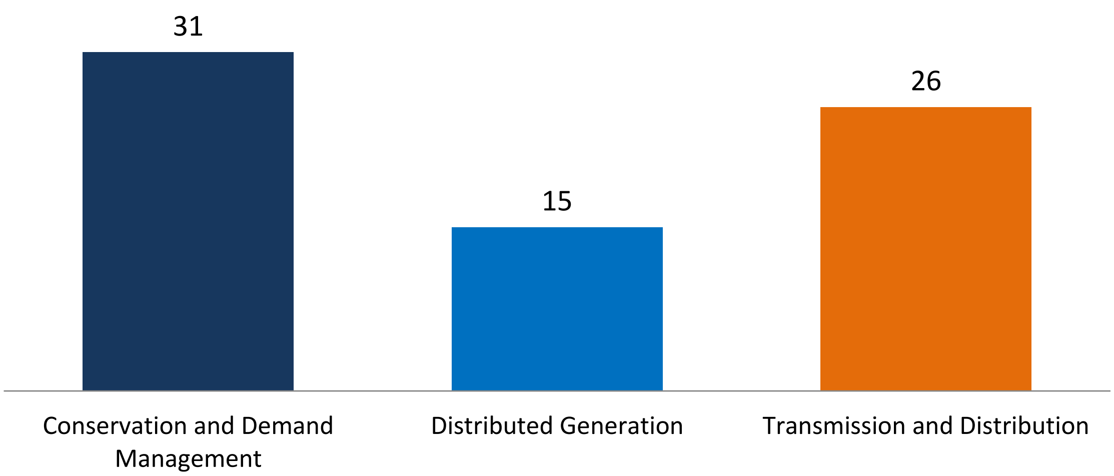
“Transmission and Distribution” also has wide support as an “appropriate” demand solution among the 72 customers surveyed. About 6-in-10 (n=42) of the respondents think it is an appropriate solution “all of the time”, around 4-in-10 (n=29) feel it should be used “some of the time” and just one person would not support “transmission and distribution” at any point in time.

The final option, “Distributed Generation”, has the least amount of support among customers, but is still considered largely an appropriate solution. Thirty-two of the 72 customers consulted feel it is appropriate “all of the time”, 39 think it should be used “some of the time” and again just one person does not think distributed generation is appropriate for any situation.

All 11 business customers surveyed support all three options in similar strength to the full sample. (“Conservation and Demand”: n=10 “all the time” and n=1 “some of the time”; “Transmission and Distribution”: n=9 “all of the time” and n=2 “some of the time; and “Distributed Generation”: n=7 “all of the time” and n=4 “some of the time”).

Figure 16a: First Choice of Demand Solution

Q Which of these solutions would be your first choice to deal with growing neighbourhood demands?
[n=72]



Notes: Residential: n=61; Business: n=11. For business- "Conservation and Demand": n=6; "Distributed Generation": n=3; "Transmission and Distribution": n=2

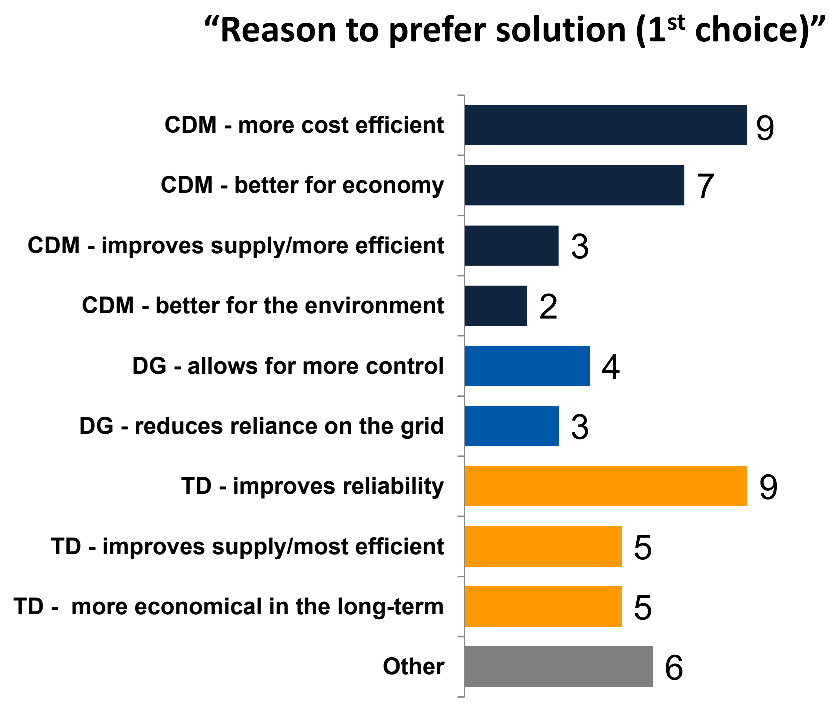
The final part of the workbook asked customers to rank their first and second choice of demand solutions and then to explain their reasoning behind it in two open-ended questions.

Just over 4-in-10 (n=31) of the remaining respondents chose "Conservation and Demand Management" as their first choice. "Transmission and Distribution" is right behind with 26 of the 72 customers picking it as their first choice. The remaining 15 felt "Distributed Generation" was their preferred solution.

Of the 11 business customers, six chose "Conservation and Demand" as their first preference, three picked "Distributed Generation" and the final two chose "Transmission and Distribution".

Figure 16b: Explanation of First Choice

Q And why do you prefer that solution over the remaining options? [OPEN-ENDED]
[n=55]



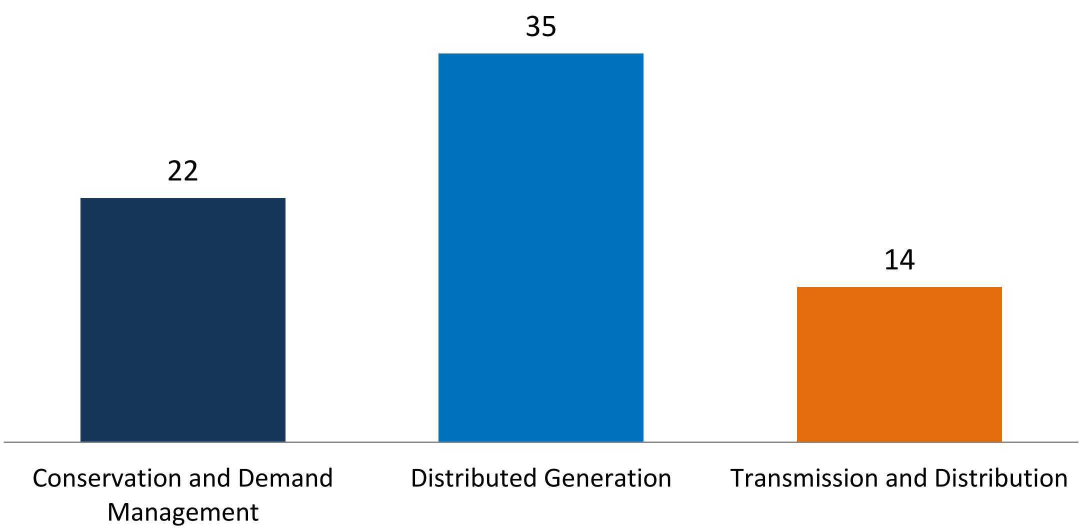
Notes: “Don’t know” (n=3) not shown.

When asked to explain why they chose that particular solution over the remaining options, fifty-five customers responded as follows:

- Of those who picked “Conservation and Demand Management” as their first choice, nine cite “more cost efficiency”, seven say “better for the economy”, three say “improves supply” and the remaining two argue it is “better for the environment”.
- The seven that chose “Distributed Generation” and responded to this question were split between “allows more control” (n=4) and “reduces reliance on the grid” (n=3).
- Finally, those that picked “Transmission and Distribution” and answered listed “improves reliability” (n=9), “improves supply” (n=5) and “more economical in the long-term” (n=5) as their reasons for support.

Figure 17a: Second Choice of Demand Solution

Q Which of these solutions would be your second choice to deal with growing neighbourhood demands?
[n=71]

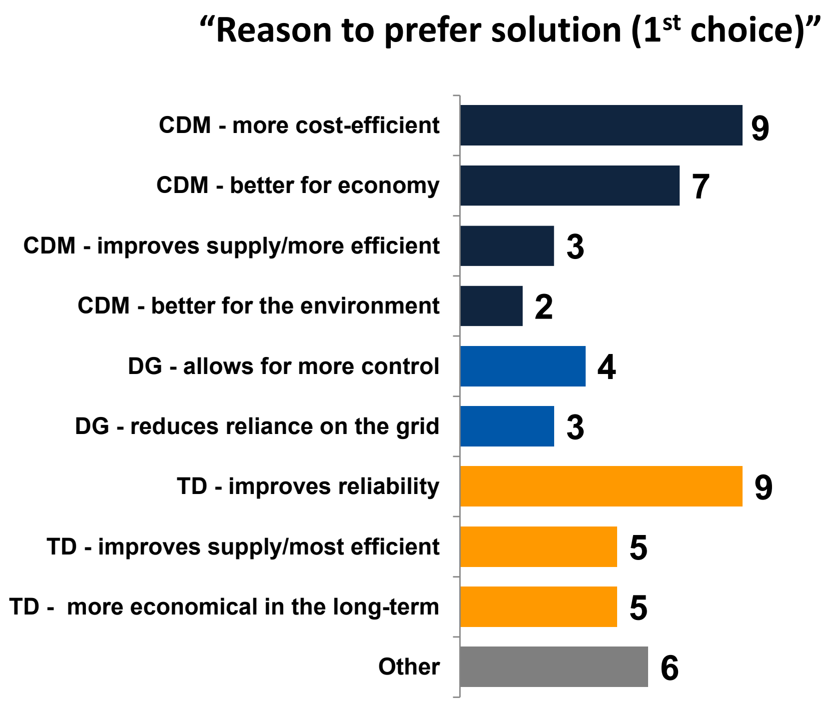


Notes: Residential: n=60; Business: n=11. For business- “Conservation and Demand”: n=7; “Distributed Generation”: n=3; “Transmission and Distribution”: n=1

The clear second choice to deal with growing demand is “Distributed Generation”: about half (n=35) of customers picked this option. Twenty-two of the remaining 71 respondents felt that “Conservation and Demand Management” was their second choice and the remaining 14 customers picked “Transmission and Distribution” as their second choice to deal with growing demand.

Figure 17b: Explanation of Second Choice

Q And why do you prefer that solution over the remaining options? [OPEN-ENDED]
[n=55]



Notes: "Don't know" (n=3) not shown.

In the last follow-up question of the survey, 54 customers explained their second choice solution as follows:

- Those who picked "Conservation and Demand Management" as their second choice cite "more cost-efficient" (n=7) and "need to reduce consumption" (n=3) as their main arguments.
- Of the plurality who picked "Distributed Generation" as their second choice, reasons included: "improving local generation" (n=7), "reduces reliance on the grid (n=6), "more control" (n=6) and "better for the environment" (n=4).
- And those that picked the third and final category "Transmission and Distribution" explained their reasoning as "better use of infrastructure" (n=4), "more economical in the long-term" (n=2) and, again, "better for the environment" (n=2).

Customer Consultation Groups

Customer Consultation Groups
with Residential and
General Service customers

PURPOSE: To gain qualitative input on planning options for Central Toronto from residential and GS < 50 kW customers and to obtain feedback into survey design

Summary

The following summary highlights key findings from the general service and residential Consultation sessions held in downtown Toronto on September 24th and 25th, 2014. Each night included one group of general service under 50 kW customers and one group of residential customers.

System Reliability: Customer Experience and Expectations

Most participants in the consultation groups have experienced an average of zero to four power service interruptions at their businesses and homes in the past 12 months. The duration of the service interruption lasted from a few minutes to, in some cases, many hours. Most general service and residential customers reported minor losses of productivity and a general inconvenience within their respected businesses and households due to outages.

Due to the relatively low number of outages, 24 of 29 participants found the current number of outages to be either very or somewhat acceptable.

That being said, many participants in both general service and residential groups felt that outside of extreme weather, there should be no system outages at all. For most customers, in both classes the key concern with outages was in the duration, and effective, accessible communications about the expected length of outages.

Improving Reliability Standards in Central Toronto

Twenty-five out of 29 participants believed it was either very or extremely important that the Central Toronto electricity system be reliable beyond the minimum standard.

Both general service and residential participants pointed to critical services like hospitals and subways to support the need for increased reliability standards in Central Toronto.

Despite acknowledging a need for increased standards, participants in both groups pointed to large-scale developments like condominiums to assume the bulk of the financial obligation of these investments. General service participants believed it was these large businesses that require increased reliability, and therefore they should be the ones to pay for it.

When setting goals for the system, residential users cared about both the frequency and the duration of the outages and requested less of both. The general service users stated that depending on the type of business, both the frequency and duration of outages can have major consequences.

Generally, participants in both groups understood the need for further investments; however, they were reluctant to see substantial increases on their bills. They have heard many stories of waste and mismanagement and expect the system will look hard for savings before asking consumers for more resources.

Planning for Extreme Events

Generally, when it came to extreme events, participants in both groups understood the rarity of these events; however, the uncertainty of future weather trends made them, for the most part, more willing to pay more.

Several participants in both groups pointed to the distribution system as a primary concern during extreme events. Both general service and residential customers requested proactivity when dealing with falling trees that cause system disruptions.

A few of the participants thought that instead of investing more in planning for extreme events, they could pay for generation themselves in the form of gas powered generators.

Several small business owners suggested that they don't have the capital to deal with the negative impacts of extreme events, such as flooding and loss of business during outages.

Customer Preferred Solutions

Seventeen out of 28 participants would select CDM as their first choice solution for dealing with growing neighbourhood demands.

That being said, many participants in both groups saw CDM as a community building tool rather than a peak demand solution.

A few participants saw Transmission and Distribution as the best "long-term" solution to meet the growing demand in Toronto. Generally they seem to see "wires" as a more tangible and reliable source of supply, compared to other sources.

Many participants saw DG as a relative unknown. Participants in both groups pointed to the need for more information and further technological advancement before selecting DG as a permanent, long-term solution for meeting growing neighbourhood demands.

Methodology

About the General Service and Residential Customer Consultation

The consultation sessions were held in Toronto on September 24th and 25th, 2014. A total of 29 general service and residential customers participated in these consultation sessions.

September 24, 2014

General Service under 50 kW Rate Class	7 participants
Residential Rate Class	8 participants

September 25, 2014

General Service under 50 kW Rate Class	6 participants
Residential Rate Class	8 participants

Recruiting Consultation Participants:

General service customers in the under 50 kW rate class were randomly selected by telephone from customer lists and screened for appropriateness as session participants. General service customers qualified for the consultation if they managed or oversaw their business' electricity bill. This was to ensure that they were at least somewhat knowledgeable of their electricity costs and that they could have an informed discussion on Central Toronto's IRRP.

Customer recruitment lists were randomly generated and provided to INNOVATIVE by Toronto Hydro.

An incentive of $100 was provided to all general service participants and $80 to residential customers who participated in the consultation sessions.

All consultation sessions were video recorded to verify participant feedback and quotations.

Consultation Session Structure:

The consultation sessions were structured around the themes contained in the workbook, which was developed by INNOVATIVE and the Central Toronto IRRP study partners.

The workbook themes consisted of the following:

1. What is this Consultation About?
2. Where Does Electricity Come From?
3. An Overview of the Central Toronto Electricity System Today
4. Planning to Meet Customer Expectations
5. Options for Meeting Central Toronto Demands

The penultimate version of the workbook was tested with the public to ensure that it provided the key information they felt they needed; as well as to test the accessibility of the language, and the effectiveness of the illustrations.

At the start of the sessions, the facilitator gave an overview explaining the purpose of the consultation and why they are seeking feedback from general service and residential customers.

After explaining the purpose of the consultation, hardcopy workbooks were distributed to act as a session guide for participants to record their answers to the question contained within.

Participants read through the workbook section-by-section and the moderator facilitated discussion based on each individual section.

When it came to the questions within the workbook, participants were asked to fill in their answers independently. The facilitator then led a group discussion on the answers participants provided and what they meant for them or their businesses.

Hardcopy workbooks were collected from the participants at the conclusion of each consultation session.

Each consultation session ran for approximately two hours. Participants commented that they felt the sessions were informative. In several groups, some participants continued to discuss the topic after the formal session was completed.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Participant Feedback

The following section summarizes the feedback from general service and residential customers.

General Service under 50kW Rate Class

System Reliability: Customer Experience and Expectation

Most general service customers had experienced an outage within the last 12 months. How and at what point the outage affected their business varied between customers.

In reference to when an outage would start to affect their business, one participant said, *"Because I'm downtown, I like to have a well-lit area and my security would go, and night is when things get weird downtown. So, after dark, that would be when I really start worrying".*

One participant, whose company operates 24-hours a day, explained the consequences of an outage, saying, *"For us, it's extremely detrimental for any period of time".* Any loss of productivity for a small business that operates 24/7 can be extremely costly.

For many general service customers, the time of day of outages greatly affects the severity of the impact. For instance, one participant who operated a catering company, said outages in the morning are costly; while a participant who ran a restaurant said the same about evenings. Additionally, a participant in the laundromat business said the after-work rush would be the most impactful time of day for an outage.

The bottom line for businesses is that an outage at any time can impact a wide variety of functions and minimizing both the number and length of outages is key to avoiding significant losses.

Improving Reliability Standards in Central Toronto

Many general service participants alluded to the need for increased reliability in critical areas. One participant said, *"Some critical areas, like hospitals that need to be running if it's life threatening. Also the banking system".*

While most participants in this group felt the need for increased reliability standards in Central Toronto, they were, for the most part, not interested in paying for it.

Many participants pointed to increasing bills without increasing reliability. One participant said, *"We've experienced probably the highest increase in rates in North America. No ifs, ands or buts. When I first started heating with electricity it was an effective way to go and now I'm stuck with it. Over the years they just keep bumping it. What are you going to do? There is no alternative".*

Again, while the need for increased reliability was felt by many in these groups, small business owners did not feel that the onus should be put on them. One participant said, *"The tax base in this city is increasing and do we see our taxes going down? The tax base is going up and our rates are going up, where's the money going? Put a surcharge on the heavy, the ones that need reliability the most.* ***You want to ride your elevator in a power outage, pay for it****"*.

Many general service participants agreed that certain high-use customers should be paying more to improve the reliability standards in Toronto. One participant said, *"I think in terms of the sustainability of the city, and the long-term plan, they definitely need a higher standard. People shouldn't be paying equal amounts. I think large developers [should be paying more]".*

Many general service customers found that the additional money needed to improve Toronto's reliability should be found from within. One participant said, *"I get really bent out of shape over the salaries that the people at Hydro are making",* another said, *"They seem to be getting more money, the salary packages are ridiculous".*

The general feeling amongst this group was to "**look first to yourself for more money".**

Planning for Extreme Events

Most general service customers were generally satisfied with the way the system has performed during major events - primarily the ice storm and flooding.

For a few participants, being prepared for major events was more important than an overall increase in reliability. One participant said, *"Major events were more important to me than normal reliability".* This concern appears to be related to the extended duration of the major outage events.

While most participants understood that these events were infrequent, they still expressed interest in improved planning for extreme events. When it came to paying for it, however, one participant said, *"I think they should do more because systems are changing and the reality, but I think how we spend that is a whole other question".*

While most participants wanted increased planning for major events, only 3 out of 13 general service customers would be willing to pay more for these system increases.

A few participants believed that while a backup plan was important during extreme events, it was not necessary to harden the whole system. One participant said, *"They need a few more generators scattered around the city, because it's not going to happen every year, or twice a year, maybe every ten years. But, in the case that it happens, it's life threatening, they need to have – as a government – a backup plan, not the hydro system by itself".*

Many small business owners stressed the fact that while investing in extreme events was important; their businesses were already struggling to keep up with rising bills as they are. With regards to paying more for increased extreme event planning, one small business owner said, *"So, when we hear hydro's going up 40%, we're freaking, because that means we're either going to have to cut staff, cut our teachers, we're going to have to work expanding our schedules, figuring out new ways to bring in that income that is going to go out to another big corporate entity".*

For the few participants that were willing to spend more to increase preparedness for extreme events, they generally believed it was a long-term investment in infrastructure that will be permanent, unlike other temporary fixes.

Customer Preferred Solutions

Ten out of 13 general service participants were either somewhat or very likely to participate in Demand Response programs. Additionally, 9 out of the same 13 selected CDM as their first choice in dealing with growing neighbourhood demand.

Many participants were attracted to CDM because they considered it to be a community building and involvement tool. Related to this, one participant said, *"You've got to deal with it on the community level and the trouble with the way Toronto Hydro has approached this thing is they are too busy shoving programs down our throat and not busy enough getting people to organize within their community".*

Additionally, many general service participants thought that CDM would be the best solution for reducing bills. One participant said, *"It makes sense to be able to do something that you can see* *immediate benefit, you feel like you actually have some impact, and the impact is the lowering of your bills".*

A few participants saw the best solution as a combination of CDM and Transmission & Distribution. One participant thoughtfully expressed her ideal combination, saying, *"What makes most sense to me is first CDM to control the problem right now while we start at the same time doing Transmission and Distribution, because that's a long-term fix. The city is going to continue to grow, so why procrastinate the fact that it needs to be done. Let's start right now with the areas that are more critical. DG doesn't take care of the heat of the area. Throwing money to the garbage unless it's placed near critical areas like hospitals".*

Residential Rate Class

System Reliability: Customer Experience and Expectation

Most residential customers had experienced an outage within the last 12 months. How and at what effect it had on them varied on the length and time of year the outage occurred.

Most participants noted minor inconveniences during shorter outages; including having to reset clocks, inability to communicate via internet or phone, and having to purchase candles to provide light.

However, participants who had experienced more prolonged outages reported more severe personal impacts. For instance, one participant said, *"My husband has health problems and so it's very important that we can be in contact with services and I just find that totally unacceptable".*

A few other residential customers were concerned with caring for the elderly and vulnerable during prolonged outages. One participant purchased a generator in case of an outage because they lived with an elderly person who utilized an electrically powered bed.

Additionally, a few residential participants noted that prolonged outages during the winter caused major property damage, such as flooding caused by frozen pipes. One participant said, *"A water pipe froze and when the power came back, the pipe burst. It cost $10,000".*

Several participants also noted that they work from home, and outages can seriously affect their productivity and cost them the ability to communicate with customers and clients.

Despite the personal impact of both short and prolonged outages, 12 of 16 residential customers found the number of outages to be either very or somewhat acceptable.

However, when it came to the length of these outages, only 9 of 16 agreed that they were either very or somewhat acceptable.

Improving Reliability Standards in Central Toronto

A few participants agreed that overall, some areas have excellent reliability, while others don't. "*Why should we pay the same amount if the system is not delivering the same amount?"*

While most residential customers agree that a higher standard is needed in Central Toronto, they were generally unhappy with the idea of paying more. One participant said, *"['I'd] prefer to have a better standard but can't afford to pay for it".*

While most participants were unwilling to pay additionally for improved reliability standards, a few said that they would, should reliability be significantly increased. One participant said, *"I would pay double if the system performed 100%".*

Despite the agreement of most participants that a higher standard was necessary, a few residential customers in the second group were generally satisfied with the current standard. One participant said, *"I don't think the change in my bill is going to make a difference".*

Planning for Extreme Events

Most participants in these groups found that more should be done to plan for the possibility of more extreme events.

However, a few participants found that this should occur gradually, and that more should be done to anticipate the unknown and strengthen the system where needed. One participant said, *"There should be a slow progression to get it to a better standard".*

Most participants feel that money from the current rates should be used to make these improvements to the system. They hear a lot about waste and mismanagement and do not believe a strong effort has been made to find savings. Again, most participants agreed that more should be invested; however, they were reluctant to pay more on their bills.

A few participants also said that instead of investing in the whole system, in order to combat these extreme events, residential customers could invest in their own self-generation.

Customer Preferred Solutions

Four out of 8 Residential customers in the first group selected Transmission and Distribution as their number one choice for dealing with increasing neighbourhood demand. Many of these participants believed it to be the most permanent solution that will help meet the growing demands. In the second group, however, zero participants selected this option at their first choice.

With regards to Transmission and Distribution solutions, one residential participant said, *"Because it seemed that the growth in demand was permanent, not temporary and because we don't have any information on how much more effective these other alternatives will become as technology advances and so if the growth is permanent it needs and increase in infrastructure and it seems as if the other two were temporary fixes to peak demand rather than a permanent, reliable increase to capacity and infrastructure".*

Eight out of a total of 15 residential customers selected CDM as their first choice; however, they believed it was important to combine several solutions to meet the demand.

A few participants noted that while conservation is a great tool, *"demand will exceed what we conserve"*.

Questionnaire Results

The following tables are the tabulations of participant feedback to questions in the hardcopy workbooks that were returned at the end of each consultation session.

Responses to *open-ended* questions were coded to generate frequency charts. Examples of transcribed responses are provided for each code.

Missing values are recorded beneath each table to indicate the number of participants who left a particular question unanswered.

1. Do you feel the current average number of electricity outages in the Central Toronto electricity system is acceptable or not acceptable?

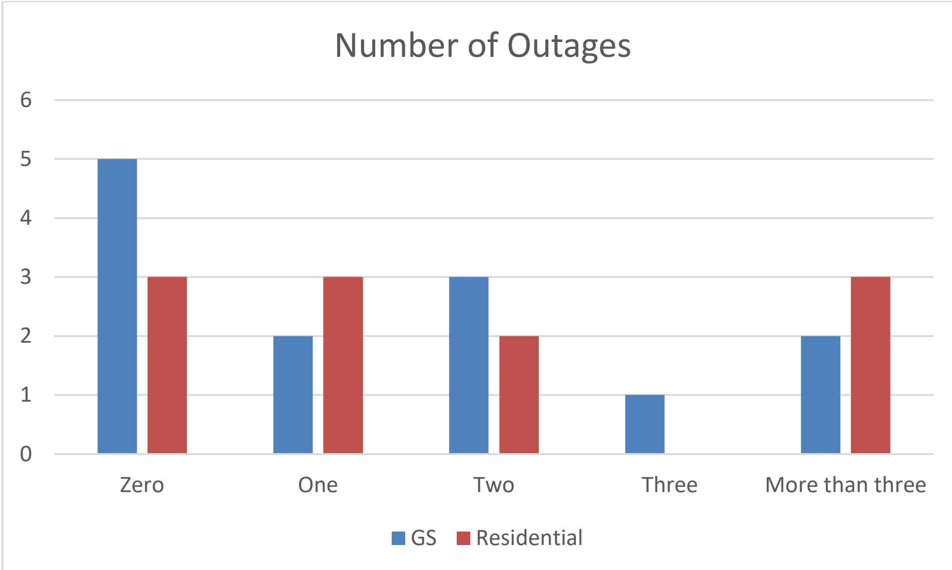
Response	GS	RS	Total	GS	RS	Total	Sum Total
Very acceptable	3	2	5	3	2	5	**10**
Somewhat acceptable	4	4	8	2	4	6	**14**
Not very Acceptable	0	1	1	1	1	2	**3**
Not acceptable at all	0	1	1	0	1	1	**2**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

2. Do you feel the average length of an outage in the Central Toronto electricity system is acceptable or not acceptable?

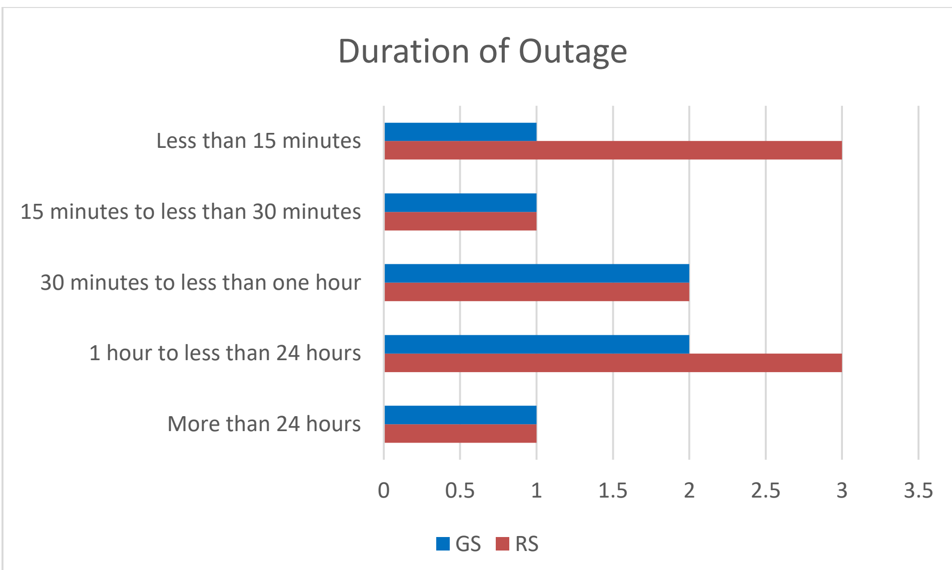
Response	GS	RS	Total	GS	RS	Total	Sum Total
Very acceptable	2	1	3	3	2	5	**8**
Somewhat acceptable	4	2	6	1	4	5	**11**
Not very acceptable	0	4	4	2	1	3	**7**
Not acceptable at all	0	1	1	0	1	1	**2**
Total	**6**	**8**	**14**	**6**	**8**	**14**	**28**

MV=1 MV=1

3. How many outages have you experienced over the past 12 months?



4. How long was the power out during your most recent outage? Please describe in hours (e.g. = .25 hours, 2 days = 48 hours)

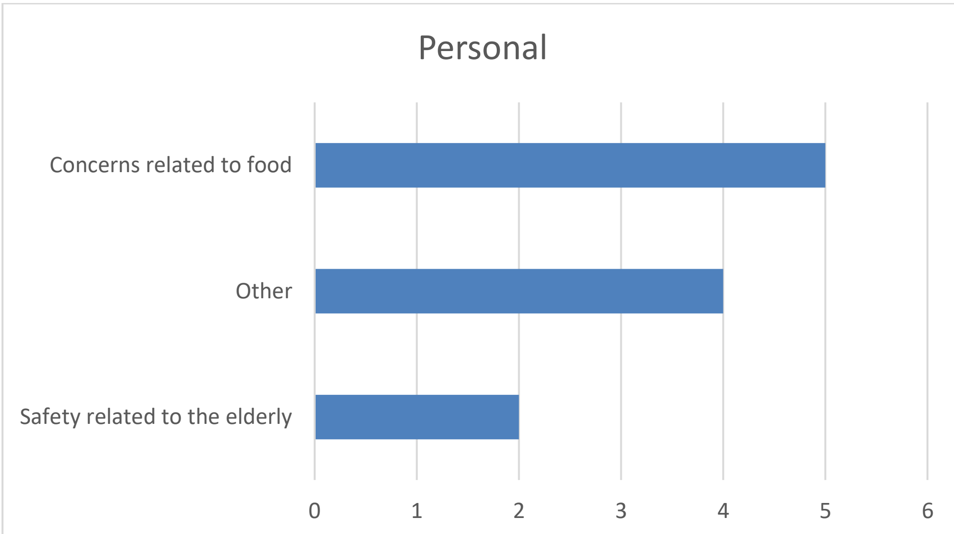


5. (IF 1 OR MORE OUTAGE)

Residential Customer

How did the power outage affect you personally?

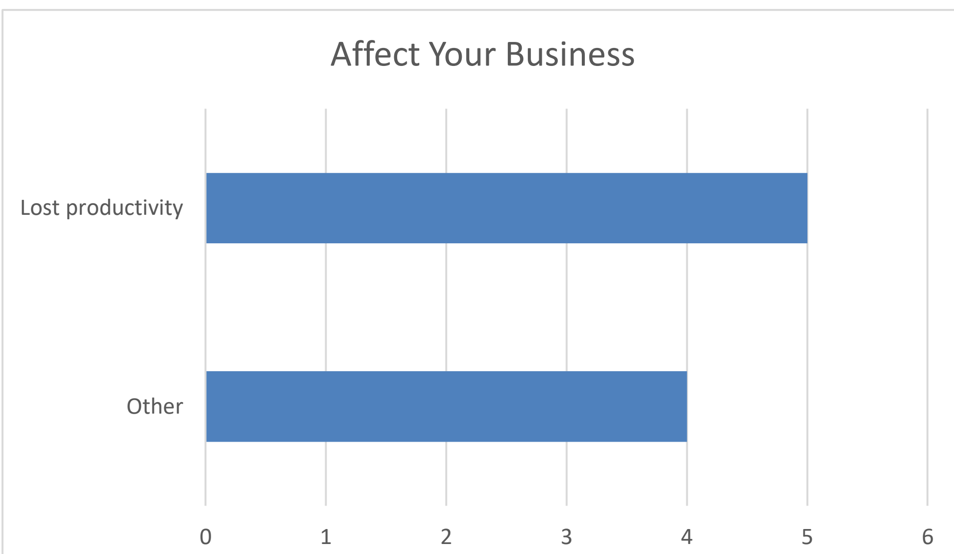
> **Concerns related to food:** *I was uncertain if food in refrigerator was affected… should it be thrown out?*
>
> **Safety related to the elderly:** *I have elderly parents and keeping them safety was an issue*
>
> **Other:** *I believe the power did go out on me one evening but it was my bed time hours so I didn't care. I was fine*



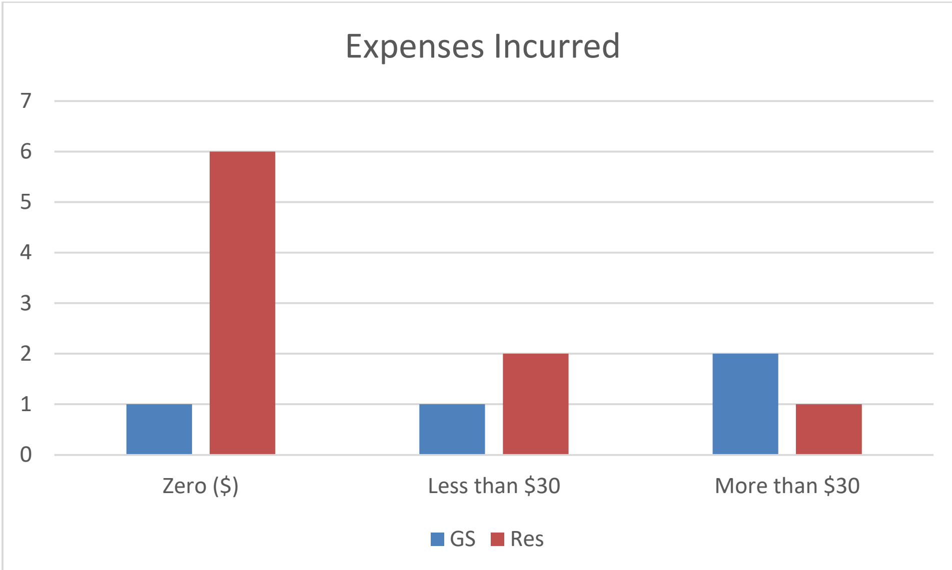
Business Customer

How did the power outage affect your business?

> **Lost productivity:** *Studio was unable to operate, no sales electronically could be made and heat issues.*
> **Other:** *Minor inconvenience*



6. (IF 1 OR MORE OUTAGE) Can you estimate the dollar value of any expenses you incurred as a result of the power outage?

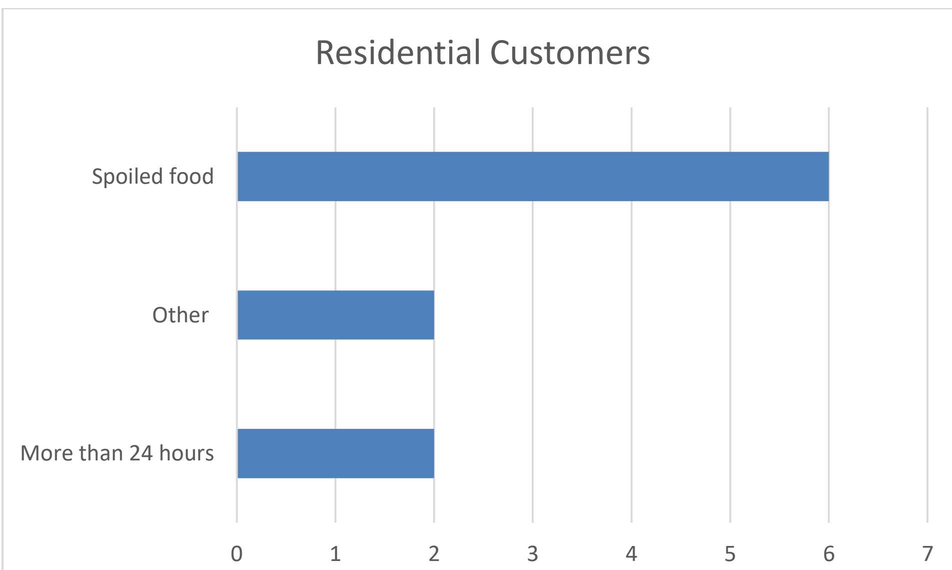


7. Is there a certain length of time at which the costs and consequences of an outage become more serious? [Yes (Please describe)

Spoiled Food: *I would consider a delay that impacted the food in my fridge to be problematic and costly*

More than 24 hours: *Particularly if it is beyond 24 hour period. The December blackout created MAJOR problems throughout my home*

Other: *2 hrs or more would cost me more*



Business responses varied, some comments included:

Winter time is very crucial if we have power outage

More than one day causes significant communication difficulties. Communication by phone only is problematic.

Electric heating system down during cold temperatures would be major inconvenience

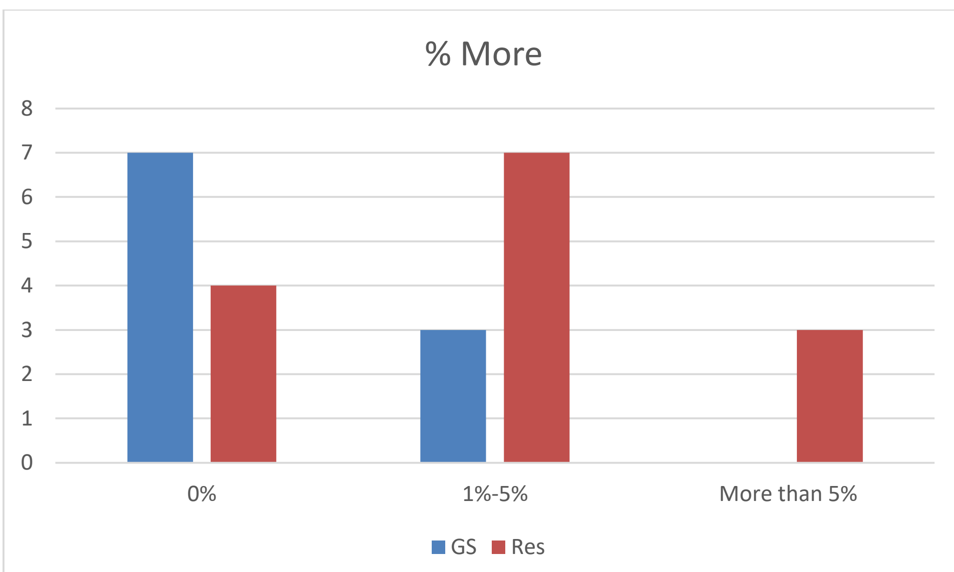
When an outage goes over 15 min at peak time

Food in freezers would be lost & the cost would be astronomical also fridges

8. How important is it that the Central Toronto electricity system be reliable beyond the minimum standard?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Extremely important	3	6	9	5	1	6	**15**
Very important	2	2	4	0	6	6	**10**
Somewhat important	0	0	0	1	0	1	**1**
Not very important	1	0	1	0	0	0	**1**
Not important at all	0	0	0	0	0	0	**0**
Don’t know	1	0	1	0	1	1	**2**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

9. Thinking of your total bill, how much more would you be willing to pay for the Central Toronto electricity system to perform better?



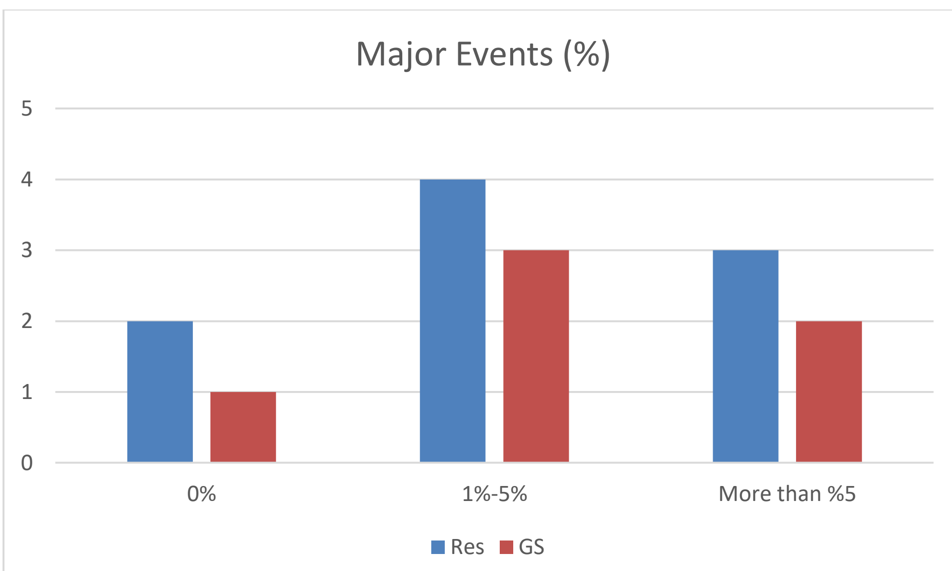
10. From what you have read here and considering your own experience, how satisfied are you with the way the Central Toronto electricity system has performed during major events?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Very satisfied	1	0	1	3	2	5	**6**
Somewhat satisfied	4	5	9	0	5	5	**14**
Somewhat dissatisfied	1	2	3	2	0	2	**5**
Very dissatisfied	0	1	1	0	0	0	**1**
Don't know	1	0	1	1	1	2	**3**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

11. To improve the ability of the Central Toronto electricity system to respond to major events beyond our current standards will require spending more money. Are you willing to pay more on your electricity bill so the Central Toronto electricity system can improve its ability to respond to major events?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Yes	1	3	4	2	3	5	**9**
No	3	3	6	3	3	6	**12**
Don't know	3	2	5	1	2	3	**8**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

11. IF YES: And thinking of a percentage of your bill, how much more would you be willing to pay for the Central Toronto electricity system to improve its ability to respond to major events?



12. Have you ever participated in any conservation activities?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Yes	6	6	12	6	5	11	**23**
No	1	1	2	0	2	2	**4**
Total	**7**	**7**	**14**	**6**	**7**	**13**	**27**
		MV=1			MV=1		MV=2

12. Have you participated in any conservation activities? If so, please describe some of them?

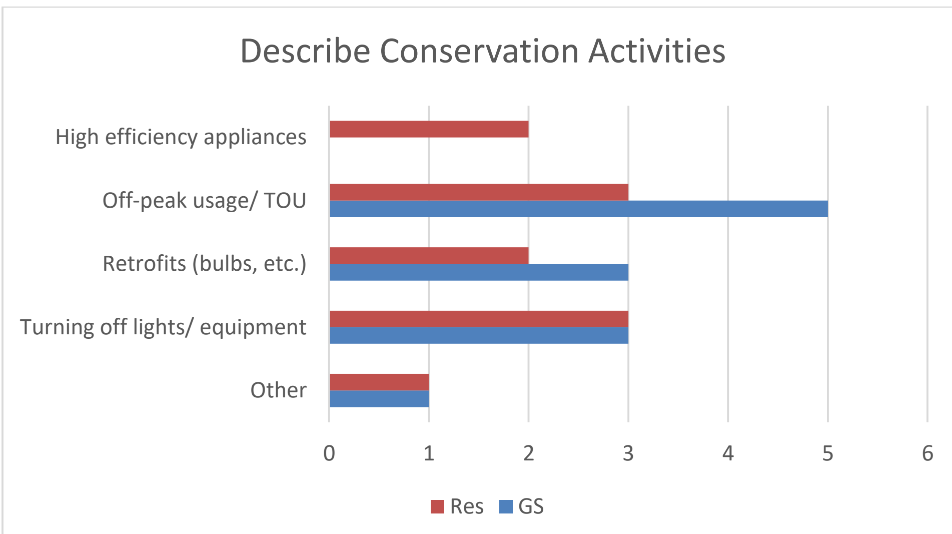
High efficiency appliances: *energy efficient equipment*

Off-peak usage/TOU: *Use washer, dryer, dishwasher off peak time, having energy saving lights and appliances*

Retrofits: *Home energy and added basement insulation, new furnace; caulking around window frames; do laundry in evening/ weekends*

Turning off lights: *Turning lights, appliances off whenever possible*

Other: *Urban agriculture, greenpeace, environmental justice campaigns*



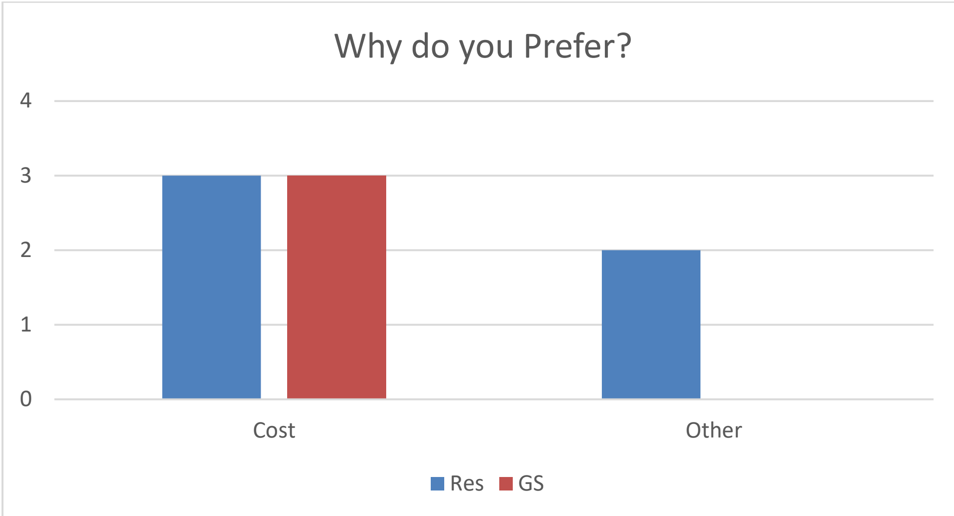
13. For CDM to provide an alternative to DG or transmission/distribution, it must provide an acceptable level of certainty as compared to DG or transmission. How likely is it that you will participate in Demand Response programs that will allow electricity system managers to cycle equipment you are using? For residences, this would involve automated devices that turn off your pool heater and air conditioner for short periods at time of peak demand. For commercial or industrial users, this would be an agreement to shut down specific equipment on request.

Response	GS	RS	Total	GS	RS	Total	Sum Total
Very likely	4	0	4	4	3	7	**11**
Somewhat likely	2	3	5	0	2	2	**7**
Not very likely	0	3	3	1	1	2	**5**
Not at all likely	1	2	3	1	1	2	**5**
Total	**7**	**8**	**15**	**6**	**7**	**13**	**28**
					MV=1		MV=1

14. (System planners should make full use of existing substations and power lines) **Why do you prefer the one view over the other?**

Cost: money, cost to my bill hydro bill is sky rocketing

Other: The existing substations are not fully utilized and have the capacity to supply enough power. The planners need to focus on the efficiency and full utilization of existing system

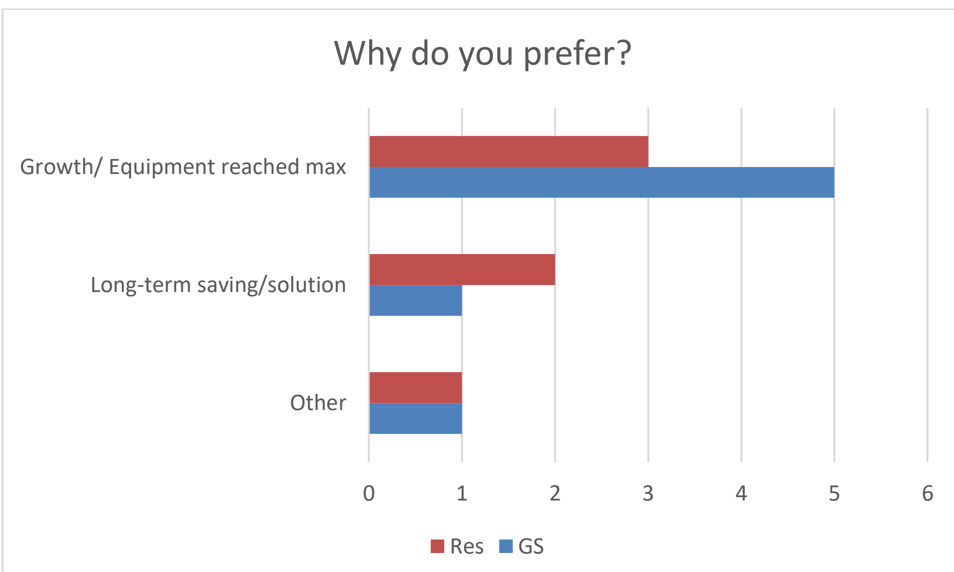


System planners should focus on improving the reliability and security of electricity. They should have the flexibility to invest in new substations and power lines to improve future reliability and security, even if there is room to expand on existing infrastructure.

Growth: *City is growing & power must keep up with the future. Newer, more efficient technologies will be available & improve: capacity, reliability & security*

Long-term saving: *I would think that this points to long term saving cost*

Other: *Because the government needs to be proactive and enhance the electrical system on an ongoing basis to avoid a total crash and a huge expense all at once*



For each of the following types of generation, please tell us what type of generation is appropriate in the Central Toronto area all of the time, some of the time or none of the time.

15. Solar

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	5	5	10	4	4	8	**18**
Some of the time	0	2	2	2	4	6	**8**
None of the time	1	0	1	0	0	0	**1**
Total	**6**	**7**	**13**	**6**	**8**	**14**	**27**

MV=1 MV=1 MV=2

16. Bioenergy (Biogas/biomass)

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	1	1	2	2	0	2	**4**
Some of the time	4	4	8	3	7	10	**18**
None of the time	1	2	3	1	1	2	**5**
Total	**6**	**7**	**13**	**6**	**8**	**14**	**27**

MV=1 MV=1 MV=2

17. Combined heat and power (CHP)

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	2	1	3	2	1	3	**6**
Some of the time	3	6	9	4	7	11	**20**
None of the time	0	0	0	0	0	0	**0**
Total	**5**	**7**	**12**	**6**	**8**	**14**	**26**

MV=2 MV=1 MV=3

18. Using emergency generators to supply at electricity peaks

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	1	1	2	1	6	7	**9**
Some of the time	3	5	8	4	1	5	**13**
None of the time	1	1	2	1	1	2	**4**
Total	**5**	**7**	**12**	**6**	**8**	**14**	**26**

MV=2 MV=1 MV=3

For each of the following types of demand solutions, please tell me if you feel that solution is appropriate in the Central Toronto area all of the time, some of the time or none of the time

19. Conservation and Demand Management

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	5	5	10	5	7	12	**22**
Some of the time	1	3	4	1	1	2	**6**
None of the time	1	0	1	0	0	0	**1**
Total	**7**	**8**	**15**	**6**	**8**	**14**	**29**

20. Distributed Generation

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	3	1	4	1	5	6	**10**
Some of the time	2	7	9	5	3	8	**17**
None of the time	1	0	1	0	0	0	**1**
Total	**6**	**8**	**14**	**6**	**8**	**14**	**28**

MV=1 MV=1

21. Transmission and Distribution

Response	GS	RS	Total	GS	RS	Total	Sum Total
All of the time	3	2	5	2	3	5	**10**
Some of the time	3	6	9	4	4	8	**17**
None of the time	0	0	0	0	1	1	**1**
Total	**6**	**8**	**14**	**6**	**8**	**14**	**28**

MV=1 MV=1

22. Which of these solutions would be your first choice to deal with growing neighbourhood demands?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Conservation and Demand Management	4	2	6	5	6	11	**17**
Distributed Generation	1	2	3	1	1	2	**5**
Transmission and Distribution	2	4	6	0	0	0	**6**
Total	**7**	**8**	**15**	**6**	**7**	**13**	**28**

MV=1 MV=1

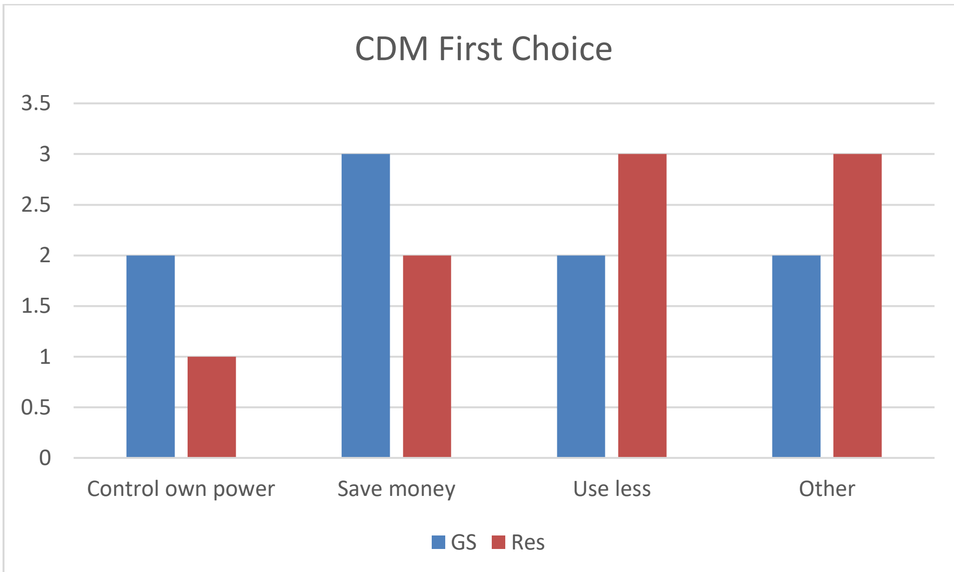
23. And why do you prefer that solution over the remaining options? **(Conservation and Demand Management)**

Control own power: *It allows us to become personally responsible for the amount of energy we use and if used in tandem with the current system would save the public and businesses alike, money.*

Save money: *it does not have a cost for me*

Use less: *we must conserve and use less*

Other: *CDM more long-term*



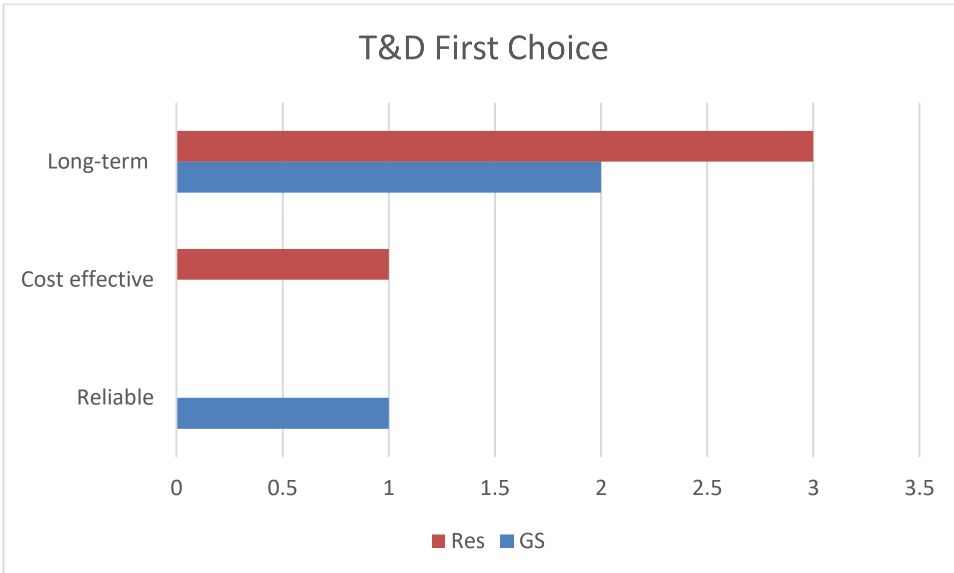
23. And why do you prefer that solution over the remaining options? **(Distributed Generation)**

Only two residential and one business customer selected **Distributed Generation** as their first choice, their responses included:

I believe this solution has less unknown and better control
This can be a permanent solution
Sets up in two to five years. Uses renewables

23. And why do you prefer that solution over the remaining options? **(Transmission and Distribution)**

> **Long-term:** *#1 permanent solutions*
>
> **Cost effective:** *It is cost effective in it does not require maintenance and other costs*
>
> **Reliable:** *I think it's more reliable than CDM and more efficient (cost) than DG*



24. Which of these solutions would be your second choice to deal with growing neighbourhood demands?

Response	GS	RS	Total	GS	RS	Total	Sum Total
Conservation and Demand Management	0	2	2	1	0	1	**3**
Distributed Generation	3	4	7	2	3	5	**12**
Transmission and Distribution	3	1	4	3	3		**10**
Total	**6**	**7**	**13**	**6**	**6**	**12**	**25**
	MV=1	MV=1			MV=2		MV=4

25. And why do you prefer that solution over the remaining options? **(Conservation and Demand Management) (Second Choice)**

Conservation and Demand Management was selected by only two respondents (1 GS & 1 Res) as a second choice, their answers are as follows:

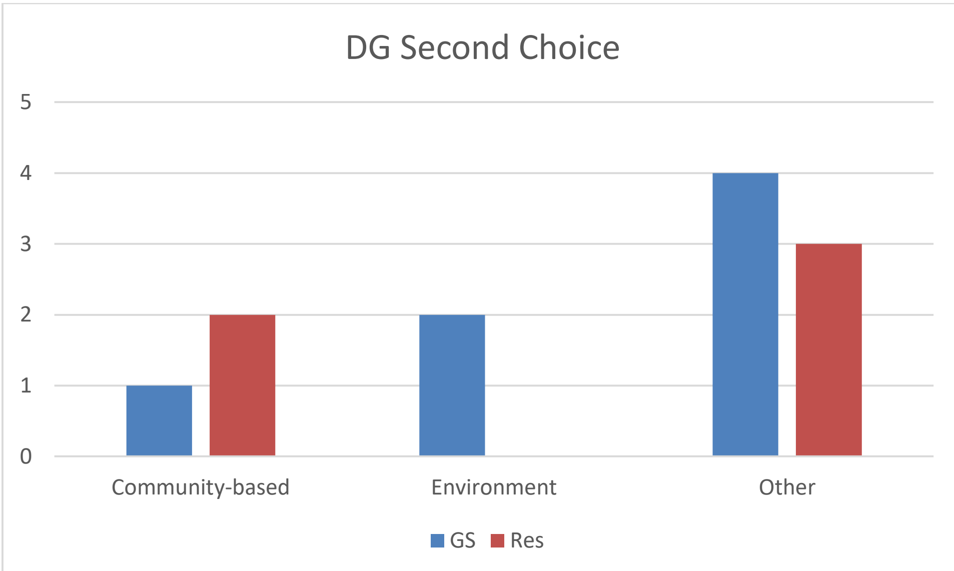
> *DG is tougher in urban areas. Windmills need space and solar isn't a consistent and continuous form of power*
>
> *Cost effective. Off sets peak demands*

25. And why do you prefer that solution over the remaining options? **(Distributed Generation) (Second Choice)**

Community-based: *It allows for the energy source to be located close to the communities it serves and can be used hand in hand with Conservation and Demand Management.*

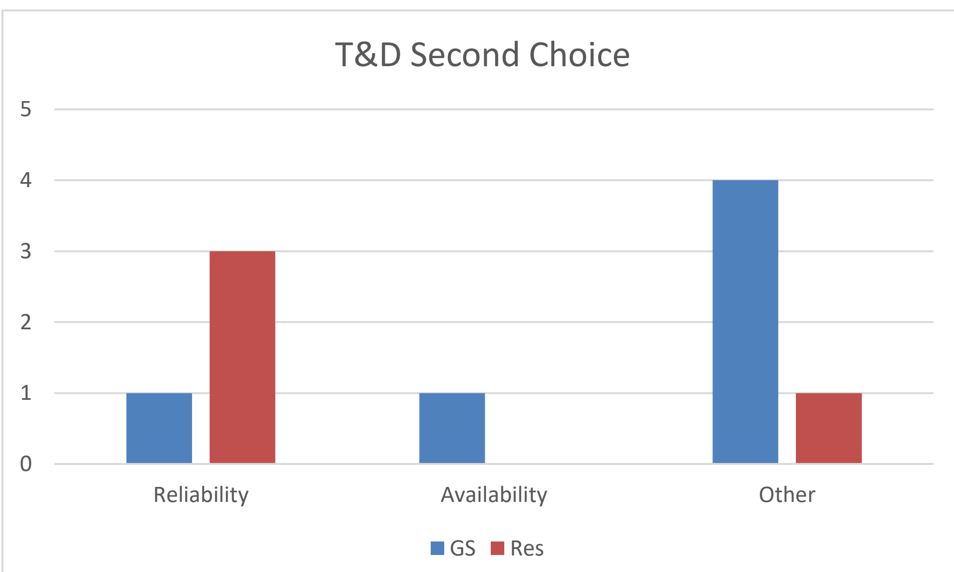
Environment: *Best environmental impact. Conservation implies a failure of delivery and capacity*

Other: *Conservation is well intentioned but not practical*



25. And why do you prefer that solution over the remaining options? **(Transmission and Distribution) (Second Choice)**

Reliability: *seems most reliable and easiest to maintain*
Availability: *Greater availability when needed*
Other: *It is important to be prepared for unforeseen events*



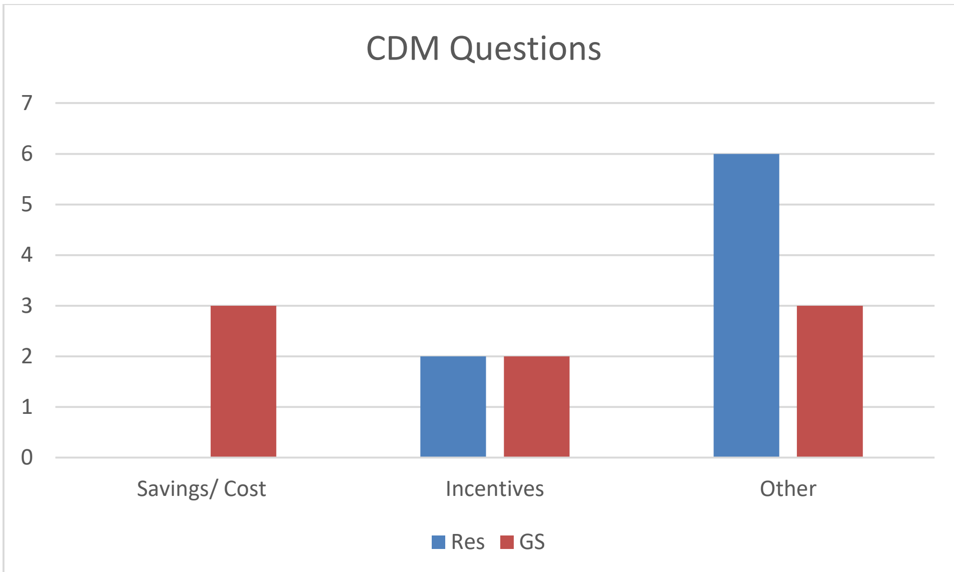
What, if any, questions would you want to have answered before deciding whether the following are appropriate for Central Toronto?

26. Conservation and Demand Management

Savings/cost: Need for new infrastructure. What cost to us?

Incentives: *How can this option be encourages and controlled. What incentives for me to buy in to this approach*

Other: *How will technological advances make this an improvingly desirable choice?*

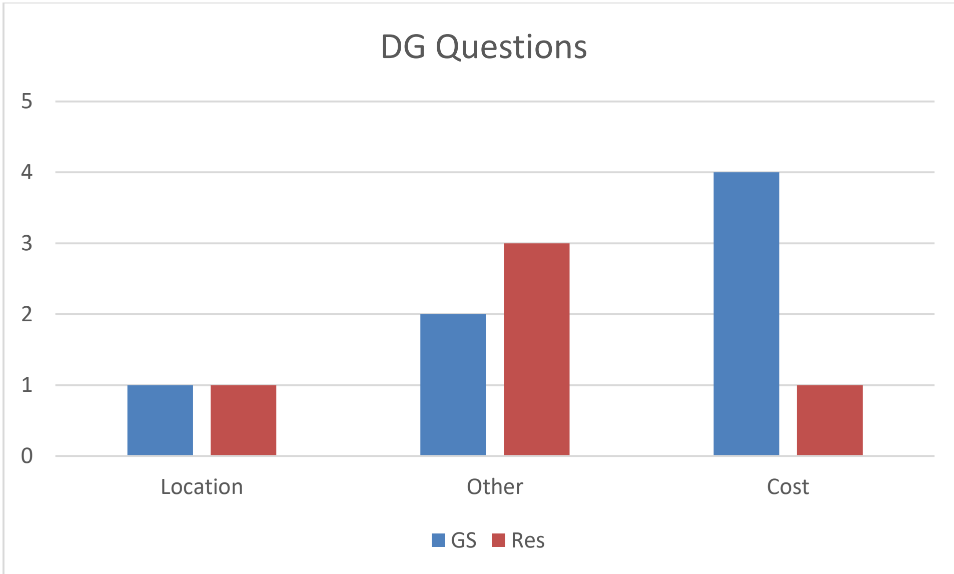


27. Distributed Generation

Location: *how much and where they would they be located? What type of energy what repercussions?*

Cost: *If the costs distributed generation are so high what would be the incentive?*

Other: *What would we do in an emergency situation?*



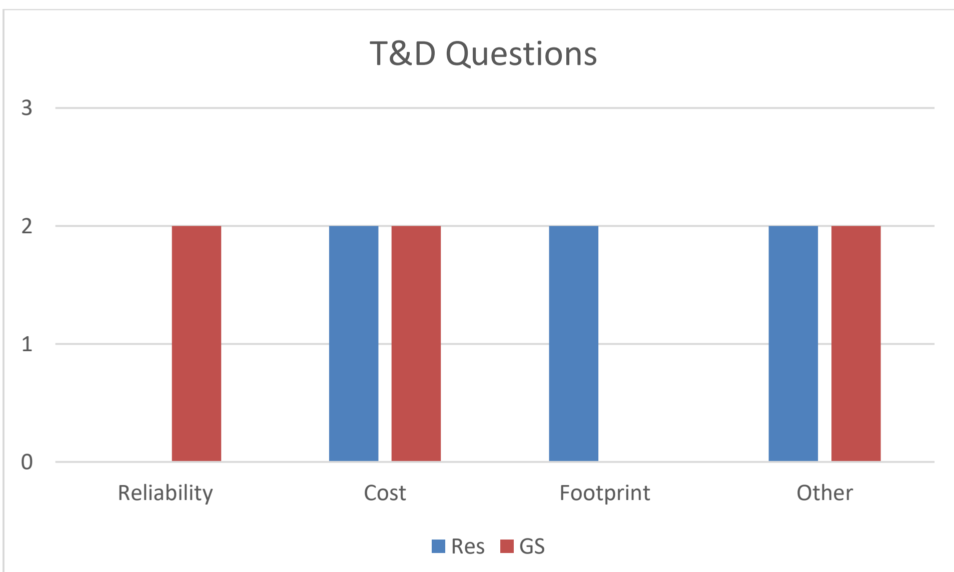
28. Transmission and Distribution

Reliability: *Reliability. All in all no more cost to the small businesses or home owners. We pay enough.*

Cost: *What is the cost per KwH?*

Footprint: *How large would the footprint be and how close to where I will it be built*

Other: *How can we make sure that transmission and distribution are fully utilized?*



Stakeholder Workshops

Workshop Presentations and Discussion Groups
with Stakeholder groups

PURPOSE: To gain qualitative input on planning options for Central Toronto from stakeholder groups and to obtain feedback into survey design

Summary

The following summary highlights key findings from the stakeholder workshop sessions held in the Toronto area on September 18, September 22 and October 20 2014.

System Reliability: Customer Experience and Expectation

- Most participants in the workshop groups felt that the electricity system works reasonably well but that there is room for improvement in system reliability.
- The first two groups were specifically concerned with the reliability of essential services, including; hospitals, water treatment facilities and public transportation.
- Several participants were also concerned with industry leaving downtown because of the increasing lack of system reliability.
- There is concern from most business and industry participants about potential rate impacts and a strong reluctance to increase reliability standards without a clear demonstration of the benefits.

Planning at a Higher Standard

- Many participants in the first two groups believe that Toronto requires planning at a higher standard than the rest of Ontario.
- The first two groups pointed to financial institutions, hospitals and vulnerable people as reasons for justifying this higher standard.
- That being said, some participants prefaced that the burden of these higher standards should not be placed solely on the ratepayers. They feel the need for higher standards is based on social needs that should be supported by government through taxes.

Planning for Extreme Events

- Generally, participants were leery of committing to funding improvements to reduce the impact of major events because of the uncertainty regarding future frequency.
- Additionally, several participants pointed to other growing pressures as more potentially damaging to existing system reliability.

Peak Demand

- The second group featured an interesting discussion regarding peak demand. Several participants agreed that a new definition was needed for peak demand.
- Additionally, some participants supported adopting the term “super peaking” in reference to these spikes, but suggested addressing the peak in a broader sense.

Community Involvement

- The two first groups placed an emphasis on the need for more granular community involvement in the planning process.
- Many participants agreed that community planning can be used to address specific, local stresses on the system.
- Additionally, many participants believed that the analysis provided in community plans would help leverage the success of this plan.

How Could the Consultation Process be Improved?

- Generally, participants found this consultation process to be useful.
- Some participants felt further community involvement could be beneficial to creating local solutions to growth pressures.
- Many participants had questions regarding the format of this consultation process, particularly regarding the role of the City of Toronto and local community organizations.
- Because these groups were quite knowledgeable of the system, participants frequently requested additional data and cost projections related to proposed projects.

Methodology

About the Stakeholder Workshop Consultation

Stakeholders were consulted on Central Toronto’s IRRP during three, two to three hour workshop sessions. Planners from the Ontario Power Authority and Toronto Hydro presented material and fielded questions while INNOVATIVE facilitated discussions and kept notes. No recordings were made so only a limited number of direct quotes are included and comments are not directly attributed to specific participants.

NOTE: Results contained within this report are based on a limited sample and should be interpreted as directional only.

Recruiting Workshop Participants:

The four organizations compiled a list of more than 300 broad-reaching stakeholders, and each was invited to provide their input on the Central Toronto IRRP. Stakeholders were encouraged to either attend one of the workshops or open houses, participate in a webinar or submit their feedback in writing.

Workshop Session Structure:

The consultation sessions were structure around the themes contained in the workbook, which was developed by INNOVATIVE and the Central Toronto IRRP Study Partners.

The workbook themes included the following:

1. What is this Consultation About?
2. Where Does Electricity Come From?
3. An Overview of Central Toronto Electricity System Today
4. Planning to Meet Customer Expectations
5. Options for Meeting Central Toronto Demands

All workshop participants were provided hard copies of the workbook at the time of the session.

Following a brief introduction explaining the purpose of the workshop, the OPA and Toronto Hydro provided a presentation of the key areas and objectives of the IRRP.

Following each section of the presentation, the facilitator led participants in a discussion, allowing time for clarification of aspects of the slideshow.

Each workshop session ran for between two and three hours.

The following stakeholders were involved in the 3 workshop sessions.

September 18, 2014	September 22, 2014	October 20, 2014
Sunnybrook Health Sciences Centre	City of Toronto	Redpath Sugar Ltd.
Toronto Clean Air Alliance	Toronto Blue Jays	Retail Council of Canada
Greenpeace Canada	Ryerson University	Toronto Region Board of Trade
Northland Power	Electricity Distributors Association (EDA)	Accenture
City of Toronto	Siemens Canada	Beechgrove Country Foods Inc.
	Weston Food	AGE Power Consultant

Participant Feedback

The following section highlights specific feedback from the three workshops.

Stakeholder Workshop Session

System Reliability: Customer Experience and Expectation

Most participants in the workshop groups did not believe that the current level of reliability is adequate.

When asked about reliability, one participant said, *it's not at all where it should be.*

In the third group, participants were less concerned with the amount of outages, rather the time it takes to restore power while the first two groups expressed similar levels of concern about frequency and duration.

Most participants in the groups noted that it was not acceptable to see outages occur at hospitals, subways, water treatment facilities or high-rise buildings.

One participant with experience in one of these key facilities noted it experienced 20-25 interruptions per year. While they were mainly short outages, they can create many risks, depending on the facility involved.

Many participants wanted to know what was being done about outages occurring at the "key facilities". One participant in the first workshop suggested that these facilities should be equipped with combined heat and power to maintain reliability.

A participant in the third workshop felt that residential and localized generation is a good way to help address reliability questions. The panel noted in some cases emergency generators can quickly run out of fuel, and that some of them may not have planned for extended outages.

Participants expressed concern over the issue of vulnerable people being stuck in high-rises because of a lack of system reliability.

Several participants agreed that system reliability in Toronto is effecting where businesses choose to build industrial facilities. One participant voiced that, *industry is moving out of downtown Toronto because of the urban pressures to the* system.

Additionally, some participants from the second group noted that for the cost needed to improve reliability, they could build their own plants onsite.

One business participant said that cost is most important and reliability is second. It was said that these were the two variable drivers that members in that participant's organization mentioned most often. These same members thought the day-to-day reliability was "pretty good", however they need to be able to recover more quickly.

When it came to reliability, a participant in the first group said *"the average consumer doesn't know how to quantify reliability, you have to build support around hospitals, subways and water treatment plants".*

Several participants in the second session noted that existing standards are significantly lower than emerging reliability standards. *"You cannot plan knowing what you know, meeting current standards is not relevant. Are we meeting the standards that will exist in five years?"*

One participant in the second session voiced a concern that reliability standards might be being met in theory, but not *"politically and in communities".*

One participant in the third workshop asked whether the IRRP study partners were coordinating with the city to push demand to other parts of GTA. The partners responded that they work closely, but have a legislated responsibly to connect whomever makes a request.

Planning for a Higher Standard

Most participants said that Toronto requires a higher standard than the rest of Ontario. That being said, a few participants noted that Toronto taxpayers should not have to pay significantly more than the rest of the province for these increased standards.

In addition to these key facilities, many participants noted that a higher standard was necessary because of the high number of disadvantaged and vulnerable people in the city. One participant said, *"These individuals cannot be stranded on the 75th floor during an outage. We have an economic, moral and ethical obligation to be more reliable."*

One participant said that the complexity of the downtown system must already put Central Toronto at a higher standard. In response, the study partners said that there is more redundancy downtown and that it experienced 1/3 the number of outages as the rest of the city. During the 2013 Manby Station flooding, it was fully re-supplied in two hours which was six hours quicker than the standard.

Another participant commented that Toronto does need a higher standard because *"individual customers are being replaced by condos the size of small towns on one city block".*

It was said that planners have to look at this need for higher reliability on an intersection scale, because new development is leading to severe increases in heat.

A participant then raised the issue of "increased performance metrics". *"Downtown Toronto needs a plan and (its development) should include The Building Owners and Managers Association (BOMA)".*

In the first two groups, participants encouraged "transformative thinking" to address a higher standard of reliability in Toronto. One participant in the first group said that "*the IESO standards are not good enough".*

In order to provide this higher standard, one participant advocated that *"all key facilities should be equipped with combined heat and power generation"*

The third group in particular focused on the question of benchmarks and standards compared to other comparable cities.

When asked about standards used in other major cities, the study partners said that it is often difficult to find these standards. Not everyone measures reliability the same way and standards vary in different cities.

The panel continued to say that core North American standards are set primarily in the US. They noted that Ontario has taken these standards and made them more specific and moved standards to local areas.

One participant said that the challenge that exists is that there is nothing with which to compare current standard in Toronto. The panel said that while there are limited standards for comparison, there are some statistics available and that Central Toronto does "stack up well" to other major cities. They also noted that there are certain redundancy standards that are common amongst big cities. The panel indicated that while comparisons are difficult, downtown Toronto does well compared to cities such as Chicago and Boston that share similar circumstances.

While there was general support for a higher standard, one participant said that standards should not be raised just for bragging rights. One participant noted that for developers, it is still a matter of how cost effective it is to get power to buildings. There needs to be a balance between reliability and how much it costs.

Planning for Extreme Events

While many participants agreed that the general, day-to-day reliability of the system was good, most suggested improvements need to be made when the system does fail during extreme weather events and other outages.

Some participants asked how climate change was being factored into current forecast projections. In response, it was said that the IESO criteria requires forecast scenarios to account for extreme weather.

Not all participants agreed. One industry participant said that they didn't expect more system redundancy for extreme weather events. This participant said that they understood these events happen, and that we should learn from them.

Another participant said *"we don't know if these things will happen again, we just have to live with them".*

Participants expressed concern about the investments that may be needed to meet these changing standards. Several participants pointed to a possible increase in customer bills to plan for these extreme events that might not occur for another 50 years.

Participants in the first two groups commented that extreme weather is not the only concerning stress being placed on the system.

In response to this comment, a participant from the City of Toronto commented that the city had tabled a report on the probability of similar weather occurrences. *"More frequent severe storms are predicted and should be accounted for in reliability planning".* Some participants agreed, one noted that *"rising temperatures and heatwaves are also a concerning trend".*

Several participants asked what kind of steps had been taken to plan for these events following the recent ice storm and flooding.

A participant in the first session asked whether "undergrounding" the whole system would make it more reliable and help mitigate the damage of such events. A response was provided that it was not *"straightforward"*, and that *"flooding can be a long-term issue for an underground system. Also, freeze/thaw effect on underground pipes and underground is not always possible, especially in urban areas".*

As a response to these participants concerns, it was said that, *"Toronto is on the leading edge for understanding extreme weather. The long-term part of the plan is working on these concerns, in fact, funding has been received from the Federal government. Specifics related to probability and type of extreme weather are being researched now. Findings from these studies will be made public when completed".*

In the third workshop, several participants agreed that while they did not believe that investments for these extreme weather events were necessary, there was a general concern regarding the prompt restoration of the system during these periods. They were not looking to avoid outages from major event but to take steps to improve restoration times.

During that discussion, a participant from a small business group said that many of his members were devastated by the response time during extreme weather events. Because the frequency of these events seems to be increasing, it is a critical issue for his small business members.

In response to these concerns, a member of the study group said that the OPA and Toronto Hydro are involved in detailed risk assessments. They have been awarded funding from Natural Resources Canada and these results are expected in spring 2015.

Planning for Growth and Development

Many participants inquired as how to the IRRP accounted and planned for growth in Central Toronto. There was a general concern that larger projects would put a significant strain on the existing system.

One participant asked how long it would take to build new capacity to handle the electrification of GO. The study group responded that they do not expect it will affect downtown much. GO lines stretch a long distance, and can be connected at various spots. Also, the 10 years proposed for this project falls within the time needed to get the necessary approval.

Additionally, a participant asked about whether the Waterfront Toronto development plans were being accounted for in this plan. The study group said that, in terms of demand, they look at the City of Toronto when deciding local demand. However, it is difficult to make concrete demand decisions when the projects have not yet received funding.

In addition to this, the panel said that transmission needs are tied to station capacities and not to other developments that are further out.

Peak Demand

The second group featured an interesting discussion regarding how to define "peak demand".

"*Super peaking*" is a term used to refer to these drastic spikes in demand, however, several participants argued that peaks should be looked at in a broader sense, addressing the peak in total. *"Other jurisdictions are having the same difficulties defining peak and this is an opportunity for thought leadership".*

In response to this, it was said that it has to be looked at from a reliability perspective. *"Transmission and distribution is limited by physics. The heat has to be taken away when stressed (i.e. summer periods). Ambient temperature is cooler in the offseason, and equipment can be run harder".*

One participant then said, *"Peak represents a demand for cooling. Peaks are going to go above 500kW, why not look into heat water cooling".*

Looking at demand, one participant questioned the ratio of peaking kW compared to means and asked *"Should the system as a whole be hardened for 100 hours?"*

In response to "super peaks", a response was given that smaller peaks don't put the system at risk. The heat can be dealt with more easily in the winter. Additionally, "critical peak pricing" is currently being looked at in addition to 'TOU' pricing that already exists.

Community & Local Involvement

Several participants in the first two sessions stressed the importance of Community Planning and Community Energy Plans. It was said that these plans *"Can provide a deep analysis of the given area and this information can be leveraged in the IRRP".*

In addition to this, a few participants felt that CDM would be enhanced through local engagement with a better understanding of where it is needed within the community.

A participant in the first group emphasized the importance of building a relationship with local groups (like the participant's), so they can know where to prioritize next community-based energy projects.

A member of a community group then continued to say, *"We are looking forward to working with Toronto Hydro, the OPA, etc. Their organization has three objectives; conservation, resilience and power generation/growth".*

In the first two sessions, there was an emphasis placed on the value of involving the City of Toronto in the process.

Specifically in the first group, a participant from the City said, *"The City can provide a human and economic element. There is great value having the City involved in this plan.*

It was also said that the municipalities are doing their own energy planning and risk assessments, including vulnerable populations.

One participant also met with the Toronto Industry Network (TIN), who said they were concerned with the cost of electricity in Toronto compared to other regions. The message that they are hearing is that they must lower costs to attract new industries.

Best Options Moving Forward

Participants were generally in agreement that the planners were looking at the right solutions for meeting demand. Despite agreement, participants offered suggestions on where they believe further emphasis should be placed. Some of these suggestions are included below.

One participant in the first group expressed concern at the conservation assumptions in the base case and sought a much more aggressive approach in the final plan. This position was strongly supported by a second participant and appeared to be supported by several other participants.

One participant asked why Toronto Hydro was not considering more underground wires solutions. The panel said that they were looking at return for investment. Ice storms still affect the underground systems and tree trimming is far more cost effective. Additionally, the study group noted that underground distribution lines would be more difficult to maintain.

A business participant felt that the system has already caught up on the capacity side, but asked what was being done on the distribution side of the system. *How do developers get connected to the load centres?* In response to this, the study group noted that the $1.3B investment did not include the distribution portion of the system. The study group noted that there is also work being done to re-distribute load.

Some participants expressed concerns regarding emissions from DG. The study group said this is a challenge, noting that for existing installations retrofitting can be an expensive challenge.

Another participant noted that one set of standards applied to facilities such as existing water boilers and that if they were converted to combined heat and power, a tougher set of rules may apply that will act as a disincentive to conversion.

One participant said that transmission and distribution solutions are the best, because the other two options (CDM and DG) are less controllable. This participant continued on to say that history indicates we can't count on CDM.

A participant from a business group said that CDM plans are municipally based, and the integration of them is crucial to get businesses on board. The participant indicated that businesses are concerned about the paperwork, timelines and standards of having inconsistent CDM plans across Ontario. The participant noted that smaller utilities don't have the same resources to facilitate the development and integration of CDM.

Some participants indicated that business would be open to CDM if incentives were great enough, but it is difficult for them to shift during times of peak demand.

Again, with regards to CDM, a participant said that they need a far more aggressive approach if they want businesses to get on board.

For developers, one participant said that it's all about transmission and distribution. These solutions are needed to meet demand that is constantly growing.

Request for Expression of Interest (RFEI)

Participants in all three groups were asked what they thought of RFEI's for DG customer driven solutions.

While many had an initially positive reaction, some participants were skeptical because they had been frustrated by these requests in the past. *"We're frustrated because we work hard on these submissions and then nothing ever happens. We are developing CHP and then having to walk away".*

Many participants found the economic costs of these past proposals to be too high.

Despite that concern, most participants appear to believe that there will be overwhelming support for any request **if it is shown that this time is for real.**

When asked about the accuracy of these proposals, participants in both groups said it was previously too high. One participant echoed the opinion of several others, saying, *"RFEI's get concepts, not prices. Ask for an accuracy of ±25%. This can be done in as little as a month. If you ask for less than that, costs too much money to produce".*

Many participants in both groups, noted that prior requests had not been clear. Projects should be framed more clearly, including the nature of project, geography and constraints. This is also helpful in terms of community DG planning.

Generally, the majority of participants expressed interest, however, the proposal process must overcome a credibility challenge to garner trust from those providing submissions.

How could the Consultation Process be Improved?

Most participants in this group found this consultation to be a positive experience.

One participant said that it was critical to keep this dialogue open. Generally, this participant thought that the reliability was there, it was just about the distribution side because it takes a long time to connect a new building.

Several participants agreed that it was important to get this information to more businesses and make sure that it's easily accessible.

Many participants said that they should seek feedback from businesses using groups like the Canadian Chamber of Commerce. It was also suggested that this sort of information be brought directly to these businesses.

A participant representing developers said that the most effective way to reach them for consultation was through consultants.

Some participants in the first two groups were unclear as to the role of communities and the City of Toronto.

Some participants were also looking for more clarity regarding timelines of the plan. There were questions asking when a final plan would be submitted.

Some participants in the first two groups felt that the process would be improved with increased community engagement.

Overall, most participants found the presentation and information provided to be useful and welcomed the opportunity to engage directly with planners.

Customer Telephone Surveys

Telephone Surveys
among Residential and GS customers

PURPOSE: To obtain statistically significant quantitative customer feedback on the planning options presented and assess reaction to customer opinions obtained from the previous research phases

Summary

The following summary highlights the key findings from two telephone surveys of 621 Toronto Hydro residential customers and 101 general service customers:

Respondents familiar, satisfied with their electricity system

- More than 6-in-10 (62%) residential customers say they are familiar with the system and nearly 9-in-10 (86%) are satisfied with their current service. General service customers are a bit less familiar (46%), but still quite satisfied (82%).

Cost is a key issue for respondents, "number of outages" a distant second

- When asked how the electricity system could improve their service, 4-in-10 say "reduce rates" (40%). Just 1-in-10 (10%) say "number of outages", the next specific improvement mentioned.

Interruptions a common thread among Residential and GS

- Half (50%) of residential and GS customers experienced power service interruptions during the major weather events of 2013. And half (51%) of residential customers experienced outages in the last 12 months during normal weather.

"Length of outage", *not* "number" a key concern for Residential customers

- Customers are far more inconvenienced by the length of outages (77%) than the number (12%). Also, they think the government should prioritize fixing length over number of outages (67% vs. 28%).
- On average, outages for residential respondents are not frequent- nearly 6-in-10 (57%) only experienced one or two in the last year. But they tended to be long. Just 15% experienced an outage of an hour or less and more than 2-in-10 (22%) experienced outages for 24 hours or longer.
- That being said, general service customers are much more concerned about short outages: three-quarters (74%) experienced one or two outages at their place of business and nearly 3-in-10 (28%) said those outages were less than an hour. More than 6-in-10 (62%) GS customers say an hour or less outage makes things difficult. And a third (32%) say that outages of 15 minutes or less are a difficulty.

Reliability a concern…but they don't want to pay more for it

- When asked to choose between the current levels of reliability and holding Toronto to a higher reliability standard even if it means paying more, staying the course wins out by 21-points (55% to 34%).

"Climate change contribution", "emissions impacting" health key concerns

- Customers' greatest environmental concerns are how the electricity system contributes to climate change (+35) and also how those emissions directly impact their health (+28).

Majority think they're getting good value for money, divided on bill impact

- Nearly 6-in-10 (58%) residential customers think they are getting either a reasonable or good deal on their electricity. And about the same amount (Residential: 57%) think they get good value for money on their electricity.
- Residential customers are divided on whether the cost of their electricity bill has a major impact on their finances (46% major impact vs. 50% no impact).
- General service customers feel a much greater impact (77%) major impact) and are less likely to think they are getting good value for money (46% vs. 52%).

Low Awareness and Interest in Distributed Generation

- Respondents are the least familiar with "Distributed Generation" (net -27 vs. +10 "Transmission and Distribution Infrastructure" and +2 "Conservation and Demand Management).
- "Distributed Generation" is the last picked solution by residential customers to deal with capacity problems (34% vs. 47% "Transmission and Distribution Infrastructure").

Most important considerations "time", "rates" and "climate change"

- When asked to rate seven considerations relating to capacity, residential customers focus the most on "reducing the time it takes to restore power" (+91), "reducing the impact on electricity rates" (+81), and "reducing impacts that contribute to climate change" (net +80).

Methodology

About the Survey

From December 15, 2014 to January 15, 2015, a total of 622 Toronto Hydro residential customers residing in Central Toronto were surveyed by telephone. As for the second sample of general service customers in Central Toronto, a total of 101 were survey by telephone from December 16, 2014 to January 16, 2015. Note: no customer calls were made between December 24, 2014 and January 2, 2015. The list of residential and general service customers were provided by Toronto Hydro.

The survey followed a stratified random sampling methodology. This is a method of sampling that involves the division of a population into smaller groups known as strata. In stratified random sampling, the strata are formed based on members' shared attributes or characteristics (in this case, customers' level of annual electricity consumption). A random sample from each stratum is taken in a number proportional to the stratum's size when compared to the customer population. These subsets of the strata are then pooled to form a random sample.

In this survey, residential and general service customers were divided into four strata based on their electricity consumption in 2013 to ensure that the sample had a mix of customers from low, medium-low, medium-high, and high electricity usage households. The sample, randomly selected from a client provided list, was weighted to ensure each stratum accounts for 25% of the total sample. In both surveys, the sample was weighted down to its "target sample".

Residential Sample

Quartile	Customer Distribution	Target Sample	Actual Sample	Difference
Low Consumption	25%	125	151	+26
Medium-Low	25%	125	147	+22
Medium-High	25%	125	128	+3
High Consumption	25%	125	196	+71
TOTAL	**100%**	**500**	**622**	**+122**

General Service Sample

Quartile	Customer Distribution	Target Sample	Actual Sample	Difference
Low Consumption	25%	25	23	-2
Medium-Low	25%	25	31	+6
Medium-High	25%	25	25	0
High Consumption	25%	25	22	-3
TOTAL	**100%**	**100**	**101**	**+1**

The residential sample is considered accurate to within ±3.9 percentage points, 19 times out of 20. The general service sample is considered accurate to within ±9.7 percentage points, 19 times out of 20. The margin of error will be larger within each quartile of the sample.

Field: Sample and Logistics

For the purposes of executing this survey, Toronto Hydro provided INNOVATIVE with a confidential contact list containing residential customers and general service customers in Central Toronto. The research team built this contact list by randomly selecting records from customer its database.

The contact list included only customers with landline contact information on file and who had been a customer of Toronto Hydro since at least December 31st, 2012. The information contained in the contact list included customer name, home telephone number, home address, service area, and total annual usage between January 1st and December 31st, 2013.

Only one customer per household or organization was eligible to complete the survey. Survey respondents were screened to certify that only the resident primarily responsible for paying their Toronto Hydro electricity bill or, in the case of general service, the person responsible for paying the organizational electricity bill was interviewed. This step was taken to ensure that survey respondents represented the most qualified person within a household or organization to answer questions about their electricity bill.

Before retiring any randomly selected telephone number from the contact list, 12 attempts to reach a potential customer, for each unique telephone number, were initially made, or until an interviewer received a refusal. Each number was called twice a day for the first four days and once a day for the final four. Each night, a new sample was released from the contact list to replace completed or retired calls.

All fieldwork was conducted using INNOVATIVE's CATI system.

Respondent Feedback

The following sections will outline key issues such as respondent satisfaction, system reliability, environment, cost and value of electricity and finally the solutions proposed to deal with capacity issues moving forward.

General Satisfaction with the Electricity System

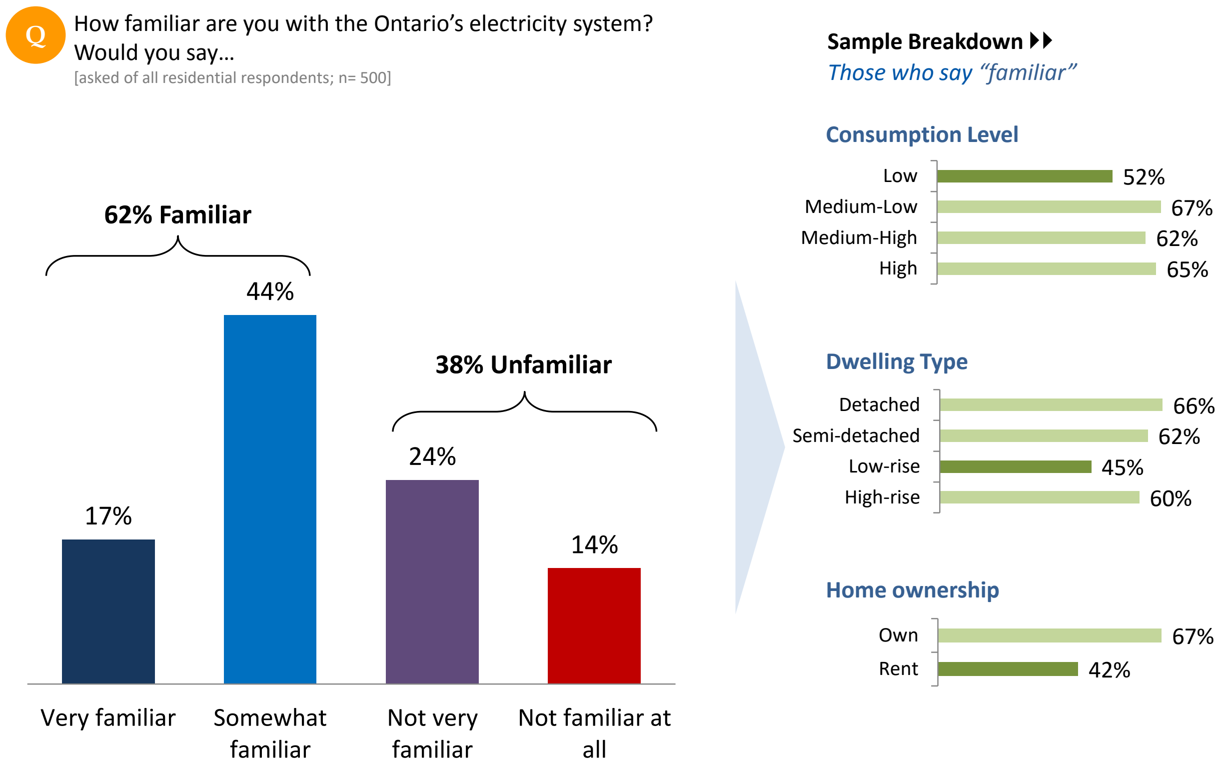
Respondents familiar, satisfied with their electricity system

- More than 6-in-10 (62%) residential customers say they are familiar with the system and nearly 9-in-10 (86%) are satisfied with their current service. General service customers are a bit less familiar (46%), but still quite satisfied (82%).
- Low-consumption users are the least familiar with the system.

Cost is a key issue for respondents, "number of outages" a distant second

- When asked how the electricity system could improve their service, four-in-10 of residential and general service say "reduce rates" (40%). Just 1-in-10 (10%) say "number of outages", the next specific improvement mentioned.
- About a quarter of residential (23%) and a third of general service respondents (33%) can't think of a way the system could be improved ("none" or "satisfied").

Figure 1RS: Familiarity with Ontario Electricity System

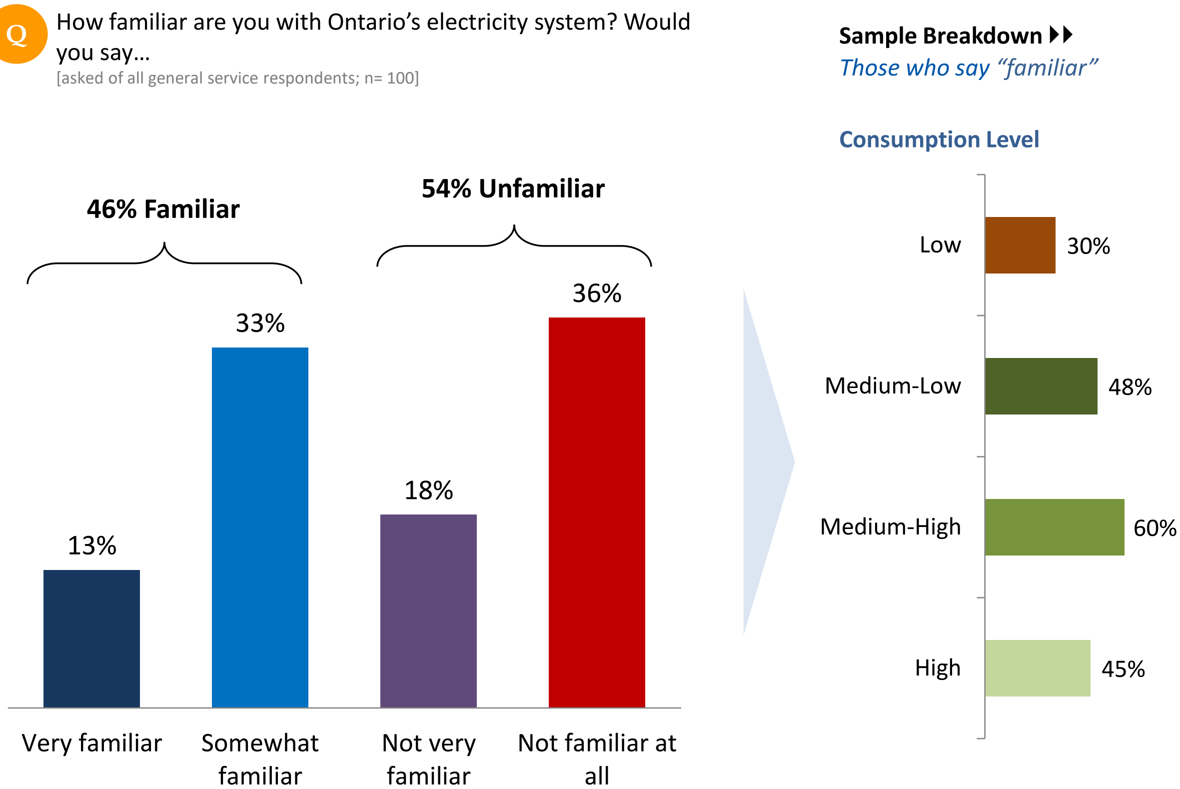


Residential customers are, for the most part, familiar with the Ontario electricity system. More than 6-in-10 (62%) say they are familiar with it and less than 4-in-10 say they are unfamiliar (38%).

- Low consumption users (52%), residents living in low-rise dwellings (45%) and renters (42%) are the least familiar with the Ontario electricity system.

Figure 1GS: Familiarity with Ontario Electricity System

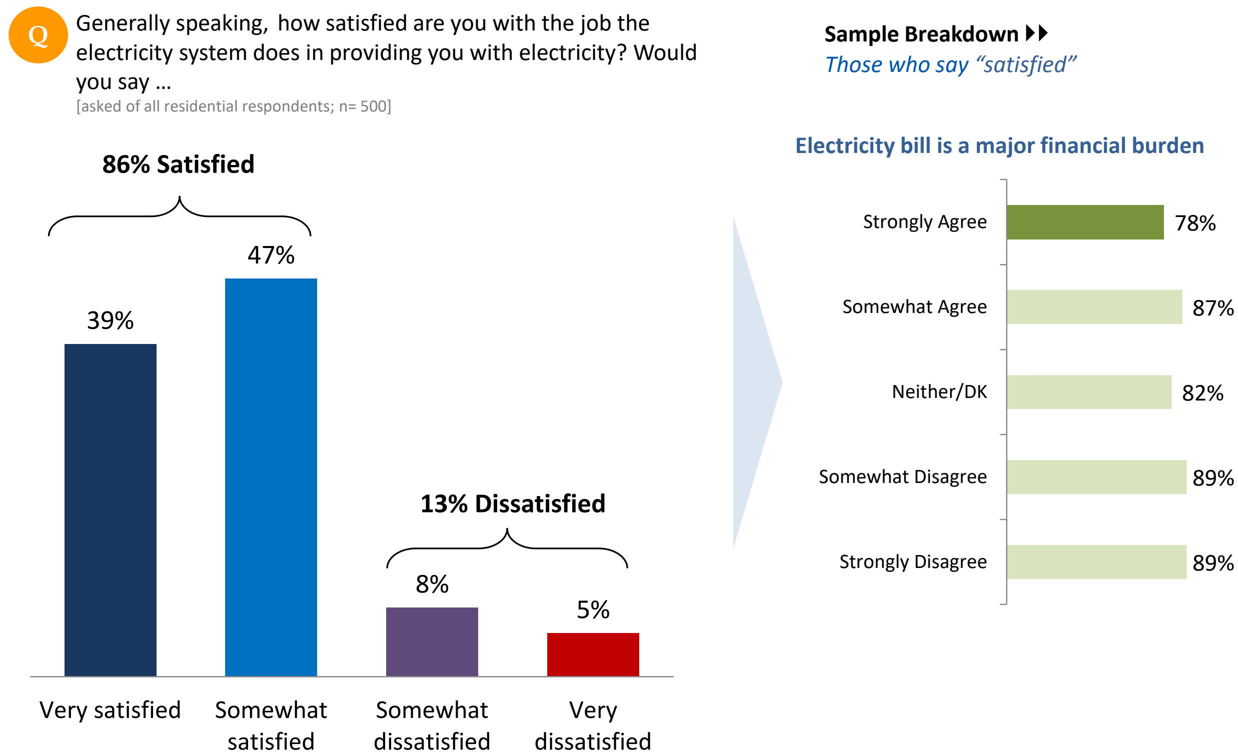
Q How familiar are you with Ontario's electricity system? Would you say…
[asked of all general service respondents; n= 100]



A large majority of general service customers are familiar (46%) with the Ontario electricity system and just over half are unfamiliar (54%).

- Again, low consumption users (30%) are the least familiar with the system.

Figure 2RS: Satisfaction with Ontario Electricity System

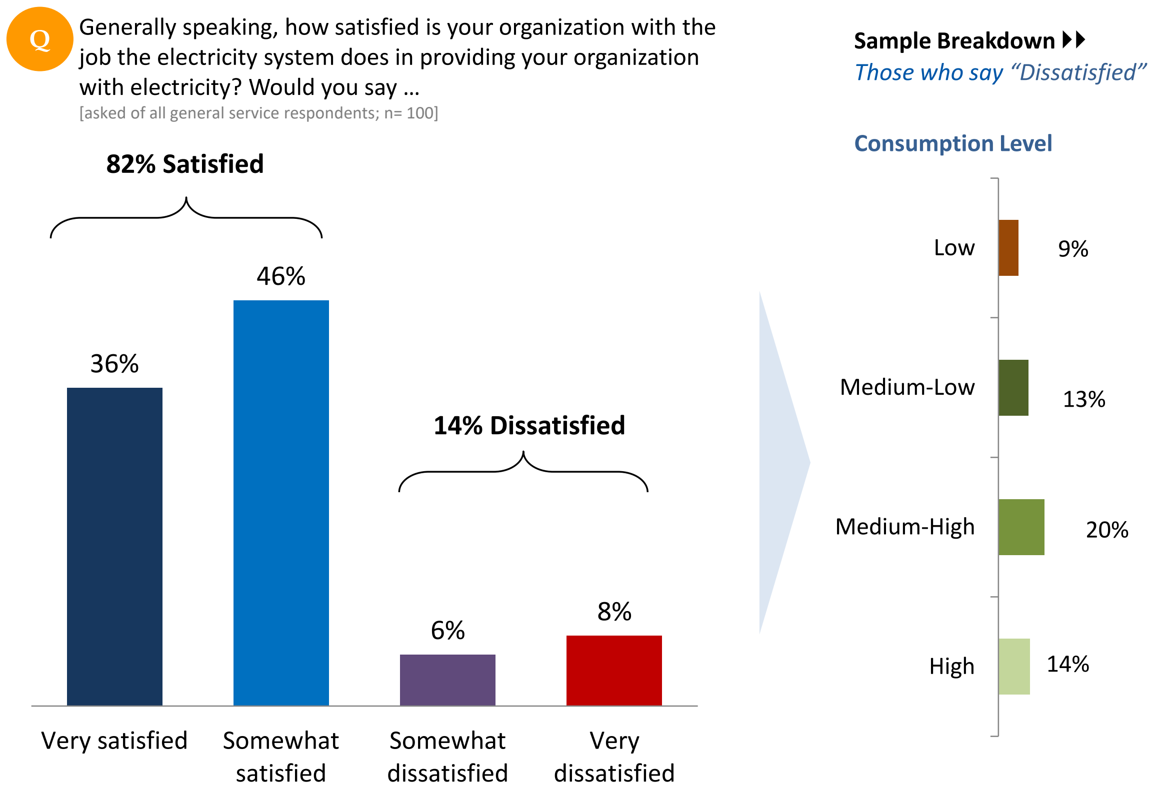


Note: 'Don't know' (<1%) not shown

Almost nine out of every 10 (86%) residential customers are satisfied with the electricity system. Just 13% say they are dissatisfied with how the system provides them with electricity.

- Those who "strongly agree" that the electricity bill is a major financial burden are a bit less satisfied (78% satisfied).

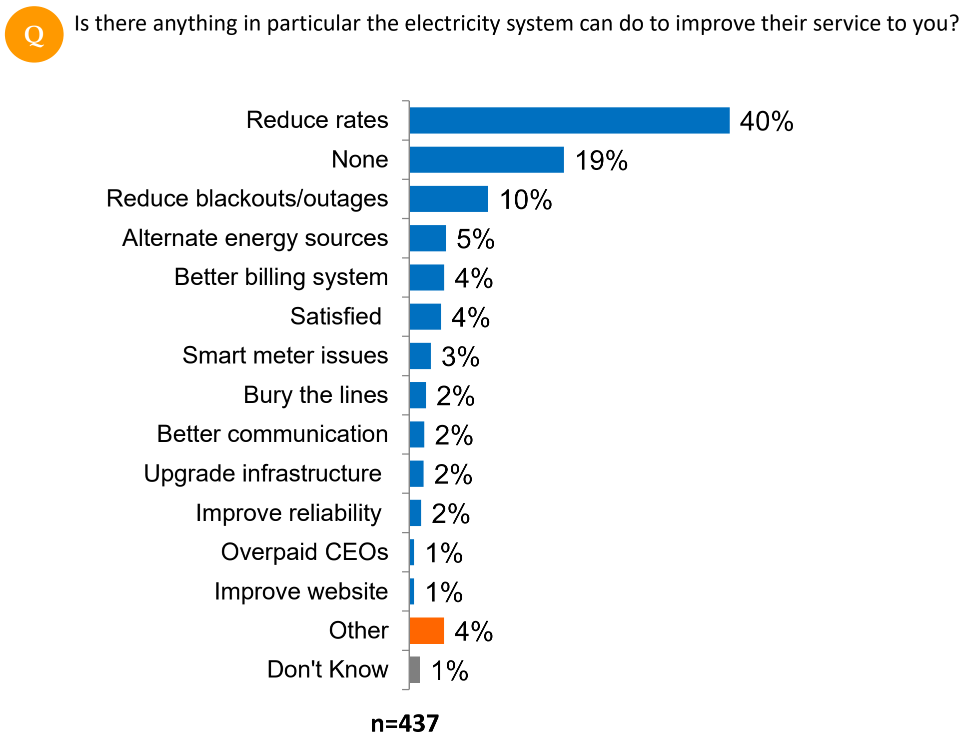
Figure 2GS: Satisfaction with Ontario Electricity System



Note: 'Don't know'/'Refused' (4%) not shown

For the 101 general service customers who responded, the satisfaction numbers are similar: more than 8-in-10 (82%) are satisfied with the system and only 14% say they are dissatisfied.

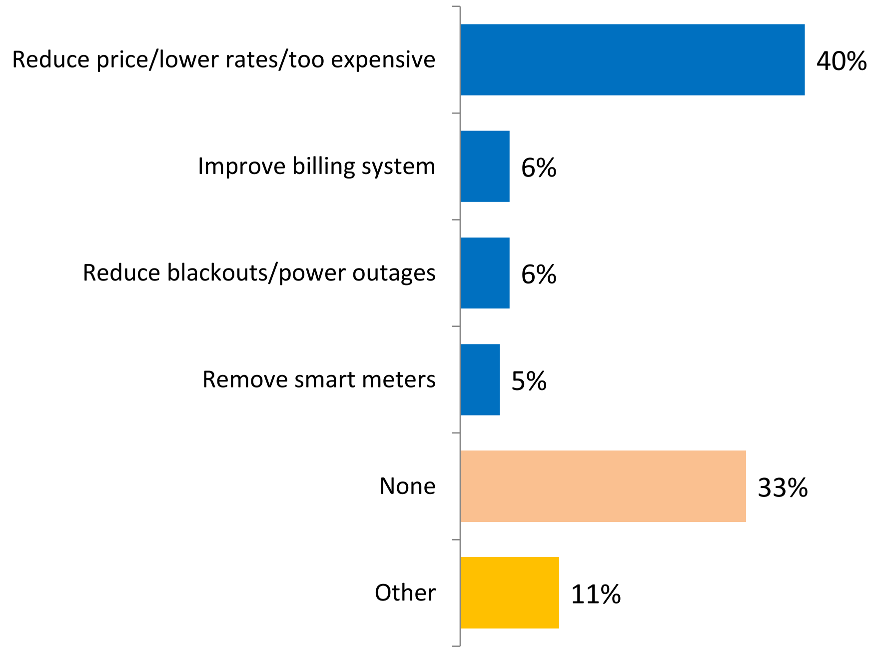
Figure 3RS: Open-ended on How to Improve Service



When asked how the electricity system could improve their service, 4-in-10 say “reduce rates” (40%). About a quarter say “none” or “satisfied” (23%)-they can’t think of anything that the system could do to improve their service. Other mentions include “reduce blackouts/outages” (10%), “alternate energy sources” (5%), “better billing system” (4%), “smart meter issues” (3%), “bury the lines” (2%), “better communication” (2%), “upgrade infrastructure” (2%), “improve reliability” (2%), “reduce pay for CEOs” (1%) and “improve the website” (1%).

Figure 3GS: Open-ended on How to Improve Service

Q Is there anything in particular the electricity system can do to improve its service to your organization?



n=87

Of the 87 general service customers who responded, 40% think “reduced rates” is the number one way to improve service. Other reasons include “improved billing system” (6%), “reduced blackouts and power outages” (6%) and “removing smart meters” (5%). A third (33%) of those 87 customers can’t think of any way to improve the electricity system.

System Reliability

This next section examines customer experiences during power service interruptions as well as their overall preferences concerning system reliability.

Interruptions are a common thread among Residential and GS

- Half (50%) of residential and GS customers experienced power service interruptions during the major weather events of 2013.
- And half (51%) of residential customers experienced outages in the last 12 months during normal weather.

Length of outage, *not* number a key concern for Residential customers

- Customers are far more inconvenienced by the length of outages (77%) than the number (12%). Also, they think the government should prioritize fixing length over number of outages (67% vs. 28%).
- On average, outages for residential respondents are not frequent- nearly 6-in-10 (57%) only experienced one or two in the last year. But they tended to be long. Just 15% experienced an outage of an hour or less and more than 2-in-10 (22%) experienced outages for 24 hours or longer.
- That being said, general service customers are much more concerned about short outages: three-quarters (74%) experienced one or two outages at their place of business and nearly 3-in-10 (28%) said those outages were less than an hour. More than 6-in-10 (62%) say an hour or less outage makes things difficult. And a third (32%) say that outages of 15 minutes or less are a difficulty.

But…they don't want to pay more for it

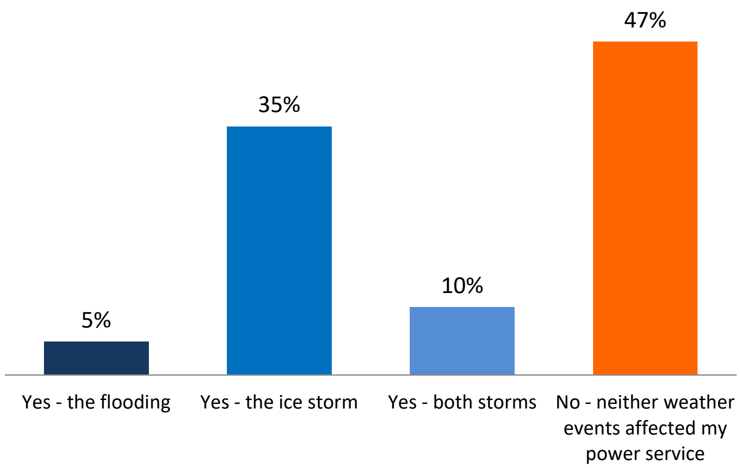
- When asked to choose between the current levels of reliability and holding Toronto to a higher reliability standard even if it means paying more, staying the course wins out by 21-points (55% to 34%).

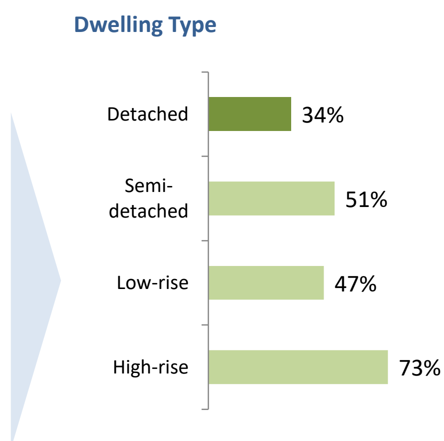
Figure 4RS: Power Service Interruptions

In 2013, electricity consumers in Toronto experienced unusually extreme weather – flooding in July 2013 and an ice storm in December 2013. These rare and unpredictable events -- which often impact a large number of people – are called "major events" in the electricity sector. These major weather events caused power outages across Toronto.

Q Did either of these major weather events cause a power outage at your home?
[asked of all residential respondents; n=500]

Sample Breakdown ▸▸
Those who say "no"





Note: 'Don't know' (3%) not shown

Half (50%) of residential customers experienced power service interruptions during the major weather events of 2013. More than a third (35%) lost power during the storm, 5% during the flooding and 10% during both. Just under half (47%) did not experience any interruption in power during these extreme weather events.

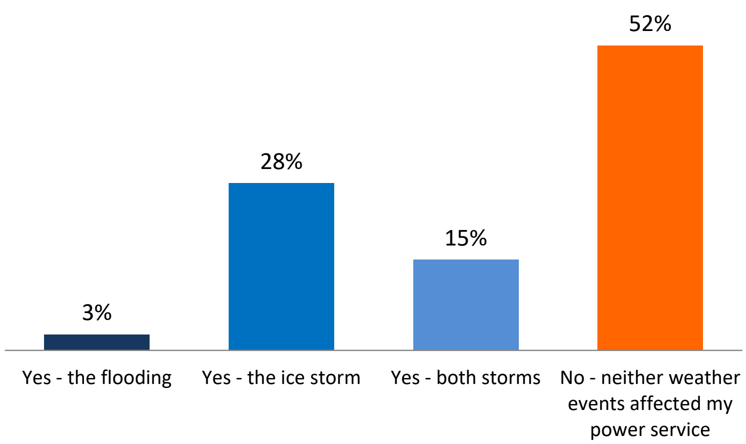
- Detached dwellings were the hardest hit during the flooding and ice storm of 2013: just a third (34%) say they did not experience an outage, compared to three-quarters (73%) of high-rise residents who had no interruptions.

Note: 'Don't know' (3%) not shown

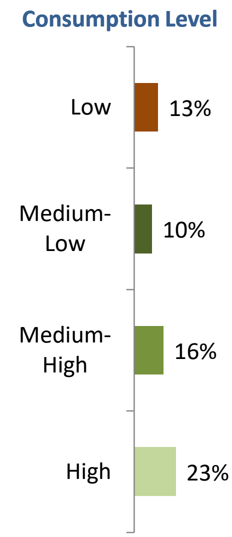
Figure 4GS: Power Service Interruptions

In 2013, electricity consumers in Toronto experienced unusually extreme weather – flooding in July 2013 and an ice storm in December 2013. These rare and unpredictable events -- which often impact a large number of people – are called "major events" in the electricity sector. These major weather events caused power outages across Toronto.

Q Did either of these major weather events cause a power outage at your organization?
[asked of all general service respondents; n=100]



Sample Breakdown
Those who say "both storms"



Note: 'Don't know'/'Refused' (2%) not shown

Roughly the same level of interruptions occurred for general service customers: around half (52%) did not experience any outage during the July 2013 flooding and December ice storm.

Figure 5RS: Other Power Outages

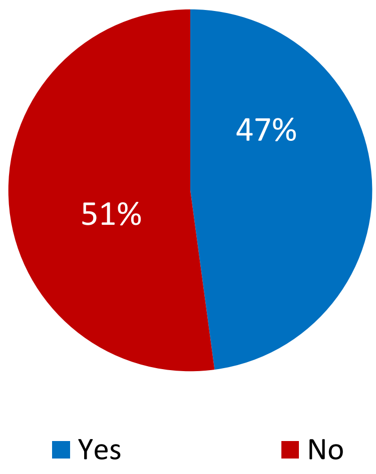
Q

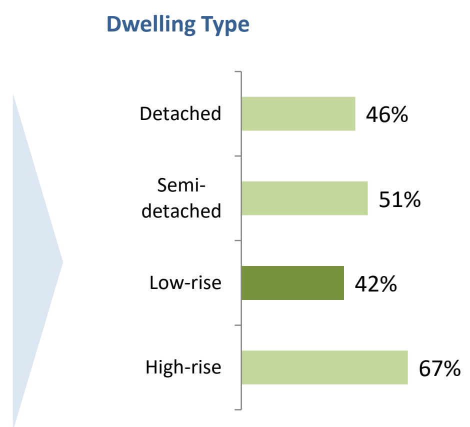
Not including power outages caused by these major weather events, did you have any other power outages in the **last 12 months**?

[asked of all residential respondents; n =500]

Sample Breakdown ▸▸

Those who say "no"





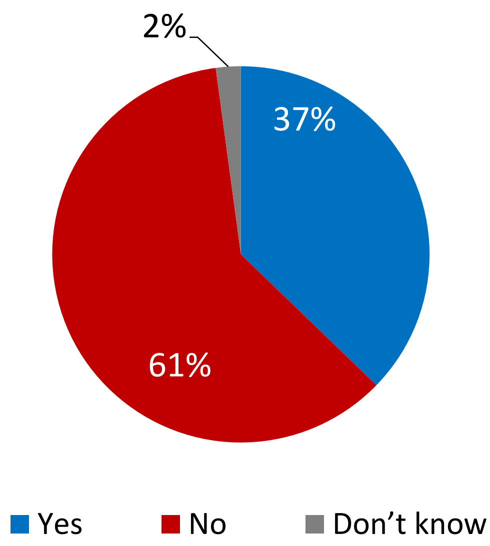
Note: 'Don't know' (3%) not shown

Not including these major weather events, nearly half (47%) of residential respondents experienced a power outage in the last 12 months.

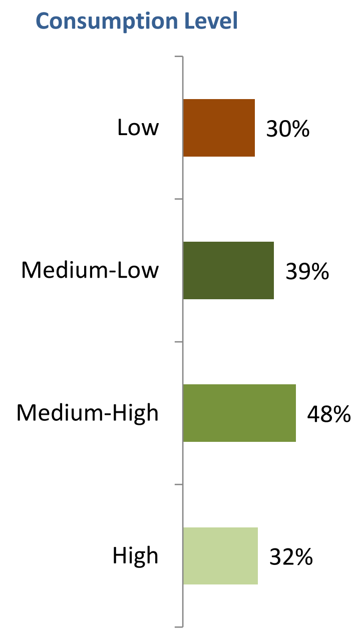
- High-rise residential customers had the least number of power interruptions during normal weather: 67% say they did not experience any in the last 12 months.

Figure 5GS: Other Power Outages

Q Not including power outages caused by these major weather events, did your organization have any other power outages in the **last 12 months**?
[asked of all general service respondents; n =100]



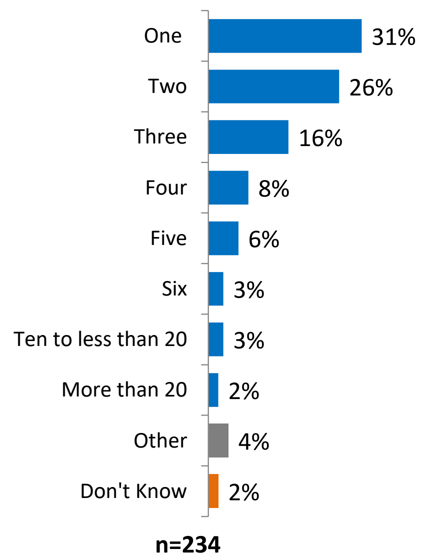
Sample Breakdown ▶▶
Those who say "yes"



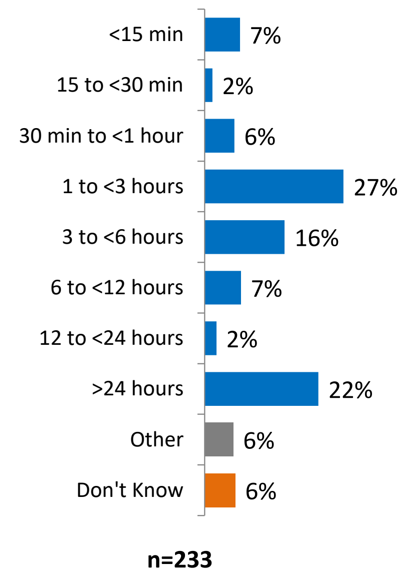
About 4-in-10 (37%) general service customers have experienced an outage in the last 12 months, not including major events.

Figure 6RS: Open-ended on Number and Length of Outages

Q [IF YES] How many outages did you experience over the past 12 months, NOT including those caused by extreme weather events?
[asked only of respondents who answered 'yes' to previous question]



Q [IF YES] And what was the longest period of time you were without power?
[asked only of respondents who answered 'yes' to previous question]



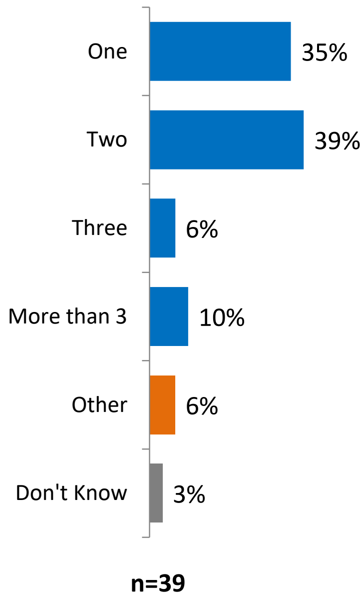
Residential respondents were asked two follow-up open-ended questions: if they had experienced outages, "how many in the past 12 months?" and also what the longest period of time was they went without power.

Nearly 6-in-10 (57%) Residential customers experienced one (31%) or two (26%) outages. About a quarter experienced three (16%) or four (8%) and 15% experienced five or more.

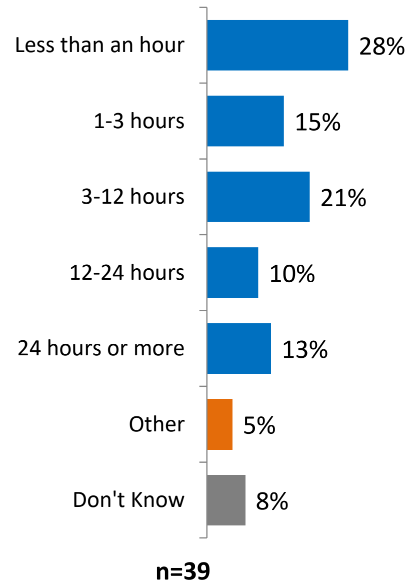
Most outages for residential respondents were on the longer side. Just 15% experience an outage of an hour or less. More than a quarter (27%) experienced an outage lasting one to three hours and another quarter (25%) experienced outages from three to 24 hours. More than 2-in-10 (22%) experienced outages longer than 24 hours.

Figure 6GS: Open-ended on Number and Length of Outages

Q [IF YES] How many outages did your organization experience over the past 12 months, NOT including those caused by extreme weather events?
[asked only of respondents who answered 'yes' to previous question]



Q [IF YES] And what was the longest period of time your organization was without power?
[asked only of respondents who answered 'yes' to previous question]



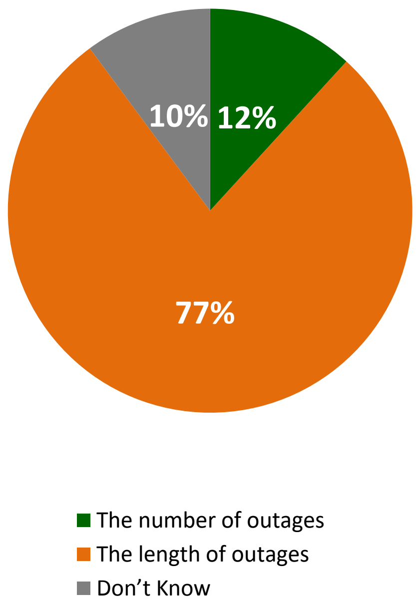
The 39 general service customers who experienced outages showed a similar breakdown. Roughly three-in-four (74%) experienced one (35%) or two (39%) breakdowns and 16% experienced three or more.

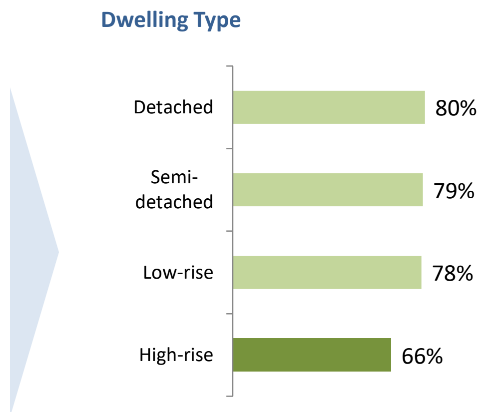
Just less than 3-in-10 (28%) general service respondents suffered outages of less than an hour and 15% lost power for 1-3 hours at their place of business. 2-in-10 (21%) experienced outages up to 12 hours long and about a quarter (23%) experienced 12 hour outages or longer.

Figure 7RS: Number vs. Length of Outages

When you do lose power, what causes you more difficulty:
[asked of all residential respondents; n = 500]

Sample Breakdown ▸▸
Those who say "length of outages"





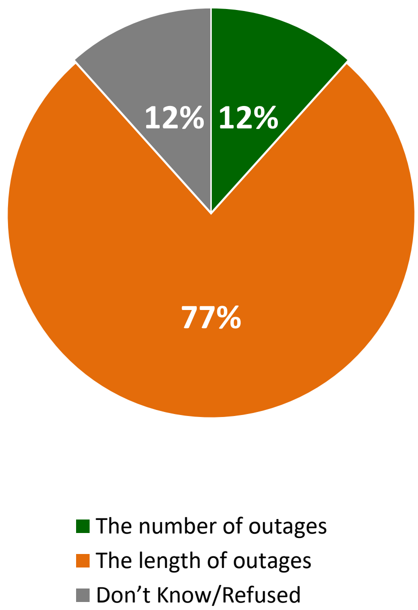
Note: 'Refused' (2%) not shown

When asked which causes them more difficulty, "number of outages" or "length", residential customers say the latter (77%) by a wide margin. Just 12% say the number of outages causes them more difficulty.

- High-rise (66%) residential customers are less likely to say "length of outages" than those living in low-rise, semi-detached or detached dwellings (78-80%).

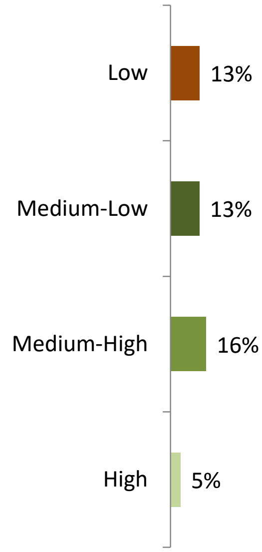
Figure 7GS: Number vs. Length of Outages

Q When your organization does lose power, what causes your organization more difficulty:
[asked of all GS respondents; n =100]



Sample Breakdown ▶▶
Those who say "number of outages"

Consumption Level

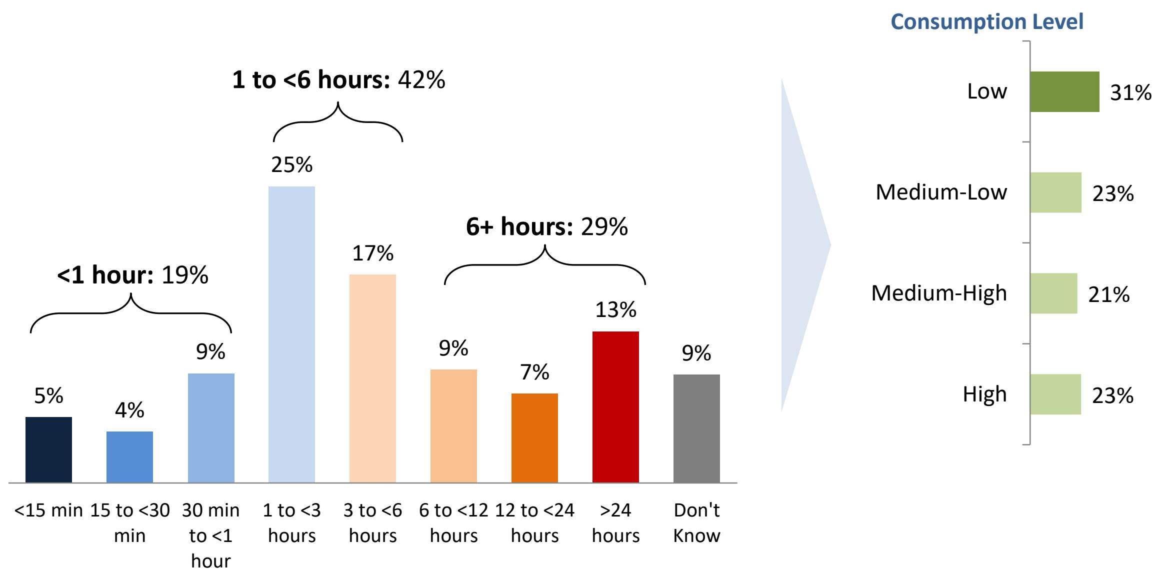


General service customers also find the length of outages (77%) more difficult than the number of them (12%) by a 65-point margin.

Figure 8RS: Length of Outage Time and Difficulty

Q Once the power goes out, is there a particular length of time at which being without power becomes more difficult for you?
[asked of all residential respondents; n=500]

Sample Breakdown
Those who say " 1 to <3 hours"

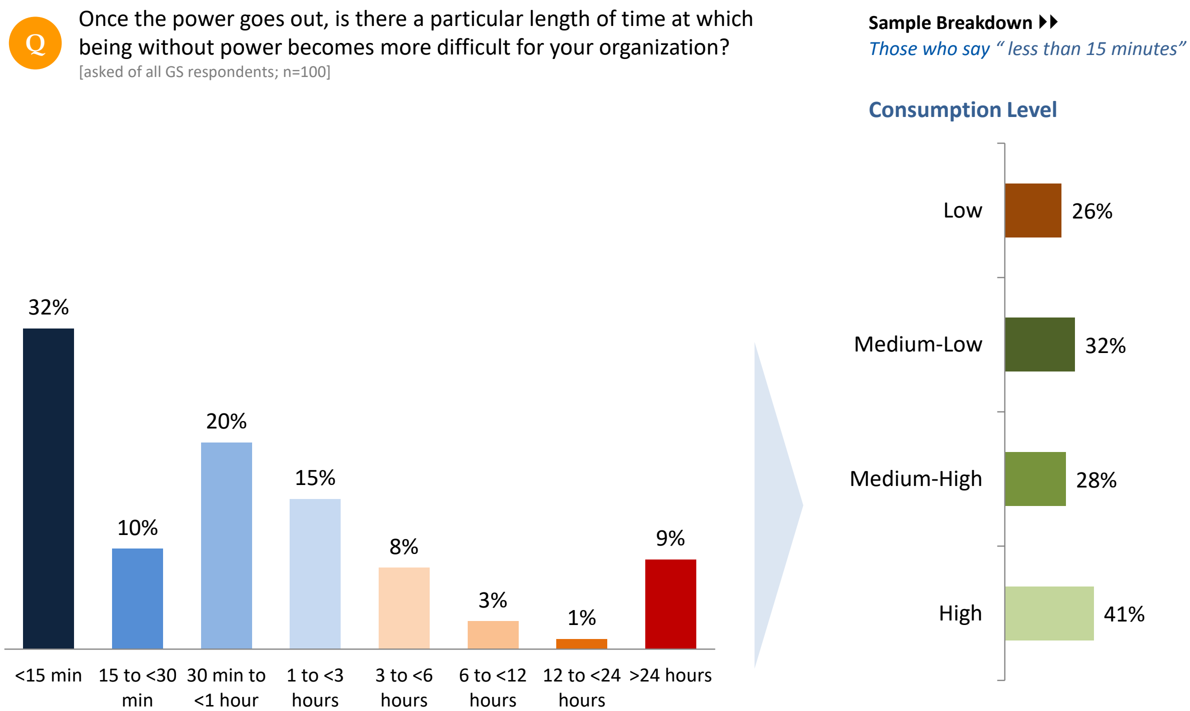


Note:'Refused' (1%) not shown

When asked if there is a particular length of time at which being without power becomes more difficult, two-in-ten (19%) residential customers say just "an hour or less". More than four-in-ten say between "one and six hours" starts making their life more difficult and three-in-ten say it only becomes difficult at six or more hours without power.

- Low-consumption residential consumers are more likely to say that even short outages make their lives more difficult (low: 31%; medium-low to high: 21-23%).

Figure 8GS: Length of Outage Time and Difficulty



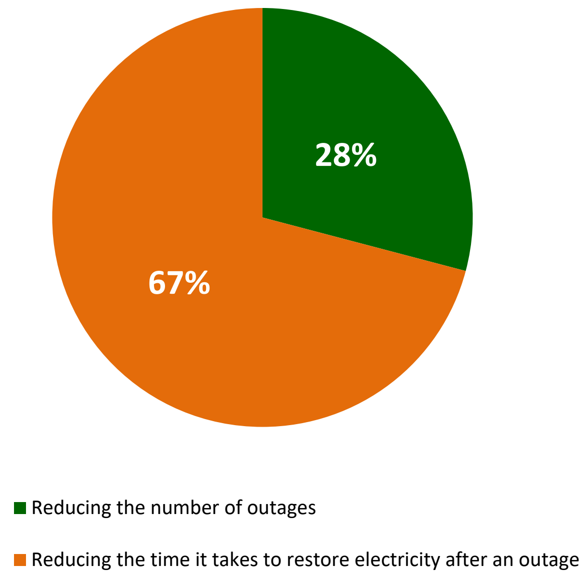
Note: 'Don't know'/'Refused' (2%) not shown

General service customers say that even a five-minute outage is a considerable problem for their organization. More than 6-in-10 (62%) say an outage of an hour or less starts making things more difficult for their organization. Of those, a third (32%) say a power outage of less than 15 minutes makes it more difficult.

- High-consumption GS customers are more likely to say that less-than-15-minute outages are a difficulty for them (41% vs. 26% low-consumption).

Figure 9RS: Priorities during Power Service Interruptions

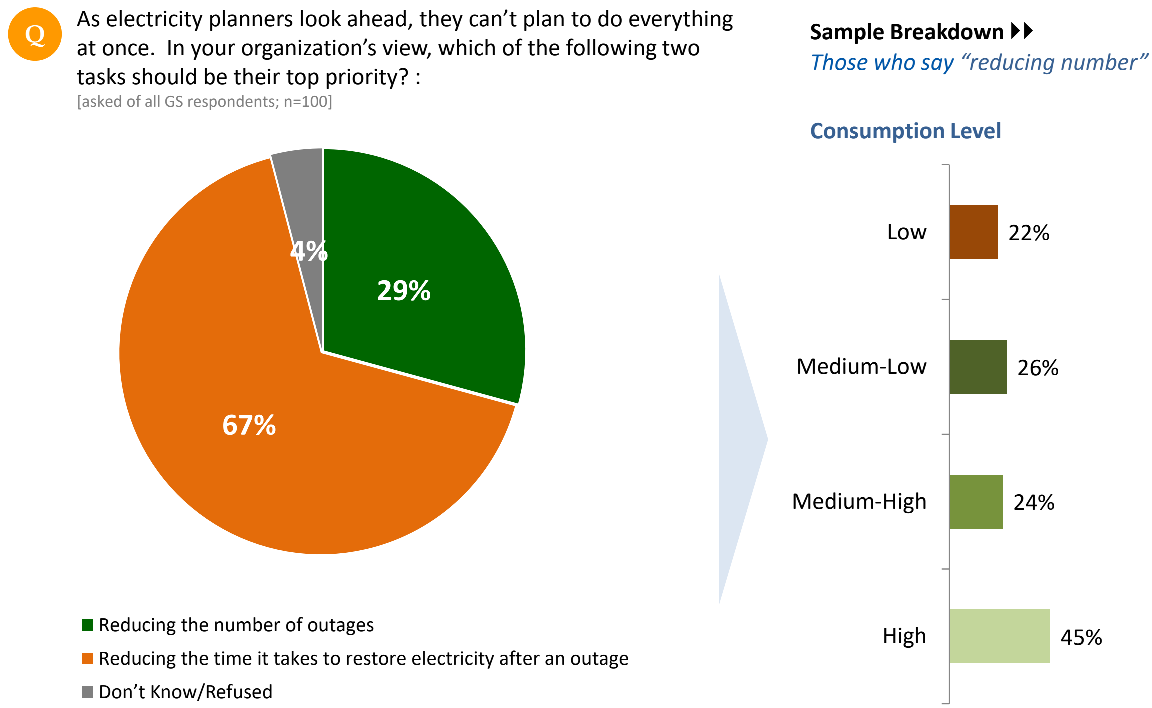
Q As electricity planners look ahead, they can't plan to do everything at once. In your view, which of the following two tasks should be their top priority? :
[asked of all respondents; n =500]



Note: 'Don't know'/'Refused' (5%) not shown

When asked to prioritize between "reducing the number of outages" (28%) and "reducing the time it takes to restore power" (67%), residential customers chose "reducing the time" by more than a two-to-one margin.

Figure 9GS: Priorities during Power Service Interruptions

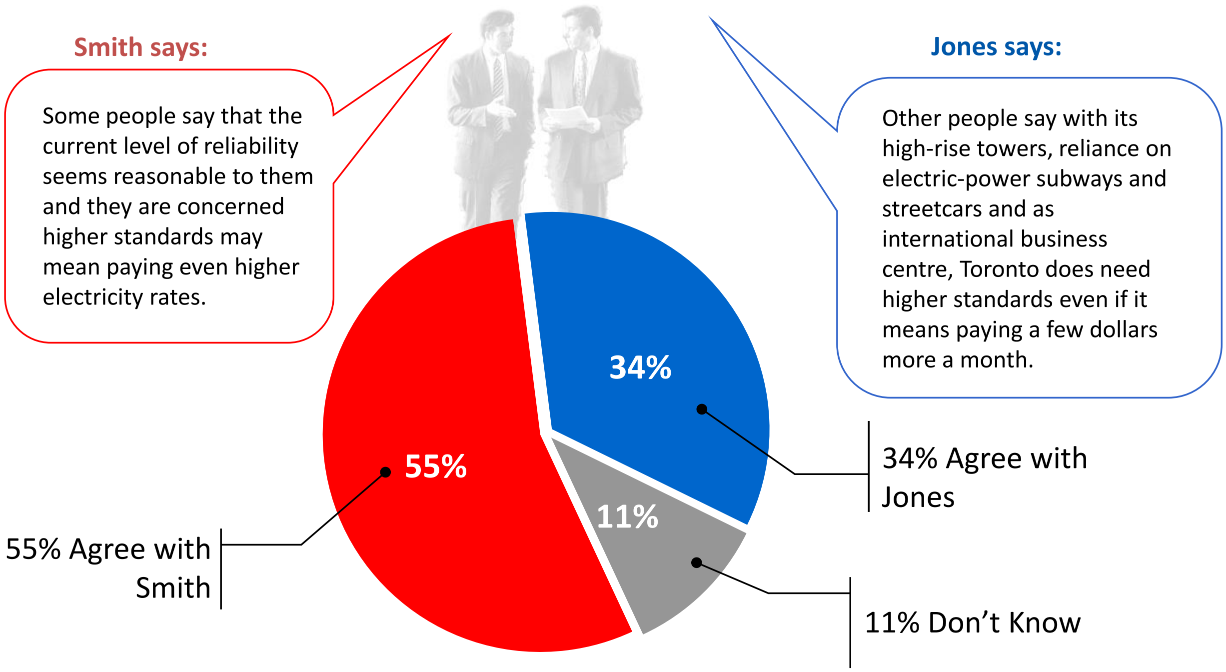


General service customers also prefer electricity planners reduce outage time over "reducing the number of outages", again by more than a two-to-one margin (67% to 29%).

- High-consumption GS respondents (45%) are more likely to want the number of outages reduced than those with lower consumption levels (22-26%).

Figure 10RS: Smith and Jones on Reliability

Q There are competing points of view about whether Toronto needs a higher standard of reliability than other places in Ontario. Which of the following two statements is closer to your own:
[asked of all residential respondents; n=500]



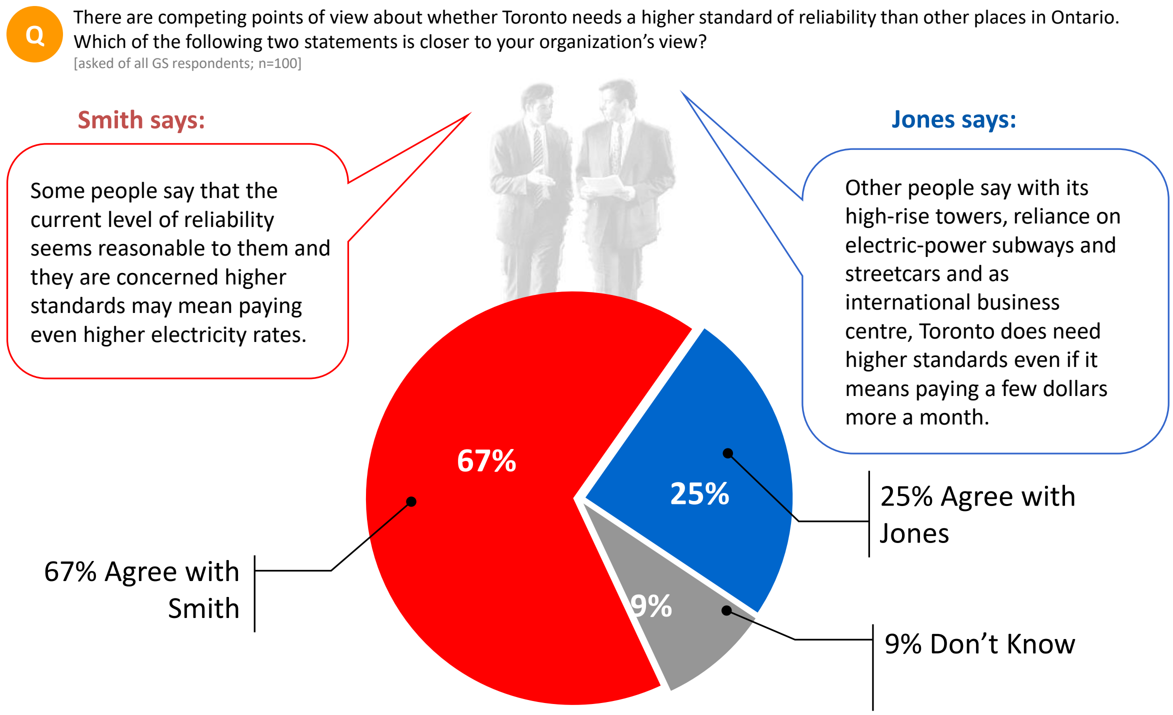
Note: Statements randomized ("some" vs. "other" will switch).

The final question on system reliability asks residential customers to choose between two competing viewpoints: that the "current level of reliability is reasonable" and higher standards would mean higher rates; or that Toronto, because of its current infrastructure needs, should be held to a higher standard even if it means paying more per month.

A majority (55%) of residential customers agree that the current level of reliability is reasonable and they are concerned that higher standards means paying even higher rates. Just a third (34%) support the opposing statement: Toronto needs to be held to a higher reliability standard even if it means paying more on their monthly bills.

- Those residential customers who consume the most power are also the most likely to support paying more for a "higher standard" of reliability (39% high-consumption vs. 32% low-consumption).

Figure 10GS: Smith and Jones on Reliability



Note: Statements randomized ("some" vs. "other" will switch).

When asked the same question, general service customers agree that the "current level of reliability seems reasonable" and are worried about higher rates. Just a quarter (25%) think Toronto needs to be held to a higher standard of reliability "even if it means paying a few dollars more a month".

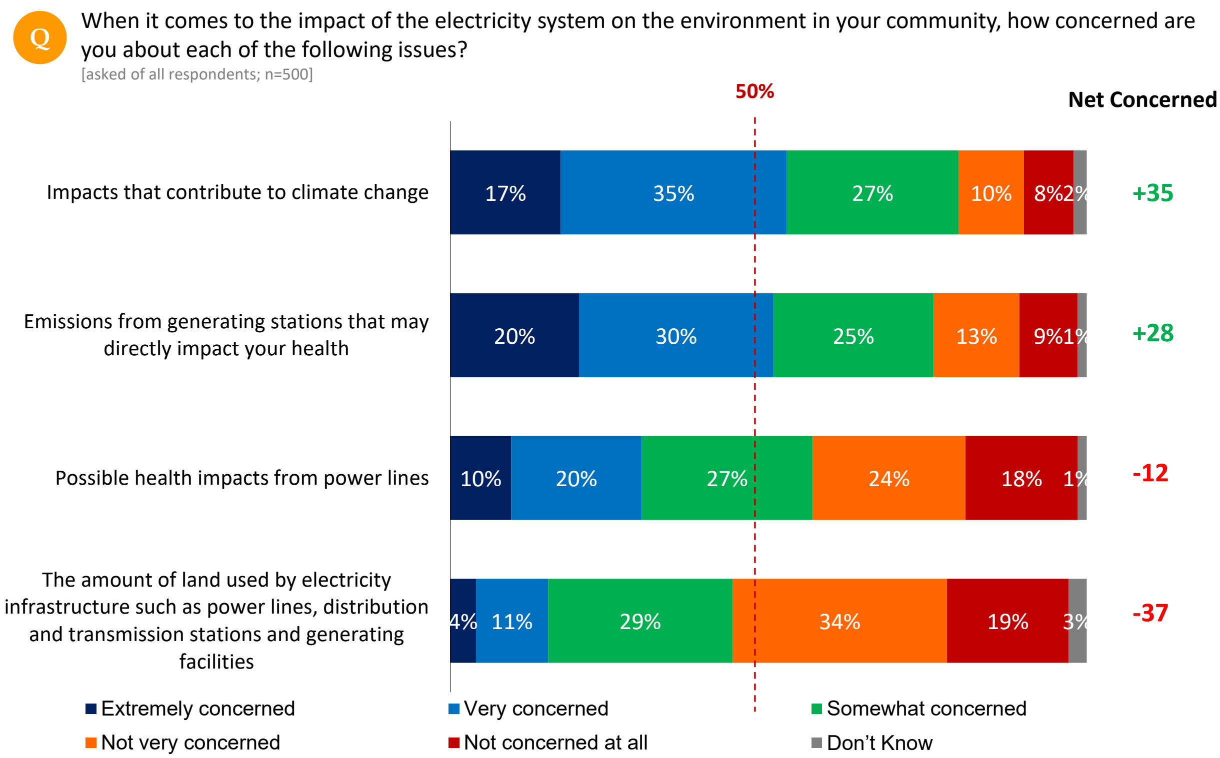
Environment

Respondents were then asked a battery of questions to gauge their environment concerns about the Ontario electricity system.

"Climate change contribution", "emissions impacting" health key concerns

- Customers' greatest environmental concerns are how their electricity system contributes to climate change (+35) and also how those emissions directly impact their health (+28).
- They are not particularly concerned with "health impacts from power lines" (-12) or "the amount of land used by electricity infrastructure" (-37).

Figure 11RS: Environmental Concern Battery



Note: 'Refused' (<1%) not shown

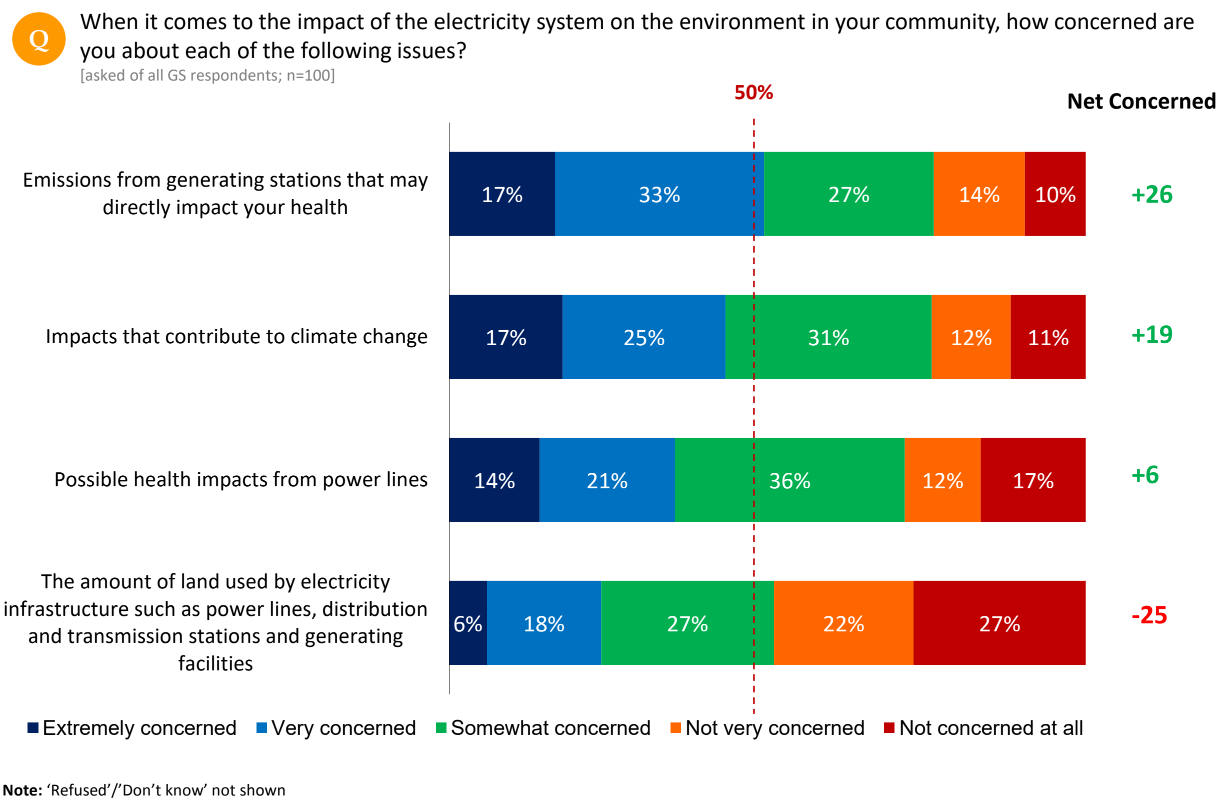
Of the four concerns polled, the one most concerning to residential customers is how Ontario electricity contributes to climate change (net +35). Over half (52%) are concerned about the electricity system impacting climate change, while less than 2-in-10 (18%) are not concerned about this issue.

Another main issue of concern for these respondents are "emissions from generating stations" that may personally affect their health (net +28%). 1-in-2 residential customers is concerned about this issue, compared to just over 2-in-10 (22%) who feel the opposite.

Overall, residential customers are much less concerned about "the possible health impacts from power lines" (net -12) and "the amount of land used by electricity infrastructure" (-37). Just three-in-ten (30%) are concerned about the former and less than 2-in-10 (15%) are concerned about the latter.

- Low-consumption users are the most concerned about the electricity system's impact on climate change (64% vs. 43% high-consumption).

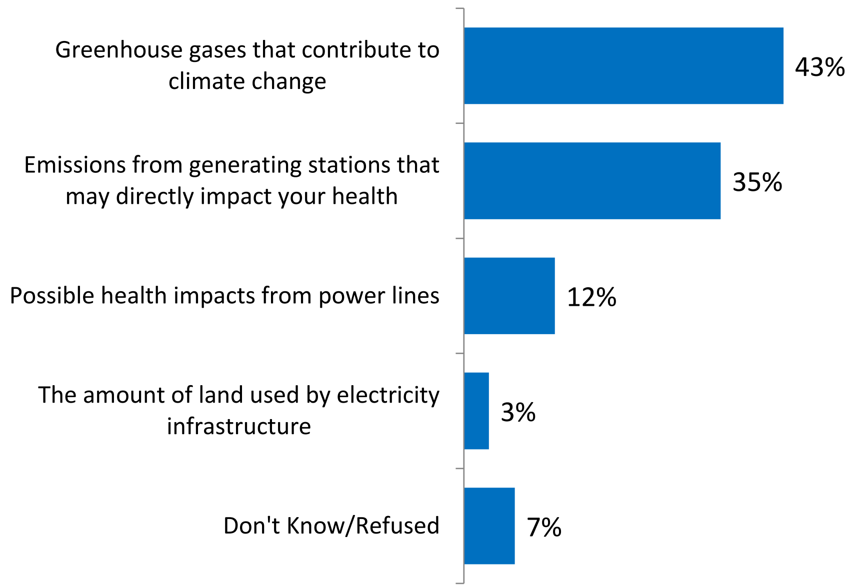
Figure 11GS: Environmental Concern Battery



Turning to general service customers, net positive concerns for them are "emissions impacting health" (+26) and the "system contributing to climate change" (net +19) as well. GS customers are also less concerned about the "possible health impacts from power lines" (+6) or "the amount of land used by electricity infrastructure" (-25).

Figure 12RS: Greatest Environmental Concern

Q And which of these environmental issues is of the greatest concern to you?
[asked all respondents; n=500]

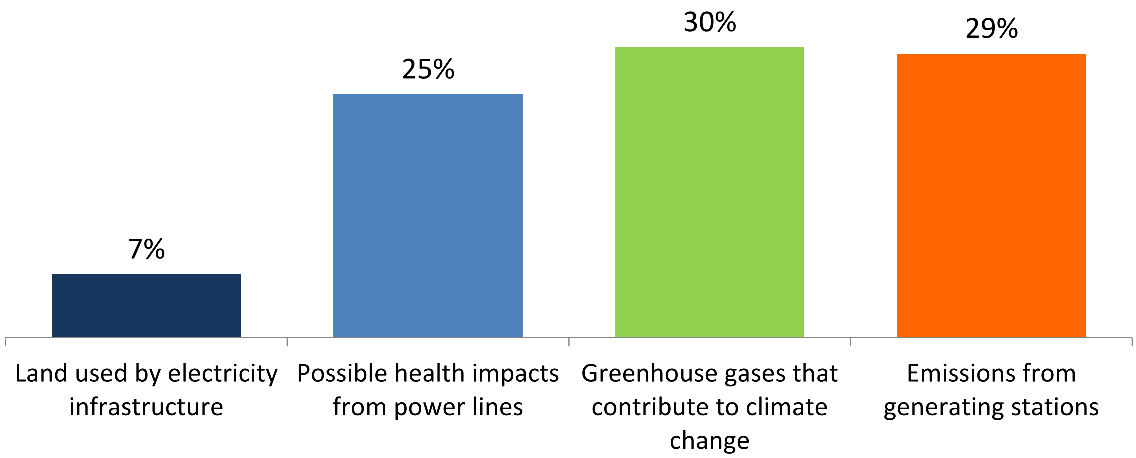


When asked which of the four electricity system issues concerns them the most, residential customers still choose “contributing to climate change” (43%) with “emissions possibly impacting their health” a close second (35%). Just over 1-in-10 (12%) voice “the possible health impacts from power lines” as their top concern and almost no one considers “the amount of land used by electricity infrastructure” (3%) their top environmental concern.

- In this question as well, low-consumption users are the most likely to consider the electricity system’s effect on climate change their key important environmental concern (55% vs. 38% high-consumption).
- On climate change and the electricity system, smaller households (single: 46%; two: 50%) and renters (52%) are more concerned than larger households (31-39%) and owners (62%), respectively.

Figure 12GS: Greatest Environmental Concern

Q And which of these environmental issues is of the greatest concern to your organization?
[asked of all GS respondents; n=100]



Note: 'Don't know'/'Refused' (9%) not shown

General service respondents feel about equally concerned with "health impact from power lines" (25%), "climate change" (30%), and "emissions from generating stations" (29%). Very few (7%) care about the amount of land used by electricity infrastructure.

Cost and Value of Electricity

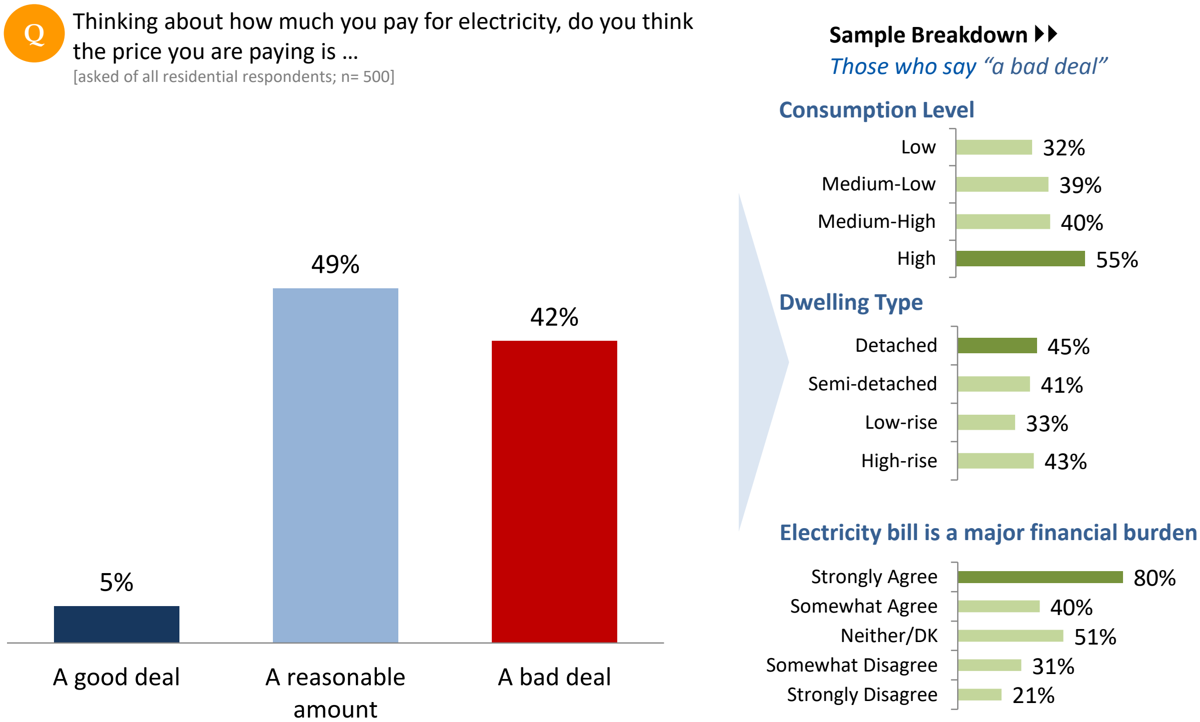
This short section examines how the cost of electricity affects the every-day lives of residential and general service customers and also whether they feel they are getting value for money on their electricity.

Majority think they're getting good value for money, divided on bill impact

- Nearly 6-in-10 (58%) residential customers think they are getting either a reasonable or good deal on their electricity. And about the same amount (Residential: 57%) think they get good value for money on their electricity.
- Residential customers are divided on whether the cost of their electricity bill has a major impact on their finances (46% major impact vs. 50% no impact).
- General service customers feel a much greater impact (77%) major impact) and are less likely to think they are getting good value for money (46% vs. 52%).
- High-consumption users are also the most impacted financially by their electricity bills (91%).

Figure 13RS: Price Paid for Electricity

Q Thinking about how much you pay for electricity, do you think the price you are paying is …
[asked of all residential respondents; n= 500]



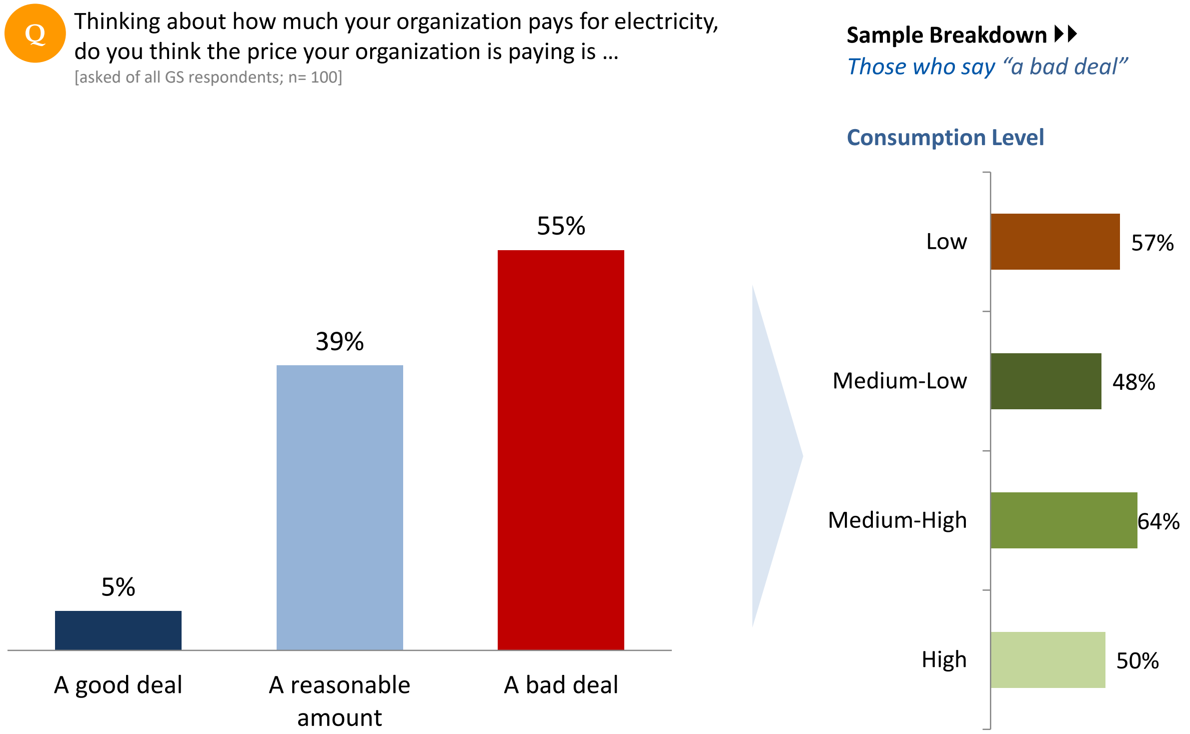
Note: 'Don't know' (4%) not shown

Turning to cost, more than 4-in-10 (42%) residential customers think they have a bad deal on their electricity. About half (49%) think they pay "a reasonable amount" and only 5% think the price they pay for electricity is "a good deal".

- High-consumption customers (55%) are more likely than lower-consumption residents (32-40%) to say they are getting a bad deal on electricity.
- Those residents who "strongly agree" (80%) that their bill is a major financial burden are by far the most likely to feel their electricity price is "a bad deal".

Figure 13GS: Price Paid for Electricity

Q Thinking about how much your organization pays for electricity, do you think the price your organization is paying is …
[asked of all GS respondents; n= 100]



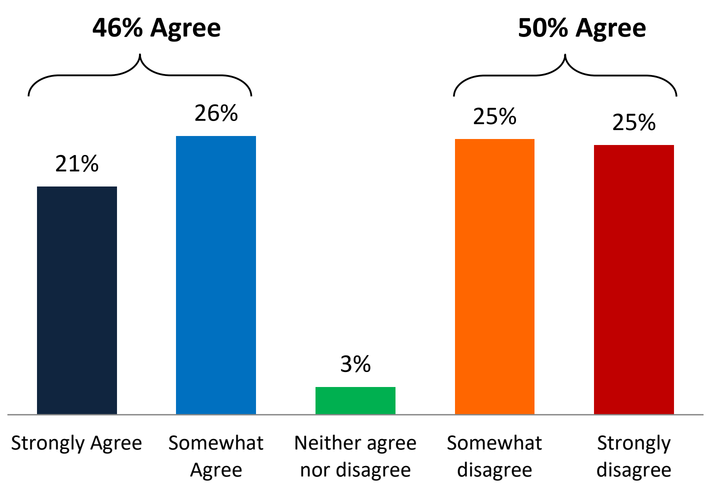
Note: 'Don't know'/'Refused' (1%) not shown

A majority (55%) of GS respondents think they are getting a bad deal on electricity. 4-in-10 (39%) say they pay a reasonable amount and only 5% think they are getting a good deal.

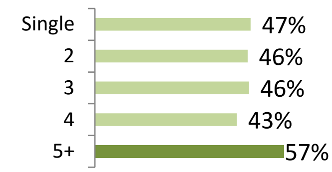
Figure 14RSa: Financial Impact of Electricity Bill

Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.
[asked of all residential respondents; n=500]

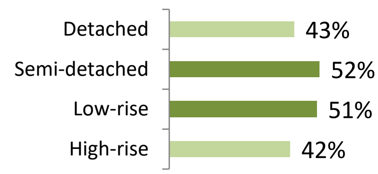
Sample Breakdown ▸▸
Those who say "agree"



Household Size



Dwelling Type

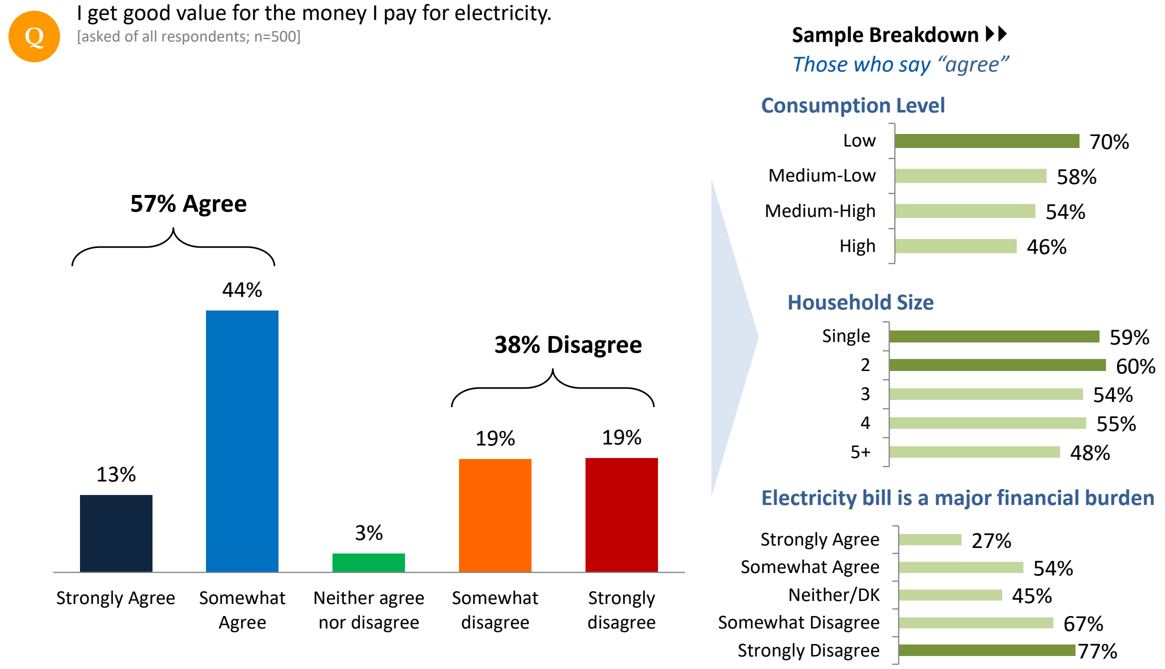


Note:'Don't Know'/'Refused' (1%) not shown

Residential customers are divided on whether the cost of their electricity bill has a major impact on their finances. Just under half (46%) feel that their bill has a major impact on their finances while half (50%) feel otherwise with roughly the same intensity (21% vs. 25% strongly agree/disagree).

- Larger households (5+ people: 57%) are more likely than smaller ones (43-47%) to feel the financial impact of their electricity bill.

Figure 14RSb: Financial Impact of Electricity Bill



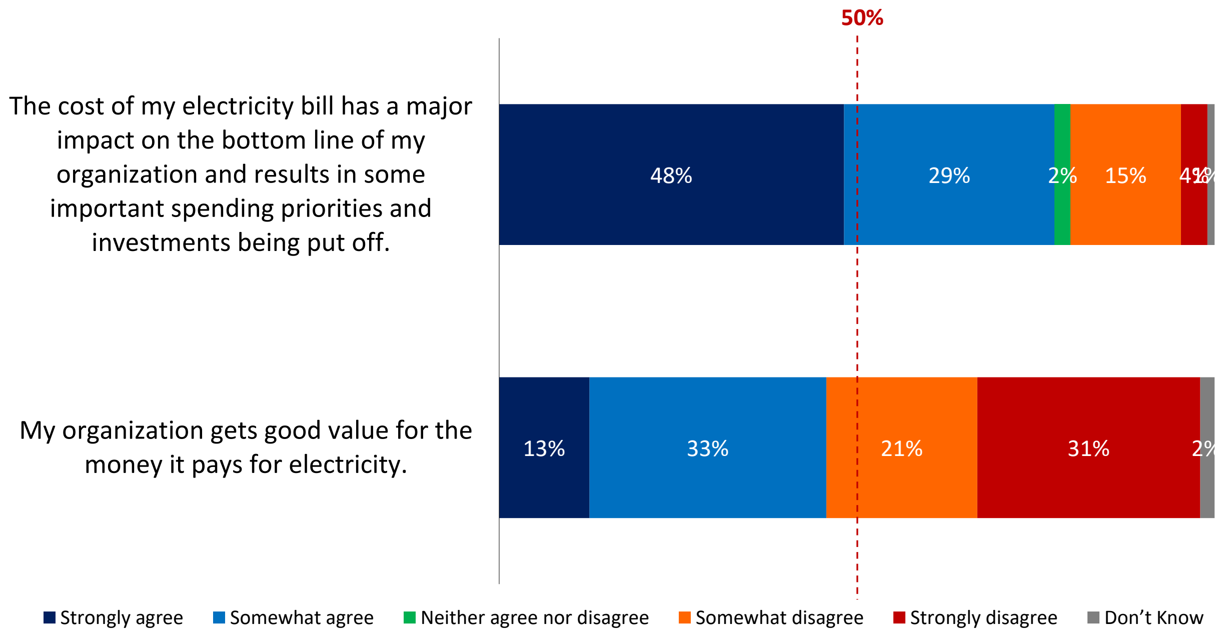
Note: 'Don't Know'/'Refused' (2%) not shown

A majority (57%) of residential customers feel they get good value for money on their electricity. Less than 4-in-10 (38%) say the opposite.

- Low-consumption users (70% vs. 46-58%), single and two-person households (59-60% vs. 48-54%), and those who feel strongly that their electricity bill is not a major financial burden (77% vs. 27-67%) are the most likely to think that they get good value for money on their electricity.

Figure 14GS: Financial Impact of Electricity Bill

Q Please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with each of the following statements. [asked of all GS respondents; n=100]



Cost Statements: AGREE	Low	Medium -low	Medium -high	High
The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.	**70%**	**74%**	**76%**	**91%**
I get good value for the money they pay for electricity.	**39%**	**48%**	**40%**	**55%**

On the question of cost, a strong majority of general service customers (77%) agree with great intensity that the cost of their bill has an impact on the organization's bottom line. Just 2-in-10 (19%) feel their bill cost does not have a major impact.

GS customers lean a bit negative on the statement "my organization gets good value for the money it pays for electricity". Less than half (46%) feel their organization gets good value, while just over half (52%) think otherwise.

- High-consumption users (91%) are the most likely to say the cost of their bill has a major impact on their finances.

Goals and Criteria

The final section of the survey outlines the three solutions to deal with capacity issues: "Conservation and Demand Management", "Distributed Generation" and "Transmission and Distribution Infrastructure". Customers are then asked to rank these solutions as well as the considerations that are most important to them when choosing one of these three options.

Low Awareness, Interest in Distributed Generation

- Respondents are the least familiar with "Distributed Generation" (net -27 vs. +10 "Transmission and Distribution Infrastructure" and +2 "Conservation and Demand Management").
- "Distributed Generation" is the last picked solution by residential customers to deal with capacity problems (34% vs. 47% "Transmission and Distribution Infrastructure").

Low Awareness and Interest in Distributed Generation

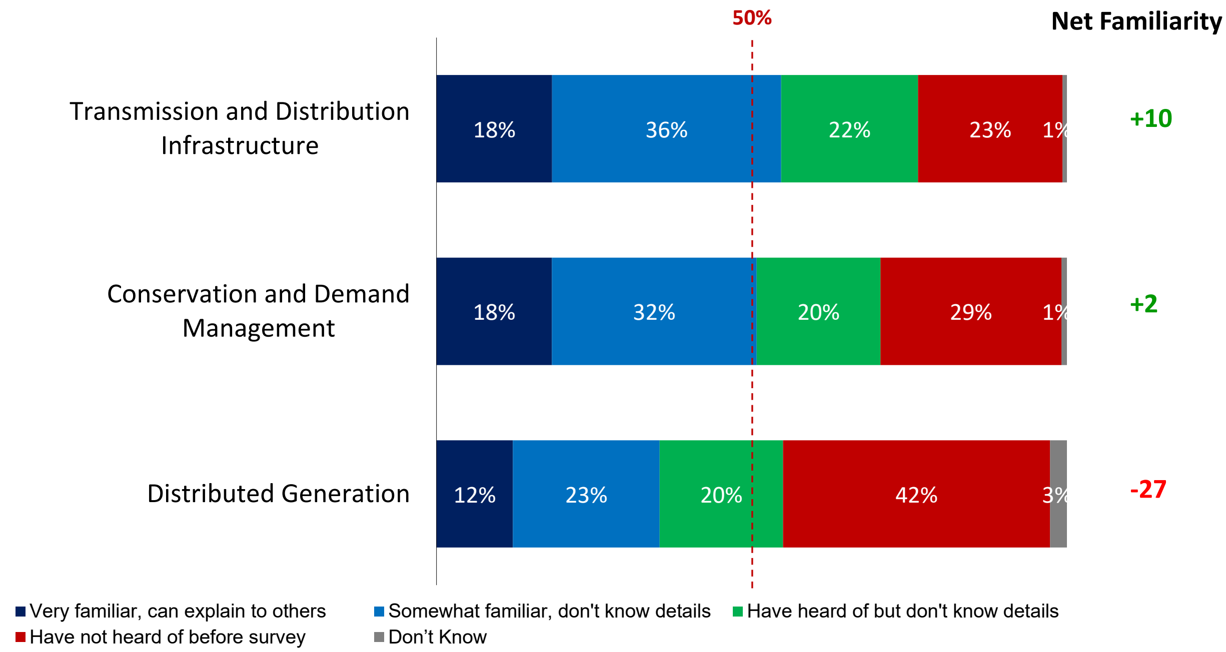
- Respondents are the least familiar with "Distributed Generation" (net -27 vs. +10 "Transmission and Distribution Infrastructure" and +2 "Conservation and Demand Management").
- "Distributed Generation" is the last picked solution by residential customers to deal with capacity problems (34% vs. 47% "Transmission and Distribution Infrastructure").

Most important considerations "time", "rates" and "climate change"

- When asked to rate seven considerations relating to capacity, residential customers focus the most on "reducing the time it takes to restore power" (+91), "reducing the impact on electricity rates" (+81), and "reducing impacts that contribute to climate change" (net +80).

Figure 15RS: Familiarity with Solutions

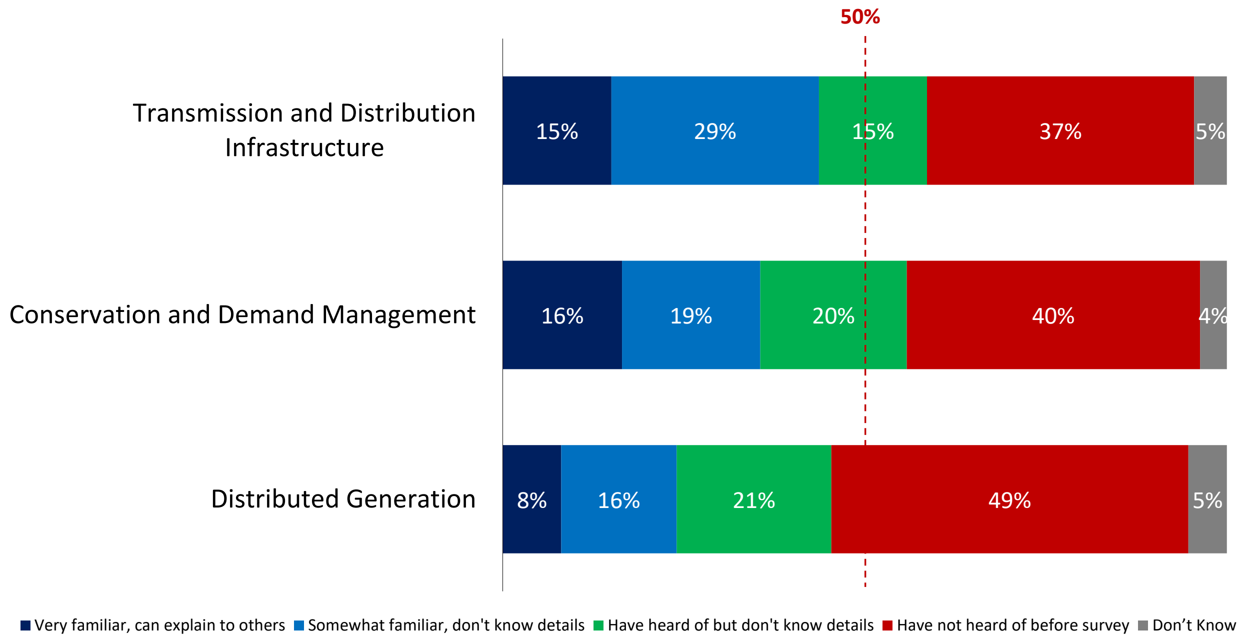
Q How familiar are you with the following terms…
[asked of all residential respondents; n= 500]



A majority of residential customers are familiar with the solutions "Transmission and Distribution Infrastructure" (net +10) and "Conservation and Demand Management" (+2). A smaller minority are familiar with "Distributed Generation" (net -27).

Figure 15GS: Familiarity with Solutions

Q How familiar are you with the following terms?
[asked of all GS respondents; n= 100]



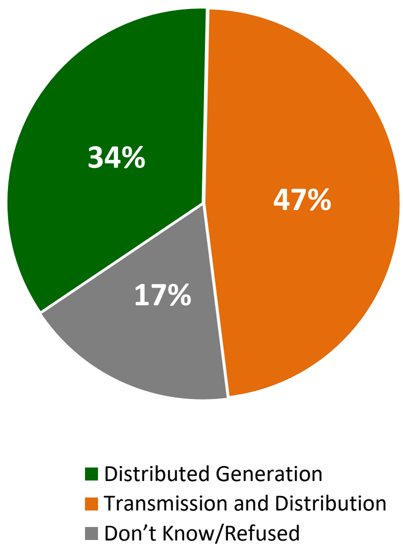
Solutions: FAMILIAR	Low	Medium-low	Medium-high	High
Transmission and Distribution Infrastructure	**61%**	**42%**	**40%**	**32%**
Conservation and Demand Management	**39%**	**48%**	**32%**	**23%**
Distributed Generation	**35%**	**23%**	**16%**	**23%**

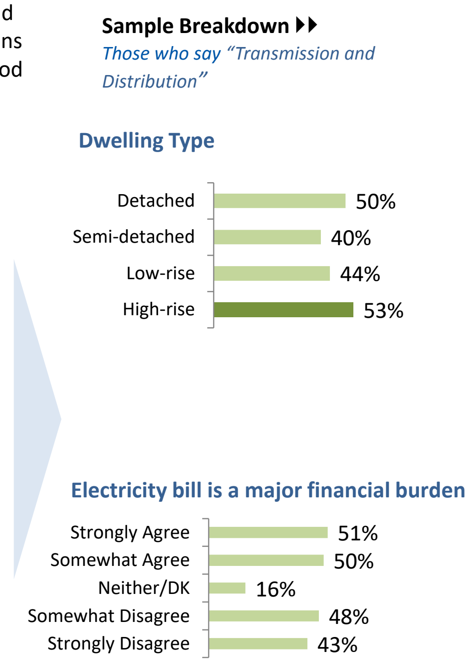
As for general service respondents, a majority are unfamiliar with all three options ("Transmission and Distribution Infrastructure": net -8; "Conservation and Demand Management": -25; "Distributed Generation" -47).

Taking into account the small sample size (n=100), low-consumption general service customers appear a bit more familiar with "Transmission and Distribution Infrastructure" (61%) and "Distributed Generation" (35%) than higher-consumption customers ("Transmission and Distribution Infrastructure": 32-42%; "Distributed Generation": 16-23%).

Figure 16RS: Second Choice Solution

Q Government policy requires planners to look at Conservation and Demand management first. Which of the two remaining solutions would be your second choice to deal with growing neighbourhood demands?
[asked of all residential respondents; n =500]

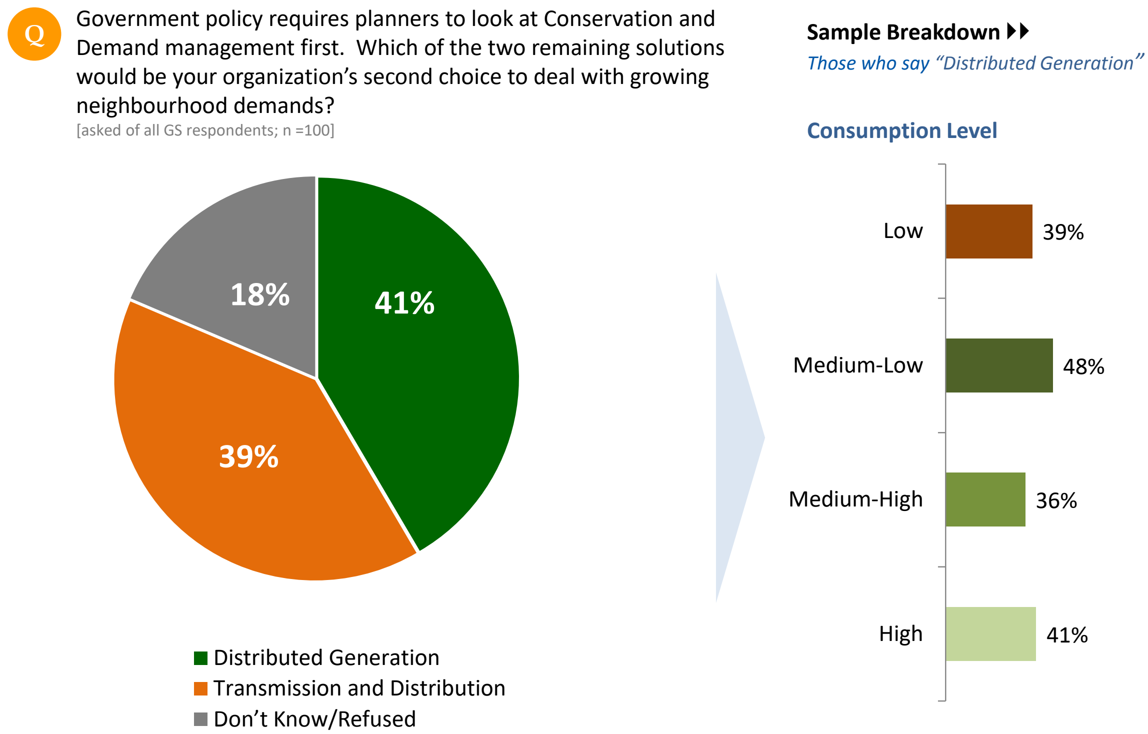




Note: ‘Refused’ (2%) not shown

After a brief preamble explaining the three possible solutions and explaining policy requires a look at “Conservation and Demand Management” first, the survey asks respondents to choose their preferred second option. Of the two remaining, nearly half (47%) choose “Transmission and Distribution” and a third (34%) pick “Distributed Generation”. Almost 2-in-10 (17%) do not know their second choice.

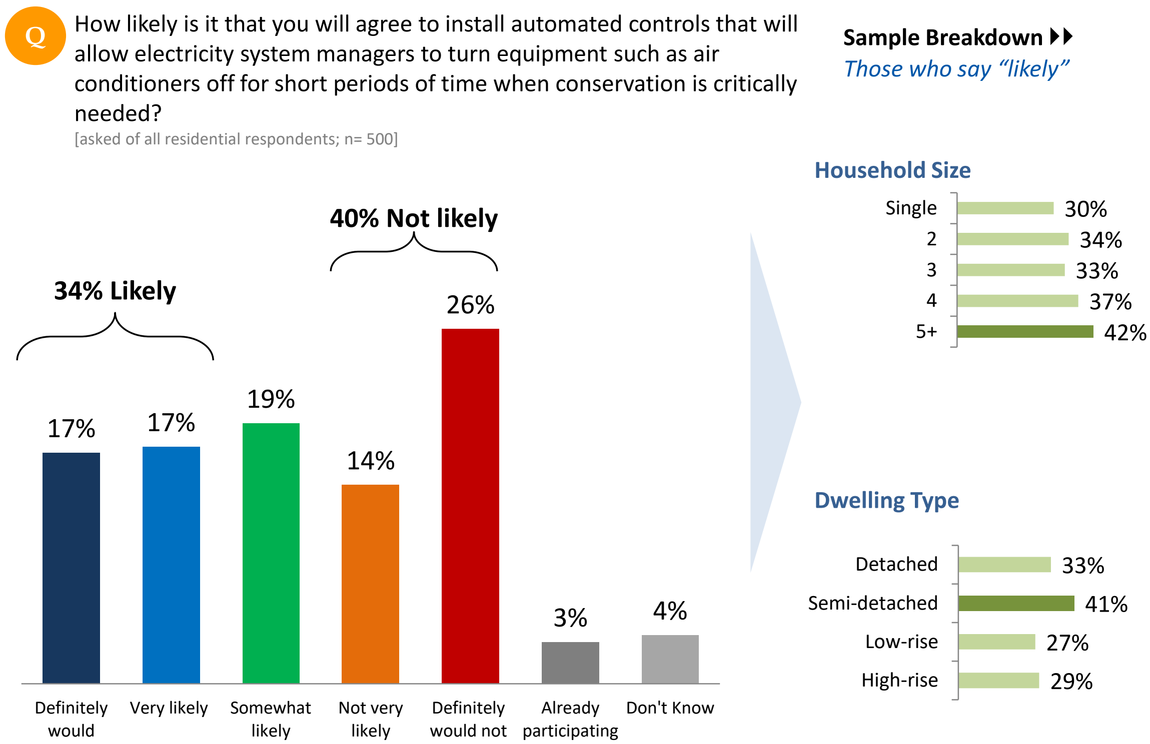
Figure 16GS: Second Choice Solution



Note: 'Don't know'/'Refused' (1%) not shown

General service respondents are more evenly divided on the remaining two options: roughly 4-in-10 say either 'Transmission and Distribution" (39%) or "Distributed Generation" (41%). Again, about 2-in-10 (18%) are not sure on their second choice.

Figure 17RS: Likelihood to Install Controls



Residential customers are divided on whether or not they would install automated controls for conservation. About a third (34%) say they are likely to do so, but 4-in-10 (40%) say they would not install controls in their home that would allow managers to turn home equipment off remotely.

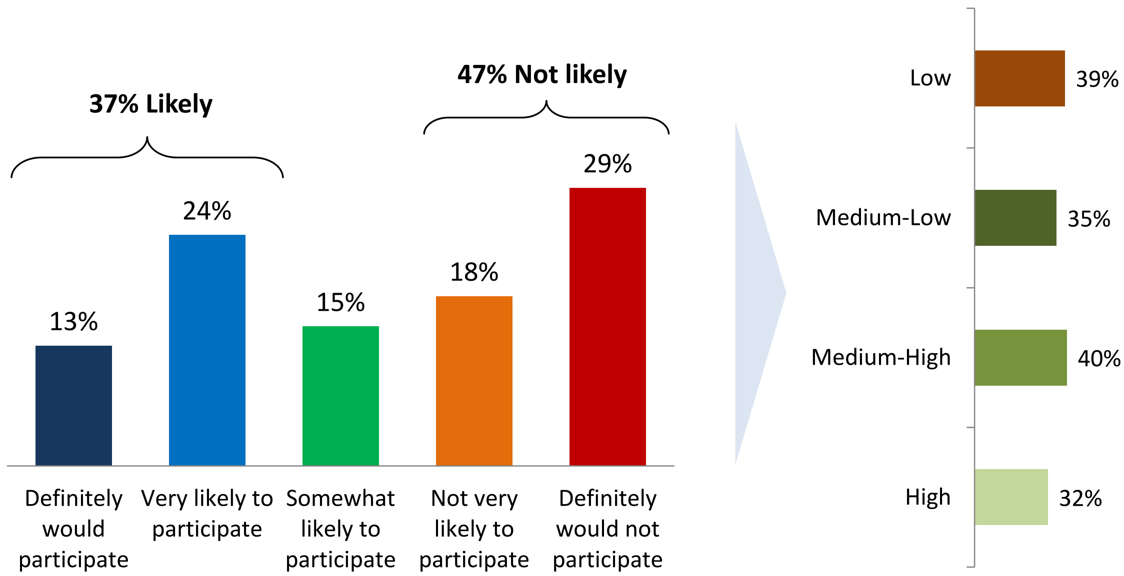
- Larger households (42% 5+ vs. 30% single) are the most likely to allow remote controls installed to automate equipment such as air conditioners.

Figure 17GS: Likelihood to Install Controls

Q How likely is it that your organization will agree to install automated controls that will allow electricity system managers to turn equipment such as air conditioners off for short periods of time when conservation is critically needed?
[asked of all GS respondents; n= 100]

Sample Breakdown ▶▶
Those who say "likely"

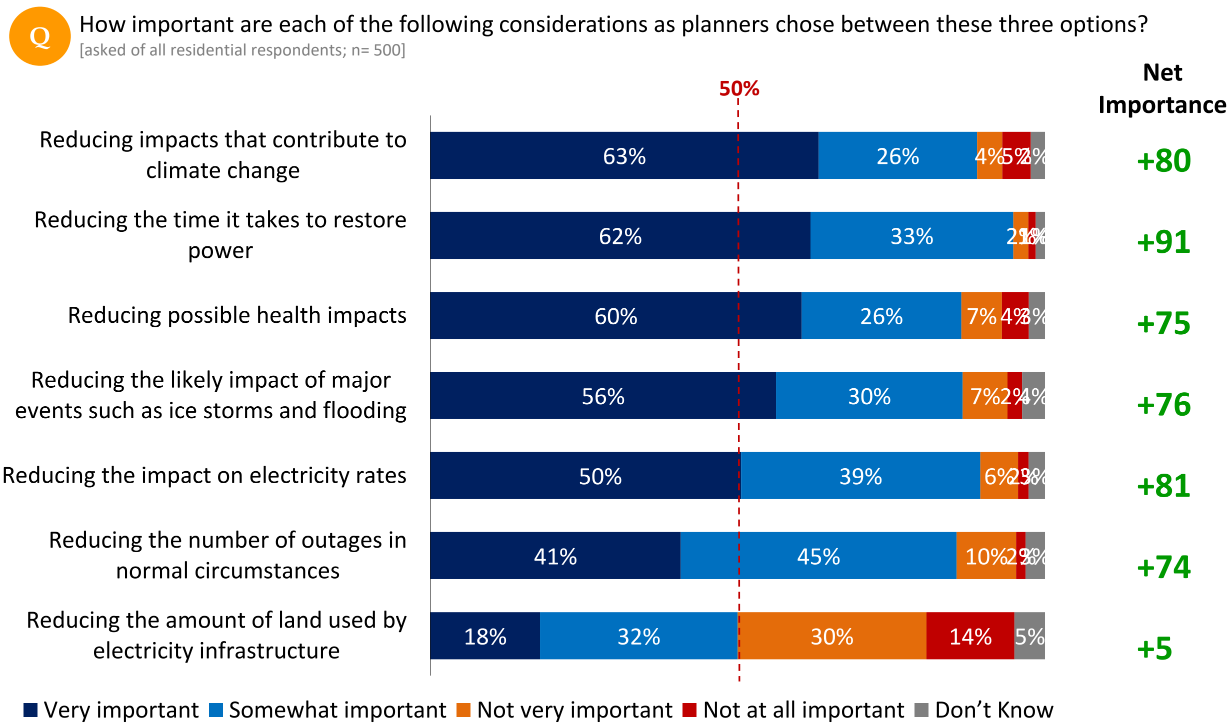
Consumption Level



Note: 'Don't know'/'Refused' (2%) not shown

General service customers are a bit less likely to allow remote control activation in their place of business. Less than 4-in-10 (37%) say they are likely to agree to install automated controls, while almost half (47%) say they would not participate in such a program.

Figure 18RS: Consideration of Choice Battery



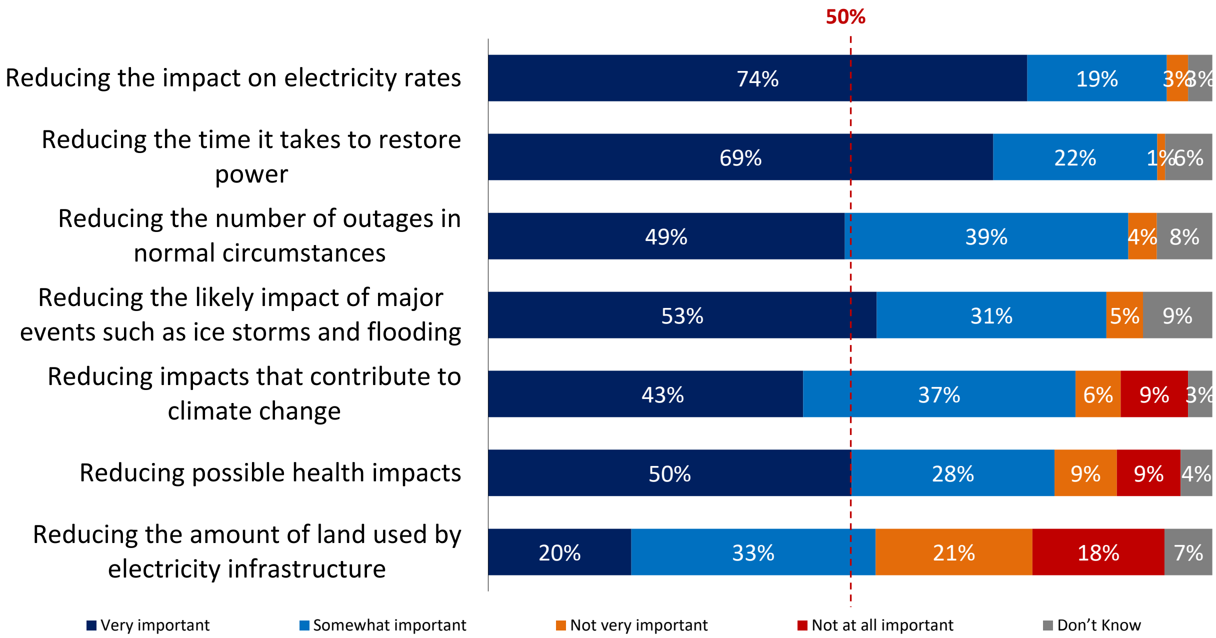
Residential customers were then asked to rate seven different considerations relating to capacity issues. Six of these options are of a high importance to customers when choosing between the three options: "reducing impacts that contribute to climate change" (net +80); "reducing the time it takes to restore power" (+91), "reducing possible health impacts" (+75), "reducing the likely impact of major events" (+76); "reducing the impact on electricity rates" (+81); and "reducing the number of outages in normal circumstances" (+74). All six of these considerations have high intensity of importance for customers (41-63%: "very important").

The least important consideration for residential customers is "reducing the amount of land used" (+5).

- High-consumption residential customers see "reducing the likely impact of major events such as ice storms and flooding" as less important than lower-consumption customers (69% vs. 74-81%). They are also a bit less worried about "reducing the impacts that contribute to climate change" than low-consumption customers (76% vs. 87% low-consumption).

Figure 18GS: Consideration of Choice Battery

Q How important are each of the following considerations as planners chose between these three options?
[asked of all GS respondents; n= 100]

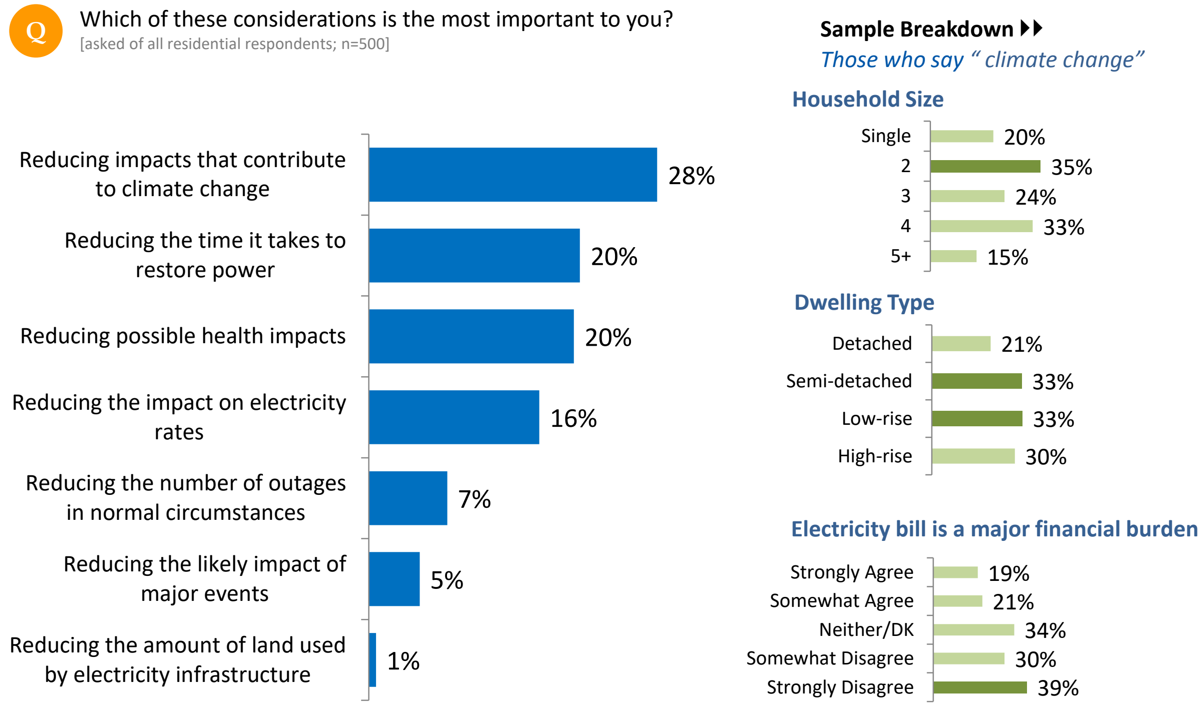


Q How important are each of the following considerations as planners chose between these three options?
[asked of all GS respondents; n= 100]

Considerations: IMPORTANT	Low	Medium-low	Medium-high	High
Reducing the number of outages in normal circumstances	83%	97%	84%	86%
Reducing the time it takes to restore power	83%	100%	92%	91%
Reducing the likely impact of major events such as ice storms and flooding	78%	90%	92%	77%
Reducing the amount of land used by electricity infrastructure	48%	61%	48%	55%
Reducing possible health impacts	70%	87%	80%	73%
Reducing impacts that contribute to climate change	78%	77%	88%	77%
Reducing the impact on electricity rates	83%	97%	96%	95%

General service customers see the same six considerations as important for deciding between the three options. For them, "reducing the impact on electricity rates" (+90 net) and reducing the time (+90) and number of outages (+84) are the top concerns. Climate change (+65) is a bit lower in the list, but still a key concern.

Figure 19RS: Importance of Considerations for Choice



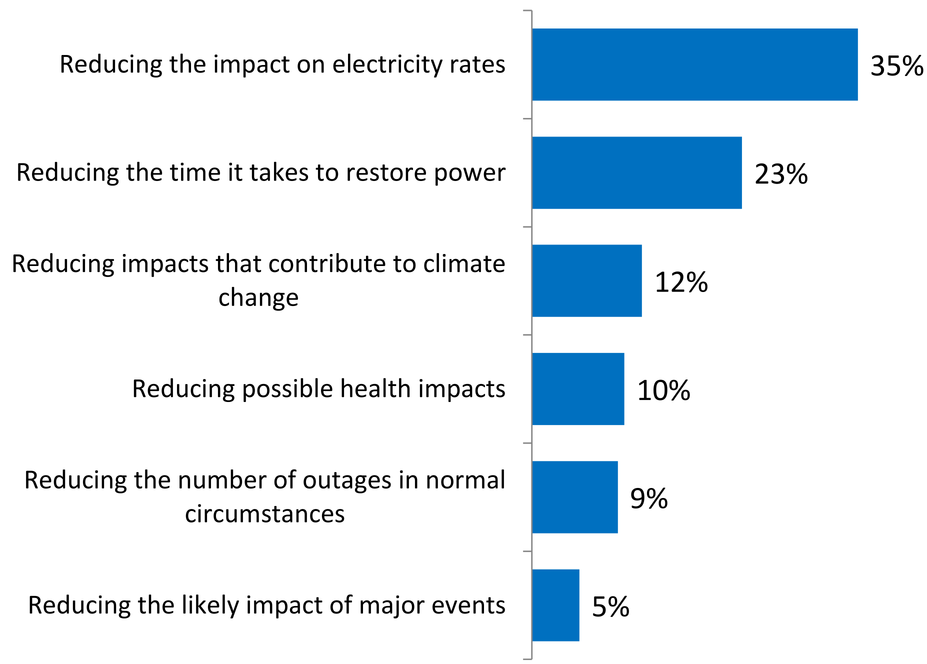
Note: 'Don't know' (3%) not shown

When asked to pick the most important consideration from the list of seven, a large minority of residential customers say "climate change" (28%). About one-in-five say "reducing the time it takes to restore power" or "reducing possible health impacts" (20%). Less important considerations include reducing "the impact on rates" (16%), "number of outages" (7%), "likely impact of major events" (5%) and "the amount of land used by electricity infrastructure" (1%).

- Those who do not feel their bill is a major burden are most likely to say "climate change" is their most important consideration (30-39% disagree "major burden" vs. 19-21%).

Figure 19GS: Importance of Considerations for Choice

Q Which of these considerations is the most important to your organization?
[asked of all GS respondents; n=100]



Note: 'Don't know'/'Refused' (6%) not shown

A large minority of general service respondents considers "reducing the impact on electricity rates" (35%) the most important for their organization. About a quarter mention "reducing the time it takes to restore power" 23% as their leading consideration.

Survey Instruments

Residential Survey Instrument

Section A: Introduction

INTRO

Hello, my name is _______________ and I'm calling from **Innovative Research Group,** a national public opinion research firm. We have been commissioned by **Toronto Hydro,** the **Ontario Power Authority,** the **Independent Electricity System Operator** and **Hydro One** to help them better understand the needs and preferences of customers like you as they prepare plans to meet your future electricity needs.

A2. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	[**continue**]
No – NOT PRIMARY BILL PAYER	2	[**go to TRANSFER-1**]
No – BAD TIME	3	**ARRANGE CALLBACK**
No – HARD REFUSAL	4	[**Terminate**]

MONIT

This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A3. Have I reached you at your home phone number?

INTERVIEWER NOTE; IF "NO" ASK: May I speak to someone who does live there?

Yes - SPEAKING, CONTINUE	1	[**continue**]
YES - TRANSFERRED – **(GO BACK TO INTRODUCTION)**	2	[**back to INTRO**]
No - NOT AVAILABLE – **(ARRANGE CALLBACK)**	3	[**ARRANGE CALLBACK]**
Refused – LOG **(THANK AND TERMINATE)**	9	[**Terminate**]

A4. Are you the person primarily responsible for paying the electricity bill in your household?

Yes	1	[**skip to A4**]
No	2	[**go to TRANSFER-1**]
Don't know (**DNR**)	98	[**Terminate**]

TRANSFER-1

Can I speak with the person in your household who usually pays the electricity bill?

Yes	1	[**BACK TO** *INTRO*]
No – NOT AVAILABLE/BAD TIME – **(ARRANGE CALLBACK)**	2	[**ARRANGE CALLBACK]**
No – HARD REFUSAL	3	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

A5. Can you confirm that your household receives an electricity bill from **Toronto Hydro**?

Yes	1	[**continue**]
No	2	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

GENDER	Note gender by observation:
Male	1
Female	2

Section B: General Satisfaction

B6. PREAMBLE-1

To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

How familiar are you with Ontario's electricity system? Would you say … [READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B7. Generally speaking, how satisfied are you with the job the electricity system does in providing you with electricity? Would you say … [**READ LIST**]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B8. Is there anything in particular the electricity system can do to improve its service to you? [**OPEN**]

Don't know (**DNR**)	98
Refused (**DNR**)	99

ROTATE SECTIONS C, D AND E – TRACK ROTATION

Section C: System Reliability

These questions are about priming the respondent to think about their experience with system reliability and to separate views about adverse weather from failing equipment.

C9. In 2013, electricity consumers in Toronto experienced unusually extreme weather – flooding in July 2013 and an ice storm in December 2013. These rare and unpredictable events -- which often impact a large number of people – are called "**major events**" in the electricity sector. These major weather events caused power outages across Toronto.

Did either of these major weather events cause a power outage at your home?

INTERVIEWER NOTE: Make sure respondents specify which storm affected their power.

Yes – flooding	1
Yes – the ice storm	2
Yes – both storms	3
No – neither weather events affected my power service	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

[Ask all respondents]

C10. <u>Not</u> including power outages caused by these extreme weather events, did you have any other power outages in the **<u>last 12 months</u>**?

Yes	1
No	2 **SKIP TO C13**
Don't know (**DNR**)	98 **SKIP TO C13**
Refused (**DNR**)	99 **SKIP TO C13**

C11. How many outages did you experience over the past 12 months, NOT including those caused by extreme weather events?

C12. And what was the longest period of time you were without power?

[**Ask all respondents**]

C13. When you do lose power, what causes you more difficulty: [**READ LIST**]

The number of outages	1
The length of the outages	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

This provides an independent measure planners can consider when assessing what periods of time should be used when setting standards.

C14. Once the power goes out, is there a particular length of time at which being without power becomes more difficult for you? **[DO NOT READ LIST, select category accordingly]** (NOTE: If respondent says depends, please ask "Thinking about a typical day, is there a particular length of time at which being without power becomes more difficult for you?")

Less than 15 minutes	1
15 to less than 30 minutes	2
[ask to specify if less than *15 minutes*, if response is "less than 30 minutes"]	
30 minutes to less than 1 hour	3
1 hour to less than 3 hours	4
3 hours to less than 6 hours	5
6 hours to less than 12 hours	6
12 to less than 24 hours	7
More than 24 hours	8
Don't know (**DNR**)	98

Refused (**DNR**)	99

Second take on restoration vs outage priorities.

C15. As electricity planners look ahead, they can't plan to do everything at once. In your view, which of the following two tasks should be their top priority? (RANDOMIZE STATEMENTS)

Reducing the number of outages	1
Reducing the time it takes to restore electricity after an outage	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

C16. There are competing points of view about whether Toronto needs a higher standard of reliability than other places in Ontario. Which of the following two statements is closer to your own.
(ROTATE AND USE APPROPRIATE FIRST WORD IN EACH CASE)

1 Some/Other people say that the current level of reliability seems reasonable to them and they are concerned higher standards may mean paying even higher electricity rates.
2 Other/Some people say with its high-rise towers, reliance on electric-power subways and streetcars and as international business centre, Toronto does need higher standards even if it means paying a few dollars more a month.

98 Don't Know

Section D: Environment

When it comes to the impact of the electricity system on the environment in your community, how concerned are you about each of the following issues. **(RANDOMIZE STATEMENTS)**

[READ LIST]

Extremely concerned	1
Very concerned	2
Somewhat concerned	3
Not very concerned	4
Not concerned at all	5
Don't know (**DNR**)	98
Refused **(DNR)**	99

D17. The amount of land used by electricity infrastructure such as power lines, distribution and transmission stations and generating facilities.

D18. Possible health impacts from power lines

D19. Impacts that contribute to climate change

D20. Emissions from generating stations that may directly impact your health

END BATTERY

D21. And which of these environmental issues is of the greatest concern to you? **(READ LIST AND RANDOMIZE STATEMENTS)**

The amount of land used by electricity infrastructure	1
Possible health impacts from power lines	2
Greenhouse gases that contribute to climate change	3
Emissions from generating stations that may directly impact your health	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

Section E: Cost

E22. Thinking about how much you pay for electricity, do you think the price you are paying is … **[READ LIST]**?

A good deal 1
A reasonable amount 2
A bad deal 3
Don't know 98

Please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with each of the following statements.

01 Strongly agree

02 Somewhat agree

03 Neither agree nor disagree **(DNR)**

04 Somewhat disagree

05 Strongly disagree

98 Don't know (**DNR**)

99 Refused (**DNR**)

E23. The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.

E24. I get good value for the money they pay for electricity.

END BATTERY

Section F: Goals and Criteria

How familiar are you with the following terms? [READ LIST]

Very familiar and can explain the details to others	1
Somewhat familiar, but don't know the details	2
Have heard of, but don't know any details	3
Have not heard of before this survey	4
Don't know **(DNR)**	98
Refused (**DNR)**	99

ROTATE F24-F26

F25. Conservation and Demand Management

F26. Distributed Generation

F27. Transmission and Distribution Infrastructure

END BATTERY

This preamble will help less informed respondents 'catch-up' with more informed people.

F28**.** **READ PREAMBLE:** There are three main solutions to deal with capacity issues.
RANDOMIZE OPTIONS

1. For this plan, Conservation and Demand Management involves consumers giving electricity system managers the ability to turn equipment such as air conditioners off for short periods of time when electricity demand peaks.
2. Distributed Generation involves small-scale power generation located in your local community where electricity is consumed.
3. Transmission and Distribution primarily involves transmission and distribution stations as well as underground and overhead wires that bring electricity from more distant generating plants to your local area.

F29. Government policy requires planners to look at Conservation and Demand management first. Which of the two remaining solutions would be your second choice to deal with growing neighbourhood demands? (**ROTATE AND READ LIST**)

Distributed Generation	1
Transmission and Distribution	2
Don't know (**DNR)**	98
Refused (**DNR**)	99

F30. For ***conservation and demand management*** to provide an alternative to ***distributed generation*** or ***transmission and distribution***, it must provide a similar level of certainty as the other options. For residences, this would involve voluntary agreements to install automated controls that allow electricity system managers to turn equipment such as pool heaters and air conditioners off for short periods of time during periods of peak demand.

How likely is it that you will agree to install automated controls that will allow electricity system managers to turn equipment such as air conditioners off for short periods of time when conservation is critically needed? [READ LIST]

Definitely would participate	1
Very likely to participate	2
Somewhat likely to participate	3
Not very likely to participate	4
Definitely would NOT participate	5
Already participate (**DNR**)	6
Don’t know (**DNR**)	98
Refused (**DNR**)	99

How important are each of the following considerations as planners chose between these three options? [RANDOMIZE F30-F36] [READ LIST]

Very important	1
Somewhat important	2
Not very important	3
Not at all important	4
Don’t know (**DNR)**	98
Refused (**DNR)**	99

F31. Reducing the number of outages in normal circumstances

F32. Reducing the time it takes to restore power

F33. Reducing the likely impact of major events such as ice storms and flooding

F34. Reducing the amount of land used by electricity infrastructure.

F35. Reducing possible health impacts

F36. Reducing impacts that contribute to climate change

F37. Reducing the impact on electricity rates

END BATTERY

F38. Which of these considerations is the most important to you? [**READ LIST**]

Reducing the number of outages in normal circumstances	1
Reducing the time it takes to restore power	2
Reducing the likely impact of major events	3
Reducing the amount of land used by electricity infrastructure.	4
Reducing possible health impacts	5
Reducing impacts that contribute to climate change	6
Reducing the impact on electricity rates	7
Don’t know (**DNR**	98
Refused (**DNR**)	99

Section G: Demographics

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

G39. In which year were you born? [**Enter YEAR**]

INTERVIEWER NOTE: if REFUSE; ask "AGE".

AGE: Can you tell me what age category do you fall into? [**READ LIST**]

Less than 18	0
18-25	1
25-34	2
35-44	3
45-54	4
55-64	5
65 years or older	6
Refused (**DNR**)	99

G40. Do you own or rent your home?

Own	1
Rent	2
Refused (**DNR**)	99

G41. How would you describe your primary residence? Would you say you live in … [**READ LIST**]

A fully-detached home;	1
A semi-detached home;	2
An apartment or condo building **<u>less than 5 stories</u>**; or	3
An apartment or condo building **<u>5 stories or higher</u>**?	4
Refused (**DNR**)	99

G42. Counting yourself, how many people live in your household?

1 person	1 **SKIP TO END**
Enter number of people	2---7
8 or more	8
Refused (**DNR**)	99 **SKIP TO END**

Ask only if H42 = 2 thru 8

G43. And how many of them are under 18?

None	0
Enter number of children	1---7
8 or more	8
Refused (**DNR**)	99

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

General Service Survey Instrument

Section A: Introduction

INTRO

INTRO. Hello, my name is ________________ and I'm calling from **Innovative Research Group** on behalf of **Toronto Hydro,** the **Ontario Power Authority,** the **Independent Electricity System Operator** and **Hydro One.**

Can I please speak to the person who is in-charge of managing the electricity bill at [**organization name**] located in Toronto?

1) Yes, speaking <**contact on the line**>	[**skip to A1]**
2) Yes <**transferred to contact**>	[**skip to A1]**
3) No <**not the right contact person**>	**[GO to "NEW"]**
4) No <**busy**> "When is a good time to callback?"	**[record call-back time]**
5) Maybe <**may I ask who is calling?**>	[**skip to GATE]**

NEW. And … can I have their …
First Name ______________
Last Name ______________
Title/Position ____________
Phone Number ___________

ASK to be transferred …

- **if transferred → go to A1**
- **if not transferred → Thank & Add to Callback List**

GATE. I'm calling from **Innovative Research Group**, on behalf of **Toronto Hydro,** the **Ontario Power Authority,** the **Independent Electricity System Operator** and **Hydro One**

INTERVIEWER NOTE: If gatekeeper asks the purpose of call → I'd like to ask the person in-charge of managing the electricity bill at your organization a few questions concerning a regional electricity customer consultation.

1) Yes <**transferred to contact**>	**[skip to A1]**

2) No <**not available**>	"When is a good time to callback?	**[record call-back time and GO to "NEW"]**
3) No <**not interested in talking**>		**[Thank & Terminate]**

A1 QUAL PREAMBLE:
Innovative Research Group is a national public opinion research firm. We have been commissioned by **Toronto Hydro,** the **Ontario Power Authority,** the **Independent Electricity System Operator** and **Hydro One** to help them better understand the needs and preferences of customers like you as they prepare plans to meet the future electricity needs of Central Toronto.

A1. Would you mind if I had ten minutes of your time to ask you some questions? All your responses will be kept strictly confidential.

Yes	1	[**continue**]
No – NOT PRIMARY BILL PAYER	2	[**go to TRANSFER-1**]
No – BAD TIME	3	[**ARRANGE CALLBACK]**
No – HARD REFUSAL	4	[**Terminate**]

MONIT
This call may be monitored or audio taped for quality control and evaluation purposes.

PRESS TO CONTINUE	1

A2. Just to confirm, does your organization receive an electricity bill from Toronto Hydro?

YES	1	**[continue]**
NO	2	**[Terminate]**
DK (volunteered)	98	**[Terminate]**

A3. As part of your job, are you in-charge of <u>managing</u> or <u>overseeing</u> your organization's electricity bill?

Yes	1	[**Continue to A4]**
No	2	[**go to TRANSFER-1**]
DK	3	[**go to TRANSFER-1**]

TRANSFER-1
Can I speak with the person who manages your organization's electricity bill?

Yes	1	[**BACK TO** *<u>INTRO</u>*]
No – NOT AVAILABLE/BAD TIME – **(ARRANGE CALLBACK)**	2	[**ARRANGE CALLBACK]**
No – HARD REFUSAL	3	[**Terminate**]
Don't know (**DNR**)	98	[**Terminate**]

Which of the following best describes the sector in which your organization operates?

MASH (Municipalities, Academic, Schools, Hospitals	1
Multi-residential	2
Commercial	3
Manufacturing/Industrial	4
Data Centre	5
Hospitality	6
Restaurant/Tavern	7
Retail	8
Warehouse	9
Other	88
Don’t know (**DNR**)	98
Refused (**DNR**)	99

GENDER	Note gender by observation:
Male	1
Female	2

Section B: General Satisfaction

We need to prime respondents to start thinking about electricity and the part of the system that Toronto Hydro operates.

B5. PREAMBLE-1 To start, I'd like to ask you a few questions about the electricity system …

As you may know, Ontario's electricity system has three key components: **generation, transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

How familiar are you with Ontario's electricity system? Would you say … [READ LIST]

Very familiar	1
Somewhat familiar	2
Not very familiar	3
Not familiar at all	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B6. Generally speaking, how satisfied are your organization with the job the electricity system does in providing your organization with electricity? Would you say … [READ LIST]

Very satisfied	1
Somewhat satisfied	2
Somewhat dissatisfied	3
Very dissatisfied	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

B7. Is there anything in particular the electricity system can do to improve its service to your organization? [OPEN]

Don't know (**DNR**)	98
Refused (**DNR**)	99

ROTATE SECTIONS C, D AND E – TRACK ROTATION

Section C: System Reliability

These questions are about priming the respondent to think about their experience with system reliability and to separate views about adverse weather from failing equipment.

C8. In 2013, electricity consumers in Toronto experienced unusually extreme weather – flooding in July 2013 and an ice storm in December 2013. These rare and unpredictable events -- which often impact a large number of people – are called "major events" in the electricity sector. These major weather events caused power outages across Toronto.

Did either of these major weather events cause a power outage at your organization?

INTERVIEWER NOTE: Make sure respondents specify which storm affected their power.

Yes – flooding	1
Yes – the ice storm	2
Yes – both storms	3
No – neither weather events affected my power service	4
Don't know (**DNR**)	98
Refused (**DNR**)	99

[Ask all respondents]

C9. <u>Not</u> including power outages caused by these extreme weather events, did your organization have any other power outages in the <u>last 12 months</u>?

Yes	1	
No	2	**SKIP TO C13**
Don't know (**DNR**)	98	**SKIP TO C13**
Refused (**DNR**)	99	**SKIP TO C13**

C10. How many outages did your organization experience over the past 12 months, NOT including those caused by extreme weather events?

C11. And what was the longest period of time your organization were without power?

[**Ask all respondents**]

C12. When your organization does lose power, what causes your organization more difficulty: [READ LIST]

The number of outages	1
The length of the outages	2
Don't know (**DNR**)	98
Refused (**DNR**)	99

This provides an independent measure planners can consider when assessing what periods of time should be used when setting standards.

C13. Once the power goes out, is there a particular length of time at which being without power becomes more difficult for your organization? [DO NOT READ LIST, select category accordingly] (NOTE: If respondent says depends, please ask "Thinking about a typical day, is there a particular length of time at which being without power becomes more difficult for you?")

Less than 15 minutes 1
15 to less than 30 minutes 2
[ask to specify if less than *15 minutes*, if response is "less than 30 minutes"]
30 minutes to less than 1 hour 3
1 hour to less than 3 hours 4
3 hours to less than 6 hours 5
6 hours to less than 12 hours 6
12 to less than 24 hours 7
More than 24 hours 8
Don't know (**DNR**) 98
Refused (**DNR**) 99

Second take on restoration vs outage priorities.

C14. As electricity planners look ahead, they can't plan to do everything at once. In your organization's view, which of the following two tasks should be their top priority? (RANDOMIZE STATEMENTS)

Reducing the number of outages 1
Reducing the time it takes to restore electricity after an outage 2
Don't know (**DNR**) 98
Refused (**DNR**) 99

C15. There are competing points of view about whether Toronto needs a higher standard of reliability than other places in Ontario. Which of the following two statements is closer to your organization's view?
(ROTATE AND USE APPROPRIATE FIRST WORD IN EACH CASE)

1 Some/Other people say that the current level of reliability seems reasonable to them and they are concerned higher standards may mean paying even higher electricity rates.
2 Other/Some people say with its high-rise towers, reliance on electric-power subways and streetcars and as international business centre, Toronto does need higher standards even if it means paying a few dollars more a month.
98 Don't Know

Section D: Environment

When it comes to the impact of the electricity system on the environment in your community, how concerned are your organization about each of the following issues. **(RANDOMIZE STATEMENTS)**

[READ LIST]

Extremely concerned	1
Very concerned	2
Somewhat concerned	3
Not very concerned	4
Not concerned at all	5
Don't know (**DNR**)	98
Refused **(DNR)**	99

D16. The amount of land used by electricity infrastructure such as power lines, distribution and transmission stations and generating facilities.

D17. Possible health impacts from power lines

D18. Impacts that contribute to climate change

D19. Emissions from generating stations that may directly impact your health

END BATTERY

D20. And which of these environmental issues is of the greatest concern to your organization? (READ LIST AND RANDOMIZE STATEMENTS)

The amount of land used by electricity infrastructure	1
Possible health impacts from power lines	2
Greenhouse gases that contribute to climate change	3
Emissions from generating stations that may directly impact your health	4
Don't know (DNR)	98
Refused (DNR)	99

Section E: Cost

E21. Thinking about how much your organization pays for electricity, do you think the price your organization is paying is … [READ LIST AND ROTATE OPTION 1 & 3]?

A good deal 1
A reasonable amount 2
A bad deal 3
Don't know 98

Please tell me if you strongly agree, somewhat agree, somewhat disagree or strongly disagree with each of the following statements.

01 Strongly agree
02 Somewhat agree
03 Neither agree nor disagree **(DNR)**
04 Somewhat disagree
05 Strongly disagree
98 Don't know (**DNR**)
99 Refused (**DNR**)

E22. The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

E23. My organization gets good value for the money it pays for electricity.

END BATTERY

Section F: Goals and Criteria

How familiar are you with the following terms? [READ LIST]

Very familiar and can explain the details to others	1
Somewhat familiar, but don't know the details	2
Have heard of, but don't know any details	3
Have not heard of before this survey	4
Don't know (**DNR)**	98
Refused (**DNR)**	99

ROTATE F24-F26

F24. Conservation and Demand Management

F25. Distributed Generation

F26. Transmission and Distribution Infrastructure

END BATTERY

This preamble will help less informed respondents 'catch-up' with more informed people.

F27. READ PREAMBLE: There are three main solutions to deal with capacity issues. For this plan… RANDOMIZE OPTIONS

1. Conservation and Demand Management involves consumers giving electricity system managers the ability to turn equipment such as air conditioners off for short periods of time when electricity demand peaks.
2. Distributed Generation involves small-scale power generation located in your local community where electricity is consumed.
3. Transmission and Distribution primarily involves transmission and distribution stations as well as underground and overhead wires that bring electricity from more distant generating plants to your local area.

F28. **Government policy requires planners to look at Conservation and Demand management first. Which of the two remaining solutions would be your organization's second choice to deal with growing neighbourhood demands? (ROTATE AND READ LIST)**

Distributed Generation	1
Transmission and Distribution	2
Don't know (**DNR)**	98
Refused (**DNR**)	99

F29. **For conservation and demand management to provide an alternative to distributed generation or transmission and distribution, it must provide a similar level of certainty as the other options. For businesses, this would involve voluntary agreements to install automated controls that allow electricity system managers to turn equipment such as air conditioners off for short periods of time during periods of peak demand.**

How likely is it that your organization will agree to install automated controls that will allow electricity system managers to turn equipment such as air conditioners off for short periods of time when conservation is critically needed? [READ LIST]

Definitely would participate	1
Very likely to participate	2
Somewhat likely to participate	3
Not very likely to participate	4
Definitely would NOT participate	5
Already participate (**DNR**)	6
Don't know (**DNR**)	98
Not applicable **(DNR)**	96
Refused (**DNR**)	99

How important are each of the following considerations as planners chose between these three options? [RANDOMIZE F30-F36] [READ LIST]

Very important	1
Somewhat important	2
Not very important	3
Not at all important	4
Don't know (**DNR)**	98
Refused (**DNR)**	99

F30. Reducing the number of outages in normal circumstances

F31. Reducing the time it takes to restore power

F32. Reducing the likely impact of major events such as ice storms and flooding

F33. Reducing the amount of land used by electricity infrastructure.

F34. Reducing possible health impacts

F35. Reducing impacts that contribute to climate change

F36. Reducing the impact on electricity rates

END BATTERY

F37. Which of these considerations is the most important to your organization? [READ LIST]

Reducing the number of outages in normal circumstances	1
Reducing the time it takes to restore power	2
Reducing the likely impact of major events	3
Reducing the amount of land used by electricity infrastructure.	4
Reducing possible health impacts	5
Reducing impacts that contribute to climate change	6
Reducing the impact on electricity rates	7
Don't know (**DNR**	98
Refused (**DNR**)	99

Section G: Firmographics

These last few questions are for statistical purposes only and we remind you again that all of your responses are completely confidential.

G38. Which of the following best describes the hours of operation of your business? Would you say … [READ LIST]

We are open 24/7	1
We operate several shifts each day, but are not open 24/7	2
We operate during regular business hours only	3
We operate outside of regular business hours, but do not have shifts	4
Other (please specify): ___________________________	88

G39. And, which of the following best describes when your business operates through the week? Would you say … [READ LIST]

We operate on weekdays only	1
We operate on weekdays and weekends	2
Other (please specify): ___________________________	88

G40. Finally, how many people are employed at your place of work? [###]
[Interviewer prompt if respondent is struggling to come up with an employee count: "… an approximation is fine"]

G41. And are those all full-time employees?

01	Yes
02	No → And how many are full-time employees? [###]
98	Don't know (**DNR**)
99	Refused (**DNR**)

THANK and END SURVEY

Thank you very much for taking the time to complete this survey.

Workbook Appendices:

Central Toronto Integrated Regional Resource Plan