MARITIME ELECTRIC
A FORTIS COMPANY

September 22, 2017

Mr. Roger King
519 Simpson Rd
Hunter River PE C0A 1N0

Dear Mr. King:

2018 Capital Budget Filing Docket UE20726
Response to Interrogatories

Please find attached the Company's response to your Interrogatories with respect to the 2018 Capital Budget Application.

Yours truly,

MARITIME ELECTRIC

Enrique Riveroll
Manager, Regulatory & Financial Planning

ER03
Enclosure

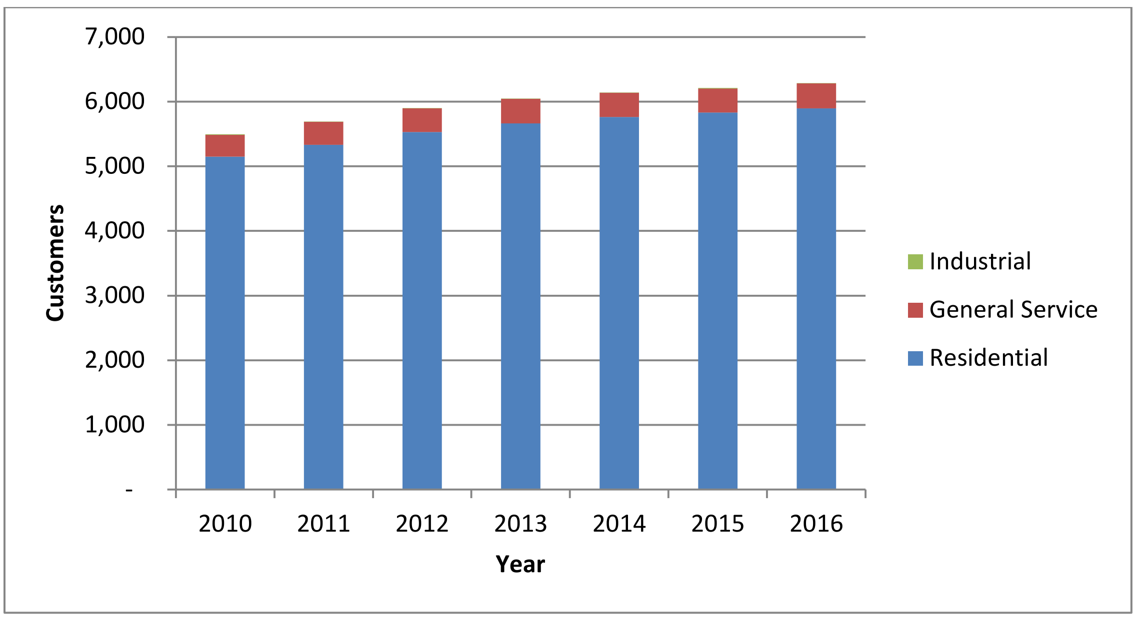
Mount Albion Substation: $1,338,000

1. For the data shown for both the Crossroads and O'Leary substations (2010 to 2019), please provide the customer-type (residential, general service and industrial) population numbers by year and each customer-type contribution to the described load growth for each of these years 2010 to 2019.

Response:

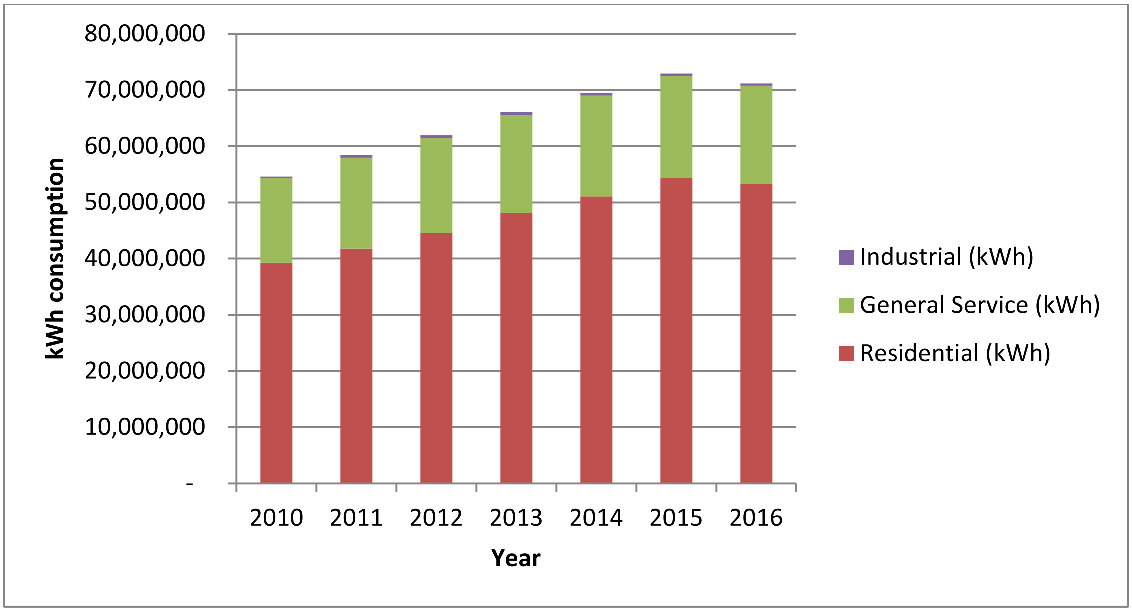
1. The bar graph below (Figure 1) shows the number of customers fed from the Crossroads substation by customer type. The increase in the number of customers is mainly from the residential sector. The number of customers fed from the Crossroads Substation increased over 14% from 2010 to 2016.

Figure 1: Number and Type of Customer Fed from Crossroads Substation



The bar graph below (Figure 2) shows the energy usage by customer type for the Crossroads substation. Similar to customer count, the energy increase at the Crossroads substation is mainly from the residential sector. This information is gathered from historical annual billing data for the 2010-2016 period. Residential demand is not metered or billed. However, the Crossroads substation kVA aggregate demand is metered at the substation on a monthly basis and used to monitor and forecast load growth.

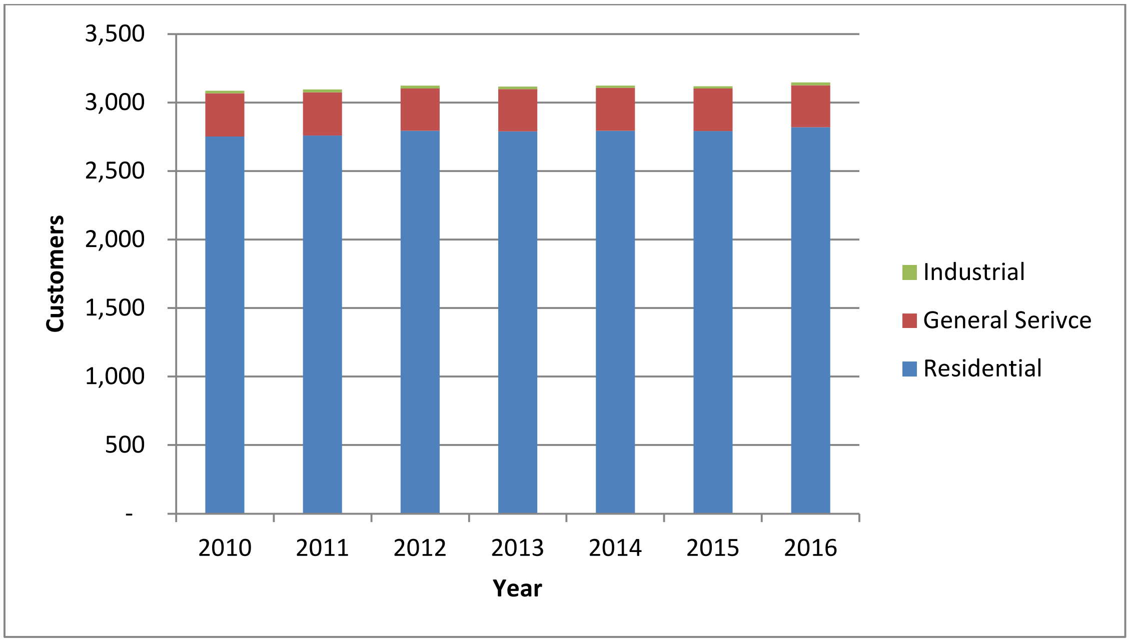
Figure 2: Crossroads Substation kWh Consumption by Customer Type



Due to the increased load growth in this geographic area, the Mount Albion substation is planned to offload Crossroads substation. Several options were evaluated to alleviate the constraints on the Crossroads substation including expanding the substation, building a new substation in Mount Mellick and building a new substation in Mount Albion. Expanding the Crossroads substation had many constraints including congestion of the existing footprint and the lack of back-up capabilities from other substations. A new substation in Mount Albion is the most practical and cost effective solution because the net total costs are slightly lower as compared to a new substation in Mount Mellick.

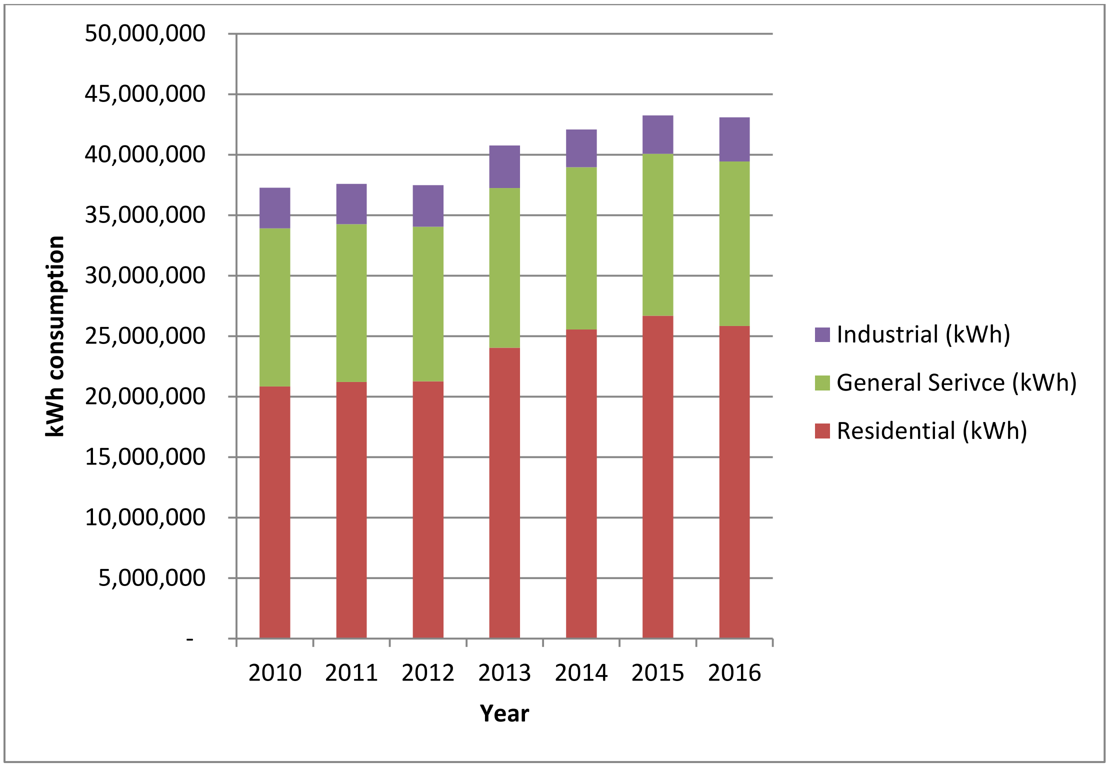
The bar graph below (Figure 3) shows the number of customers fed from the O'Leary substation by customer type. The increase in the number of customers is mainly from the residential sector.

Figure 3: Number and Type of Customer Fed from O'Leary Substation



The bar graph below (Figure 4) illustrates the energy usage by customer type for the O'Leary substation. Similar to the customer count, the energy consumption increase at the O'Leary substation is mainly from the residential sector. The O'Leary substation kVA aggregate demand is metered at the substation on a monthly basis and is used to monitor and forecast load growth. The energy consumption is 15.6% higher in 2016 as compared to 2010, most likely due to customer's converting to electric heat.

Figure 4: O'Leary Substation kWh Consumption by Customer Type



Due to the increased load growth in this geographic area, the 7.5/10 MVA power transformer in O'Leary substation is currently loaded at 95 percent capacity and is forecasted to be overloaded in Winter 2018. The budget provides for the expansion of the O'Leary substation to accommodate a second power transformer.

Mount Albion Substation: $1,338,000 (Cont'd)

2. For comparative context, please also provide these customer-type load growth details for both the Hunter River and Rattenbury Road substations leading to the approval of the New Glasgow substation in 2015.

Response:

2. The bar graphs below (Figure 5 and Figure 6) show the energy usage by customer type for the Hunter River substation and the Rattenbury substation, respectively. Similar to the energy consumption at the Crossroads substation and O'Leary substation, the energy consumption increase at the Hunter River and Rattenbury substations are mainly from the residential sector. The energy consumption at Hunter River and Rattenbury substations are 22% and 25% higher respectively in 2016 as compared to 2010. Due to increased load growth in the area, the construction of the New Glasgow substation is required to offload both the Hunter River and Rattenbury substations.

Figure 5: Hunter River Substation kWh Consumption by Customer Type

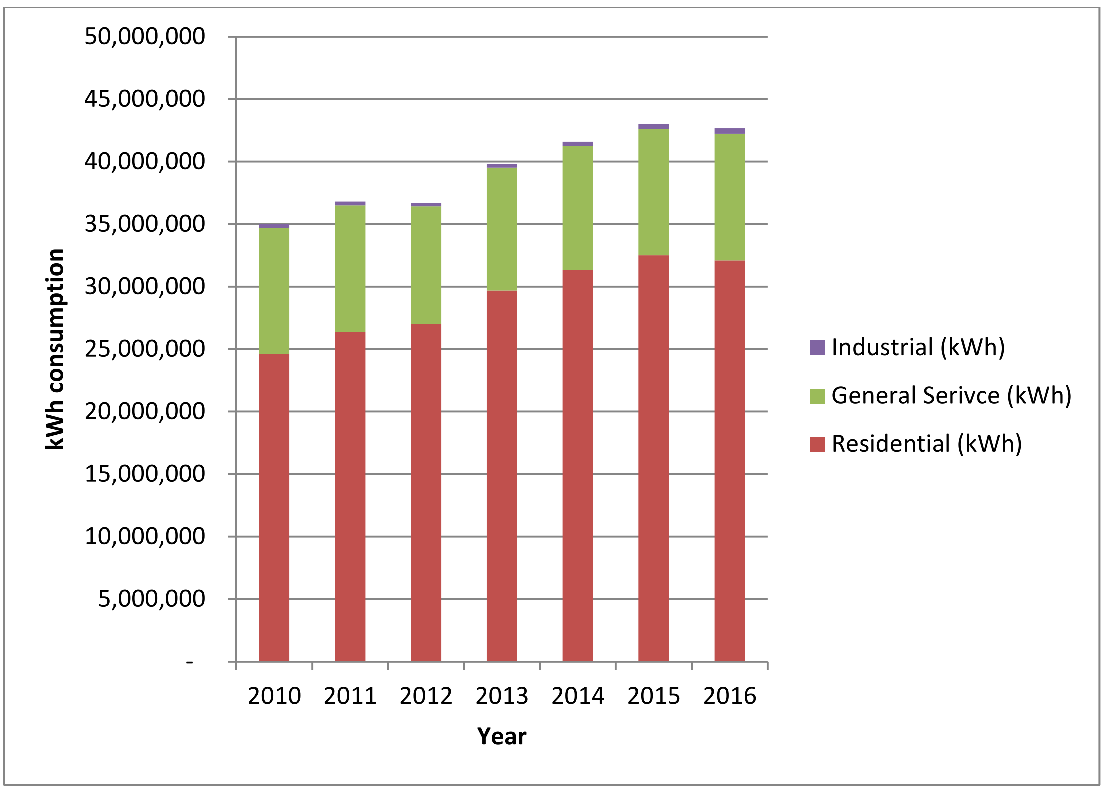
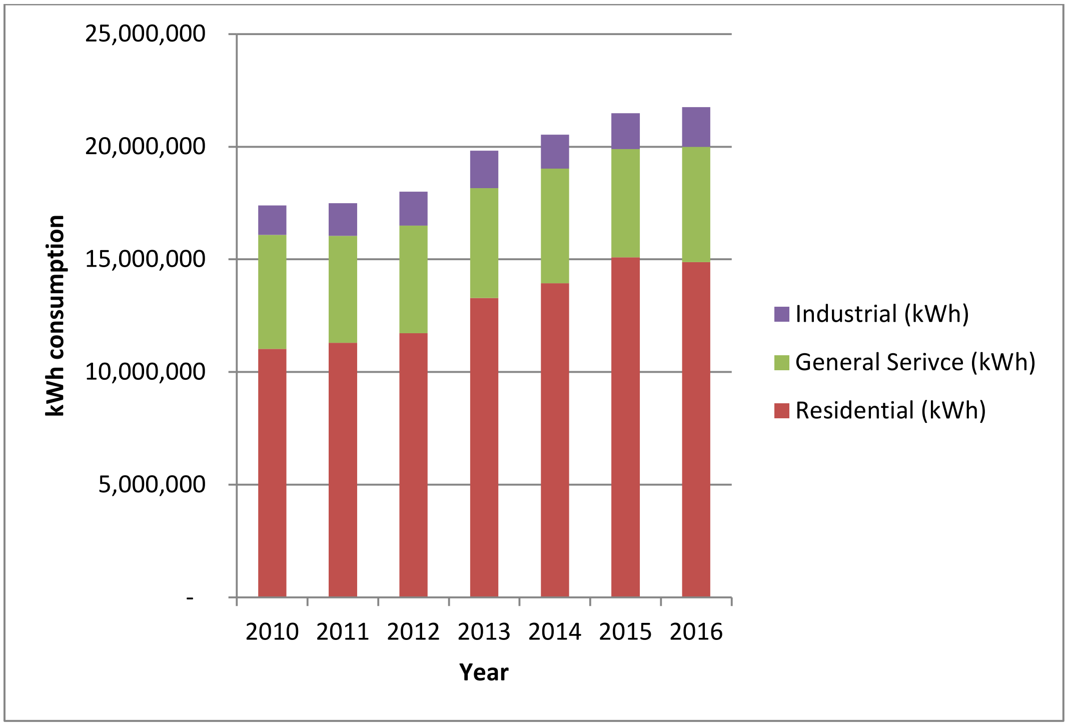


Figure 6: Rattenbury Substation kWh Consumption by Customer Type



The bar graphs below (Figure 7 and Figure 8) show the number of customers fed from the Hunter River substation and Rattenbury substation, respectively by customer type. Similar to the energy consumption, the increase in the number of customers is mainly from the residential sector.

Figure 7: Number and Type of Customer Fed from Hunter River Substation

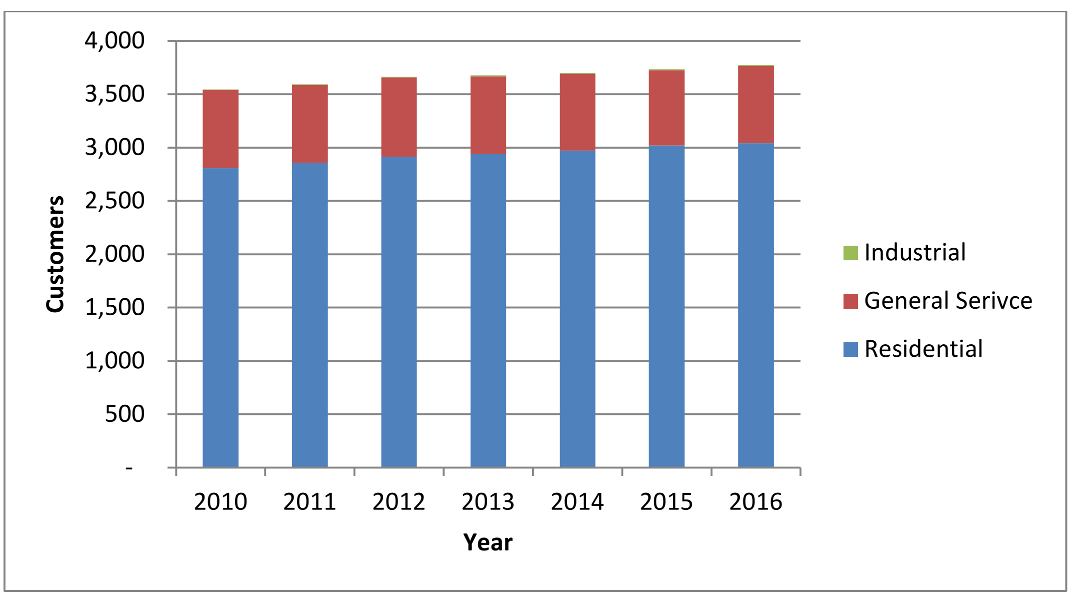
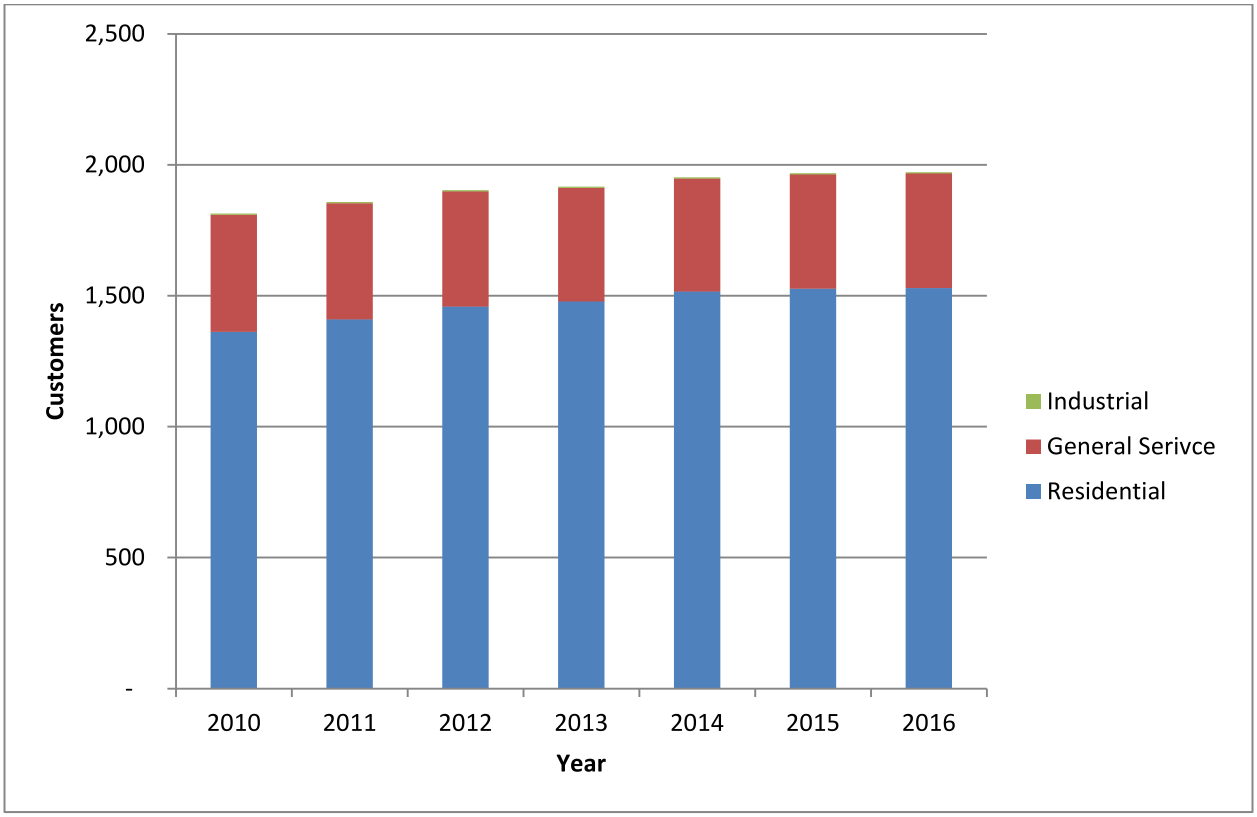


Figure 8: Number and Type of Customer Fed from Rattenbury Substation



Mount Albion Substation: $1,338,000 (Cont'd)

3. The 2016 capital budget entry for the New Glasgow substation indicated $1,374,000 yet interrogatories data provided in 2016, showed the total project cost for distributing load from the Hunter River and Rattenbury Road substations to be:

New Glasgow Substation - $1,374,000
T-1 Line Extension - $1,030,000
Three Phase Distribution - $500,000
Total - $2,904,000

Please provide the complete or connected set of project costs for the construction of the proposed Mount Albion substation.

Response:

3. Table 1 below shows the capital budget breakdown for the Mount Albion substation as specified in the 2018 Capital Budget submission.

Table 1

2018 Capital Budget Reference	Item	Budget
6.1	Mount Albion Substation	$ 1,338,000
6.1	Mount Albion Transformer (7.5/10 MVA)	$ 822,000
6.2c	Transmission line extension	$ 141,000
5.4	Distribution line extension	$ 1,004,000
	Total Mount Albion	**$ 3,305,000**

Y-109 Reliability Extension: $1,910,000

1. Explain the "N-1 security of supply" reliability assessment calculations that now apply to having three mainland transmission cable from Memramcook to the sub-marine termination points at Murray Corner and Cape Tormentine and the four sub-marine cables with termination at Richmond Cove and Borden-Carlton. If there are a number of different reliability "N-1" scenarios please describe these.

Response:

1. There are two "N-1" scenarios that the Y-109 extension project is designed to address:

Scenario 1 - Loss of the Memramcook to Murray Corner 138 kV line (Line 1142):
Once NB line 1244 construction is complete in 2017, there will be three parallel 138 kV circuits supplying PEI from the Memramcook Substation in New Brunswick:

- Line 1142 + Cables 1 & 2 (Memramcook to Murray Corner / Bedeque – 200 MW);
- Line 1143 + Cable 3 (Memramcook to Cape Tormentine / Borden – 180 MW); and
- Line 1244 + Cable 4 (Memramcook to Cape Tormentine / Borden – 180 MW).

All PEI load up to at least 300 MW will be able to be maintained for a loss of either of the Line 1143 or Line 1244 circuits without any thermal overloads because both Bedeque and Borden will continue to receive supply from NB. 300 MW is the maximum firm transmission capability across the NB to NS/PEI transmission interface.

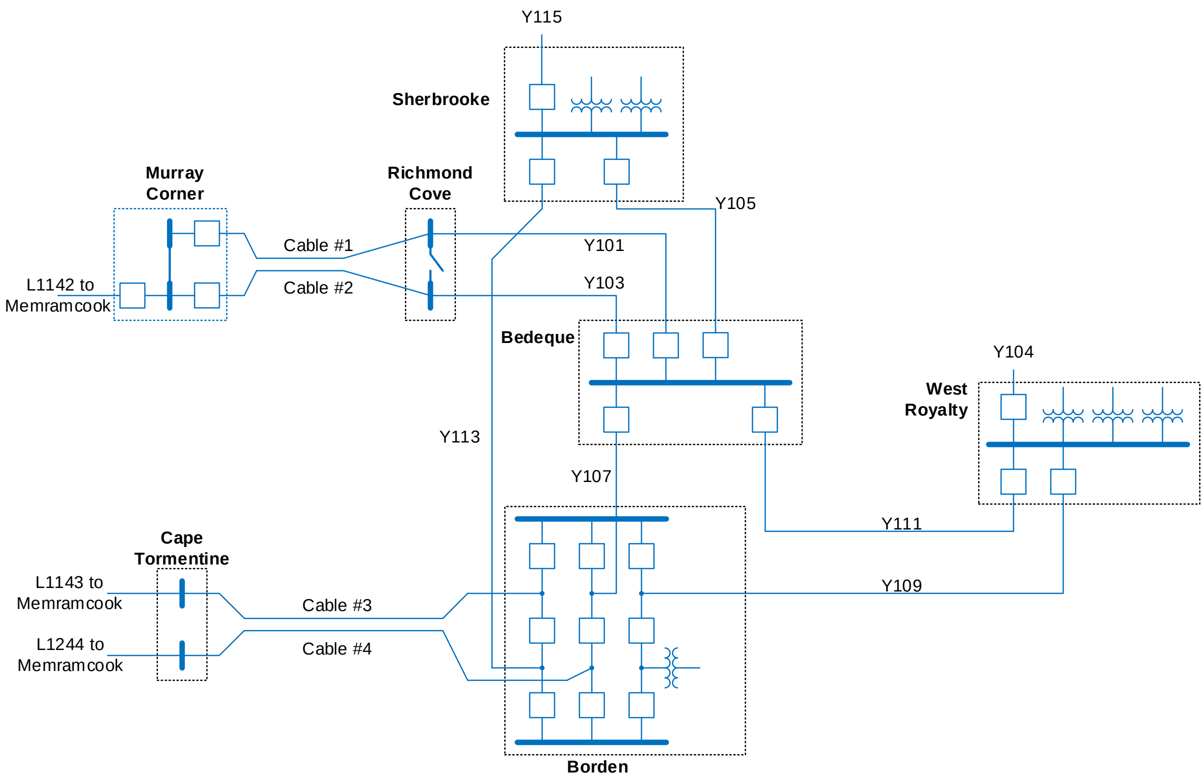
For loss of the Line 1142 circuit due to an outage of Line 1142, there would be zero delivery to Bedeque over Cables 1 & 2. Because there are currently only two transmission lines (Y-107, to Bedeque, and Y-113, to Sherbrooke) that connect the Borden Substation to the rest of the PEI system, delivery from the Borden Substation to the PEI system is limited to 240 MW due to thermal overload of Y-107, even though the combined capacity of Cables 3 & 4 is 360 MW. The Y-109 extension project will address this constraint by connecting a third 138 kV line (i.e. Y-109) to the Borden Substation from the PEI system. With Y-109 re-terminated at Borden, up to at least 300 MW will be able to be delivered to PEI through Cables 3 & 4 for loss of Line 1142.

To fully utilize the combined 360 MW capacity of Cables 3 & 4, additional voltage support will be required in PEI. How best to provide this will be a subject of future transmission planning work. As well, an increase in NB to NS/PEI transfer capability would be required to fully utilize the combined thermal capacity of Cables 3 & 4. This requires transmission system upgrades on the mainland.

Scenario 2 - Loss of the Bedeque 138kV bus: Currently, an unplanned outage of the Bedeque Substation 138kV bus will cause an outage to all eastern PEI load, since both of the 138kV lines supplying Charlottetown and eastern PEI (Y-109 and Y-111) are terminated on the Bedeque 138kV bus. With Y-109 re-terminated at Borden, for system loads up to 225 MW (98.4% of hours in 2016) there will be no loss of load for loss of the Bedeque 138 kV bus.

At the new 138 kV Borden Substation, there is no single contingency that can cause a complete outage at the Substation. This has been achieved by using a "breaker and a half" scheme at the new Borden Substation. This approach uses three circuit breakers for every two circuits connected to the substation, which results in improved reliability.

A single line diagram of a portion of the 138 kV system is shown below. The diagram shows line Y-109 terminated at the Borden substation



Y-109 Reliability Extension: $1,910,000 (Cont’d)

2. Using the explanation as for 1) above, please provide the transmission reliability improvement and/or the extent to which future load growth capacity is increased by this $1.9M transmission extension.

Response:

2. The answer to this question has been incorporated into the answer to Question 1 above.

Y-109 Reliability Extension: $1,910,000 (Cont'd)

3. Please describe how all these reliability scenarios have been factored, if at all, by cable loading reduction due to having 600GWh PEI wind energy available for PEI use. This question assumes that the low physical export of wind energy of around 2% in 2011 has continued; please provide the physically exported wind energy data (GWh) for 2012 to 2016.

Response:

3. Cable loading reduction due to on-Island wind generation has not been taken into account, because for the loss of the Bedeque bus at system peak load (Scenario 2: Y-109 Reliability Extension interrogatory response #1), the 60 MW of wind generation in eastern PEI and 50 MW of generation from Combustion Turbine #3 (CT3) would not be sufficient to make up for the loss of load in eastern PEI. Under this scenario, the submarine cables are not the constraint. The constraint is the lack of on-Island transmission capacity to the West Royalty substation.

With Y-109 re-terminated at the Borden substation, a loss of the Bedeque bus will result in a loss of some of the load in eastern PEI when the PEI system load is greater than 225 MW. Wind generation in eastern PEI and/or generation from CT3 will be required in this case.

Table 2 below provides physical wind energy exports for 2012 – 2016.

Table 2

Year	Physical Wind Export (GWh)
2012	7.6
2013	6.2
2014	15.1
2015	16.4
2016	10.1

Y-109 Reliability Extension: $1,910,000 (Cont'd)

4. Explain why the cost of this extension was not included in the $142.5M new cables project. To assist in understanding the answer here, please describe the end-state capital ownership of the entire new cables project between the PEI Government, MECL and New Brunswick Power (NBP).

Response:

4. The new submarine cables project consists of three components:

- **Transmission additions in New Brunswick and new Cape Tormentine Substation –** The Cape Tormentine Substation is the termination point for the NB end of Cables 3 & 4 and includes five 138 kV switches. A third 138 kV transmission line (Line 1244) to supply PEI, running from Memramcook Substation to Cape Tormentine, plus an extension of the previously existing Line 1143 to Cape Tormentine. These transmission additions are owned by NB Power and were fully paid for by the Province of PEI as designated facilities under NB Power's Open Access Transmission Tariff.

- **Cables 3 & 4 –** These are the submarine cables running between Cape Tormentine and Borden, including the riser station at Cape Tormentine where the cables connect to overhead transmission lines. The submarine cables are owned by the Province of PEI.

- **New 138 kV Borden Substation –** This is the termination point for the PEI end of Cables 3 & 4, and it includes two 30 MVAr reactors and nine 138 kV circuit breakers. This substation is owned by the Province of PEI.

The submarine cable interconnection project included new facilities in PEI, namely the Borden cable risers and Borden switching station that were to be owned by the Province of PEI, and thus eligible to receive 50% funding from the Federal Government. Given the complexity of the submarine cable interconnection project, and the resulting commitment of the Company's engineering resources to the project, it was not considered prudent to reconfigure the Company's existing submarine cable in-feed infrastructure until the new submarine cable interconnection facilities were fully operational.

Although the Y-109 extension is a consequence of the new submarine cable interconnection, its prime driver is increased system reliability for eastern PEI since there will now be two separate supply paths from the interconnection to eastern PEI. Rerouting Y-109 to Borden also allows the entire Bedeque substation to be taken out of service for maintenance at most times of the year without the need for on-island generation and with no impact to customers on PEI.

System Meters

1. Provide the break-down costs for bridge meter installation and how each of these costs compare with the watt-hour and combination meters; explain what additional customer-site equipment and/or MECL operations-center equipment will be required for deployment of the bridge meters.

Response:

1. Table 3 shows the costs (not including engineering and supervision) for the different types of meters.

Table 3: Cost comparison for different types of meters		
Meter	**Unit Cost**	**Labour to Install**
Watt-hour	$46	$16
Watt-hour combination	$250	$20
Bridge Watt-hour	$125	$16
Bridge Combination	$325	$20

The breakdown of the budgeted costs for the 2018 pilot project is shown in Table 4 below.

Table 4: Bridge Meter Pilot Project Costs	
Management and security software (includes support and consulting services from Itron)	$30,000
Project Management / Technical Resources (MECL)	$6,000
Bridge meters (100)	$12,500
Installation of meters	$1,600
Total (Rounded)	**$50,000**

The objective of the pilot project is to further understand the communications infrastructure and the related meter data management repository that would be required for the volume of data associated with continuous meter interrogations for large scale adoption.

System Meters (Cont'd)

2. Explain the differences of the proposed Itron Bridge meter as compared to the Summerside Electric Utility smart meters installed, the meters used previously in the MECL Power shift Atlantic pilot sites and the "mass memory interval meters with pulse output" that NBP are currently using.

Response:

2. The Itron Bridge meter was selected for the pilot project because of its compatibility with the existing Itron RF meters and 'drive-by 'mobile collection system. The purpose of the pilot project is to investigate the capability and functionality of bridge meters which are capable of Advanced Metering Infrastructure (AMI). The Company has not investigated the meters used by Summerside Electric Utility and NB Power, however, the Itron Bridge meter will provide similar advanced metering benefits such as hourly interval data, remote service switch operations and demand reset capabilities.

For the Power Shift Atlantic program Maritime Electric used a device installed in the home that received the radio frequency pulses from the customer's existing Itron RF meter. Readings collected by this device were transmitted back to Maritime Electric using the customer's home Internet connection. One of the findings of the program was that communication to the device using the customer's Internet connection was at times not adequate.

<u>System Meters</u> (Cont'd)

3. Please explain:

a) Why is the cost of purchasing and installing 100 bridge meters $50,000 and the cost of purchasing and installing 92 combination meters $143,000?
b) Why continue with the purchase of the limited combination meters when the Bridge meter provides more than the requirements of the combination meters and is compatible with earlier RI meters.
c) Will the pilot Bridge Meter project target new, replacement or both residential (watt-hour meters) installations?

<u>Response:</u>

3. a) The Bridge meters in the pilot project are residential watt-hour meters that are less expensive than combination meters which are used in commercial applications. Estimated installation costs for the Bridge meters are also less expensive than that of combination meters because they require no configuration prior to installation and installation does not require specialized technical resources. The combination meters must be installed by a meter technician and often require modifications for mounting or the addition of metering equipment such as current transformers and potential transformers.

b) The purpose of the pilot project is to investigate the capability and functionality of bridge meters which are capable of Advanced Metering Infrastructure (AMI), to identify the ancillary or supporting systems required to collect and manage the data and to fully understand the communications infrastructure. The 2014 Auditor General of Ontario's report (Appendix C) on Smart Metering Initiative in that Province describes the downside of aggressively adopting AMI Technology. The audit found that Smart Metering was aggressively rolled out without sufficient planning and monitoring. Without properly assessing these meters through a pilot project to fully understand the costs involved in their implementation, an economically justifiable business case cannot be developed. The Company does not believe it is prudent to advance large scale adoption prior to completing this assessment.

c) A specific customer group has not been identified for the deployment of bridge meters. However, meter deployment will be done strategically in order to:

- Test new functionality, such as remote connect/disconnect capabilities.
- Enable the collection of interval data provided by the bridge meter.
- Analyze customer usage patterns. This may include both new and existing customer installations.

System Meters (Cont'd)

4. Please present the two scenarios of customer "Cost of Ownership", irrespective of the type of meter used for replacement, when the recurring annual meter replacement program is included as part of the capital budget as compared to expensing the replacement cost each year.

Response:

4. The comparison of the cost of capitalizing versus cost of expensing the meter replacement program implies a steady state scenario where an even number of meters is replaced annually over the life cycle of the meters. Appendix A illustrates an example of this. Assuming there are 60,000 Residential Meters in the system, an annual replacement of 3,000 meters would be required over 20 years, at which point the first meters replaced would be retired and the cycle would begin once again. At this point, the annual cost of capitalization and expense is in a steady state going forward. In such a scenario, the net additional cost of capitalizing the proposed meter replacement program of 3,000 meters versus expensing the cost of the program in the year incurred is $648,800.

However, the proposed replacement program for approximately 1,000 meters in 2018 is not part of a steady state scenario, as Table 5 shows. Table 5 shows the variability of the Company's actual meter installation program, starting with 2004 - 2012 when the conversion from electromechanical watthour meters to Remote Interrogation (RI) meters took place. During this period, approximately 70,000 meters were replaced. Following the conversion to RI meters, annual requirements are based on the expected testing cycle of existing meters, estimated requirements for load growth, meter failures, and the eventual replacement of the RI meters at the end of their useful lives. The replacement program requirements can vary significantly depending on the stage of the life cycle of the meter replacement program.

In 2018, the proposed cost of the meter replacement program is relatively low as the planned replacements are limited to those required for testing by Measurement Canada, anticipated growth in new customers and estimated replacements for meter failures based on historical failure rates. However, the required number of meters being tested annually is expected to increase in coming years as more of the original RI meters reach their 10 year testing requirement. Also, as the existing RI meters in the system continue to age, the number of failed meters will increase and the budget for the replacement of these will need to be increased accordingly. By 2024, as the first RI meters approach the end of their expected useful lives, the number of meter replacements will also increase.

Table 5: Potential Life Cycle of Meter Replacement Program					
Year	Conversion to RI	Testing*	Load Growth/Failures	RI Replacement	Total
2004	3,000	-	-	-	3,000
2005	4,500	-	-	-	4,500
2006	5,000	-	-	-	5,000
2007	5,000	-	-	-	5,000
2008	9,600	-	-	-	9,600
2009	9,000	-	-	-	9,000
2010	10,000	-	-	-	10,000
2011	10,500	-	-	-	10,500
2012	13,400	-	-	-	13,400
2013		84	202	-	286
2014		215	209	-	424
2015		215	158	-	373
2016		261	226	-	487
2017		310	660	-	970
2018		570	464	-	1,034
2019		720	890	-	1,610
2020		670	855	-	1,525
2021		1,200	865	-	2,065
2022		1,470	925	-	2,395
2023		1,000	825	-	1,825
2024		870	500	3,000	4,370
2025		310	508	4,500	5,318
2026		570	516	5,000	6,086
2027		720	524	5,000	6,244
2028		670	532	9,600	10,802
2029		1,200	540	9,000	10,740
2030		1,470	548	10,000	12,018
2031		-	556	10,500	11,056
2032		-	564	13,400	13,964

* Represents meters to be tested each year, however it does not represent meter requirements that year. Should a group fail sample testing it would result in additional meter replacement.

As shown in this table, the steady state scenario can never be reached. It is neither practical nor realistic to immediately expense the meter replacement program as this would result in significant fluctuations in annual costs and potential rate shock for customers.

A second issue with expensing meters is that it would not be in keeping with generally accepted accounting principles ("GAAP"). Under GAAP, the normal practice for a long life asset is to amortize its cost over the useful life of the asset, so as to match the cost of the asset to the related revenue stream. In other words, where expenditures provide future benefit, it is considered an asset which should be recorded on the Company's balance sheet and amortized over the estimated useful life of the asset. As these meters have an expected life of approximately 20 years, GAAP requires amortizing the cost of the meter over its 20 year useful life. Further, GAAP requires consistent application of accounting policies and it would be inappropriate to jump back and forth between capitalizing in the years where higher investments are required, as was the case during the RI conversion program, to expensing in years that require lower investment, as is the case for 2018.

Future Planning – Context for the 2018 Capital Budget

1. A new phrase "the long term layup mode" for the CTGS is used in this application. Please describe this provisional end state of the site. Will equipment be de-commissioned/removed and buildings vacated/demolished and chimney stacks removes.

Response:

1. The "long term layup mode" noted in the application does not represent the end state of the Charlottetown Thermal Generating Station (CTGS). This transitional mode of operation will be employed, in a manner similar to what Maritime Electric has used in the past to seasonally lay-up CTGS generating units, while we conduct the decommissioning study for the facility and eventually transition it to retirement.

   A Request for Proposals is currently being finalized to engage an engineering consulting firm to prepare a Decommissioning Plan and Study Report for the CTGS. This report will be filed with IRAC by June 2018 and will detail the manner in which the equipment, stacks and building structures will be decommissioned and removed and how this will be accomplished.

Future Planning – Context for the 2018 Capital Budget (Cont'd)

2. The "Summary of Capital Expenditures (2009-2018) in this application shows a "Less: Customer Contributions" category. Please explain the source and content of each entry.

Response:

2. Contributions represent the cost of property, plant and equipment contributed by customers. Contributions are amortized by an amount equal to the annual charge for amortization provided on the related assets. The main sources of contributions relate to Distribution Services and Extensions, and Transmission Lines. For example, the General Rules and Regulations ("GRR") include a charge or customer contribution from the customer requesting a new service line extending in excess of 90 meters. Contributions for extensions are charged in accordance with the approved GRR and will sometimes have a refundable portion for subsequent service additions added to the line in the first five years. The amount of contributions is driven by customer's request, and as a result fluctuates from year to year. Since the amount of work subject to contributions is out of the Company's control, the budget and forecast amounts are conservatively estimated at the lower end of recent year's actual results.

The content of customer contributions by year is in Appendix B.

Future Planning – Context for the 2018 Capital Budget (Cont'd)

3. As much of the capital budget is driven by peak load growth, please update the tables that show the "PEI monthly net peak loads" (page 11 in the specific data supplied via the current OATT application) to show data for 2016 and the partial data for 2017 to date.

Response:

3. Table 6 shows the PEI monthly net peak loads for 2016 and 2017 (YTD).

Table 6: PEI Net Peak Load (MW)		
Month	**2016**	**2017**
January	245.3	263.3
February	230.8	248.6
March	226.9	244.0
April	208.2	199.7
May	185.5	189.7
June	183.8	188.7
July	199.9	200.3
August	189.8	N/A
September	192.6	N/A
October	193.9	N/A
November	212.0	N/A
December	264.2	N/A

Future Planning – Context for the 2018 Capital Budget (Cont'd)

4. Does MECL have any information on the extent to which "Power Factor Correction" is used by General Service and Industrial customers at their sites? Has or would MECL consider offering a customer education and installation program for deploying local site "Power Factor Correction"?

Response:

4. Maritime Electric does not have information on the extent to which General Service and Industrial customers use power factor correction at their sites.

From time to time Maritime Electric has provided education workshops for commercial, institutional and industrial customers that include information on power factor correction as one of the opportunities for customers to use electricity more efficiently and reduce their electricity bills. The most recent of these was in March 2016, when the Company together with Natural Resources Canada hosted three energy conservation workshops for Island businesses and community groups. The workshops were held on March 29 in Montague, on March 30 in Charlottetown and on March 31 in Summerside. These workshops referenced power factor correction.

Future Planning – Context for the 2018 Capital Budget (Cont'd)

5. Is MECL maintaining the draft "2011-2020 Advance Plan" as authored by John Cunniffe in 2010? If not, why not?

Response:

5. MECL has recently developed an "Integrated System Plan" which will take the place of the "Advance Plan" in the future.

Future Planning – Context for the 2018 Capital Budget (Cont'd)

6. In compiling this budget application does MECL make reference to a similar internal future planning/strategy document?

Response:

6. MECL developed an Integrated System Plan in advance of filing the 2018 Capital Budget. It provides a roadmap for future capital expenditures in the areas of generation, transmission and distribution. The plan will be updated periodically based on system conditions and changing technologies. The Integrated System Plan will be filed with the Commission in the near future.

<u>Future Planning – Context for the 2018 Capital Budget</u> (Cont'd)

7. If a document as of 6) above exists does MECL intend to publish this document or an equivalent Integrated Resource Plan (IRP) soon? If not, why not?

<u>Response:</u>

7. See response to Question 6 above.

APPENDIX A

Response to System Meters Interrogatory #4

Appendix A
Maritime Electric Company, Limited
20 Year Life Cycle Analysis of Meter Replacement Program

	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
Additions:												
# Meters Replaced	A	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Cost	B	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000
Retirement	C											
Amortization (20 year amortization) *	D = (E - (B+C)X50%) X 5%	19,050	57,150	95,250	133,350	171,450	209,550	247,650	285,750	323,850	361,950	400,050
Gross Cost	E = PY E + B + C	762,000	1,524,000	2,286,000	3,048,000	3,810,000	4,572,000	5,334,000	6,096,000	6,858,000	7,620,000	8,382,000
Accumulated Amortization	F = PY F - D	(19,050)	(76,200)	(171,450)	(304,800)	(476,250)	(685,800)	(933,450)	(1,219,200)	(1,543,050)	(1,905,000)	(2,305,050)
NBV	G = E + F	742,950	1,447,800	2,114,550	2,743,200	3,333,750	3,886,200	4,400,550	4,876,800	5,314,950	5,715,000	6,076,950
Cost of Debt (60/40)@5.69%	H = G X 60% X 5.69%	25,364	49,428	72,191	93,653	113,814	132,675	150,235	166,494	181,452	195,110	207,467
ROE (60/40) @9.35%	I = H X 40 % X 9.35%	27,786	54,148	79,084	102,596	124,682	145,344	164,581	182,392	198,779	213,741	227,278
Tax Cost of Equity	J = I X (1-31.5%) X 31.5%	12,778	24,900	36,367	47,179	57,336	66,837	75,683	83,874	91,409	98,290	104,515
Total Cost of Capitalization	**K = D + H + I +J**	**84,978**	**185,626**	**282,892**	**376,778**	**467,282**	**554,406**	**638,148**	**718,510**	**795,491**	**869,091**	**939,310**
Immediate Expense	L = B	762,000	762,000	762,000	762,000	762,000	762,000	762,000	762,000	762,000	762,000	762,000
Working Capital Allowance (3.6%)	M = K X 3.6%	27,400	27,400	27,400	27,400	27,400	27,400	27,400	27,400	27,400	27,400	27,400
Total Cost Immediate Expense	**N = L + M**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**
Net Cost Differential	**O = K - N**	**$ (704,422)**	**$ (603,774)**	**$ (506,508)**	**$ (412,622)**	**$ (322,118)**	**$ (234,994)**	**$ (151,252)**	**$ (70,890)**	**$ 6,091**	**$ 79,691**	**$ 149,910**

	Reference	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22
Additions:												
# Meters Replaced	A	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Cost	B	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000	$ 762,000
Retirement	C										$ (762,000)	$ (762,000)
Amortization (20 year amortization) *	D = (E - (B+C)X50%) X 5%	438,150	476,250	514,350	552,450	590,550	628,650	666,750	704,850	742,950	762,000	762,000
Gross Cost	E = PY E + B + C	9,144,000	9,906,000	10,668,000	11,430,000	12,192,000	12,954,000	13,716,000	14,478,000	15,240,000	15,240,000	15,240,000
Accumulated Amortization	F = PY F - D	(2,743,200)	(3,219,450)	(3,733,800)	(4,286,250)	(4,876,800)	(5,505,450)	(6,172,200)	(6,877,050)	(7,620,000)	(7,620,000)	(7,620,000)
NBV	G = E + F	6,400,800	6,686,550	6,934,200	7,143,750	7,315,200	7,448,550	7,543,800	7,600,950	7,620,000	7,620,000	7,620,000
Cost of Debt (60/40)@5.69%	H = G X 60% X 5.69%	218,523	228,279	236,734	243,888	249,741	254,293	257,545	259,496	260,147	260,147	260,147
ROE (60/40) @9.35%	I = H X 40 % X 9.35%	239,390	250,077	259,339	267,176	273,588	278,576	282,138	284,276	284,988	284,988	284,988
Tax Cost of Equity	J = I X (1-31.5%) X 31.5%	110,084	114,999	119,258	122,862	125,811	128,104	129,742	130,725	131,053	131,053	131,053
Total Cost of Capitalization	**K = D + H + I +J**	**1,006,148**	**1,069,605**	**1,129,681**	**1,186,376**	**1,239,690**	**1,289,623**	**1,336,176**	**1,379,347**	**1,419,138**	**1,438,188**	**1,438,188**
Immediate Expense	L = B	762,000	762,000	762,000	762,000	762,000	762,000	762,000	762,000	762,000	762,000	762,000
Working Capital Allowance (3.6%)	M = K X 3.6%	27,400	27,400	27,400	27,400	27,400	27,400	27,400	27,400	27,400	27,400	27,400
Total Cost Immediate Expense	**N = L + M**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**	**789,400**
Net Cost Differential	**O = K - N**	**$ 216,748**	**$ 280,205**	**$ 340,281**	**$ 396,976**	**$ 450,290**	**$ 500,223**	**$ 546,776**	**$ 589,947**	**$ 629,738**	**$ 648,788**	**$ 648,788**

* Assumes 50% amortization of new additions and retirements.
PY = Prior Year

APPENDIX B

Response to Future Planning – Context for the 2018 Capital Budget Interrogatory #2

	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Budget	2017 Forecast	2018 Budget
Distribution Services & Extensions	$ (702,100)	$ (585,580)	$ (1,123.325)	$ (774,297)	$ (656,795)	$(525,236)	$ (393,264)	$(1,277,088)	$(400,000)	$(400,000)	$(400,000)
Transmission Line	$(4,669,714)	$ (219,338)	-	-	-	-	$ (1,575)	-	-	-	-
Refunds of Extensions	$ 58,528	$ 186,889	$ (17,186)	$ 13,853	$ 12,875	-	$ 12,147	$ 14,571	-	-	-
TOTAL	**$(5,313,287)**	**$ (618,029)**	**$(1,106,139)**	**$ (760,444)**	**$ (643,920)**	**$(525,236)**	**$ (382,693)**	**$(1,262,517)**	**$(400,000)**	**$(400,000)**	**$(400,000)**

APPENDIX C

Chapter 3 Section 3.11 Ministry of Energy

Smart Metering Initiative

Background

In April 2004, the Ontario government announced a plan to reduce energy consumption in the province by creating a culture of conservation. One aspect of the plan was the provincial Smart Metering Initiative (Smart Metering)—the first and the largest smart-meter deployment in Canada—to install new "smart" electricity meters throughout the province to measure both how much and when electricity is used. The new meters would make it possible to introduce time-of-use (TOU) pricing to encourage ratepayers to shift their electricity use to times of lower demand. Smart Metering reflected the intention of the Ministry of Energy (Ministry) to manage demand for electricity in Ontario so as to more efficiently use existing power-generating capacity in the province while reducing reliance on out-of-province power purchases.

The Ministry set aggressive Smart Metering implementation targets, including an interim goal of 800,000 smart-meter installations by 2007 and complete coverage for all residential and small-business ratepayers by 2010. Entities involved in Smart Metering included the Ministry, the Independent Electricity System Operator (IESO), the Ontario Energy Board (OEB) and Ontario's 73 local electricity distribution companies, including Hydro One. Key roles and responsibilities of each entity are summarized in **Figure 1**, while **Figure 2** shows key events in implementation of Smart Metering.

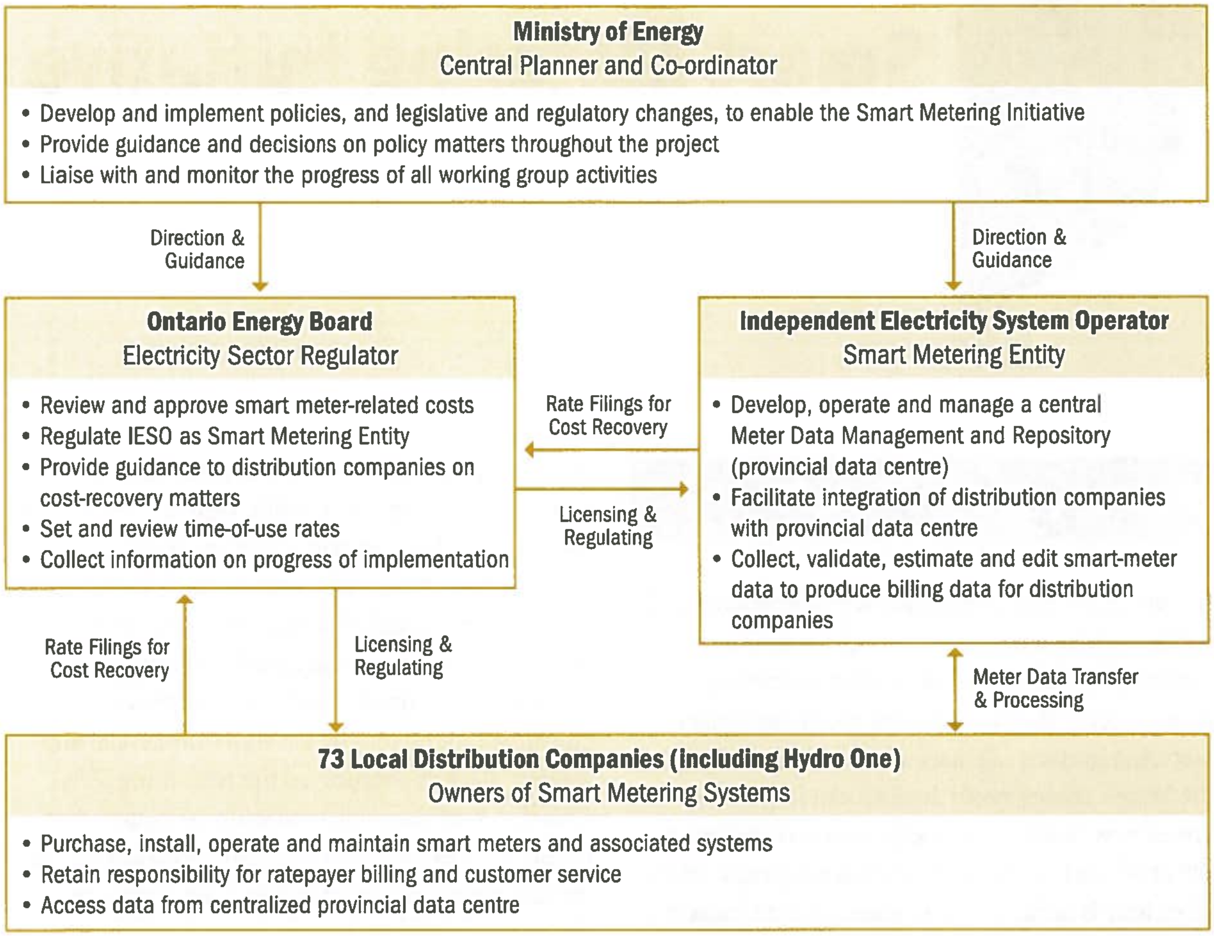
As of May 2014, there were about 4.8 million smart meters installed across Ontario, covering almost all residential and small-business ratepayers, and accounting for 45% of all electricity consumed in the province (large commercial and industrial users account for the remaining 55%). Smart meters resemble conventional meters, but differ with respect to how consumption data is displayed, measured, recorded and communicated, as illustrated in **Figure 3**.

Smart meters are the base infrastructure for developing a smart grid, which is the application of information and communications technology to improve the functioning of the electricity system and optimize the use of natural resources to provide electricity. In the *Electricity Act, 1998*, the smart grid and its objectives are set out as the information-exchange systems and equipment used together to improve the flexibility, security, reliability, efficiency and safety of the power system, particularly for the purposes of increasing renewable generation; expanding provision of price information to electricity customers; and enabling innovative energy-saving technologies.

Under TOU pricing, electricity rates charged are highest during the day, but drop at night, on

Figure 1: Key Roles and Responsibilities of Entities Involved in the Provincial Smart Metering Initiative

Prepared by the Office of the Auditor General of Ontario



weekends and holidays. The combination of smart meters and TOU pricing was expected to encourage electricity conservation and reduce demand during peak times by providing ratepayers with information and incentives to manage their electricity use by:

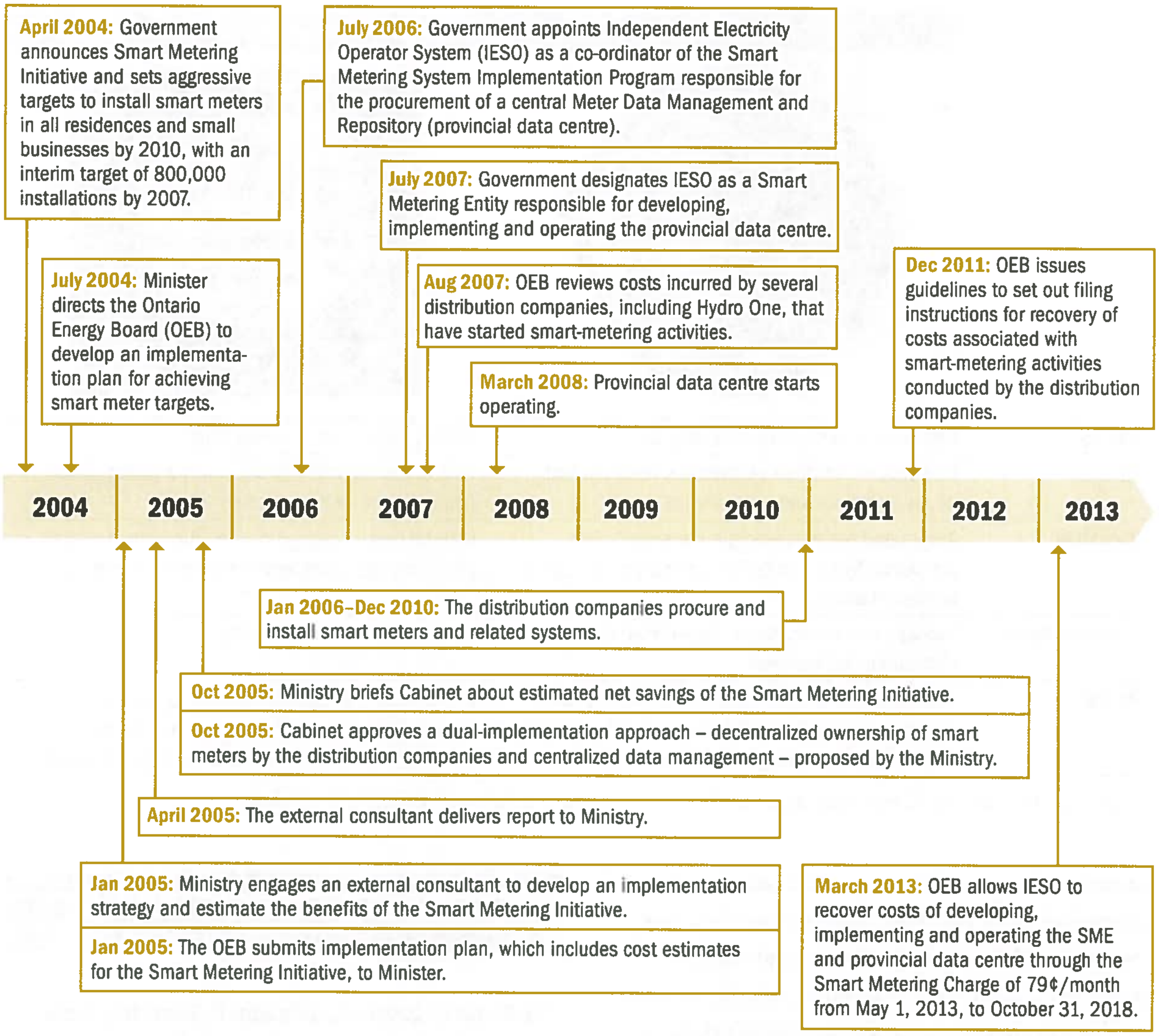
- moving consumption from peak to off-peak times (for example, running the dishwasher or dryer at night rather than in the after-noon); and
- reducing consumption during peak times (for example, setting the air conditioner a few degrees warmer on summer afternoons).

The Ministry set several targets to reduce peak electricity demand: a 1,350MW reduction by 2007; a further 1,350MW drop by 2010; and an additional 3,600MW reduction by 2025. The potential reduction in peak demand was intended to lighten the burden on electricity infrastructure, which in turn could reduce the need to build new power plants, expand existing ones, or enter into additional power-purchase agreements. It was also expected to help bring about the closing of coal-fired power plants, which were typically only used during periods of peak demand.

Audit Objective and Scope

Our audit objective was to assess whether effective systems and procedures were in place to:

Figure 2: Timeline of Key Events Relating to Implementation of the Provincial Smart Metering Initiative
Prepared by the Office of the Auditor General of Ontario



- ensure that the Smart Metering Initiative (Smart Metering) was planned, implemented and managed economically and efficiently, and in compliance with applicable policies and requirements; and
- measure and report on whether the objectives of Smart Metering were met in a cost-effective way.

Senior management at the Ministry of Energy (Ministry), the Independent Electricity System Operator (IESO) and the Ontario Energy Board (OEB) reviewed and agreed to our objective and associated audit criteria. We conducted this audit from October 2013 to May 2014.

In conducting our audit, we reviewed applicable legislation, regulations, policies, studies and other documents; analyzed electricity consumption and billing data; and interviewed appropriate staff at the Ministry, the IESO and the OEB. We surveyed 60 of Ontario's 73 distribution companies, with a response rate of over 70%, and interviewed staff from the remaining 13 distribution companies, including Hydro One, the only distribution company owned by the province. **Appendix 1** contains the

Figure 3: Comparison of Smart Meter and Conventional Meter

Prepared by the Office of the Auditor General of Ontario

	Smart Meter	Conventional Meter
		
Display	Digital meter with numerical display	Analog meter with spinning dials
Measure	How much and when electricity is used (typically hourly with date and time stamp)	How much electricity is used over a billing period (typically one or two months)
Recording	Automated meter reading: meters send data electronically to distribution companies through a wireless network*	Manual meter reading: distribution company staff physically visit ratepayer premises to record data
Communication	Two-way communication between meters and distribution companies*	No communication capability
Pricing	Time-of-use pricing (a three-tiered rate structure: on-peak, mid-peak, and off-peak) to reflect changing electricity costs throughout the day	Two-tiered pricing, with one rate applied to consumption up to a threshold and a second rate for electricity consumed in excess of this threshold

* See Figure 11 for data flow between the distribution company's smart-metering system and the IESO's provincial data centre.

questions posed to the distribution companies we interviewed and surveyed, and summarizes their responses. We also reviewed data and studies from the Ontario Power Authority, which has been involved in co-ordinating and assessing province-wide energy conservation efforts, including time-of-use (TOU) pricing enabled by smart meters. As well, we met with the Electricity Distributors Association, which represents all distribution companies across the province. In addition, we conducted research on smart-metering programs in other jurisdictions to identify best practices, and we engaged on an advisory basis the services of an independent expert with knowledge of smart metering.

Summary

The Ontario government's Smart Metering Initiative (Smart Metering) is a large and complex project that required the involvement of the Ministry of Energy (Ministry), the Ontario Energy Board (OEB), the Independent Electricity System Operator (IESO), and 73 distribution companies, including Hydro One. Our audit found that Smart Metering was rolled out with aggressive targets and tight timelines, without sufficient planning and monitoring by the Ministry, which had the ultimate responsibility to ensure that effective governance and project-management structures were in place to oversee planning and implementation. As yet, many of the anticipated benefits of Smart Metering have not been achieved and its implementation has been much more costly than projected.

Our report highlights the difficulties that have been experienced in rolling out Smart Metering, which represents an initial step towards creating a smart grid—using information and communications technology to improve the functioning of the electricity system and optimize the use of natural resources to provide electricity. We hope that lessons learned from implementing smart meters can be applied to the government's ongoing efforts to develop a smart grid in Ontario.

Some of our key observations related to Smart Metering are as follows:

Decision to Mandate Smart Metering Not Supported by Appropriate Cost-benefit Study

The government announced Smart Metering in April 2004, and shortly thereafter the Minister of Energy issued a directive to the OEB under the *Ontario Energy Board Act, 1998*. The directive required the OEB to develop an implementation plan to achieve the government's targets of 800,000 smart-meter installations by 2007 and complete coverage for all residential and small-business ratepayers by 2010. The Ministry did not complete any cost-benefit analysis or business case prior to making the decision to mandate the installation of smart meters. This is in contrast to other jurisdictions, including British Columbia, Germany, Britain and Australia, which all assessed the cost-effectiveness and feasibility of their smart-metering programs. As well, even though the electricity market in Ontario continued to change, the Ministry never adjusted the smart-meter implementation plan.

Subsequent Cost-benefit Study Flawed

After the government announced the rollout of Smart Metering in April 2004, the Ministry prepared a cost-benefit analysis of Smart Metering, and submitted it to Cabinet in October 2005. However, the analysis was flawed; its projected net benefits of approximately $600 million over 15 years were significantly overstated by at least $512 million because it excluded an annual net increase in the projected operating costs of distribution companies. In other words, the projected net benefits should have been reflected as only $88 million over 15 years.

Smart Metering Costs to Date Exceed Projected Costs and Benefits

The Ministry has neither updated the projected costs and benefits of Smart Metering, nor tracked its actual costs and benefits, to determine the actual net benefits being realized. Up to the end of 2013, our analysis shows that total smart metering-related costs incurred only by the distribution companies had already reached $1.4 billion—well in excess of the Ministry's initial total projected costs of $1 billion. When costs of the Ministry, the OEB and the IESO are included, we noted that total costs relating to implementation of Smart Metering had reached almost $2 billion at the time of our audit. Additional costs are expected in the future because some distribution companies had not yet incorporated all of their implementation costs into their charges to ratepayers (these additional costs will be subject to OEB review and approval). As well, the benefits of Smart Metering in reducing distribution companies' operating costs and reducing electricity bills to ratepayers were so far limited: Of the distribution companies we consulted, 95% said they realized no savings and their operating costs actually rose, and over half said they received a high volume of ratepayer complaints about "increased bills with no savings."

Significant Smart Metering System Development and Integration Challenges Encountered

In other jurisdictions, mass deployment of smart meters was carried out by only a few distribution companies, or even just one. The challenge in Ontario was that 73 distribution companies were each separately responsible to purchase, install, operate and maintain smart meters, as well as to bill ratepayers. This made it difficult to ensure a cost-effective implementation of Smart Metering. Three-quarters of the distribution companies we consulted ranked data management and system integration as one of the top three challenges of Smart Metering, and 83% said it was difficult and costly to integrate their systems with the provincial data centre. There have been many system upgrades, including changes made in order for Ontario to comply with Measurement Canada's billing disclosure requirements after smart meters were installed.

Peak-demand Reduction Targets Not Met

The purpose of Smart Metering was to enable time-of-use (TOU) pricing, which was expected to reduce electricity demand during peak periods. The Ministry set several targets to reduce peak electricity demand (a 1,350MW reduction by 2007, a further 1,350MW drop by 2010, and an additional 3,600MW reduction by 2025). However, the initial target of reducing peak demand by 1,350MW was irrelevant to Smart Metering anyway because it was supposed to be achieved by 2007, three years before full installation of smart meters was to be completed. With respect to the second target of an additional 1,350MW reduction by 2010, peak electricity demand did not fall, but actually rose slightly by about 100MW between 2004 and 2010.

Ontario's Surplus Power Exported to Other Jurisdictions at Less than Cost

The reduction of electricity demand during peak times was intended to delay the need to expand power-generating capacity in Ontario, along with the related costs. In the decade since the Ontario government announced Smart Metering, peak demand has remained essentially unchanged, but the Ministry has approved significant increases in new power generation, such as renewable energy, creating power surpluses in Ontario. The overall financial impact has been that other jurisdictions are able to buy this surplus power from Ontario at a price considerably lower than what it actually cost Ontario to produce this power. The total cost of producing the exported power was about $2.6 billion more than the revenue Ontario received from exporting that power between 2006 and 2013.

Electricity Billing Amounts Varied by Distribution Company

Ratepayers pay different amounts for the same power usage depending on where they live in Ontario, mainly due to different delivery costs of the 73 distribution companies. For example, a typical residential electricity bill could vary anywhere between $108 and $196 a month, mainly due to the variation in delivery costs ranging from $25 to $111 a month charged by different distribution companies to ratepayers. Implementation of Smart Metering significantly impacted the costs for each of the distribution companies, which chose different smart meters and IT solutions for their in-house systems. The cost per meter therefore varied with each distribution company, ranging from $81 per meter to $544 per meter, depending mainly on geography and the amount of upfront costs. For example, Hydro One, the only distribution company owned by the province, incurred significant costs to implement its smart-metering project. By the end of 2013, Hydro One accounted for $660 million, or almost 50%, of the $1.4-billion implementation costs incurred by all 73 distribution companies. However, it installed 1.2 million smart meters, which represented only about 25% of the 4.8 million smart meters installed in Ontario.

Of the $660 million spent by Hydro One, more than $125 million went to a private-sector vendor with whom it signed multiple contracts for services, such as system integration and project management, and approved a number of change orders. Hydro One selected this vendor based on several criteria, including price. However, pricing evaluation was not based on the overall contract cost. Hydro One explained the contract cost could not be fixed due to the "unknown nature of all the business requirements at the time of the Request for Proposal (RFP)." Granting a contract through the RFP process without acquiring enough knowledge about the business requirements would lead to risks of significant cost increases due to change orders.

Time-of-use (TOU) Pricing Model Has Had Minor Impact on Reducing Peak Demand

Smart Metering was undertaken to enable the introduction of time-of-use (TOU) rates to encourage people to shift power use to Off-Peak periods. However, TOU rates and periods may not be designed effectively to reduce peak demand as intended. Specifically:

- The difference between the On-Peak and Off-Peak rates has not been significant enough to encourage a change in consumption patterns. When TOU rates were introduced in 2006, the On-Peak rate was three times higher than Off-Peak; by the time of our audit, that differential had fallen to 1.8 times, due to significant increases in the Global Adjustment, another component of electricity bills in Ontario. In particular, the Off-Peak rate increased the most, by 114%, while On-Peak increased the least, by 29%. As a result, the difference between On-Peak and Off-Peak rates has narrowed, thus undermining TOU pricing as an incentive for ratepayers to shift power use to Off-Peak periods.
- The distribution of On-Peak, Mid-Peak and Off-Peak periods does not fully reflect actual patterns of electricity demand. In particular, in response to amendments to Ontario Regulation 95/05, the OEB moved the start of Off-Peak in 2010 from 9 p.m. to 7 p.m. on weeknights, making the early evening hours of 7 p.m. to 9 p.m. Off-Peak, even though demand at those times is high.

In 2013, separate studies released by the Ontario Power Authority and the OEB indicated that TOU pricing had a modest impact on residential ratepayers, reducing their peak demand by only about 3%, but a limited or unclear effect on small businesses, and none at all on energy conservation. Our review also found that:

- Of about 1.8 million ratepayers on TOU rates that we reviewed, only 35% of residential ratepayers and 19% of small businesses reduced their consumption during On-Peak periods, while a majority of them (65% of residential and 81% of small businesses) did not.
- About 77,000 ratepayers with smart meters paid set rather than TOU rates because they signed fixed-price contracts with electricity retailers, who do not charge based on time of use. Consumption patterns of retail and TOU ratepayers were about the same, suggesting that TOU pricing provided no more incentive to change usage behaviour than retail contracts.

Significant Impact of Global Adjustment on TOU Rates Not Transparent to Ratepayers

The Electricity Charge on ratepayer electricity bills is composed of two parts: the electricity market price and the Global Adjustment, added to the market price mainly to cover the guaranteed prices paid to contracted power generators in Ontario. From 2006 to 2013, the Global Adjustment increased almost 1,200%, while the average market price actually dropped 46%. The impact of the Global Adjustment has been significant on ratepayer electricity bills as follows:

- The total Global Adjustment paid by Ontario ratepayers has grown from $654 million in 2006 to $7.7 billion in 2013. More contracted generators, especially producers of higher-priced renewable power, will soon be coming online, so the total Global Adjustment is expected to increase even more. Between 2006 and 2015, the 10-year cumulative actual and projected Global Adjustment stands at about $50 billion, equivalent to almost five times the 2014 provincial deficit of $10.5 billion. In essence, the $50 billion is an extra payment covered by ratepayers over and above the actual market price of electricity.
- The vast majority of residential and small-business ratepayers pay for electricity based on the three TOU rates—Off-Peak, Mid-Peak and On-Peak—which were seen as critical in encouraging ratepayers to shift power use to times of lower demand. The Global Adjustment now accounts for about 70% of each of

the three TOU rates. While the Global Adjustment has increased significantly and accounts for a substantial proportion of TOU rates, its impact is not transparent to ratepayers because it is embedded in TOU rates and does not appear as a separate line on most electricity bills (the Global Adjustment appears separately only on bills of those ratepayers who have signed contracts with electricity retailers, who do not offer TOU rates).

Ratepayer Complaints Stemmed from Time-of-use (TOU) Rates and Billing Errors

Many distribution companies did not track or log the nature or type of complaints they received. They were therefore unable to quantify the volume of complaints they received before and after smart-meter implementation; nor could they separate smart meter-related concerns from billing-system issues. Without proper tracking and monitoring of ratepayer concerns, key information could not be collated to identify and resolve common or recurring problems on a timely basis. Those distribution companies that did track complaints found that most ratepayers were upset about TOU pricing, which they believed resulted in higher electricity bills than previously. Our work at Hydro One also noted complaints from ratepayers about estimated bills or no bills for extended periods due to Hydro One's billing-system problems and connectivity issues between smart meters and associated communication systems; and about bills based on errors arising from smart meters connected to incorrect addresses.

Duplication of Services by Provincial Data Centre and Local Distribution Companies' In-house Systems

Under Smart Metering, the IESO is recovering the cost of its $249-million provincial data centre, called the Meter Data Management and Repository (provincial data centre), from all residential and small-business ratepayers through a Smart Metering Charge of 79¢ per month that began in May 2013 and was set to end in October 2018. These costs were not included in the initial cost projection of $1 billion made by the OEB for implementing Smart Metering.

Of the 4.8 million smart meters installed across the province, approximately 812,000 have not transmitted any data to the provincial data centre for processing. Although these ratepayers have never benefited from the provincial data centre, they still have to pay the monthly Smart Metering Charge of 79¢, totalling about $42.1 million up to October 2018.

The IESO has exclusive authority to develop and operate a provincial data centre in which to process smart-meter data for the province. However, the goal of operating the provincial data centre as a central system to ensure standard and cost-effective data processing has not been met because most distribution companies have used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial data centre) for billing purposes. The provincial data centre was not available when some distribution companies started to roll out smart meters. Of the distribution companies we consulted, 88% indicated that the provincial data centre and their own systems have similar functions, resulting in redundancy. The costs of this duplication—one system at the provincial level and another locally—are passed on to ratepayers. The monthly operating cost for the local systems is, on average, about 21¢ per meter, which is being borne by ratepayers on top of the 79¢-a-month Smart Metering Charge.

Limitations of Provincial Data Centre and Distribution Companies in Processing Smart-Meter Data

Several limitations in processing smart-meter data by the provincial data centre and the business processes at the distribution companies have affected the quality and usefulness of smart-meter data, which in turn can affect billings to ratepayers. These limitations were associated with situations such as meter replacements and power blackouts. Also, half the distribution companies we consulted indicated that the provincial data centre has limited capabilities for data retrieval and querying. In

August 2013, the IESO reported to its board that the provincial data centre was able to manage data queries during its early stage of implementation, but it was not designed to support the expected increases in volume of data-retrieval requests from distribution companies.

Contract Terms for Operating Fee of Provincial Data Centre Not Clear

The IESO and a private-sector vendor signed a five-year contract in 2006, with an option to extend for another two years, for developing, implementing and operating the provincial data centre. The IESO paid the vendor $81.7 million for services up to March 2013. However, the $13.4-million-a-year contract fee for the two-year extension period was almost double the $6.8-million-a-year cost of the previous five years. The IESO attributed a portion of the fee increase to the additional costs associated with changes made to the provincial data centre and the higher number of meters being put in service during the two-year extension period. We found that the fee increase was due mainly to an error stemming from a contract amendment that did not clarify the fee for the two-year extension period. The IESO noted that this was an oversight on the part of the vendor, the IESO and their counsels, and that since the vendor incurred losses on the contract, the error offered the vendor an opportunity to improve its commercial position.

Monitoring of Smart Metering-related Fire Safety Risk Not Sufficient

There have been cases of fires arising from smart meters in Ontario and in other jurisdictions. However, no accurate and complete information on smart meter-related fires was available in Ontario to determine and monitor the scope and extent of the problem across the province. Only anecdotal evidence was available, which indicated three possible root causes for the fires: improper installation of smart meters, defective smart meters and problems with old meter bases where smart meters are mounted.

OVERALL MINISTRY RESPONSE

Electricity systems around the world are adapting to meet the new and complex demands of technology advances and customer expectations. In 2004, the province took a critical step towards modernizing Ontario's electricity grid with the announcement of the Smart Metering Initiative.

The Ministry acknowledges that given the ambitious timeline to install smart meters by 2010 and the inherent structure of the distribution industry, with over 70 local distribution companies, that the initiative was both complex and challenging.

Faced with these challenges, the Ministry, the IESO, the OEB and local distribution companies worked collaboratively to make Ontario one of the first jurisdictions in North America to roll out smart meters.

The deployment of 4.8 million smart meters has brought a number of benefits to the province, including the ability of consumers to respond to price signals. Going forward, smart meters, as the base technology for a modern grid that enables emerging technologies and applications like electric vehicles, electricity storage and innovations to make Ontario homes smarter, will continue to deliver value to Ontario.

The Ministry will incorporate the recommendations of the Auditor General's report when working in partnership with our agencies and the broader sector to deliver future smart meter initiatives and related investments.

Detailed Audit Observations

Governance and Oversight of Planning and Implementation

In April 2004, the Ontario government announced the Smart Metering Initiative (Smart Metering)—the first and the largest smart-meter deployment in

Canada—and set aggressive targets to install smart meters at the premises of all residential and small-business ratepayers by 2010, with an interim target of 800,000 installations by 2007. Given the size and complexity of Smart Metering, the Ministry of Energy (Ministry) had, and continues to have, an ongoing and ultimate responsibility as a central planner to ensure that effective governance and project management are in place to monitor planning and implementation.

Insufficient Justification and Planning for Smart Metering

A key principle of effective governance and project management is the use of comprehensive and relevant information about costs, benefits and risks to assess whether a proposed project is cost-effective and viable on an ongoing basis. This helps ensure that money is invested only if there is a continuing net benefit. Typically, cost-benefit analyses and business cases are two ways to evaluate the cost-effectiveness of a project, ensure that prudent decisions are made, and determine how stakeholders, and in this case electricity ratepayers, could be affected. As noted in the following sections, we found that the justification and planning for Smart Metering were insufficient.

Cost-benefit Analysis Not Done *Before* Public Announcement of Smart Metering

All key parties involved in implementing Smart Metering, including the Ministry, the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO), confirmed to us that no cost-benefit analyses or business-case studies were done before the government announced Smart Metering in April 2004. Specifically, the OEB said it did not undertake any cost-benefit study because the Minister directed it only to develop an implementation plan (see **Figure 2**). The OEB plan noted, however, that many stakeholders and ratepayers expressed concern about the lack of a cost-benefit analysis and felt that, in particular, smart meters would not be justified for ratepayers using low volumes of electricity. In addition, senior IESO management asked the Ministry several times for a business case to support Smart Metering, but never got one.

From our research, we noted that other jurisdictions have initially and continuously assessed the cost-effectiveness and feasibility of their smart-metering programs. For example:

- British Columbia began a smart metering program in 2011 after BC Hydro developed a business case in 2006, which it updated in 2010 because of the continued evolution of the smart-metering industry and technologies. The business case summarized the cash flows for costs and benefits over a 20-year term, and estimated the annual impact on electricity bills. In response to ratepayers who did not want smart meters, BC Hydro announced in July 2013 that anyone could opt out of the smart-metering program by paying a monthly fee to cover the cost of manual meter readings.
- The government in Victoria, Australia, commissioned two cost-benefit studies in 2004 and 2005 that became the basis for its 2006 decision to mandate the rollout of smart meters to all homes and small businesses. However, the Australian Government Productivity Commission concluded in 2012 that inadequate cost-benefit analysis had been done and that, overall, the decision to roll out smart meters appeared to be premature and/or poorly planned, with inadequate knowledge about smart-meter technologies, their costs and associated risks.
- In Germany, the government published a study in July 2013 that analyzed the costs and benefits of a full rollout of smart meters. The study concluded that smart meters were not cost-efficient for small ratepayers because they would cost more to buy, install and operate for average households than the

potential savings they would generate. The German government concluded it was not in the interest of ratepayers to implement a 2009 European Union recommendation that member states provide smart meters to 80% of ratepayers by 2020, and suggested instead a rollout tailored to different ratepayer groups, based on how much electricity they consume.

- The British government began preparatory work on its smart-metering program in 2009 and a business case was approved two years later. The government conducted further assessments in January 2014 to update the initial cost and benefit estimates, and it developed an overall strategy in mid-2014 to install smart meters in all homes and small businesses by 2020.

Compared to the experience in these other jurisdictions, the implementation of Smart Metering in Ontario without proper cost-benefit analysis to support the initial decision to install smart meters significantly exposed the province to unanticipated risks and unknown costs.

OEB's Role as Independent Regulator Set Aside

Shortly after the government announced Smart Metering in April 2004, the Minister of Energy (Minister) issued a directive to the OEB under the *Ontario Energy Board Act, 1998* (Act), requiring it to develop an implementation plan to achieve the government's smart-meter targets. Under the Act, the Minister has the authority to direct the OEB to promote electricity conservation in a manner consistent with government policy. The Ministry also contracted with an external consultant in January 2005 to analyze different implementation strategies and to estimate the benefits of Smart Metering.

Both the Act and the directive essentially provided the Minister with the authority to set aside the regulatory role of the OEB (an independent Crown corporation responsible for regulating Ontario's electricity and natural-gas sectors in the public interest) in Smart Metering. The OEB's mandate includes protecting the interests of ratepayers with respect to electricity prices. However, instead of conducting a cost-benefit analysis to justify its decision, and submitting the analysis to the OEB for independent review and objective evaluation, the Ministry, as a proponent of Smart Metering, directed the OEB to develop the implementation plan and project the costs of Smart Metering, as noted in the following section.

Cost-benefit Analysis, Prepared *After* Public Announcement of Smart Metering, Flawed

In the implementation plan it submitted to the Ministry in January 2005, the OEB projected the total cost of implementing Smart Metering at $1 billion, plus a net increase of $50 million a year to the operating costs of the province's distribution companies. A separate consultant's report, delivered to the Ministry three months after the OEB submitted its implementation plan, projected total benefits of Smart Metering would be approximately $1.6 billion over 15 years from four sources as shown in **Figure 4**, which indicated that about half of the projected benefits would result from a reduction in distribution companies' operating costs and a reduction in ratepayers' energy costs, and half

Figure 4: Summary of Projected Net Benefits of Smart Metering Initiative ($ billion)

Source of data: Ministry of Energy

	Approximate Amount
Reduction in distribution companies' operating costs	0.4
Reduction in ratepayers' energy costs	0.4
Avoidance of expanding power generating capacity	0.6
Deferral or avoidance of expanding transmission and distribution systems	0.2
Total Projected Benefits[1]	**1.6**
Total Projected Implementation Cost[2]	**(1.0)**
Projected Net Benefits	**0.6**

1. Benefits projected by an external consultant engaged by the Ministry.
2. Cost projected by the OEB.

from deferring or avoiding the expansion of power generating capacity as well as transmission and distribution systems.

After considering the OEB's implementation plan and the separate consultant's report, as well as consulting the distribution companies, the Ministry requested Cabinet approval to proceed with smart metering based on a dual-implementation approach: decentralized ownership of smart meters by the distribution companies, and centralized data management by a provincial agency (see **Figure 2** and the section **Smart-meter Data Processing Systems and Costs**). In its October 2005 request to Cabinet, the Ministry indicated to Cabinet that Smart Metering could yield net benefits of close to $600 million over 15 years. As shown in **Figure 4**, the Ministry arrived at this number simply by subtracting the projected implementation cost of $1 billion in the OEB plan from the projected benefits of $1.6 billion over 15 years in the consultant's report. However, we found that the $600 million in net benefits was overstated, because it did not include the OEB plan's projected net increase of $50 million a year to distribution companies in operating costs. By taking the $50-million-a-year figure into account, we calculated that the projected net benefits over 15 years would be reduced seven-fold, from $600 million to $88 million in today's dollars.

Ineffective Implementation and Oversight of Smart Metering

Given the large scale of Smart Metering and the high risk associated with new technology, its implementation should have warranted strong governance and oversight. However, we identified the following issues regarding the targets of reducing peak electricity demand, the assessment of changes in the electricity market, and the monitoring of costs and benefits of Smart Metering.

Peak-demand Reduction Targets Not Met

The key objective of Smart Metering was to reduce peak electricity demand, and therefore defer the need to expand power-generation capacity in Ontario. In the decade since Smart Metering was announced, the province approved significant increases in new generation, including renewable energy, and the supply of power actually rose 12%. During this same period, average electricity demand also dropped 8% due to a slowing economy and other conservation efforts, including, for example, newer energy-efficient appliances. Despite the reduction of average demand, peak demand has remained essentially unchanged over the same period.

The Ministry indicated that Smart Metering was only a component of the government's overall electricity conservation plan, and so there was no other specific target for Smart Metering. Instead, the Ministry set several peak-demand reduction targets to measure overall electricity conservation, including a 1,350MW reduction by 2007, an additional 1,350MW drop by 2010, and a further 3,600MW reduction by 2025. We found that:

- The initial 1,350MW targeted reduction in peak demand was irrelevant to Smart Metering anyway because it was supposed to be achieved by 2007, three years before full installation of smart meters was to be completed.
- The second target of reducing peak demand by an additional 1,350MW by 2010, for a total reduction of 2,700MW, was also irrelevant to Smart Metering, which had not been fully implemented by 2010. While approximately 4.6 million ratepayers had smart meters installed by the end of 2010, only about one-third (or 1.6 million) of them were being billed based on time-of-use (TOU) pricing. Actual peak demand in fact rose slightly by about 100MW, from 24,979MW in 2004 to 25,075MW in 2010. In measuring against the target, the Ministry indicated that as of December 31, 2010, peak demand was

reduced by about 1,800MW when measured against forecast and weather-adjusted peak demand data rather than actual demand data, but the 2010 reduction target of 2,700MW still was not met. Since 2010, actual peak demand has remained relatively stable.

Ongoing Changes in Electricity Market Not Properly Assessed or Addressed

The pace of change in the electricity sector has been rapid, so proper and adequate planning, with ongoing assessment and monitoring of plans, is important to prepare for potential risks and costs in implementation of any new electricity initiative. However, we noted that Smart Metering was implemented without sufficient periodic re-evaluation of Ontario's electricity supply and demand positions throughout the implementation period.

During the early implementation stage of Smart Metering in 2006, demand for electricity fell in Ontario as a result of an economic recession and other conservation efforts. However, instead of adjusting to this fall in demand, the province approved significant new increases in power-generation capacity to replace coal, and maintained the aggressive timelines set for implementation of Smart Metering. As a result, the supply of available power has steadily increased, and has been consistently higher than peak demand, thereby reducing the effectiveness of Smart Metering and other conservation programs. Although the IESO is required to maintain an operating reserve of between 1,300MW and 1,600MW for contingencies and other uncertainties, we noted that since 2009, the available surplus power of between 4,000MW and 5,900MW was considerably more than the required reserve. The IESO expected that the surpluses will continue in 2015, but could decline in the latter half of this decade when several nuclear plants will be refurbished or retired.

Ontario has been exporting most of its surplus power to the United States through the transmission grid connecting it to neighbouring jurisdictions, including New York, Michigan and Minnesota. We noted that net exports have grown by 158%, from 5.2TWh in 2006 to 13.4TWh in 2013, representing 3% and 9% of Ontario's total generation, respectively.

However, the export price has been well below the actual cost of generating this power. On average, other jurisdictions paid only about three to four cents per kWh for power that cost Ontario ratepayers more than 8¢ per kWh to produce because of the Global Adjustment, an extra charge on top of the electricity market price (see the section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**). The total cost of producing the exported power was about $2.6 billion more than the revenue Ontario received from exporting that power between 2006 and 2013. However, given that Ontario ratepayers would still have to pay for the production of surplus power even if that power was not exported, revenue from exports did help Ontario ratepayers pay for part of the Global Adjustment.

Costs and Benefits Not Monitored

The Ministry has neither updated the projected costs and benefits prepared in early 2005 during evolution of the implementation process, nor tracked the actual costs and benefits in order to monitor the amount of net benefits realized. We conducted our own analysis to determine the actual costs and benefits to date, and found as follows:

- With respect to costs, the OEB confirmed that there was no process to check or update its projected implementation cost of $1 billion and compare it against actual costs because the Minister never formally approved the OEB's implementation plan. We calculated that, based on our review of information submitted by the distribution companies to the OEB, the total cost incurred by the distribution companies to implement Smart Metering was about $1.4 billion up to the end of 2013, or $400 million more than the cost projection in the OEB plan. The final total will be higher still because some distribution companies were still carrying out implementation at the time of our audit and had not yet submitted all of their costs to the OEB for review. The OEB also indicated that the Ministry, the IESO and the distribution companies incurred additional costs for activities brought in after the OEB's implementation plan was prepared, including the development, implementation and operation of a provincial data centre at a cost of about $249 million (see the section **Ratepayers Charged for Redundant or Unused Provincial Data Centre Service**). As shown in **Figure 5**, we noted that as of May 2014, the total approximate costs of implementing Smart Metering had reached almost $2 billion.

- With respect to benefits, only 5% of the distribution companies we consulted reported operational savings, mainly from no longer having to send staff to read meters manually, and all of these were of modest size; the other 95% said they realized no savings and their operating costs relating to smart-metering activities since implementation had actually risen. As well, the savings achieved by ratepayers were so far limited, contrary to government communications to the public that smart meters and TOU pricing would help "save money" and "lower electricity bills" if appliances were run during Off-Peak hours. In fact, over half of the distribution companies we consulted received a high volume of complaints about "increased bills with no savings" from ratepayers with smart meters who paid TOU rates (see **Appendix 1**). In addition, several large distribution companies analyzed a sample of their residential ratepayers and found that a majority would see no reduction in their bills after implementation of TOU pricing. Therefore, of the four sources of projected benefits shown in **Figure 4**, two of them (reduction of distribution companies' operating costs and reduction in ratepayers' energy costs) have not been achieved. The remaining two sources of benefits (avoiding expansion of power-generation capacity and deferring or avoiding expansion of transmission and distribution systems) have yet to be seen because, as noted previously, the 2010 peak-demand reduction target was not met and actual peak demand has remained relatively stable since 2010.

RECOMMENDATION 1

To ensure that any future major initiative in the electricity sector is implemented cost-effectively and achieves its intended purposes, the Ministry of Energy should:

- conduct cost-benefit analysis or business cases prior to implementing an initiative to assess costs, benefits and risks;
- review the role of the Ontario Energy Board as an independent regulator when ministerial directives that impact electricity rates are issued;
- consider different scenarios or alternatives as part of the planning process to assess possible risks and uncertainties; and
- re-evaluate and update the implementation plan periodically to identify and respond to changing conditions and unforeseen events in the electricity market.

MINISTRY RESPONSE

In line with best practice, the Ministry will ensure that the proper analysis is completed ahead of implementing major initiatives. In addition, the Ministry will continue to work with the relevant sector participants in a partnership approach to ensure that cross-sector initiatives are appropriately planned and consider the respective roles of those involved.

Also in line with best practice, the Ministry respects the need to evaluate programs on a regular basis to maximize efficiencies. To this end, the Ministry will work with its agencies to re-evaluate the implementation of smart meters, including the potential benefits they could enable through the development of a smart grid in Ontario.

Figure 5: Summary of Costs Incurred by Entities Involved in the Smart Metering Initiative, 2005–2014

Prepared by the Office of the Auditor General of Ontario

Entity	Date	Cost Description	Approx. Cost ($ 000)	Report Section (if applicable)
Ministry of Energy	Jan. 2005–Apr. 2005	Engaging an external consultant to develop an implementation strategy and to estimate the benefits of Smart Metering	160[1]	Ineffective Implementation and Oversight of Smart Metering Initiative
	Nov. 2005–Apr. 2006	Engaging experts for technical, system and legal supports during early implementation stage of Smart Metering	400[1]	
	2006–2010	Developing Communication templates and materials for use by the distribution companies to raise public awareness and understanding of Smart Metering	640[1]	
Ontario Energy Board (OEB)	Jul. 2004–Jan. 2005	Developing the implementation plan for Smart Metering Initiative requested by the Minister	420	Ineffective Implementation and Oversight of Smart Metering Initiative
	Nov. 2010–May 2014	Engaging an external consultant to set time-of-use (TOU) rates	410	Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers
	Mar. 2013–Mar. 2014	Engaging an external consultant to assess the impact of TOU rates on consumption patterns	180	Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers
Independent Electricity System Operator (IESO)	2006–2014	Developing, implementing and operating a Smart Metering Entity and a provincial data centre	160,000[1,2]	Ratepayers Charged for Redundant or Unused Service
Local Distribution Companies	2006–2013	Implementing Smart Metering	1,400,000[3]	Ineffective Implementation and Oversight of Smart Metering Initiative
	2005–2014	Scrapping conventional analog meters	400,000[4]	Additional Costs of Implementing Smart Metering Initiative
Total			**1,962,210[5]**	

1. Covers activities added after OEB's 2005 implementation plan, or those outside the original scope of the Smart Metering Initiative.
2. Total approved by the OEB was $249 million up to 2017. This cost is being recovered from ratepayers through a monthly smart-metering charge of 79 cents. The amount up to 2014 was approximately $160 million.
3. Hydro One accounted for more than $660 million of the $1.4 billion spent by all 73 distribution companies. About $500 million (mainly from Hydro One) of the $1.4 billion is under review by the OEB and has yet to be approved by the OEB.
4. We reviewed the OEB's 2005 estimate. In our view, this is a reasonable estimate of total stranded costs.
5. See Figure 15 for other system-related costs incurred by the distribution companies that we interviewed and surveyed.

Billing Impacts on Electricity Charge to Ratepayers

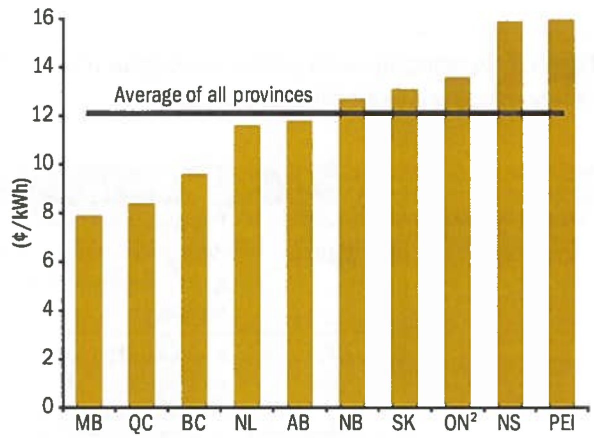
Our research noted that the average electricity bill for residential and small-business ratepayers in Ontario has been among the highest in Canada, as shown in **Figure 6**. Ontario's typical electricity bill for residential and small-business ratepayers contains four categories of charges: Electricity, Delivery, Regulatory and Debt Retirement. Smart Metering has had an impact on the two biggest categories, Electricity and Delivery, as described in **Figure 7**. There are three key pricing methods for the Electricity Charge, as illustrated in **Figure 8**. Over 90% of residential and small-business ratepayers pay this charge based on time-of-use (TOU) pricing, which is enabled by smart meters to measure the exact time when electricity is used. The remaining 10% pay either a two-tiered rate, often because they live in places where it is not technically feasible or cost-effective to install smart meters, or fixed-contract prices to electricity retailers, who do not offer TOU rates.

Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers

The Electricity Charge accounts for more than half of a typical residential electricity bill, as shown in **Figure 7**, and is made up of two components: the electricity market price and the Global Adjustment. The Global Adjustment is an extra charge, resulting from a government policy decision, that is tacked onto the electricity market price mainly to cover the gap between the guaranteed prices paid to contracted power generators and the electricity market price. It exists because most power generators in Ontario have contracts with the province that pay them more than the market price. For example, most renewable-energy generators such as wind and solar have contracted with the Ontario Power Authority under the Feed-in Tariff program that offers wind-power generators 11.5¢/kWh and solar power generators between 28.8¢/kWh and 39.6¢/kWh. These contract prices are considerably higher than the average electricity market price of about 3¢/kWh.

Figure 6: Comparison of Average Electricity Bill (Excluding Taxes) for Residential and Small-business Ratepayers[1] by Province, as of April 1, 2014

Source of data: Hydro Quebec



1. Residential electricity bill was based on average ratepayer with consumption of 750 kWh/month. Small-business electricity bill was based on average ratepayer with power demand of 40 kW/month.
2. Ontario figure includes Ontario Clean Energy Benefit, which is a 10% rebate on the total electricity bill, as illustrated in Figure 7.

Our review of trends in the Electricity Charge noted that the Global Adjustment has continued to increase to the point where it now significantly exceeds the electricity market price. This is the result of many new generators, especially in the renewable-energy sector, coming online with long-term contracts just as the market price has fallen due to oversupply of power and thus been insufficient to cover guaranteed contract prices. As shown in **Figure 9**, the Global Adjustment increased by a dramatic 1,200% between 2006 and 2013, from 0.4¢/kWh to 5.5¢/kWh, and is expected to grow to 6.7¢/kWh by 2015. During the same period, the average electricity market price has dropped by 46%, from 4.9¢/kWh to 2.7¢/kWh, and is expected to fall to 2.4¢/kWh by 2015 due to increasing electricity supply.

The total Global Adjustment charged to ratepayers has grown from $654 million in 2006 to $7.7 billion in 2013, as shown in **Figure 10**. With more new contracted generators, especially of renewable energy, expected to begin producing energy at higher contract prices, the total Global Adjustment is expected to grow further, to $8.5 billion in 2014 and $9.4 billion in 2015. From 2006 to 2015, the 10-year cumulative actual and projected Global Adjustment is about $50 billion—an extra charge to ratepayers over and above the market price of electricity. To put this into perspective, $50 billion is:

- sufficient to cover the 2014 provincial deficit of $10.5 billion almost five times;

Figure 7: Components of Electricity Bill with Examples, 2013 (Average Typical Residential Ratepayer Consuming 800 kWh/Month)

Source of data: Ontario Energy Board (OEB)

Bill Component	Description	Examples: Distribution Company A ($)	Examples: Distribution Company B ($)	Avg. of all Distribution Companies ($)
Electricity Charge	The cost of the actual electricity consumed. Presentation of this charge on bills varies, depending on whether the ratepayer buys electricity from a distribution company or has signed a contract with a retailer. Over 90% of low-volume power use ratepayers (residential and small businesses) pay power charges based on time-of-use pricing, enabled by installation of smart meters (see Figure 6).	71.1	71.1	71.1
Delivery Charge*	The cost of delivering electricity from power-generating facilities to ratepayers via high-voltage (transmission) and low-voltage (distribution) systems. Transmission is handled primarily by Hydro One and distribution is handled by the distribution companies, including Hydro One. Costs of implementing and operating smart meters are included in this line and vary from one distribution company to another, usually with higher charges in rural and remote locations.	24.9	110.6	43.6
Regulatory Charge	The cost to operate the electricity market and maintain the reliability of the provincial grid. This includes the operational costs of the IESO and the Ontario Power Authority as well as a portion of administrative costs of local distribution companies.	4.9	5.1	5.0
Debt Retirement Charge	Charge mandated by the government to help pay off the residual stranded debt of the old Ontario Hydro that could not be funded by other revenues. The 2014 Budget proposed to eliminate this charge for residential ratepayers after December 31, 2015.	5.6	5.6	5.3
Electricity bill before tax and benefit		**106.5**	**192.4**	**125.0**
Harmonized Sales Tax	The 13% tax that took effect on July 1, 2010, replacing the federal goods and services tax (GST) and the provincial sales tax (PST).	13.9	25.0	16.3
Ontario Clean Energy Benefit	A 10% rebate on the total electricity bill for the first 3,000 kWh/month of electricity consumed. Rebate is in effect from 2011 to 2015. Annual cost of rebate is funded by taxpayers.	(12.0)	(21.8)	(14.1)
Total Electricity Bill		**108.4**	**195.6**	**127.2**

* See Appendix 2 for the Delivery Charge of each distribution company in Ontario.

- enough to pay the annual salary of about 2.3 million Ontarians working full time at the provincial minimum wage; or
- about 7.5 times more than the $6.6-billion spent in the 2012/13 fiscal year on social-assistance programs such as the Ontario Disability Support and Ontario Works programs administered by the Ministry of Community and Social Services.

For ratepayers whose Electricity Charge is based on TOU pricing, the Global Adjustment now accounts for about 70% of each TOU rate. Even though the Global Adjustment has increased significantly and accounts for a substantial proportion of

Figure 8: Pricing Methods for Electricity Charge

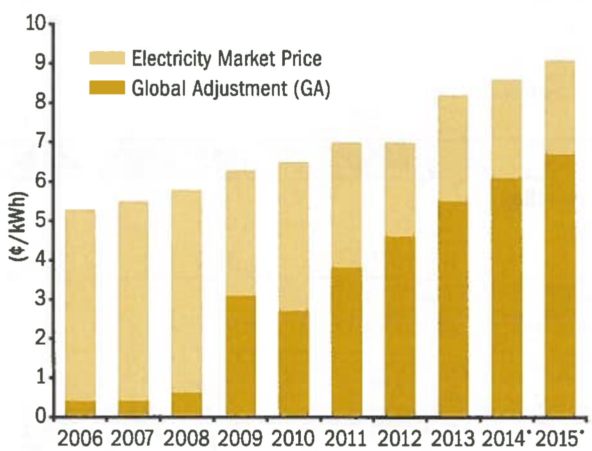
Source of data: Ontario Energy Board (OEB)

Pricing Method	Time-of-Use (TOU)	Tiered	Retail Contract
Electricity Provider	Local Distribution Company	Local Distribution Company	Electricity Retailer
Electricity Charge based on Time-of-Use?	YES Rates vary depending when electricity is used, reflecting that electricity costs more as demand rises (highest during the day on weekdays and lowest in evenings, at night, on weekends and holidays).	NO Rates are fixed in two tiers regardless of when electricity is used (a lower rate for monthly usage up to a threshold and a higher rate for usage over the threshold).	NO Rates are fixed by contracts that ratepayers sign with retailers no matter what time of day electricity is used.
Electricity Charge Regulated by Ontario Energy Board (OEB)?	YES OEB reviews and sets TOU and tiered rates twice a year (May 1 and Nov 1) based on future electricity prices estimated by an external consultant.		NO
Global Adjustment* Shown Separately on Bill?	NO Global Adjustment is blended into TOU and tiered rates, and embedded in the Electricity Charge line on electricity bill.		YES Global Adjustment appears as a separate line on electricity bill.

* The Global Adjustment is an extra charge designed to cover the contract prices paid to power generators, such as renewable energy generators, and the cost of conservation programs.

Figure 9: Historical and Projected Electricity Charge in Ontario, 2006–2015

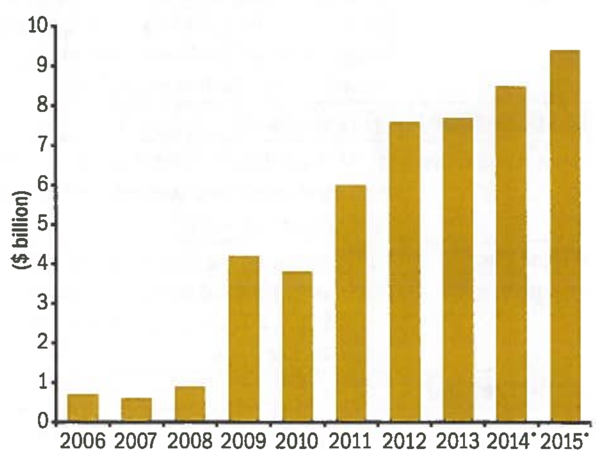
Source of data: Independent Electricity System Operator and Ontario Power Authority



* projected

Figure 10: Historical and Projected Total Annual Global Adjustment Charged to Electricity Ratepayers in Ontario, 2006–2015

Sources of data: Independent Electricity System Operator and Ontario Power Authority



* projected

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the TOU rates, its impact is not transparent to most ratepayers because it does not appear on electricity bills as a separate line; instead, it is embedded in the TOU rates used to calculate the Electricity Charge (As shown in **Figure 8**, the Global Adjustment only appears separately on bills of those ratepayers who have signed contracts with electricity retailers).

Ineffective Design of Time-of-use Rates and Periods

As part of Smart Metering, there are three time-of-use (TOU) rates: On-Peak, Mid-Peak and Off-Peak, consistent with the TOU design in other jurisdictions. As illustrated in **Figure 11**, TOU rates vary, depending on the time of the day, day of the week, and season, to reflect the assumption that as demand rises, electricity costs more to supply. Like many cell phone plans, TOU rates are lowest in the evenings, on weekends and holidays; and highest during the day on weekdays. The combination of smart meters and TOU pricing was expected to encourage energy conservation by giving ratepayers information and incentives to manage their electricity usage.

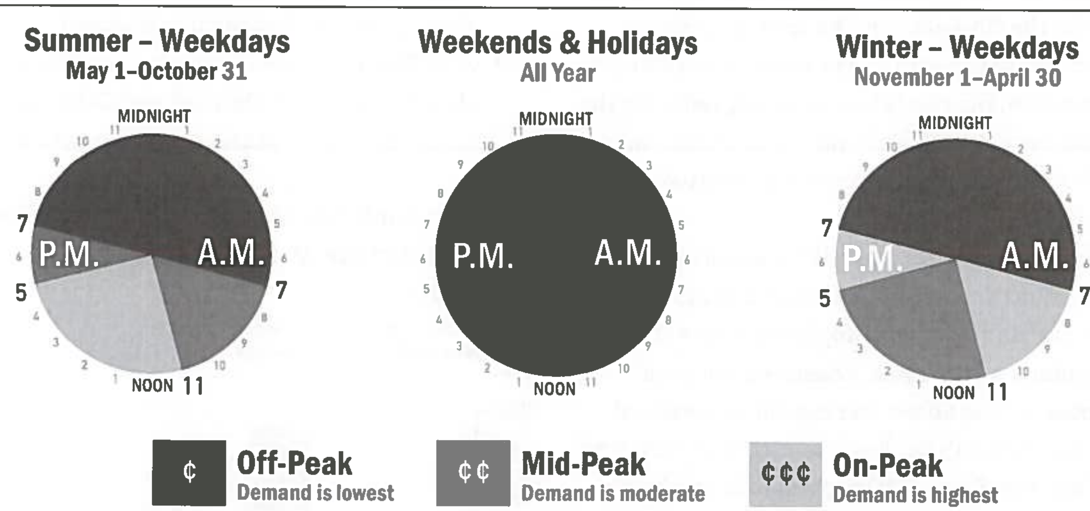
To account for seasonal variations in electricity consumption patterns, the OEB reviews and sets TOU rates every May and November, based on consumption and cost projections made by an external consultant with whom it contracted. Ontario Regulation 95/05 requires that the OEB set the TOU rates to meet three objectives:

- recover from ratepayers the full cost of electricity supply;
- reflect the differences in the costs of supplying electricity at different times and seasons; and
- provide ratepayers with incentives to change their time of use.

In order to encourage conservation and reduce peak electricity demand, TOU rates and periods

Figure 11: Time-of-use Pricing Periods in Ontario for Residential and Small-business Ratepayers

Source of data: Ontario Energy Board (OEB)



Summer Weekdays (May 1–October 31)	Weekends & Holidays (All Year)	Winter Weekdays (November 1–April 30)
One On-Peak period in the afternoon (11 a.m.–5 p.m.), mainly due to the increase in air conditioner use during the hottest hours.	No On-Peak period and all hours Off-Peak, mainly because of comparatively lower overall demand.	Two On-Peak periods, mainly due to less daylight. • In the morning (7 a.m.–11 a.m.) when people turn on lights and appliances. • In the evening (5 p.m.–7 p.m.) when people get home from work.

must be set to provide an incentive to reduce usage during On-Peak times, when both demand and price are high, or shift it to Off-Peak times, when both demand and price are low.

With respect to the TOU rates, the greater the difference between On-Peak and Off-Peak rates, the higher the likelihood that ratepayers will change their usage patterns. However, we noted that the difference between On-Peak and Off-Peak rates in Ontario may not be significant enough to provide ratepayers with an incentive to change their electricity-use behaviour. Specifically:

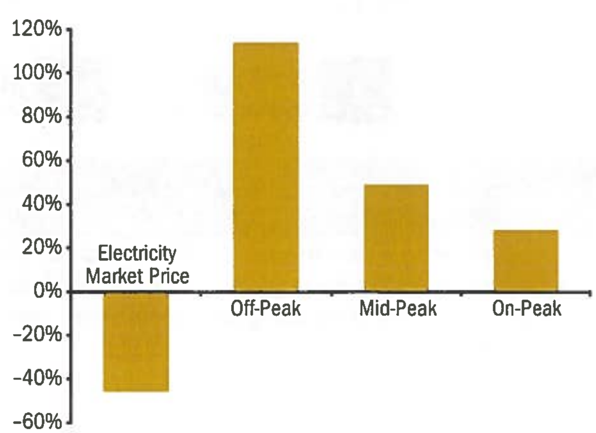
- When TOU pricing was introduced in 2006, the initial On-Peak–to–Off-Peak ratio was three-to-one, meaning that On-Peak power cost three times as much as Off-Peak. However, the ratio had dropped to 1.8-to-one at the time of our audit due to the impact of the substantial growth of the Global Adjustment, as discussed in the section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**. In particular, the Off-Peak rate rose the most, by 114%, and the On-Peak rate the least, by 29%, as shown in **Figure 12**. As a result, the difference between the two rates narrowed, reducing the On-Peak–to–Off-Peak ratio and undermining TOU pricing as an incentive for ratepayers to shift to Off-Peak.
- In 2010, the OEB commissioned an external consultant to study TOU rates around the world and assess the appropriateness of Ontario's TOU rates. Consistent with our observation above, the consultant reported that Ontario's On-Peak–to–Off-Peak ratio was "low relative to TOU programs in other jurisdictions and will likely produce modest ratepayer response or bill savings." The average ratio elsewhere was four-to-one, compared to Ontario's 1.8-to-one. The Ontario ratio could deliver only about a 1% drop in the average ratepayer's peak demand, while a four-to-one ratio could potentially yield a drop three times greater. The study proposed several options to increase the ratio. However, following a consultation in 2011, the OEB chose not to make any change because a majority of stakeholders said such a move would be premature in the absence of robust and reliable Ontario-based empirical data.

With respect to the TOU periods, we noted that the distribution of On-Peak, Mid-Peak and Off-Peak periods did not fully reflect actual patterns of electricity use. Specifically:

- There has been a mismatch between demand and TOU rates on weekday early-evening hours (7 p.m.–9 p.m.), when demand is high but ratepayers pay the Off-Peak, or lowest, rate. The OEB initially set the Off-Peak period on weekday evenings to begin at 10 p.m., and then moved it to 9 p.m. in November 2009 to better reflect actual patterns of demand. However, in response to amendments to Ontario Regulation 95/05 in December 2010, the OEB set the start of Off-Peak at 7 p.m., making the early evening hours of 7 p.m. to 9 p.m. Off-Peak, even though demand remained high at those times, as illustrated in **Figure 13**.
- A 2013 study by an Ontario university found that the choices of On-Peak and Off-Peak times, number of seasons, and season start

Figure 12: Percentage Change of Time-of-use (TOU) Rates and Electricity Market Price in Ontario, 2006–2014

Source of data: Ontario Energy Board and Independent Electricity System Operator



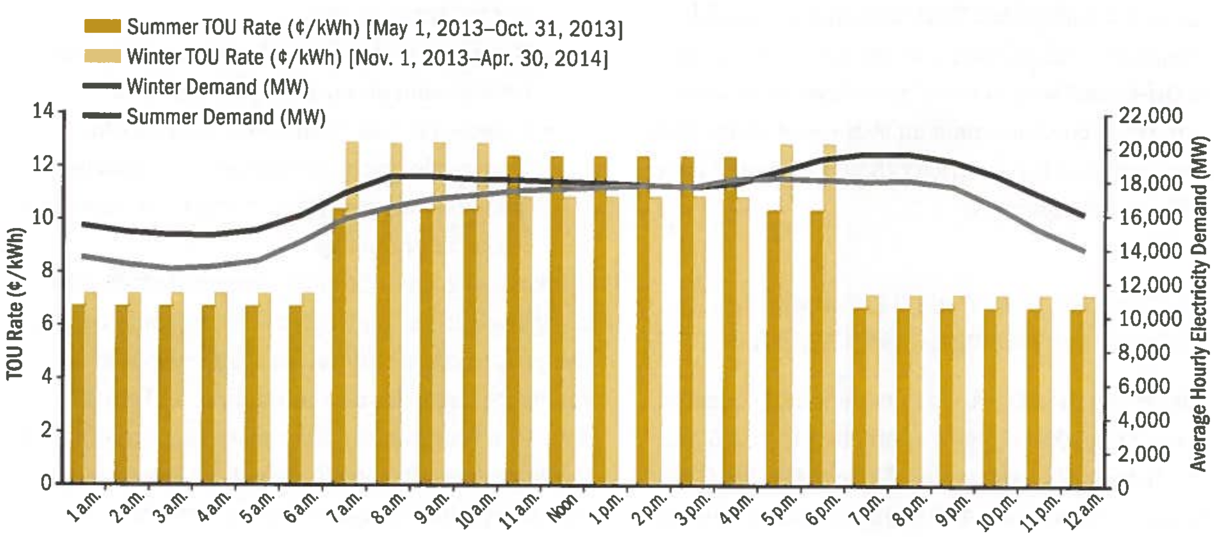
and end times used in Ontario's TOU pricing were far from optimal. The study echoed our observation that the distribution of On-Peak, Mid-Peak and Off-Peak periods did not properly reflect the actual distribution of demand. The study also found that while the current TOU pricing structure has two seasons (summer: May 1-October 31, and winter: November 1-April 30), the optimal number of seasons should be four, beginning March 11 (spring), May 20 (summer), September 16 (fall) and November 4 (winter). If the current two-season pricing structure is to be maintained, the study said, summer should start on April 15 rather than May 1, and winter on October 14 rather than November 1.

Limited Effectiveness of Time-of-use Pricing Model

At the time of our audit, the distribution companies we consulted said they did not conduct studies to examine the changes in consumption after implementation of TOU pricing. The impacts of TOU pricing were evaluated in 2013, when the Ontario Power Authority (OPA) and the OEB contracted with external consultants to examine the effectiveness on a sampling of ratepayers of TOU pricing in encouraging conservation and reducing peak demand. Both agencies released their studies in late 2013 with similar findings: TOU pricing has had a modest impact on reducing peak demand among residential ratepayers, a limited or unclear effect on small businesses, and no impact at all on energy conservation. Specifically:

- In November 2013, the OPA released its study, based on 105,000 residential ratepayers in four distribution companies, and 32,000 small businesses in two distribution companies. The study found that TOU pricing had a far smaller impact on reducing peak demand of small businesses than it did for residential ratepayers. Depending on the distribution company, the drop in peak demand during the summer ranged from 2.6% to 5.7% for residential ratepayers, but only from 0% to 0.6% for small businesses. The study also found that the impact of TOU pricing on energy conservation was "limited, being very small or zero," for residential ratepayers, and "negligible and generally insignificant" for small businesses.
- In December 2013, the OEB released its study, based on a sample of 10,000 residential ratepayers and 4,000 small businesses in

Figure 13: Time-of-use (TOU) Rates and Average Hourly Electricity Demand in Ontario, May 2013–April 2014
Sources of data: Independent Electricity System Operator and Ontario Energy Board



16 distribution companies. The study found that TOU pricing reduced peak demand by about 3.3% for residential ratepayers while its impact on small businesses was "ambiguous." The study also found that TOU pricing had no significant impact on energy conservation in the summer.

We performed further analyses based on more current data and larger sample sizes. Specifically, we reviewed consumption patterns of about 1.8 million ratepayers (1.7 million residential ratepayers and 86,000 small businesses in 50 of 73 distribution companies), who paid TOU rates. While 35% of residential ratepayers and 19% of small businesses reduced their consumption during On-Peak periods, the remaining 65% of residential and 81% of small businesses did not.

Since the aforementioned studies by the OPA and the OEB did not specifically cover ratepayers with smart meters who signed fixed-price contracts with energy retailers and so do not pay TOU rates, we examined the consumption patterns and bills of about 77,000 of these ratepayers. Given that they paid fixed prices regardless of time of use, these ratepayers have little or no incentive to confine their consumption to Off-Peak periods, when TOU rates were lowest. However, we noted that consumption patterns of ratepayers paying fixed-contract prices to electricity retailers, and of ratepayers paying TOU rates, were about the same, indicating that TOU rates did not provide ratepayers with sufficient incentive to shift usage to Off-Peak. We also noted that those ratepayers with retail contracts paid an average of about $500 more per year for electricity than they would have without the contracts.

Ratepayer Complaints Stemmed from Time-of-use Pricing and Billing Errors

Ratepayers usually raised questions and concerns about Smart Metering by contacting the OEB and the distribution companies. Since 2008, the OEB has received about 2,400 enquires and complaints relating to smart meters and TOU pricing; about two-thirds of them questioned the TOU pricing structure and whether it would save them money. Given that ratepayers get their bills directly from the distribution companies, the companies received even more enquiries and complaints.

Many distribution companies we consulted did not track enquiries and complaints separately, nor did they log the nature or type of complaints. They were thus unable to quantify the volume of complaints relating to Smart Metering before and after its implementation, and could not separate concerns about smart meters from those about billing. Without proper tracking and monitoring of ratepayer concerns, key information could not be collated to identify and resolve common or recurring problems on a timely basis.

Those distribution companies that had tracked the nature of complaints reported that a majority of the concerns raised by ratepayers related to TOU pricing and fell into the following categories (see **Appendix 1**):

- Ratepayers were upset about high electricity bills or "increased bills with no savings," which they believed were caused by faulty smart meters, but were in fact due to the increase of TOU rates as a result of the significant growth of the Global Adjustment (see section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**).
- Ratepayers had "limited understanding and information about TOU pricing;" and
- Ratepayers had "limited or no ability to change electricity consumption," especially small businesses and individuals at home during most of the day.

For Hydro One, Ontario's largest distribution company and the only one owned by the province, we performed additional detailed reviews of ratepayer enquiries and complaints. In February 2014, four months after we began our audit, the Ontario Ombudsman also began an investigation into complaints at Hydro One. In order to avoid duplication with that undertaking, we modified our audit scope to focus on identifying the root causes of billing issues potentially relating to smart meters and TOU pricing. Of the complaints we examined at Hydro One, most related to high electricity bills due mainly to TOU rates and not to defective smart meters, just like the other distribution companies noted above. In addition to the high-bill concerns relating to TOU rates, we also identified a number of complaints about billing anomalies that fell into the following categories:

- **Billing System Problems:** In May 2013, Hydro One transitioned to a new billing system. However, the transition was not smooth. At the time of our audit, Hydro One was adapting to and working on some technical issues with its new system, but more complex issues had yet to be fixed. We identified complaints about erroneous bills, prolonged estimated bills, delayed bills, multiple bills or no bills at all, that were due to problems with the billing system. For example:
  - In September 2013, a ratepayer received a bill for about $37 million as a result of an error made in calculating electricity consumption, but Hydro One's billing system did not catch this error. In January 2014, the company cancelled the bill and revised the amount owing to about $35,000.
  - In September 2013, a ratepayer with a smart meter received an estimated bill covering electricity usage for seven months. After that, the ratepayer received no bills for five months due to billing-system problems. In April 2014, Hydro One issued 12 bills, all on the same date and for a total of over $4,900. Of these 12 bills, seven were to correct the under-estimated bill issued in September 2013 and five were to "catch-up" on the no-bill period since October 2013.
  - A smart meter installed in March 2012 was found to be malfunctioning, and was replaced in October 2012. However, the ratepayer was not billed until April 2013 due to problems in the billing system. In April 2013, the ratepayer received a "catch-up" bill of about $4,000 for usage between March 2012 and April 2013.
- **Communication System Problems:** Ratepayers did not receive any bills, or received only estimated bills, for extended periods, because actual consumption data was not available due to connectivity issues between the smart meters and associated local communication systems. The problems could be caused by non-communicating smart meters or by seasonal variations in system performance. With respect to the latter, Hydro One's service territory includes rugged terrain and extensive foliage that could block meter signals from reaching the systems, depending on the season. Communication systems in one region may work well in the fall and winter when most trees are bare of leaves, for example, but it may not function properly in the spring when trees have new leaves.
  - In December 2013, a ratepayer complained about receiving estimated bills for seven months, ranging from $400 to $500 per month, which was about two to three times higher than the previous monthly bills. Hydro One found that the smart meter was working properly, but it could not capture actual meter readings because its communication system was not producing a signal. Hydro One then corrected the over-estimated bills and credited the ratepayer for about $1,300 against future bills.
  - In December 2013, another ratepayer complained about receiving high estimated bills for nine months. Hydro One found that the bills were based on estimates rather than actual meter readings because the smart meter was not communicating with the system. Hydro One then cancelled the over-estimated bills and issued a credit of about $2,700 to the ratepayer.

- **Mixed or Cross-Metering Issues:** Ratepayers were billed based on errors arising from smart meters connected to wrong addresses during installation. Hydro One indicated that these issues also existed prior to the installation of smart meters but occurred rarely. Most ratepayers did not notice these issues because the amount of the errors was usually not significant; in other cases, however, they were. For example:
  - In response to a January 2012 query from a ratepayer about a high bill, Hydro One found that four smart meters in the same building had been mistakenly wired into the wrong addresses, and that the ratepayer who complained had been overbilled by about $1,000.
  - In response to an enquiry from another ratepayer in April 2013, Hydro One found that a smart meter in an apartment was erroneously connected to another address, and that the ratepayer was overbilled by about $200 from November 2012 to March 2013, when the smart meter was incorrectly connected.
- **Seasonal High Bills:** Unlike other distribution companies, Hydro One has wider geographic coverage and more seasonal ratepayers who own residential properties, such as cottages in rural or remote areas, in addition to their primary residence. Even though seasonal ratepayers used their properties mainly on weekends and holidays, they still received high electricity bills. For example, in February 2014, a ratepayer complained of bills totalling $7,000 a year on a cottage that was only used six months a year. The ratepayer attributed the high bills to a faulty smart meter, but Hydro One found that the smart meter was functioning properly. We identified other similar complaints that were caused by one or all of the following reasons:
  - The Electricity Charge on seasonal ratepayer bills rose because of the increases of all three TOU rates (see section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**).
  - The Delivery Charge to seasonal ratepayers was higher than for typical residential ratepayers because delivering power to remote seasonal properties through forests and around lakes requires more infrastructure, such as poles, lines and transformers, and is therefore more expensive than service to more populated areas.
  - Seasonal ratepayers were surprised by the unanticipated consequence of billing changes after smart-meter installation. For example, before installing smart meters, Hydro One would issue four bills a year to seasonal ratepayers—one based on an actual meter reading carried out by Hydro One staff at the ratepayer's premises, and three based on estimates. After the installation of smart meters, which enable TOU pricing to measure the exact time when electricity is used, seasonal ratepayers began to receive much higher bills in the summer and lower bills in the winter.

At the time of our audit, we noted that Hydro One had been taking some actions to resolve the existing billing issues. For example, Hydro One was improving its training to customer-service staff; providing refund options (a cheque or a credit on account) to ratepayers who were overbilled; waiving late payment charges; and not sending disconnection notices to ratepayers who experienced billing issues caused by Hydro One.

RECOMMENDATION 2

To ensure that the combination of smart meters and time-of-use (TOU) pricing is effective in changing ratepayer electricity-usage patterns to reduce peak electricity demand and related infrastructure costs, and that ratepayers understand the impacts of TOU pricing on their electricity bills, the Ministry of Energy should work with the Ontario Energy Board and/or the distribution companies to:

- evaluate TOU pricing design, including TOU rates, TOU periods and the allocation of the Global Adjustment across the three TOU rates;
- monitor trends in ratepayer electricity consumption to evaluate the effectiveness of TOU pricing over time; and
- disclose the components of the TOU rates (electricity market price and Global Adjustment) separately on electricity bills so that the impact of the Global Adjustment is transparent to ratepayers.

MINISTRY RESPONSE

As established in the *Ontario Energy Board Act, 1998* and prescribed in Ontario Regulation 95/05, the OEB is responsible for setting rates for residential and small business customers on the Regulated Price Plan (RPP), which includes time-of-use (TOU) pricing.

TOU rates continue to evolve as the province balances both system and customer benefits, and as we learn more about how consumers are responding to TOU rates.

Further analysis is under way and the Ministry looks forward to the OEB's planned review of the RPP and TOU pricing that is currently under way.

The OEB's RPP review is timely in that it will build on the robust analysis of the actual impacts of TOU prices in Ontario that have been completed by the OEB and OPA.

OEB RESPONSE

The OEB is undertaking a review of TOU pricing. That review will consider all of the matters identified by the Auditor General, including the structure of the TOU periods, the TOU prices, and the forecasting of the costs and the Global Adjustment to be recovered in those prices. We anticipate that this review will be completed during the OEB's 2014/15 fiscal year. The OEB would be pleased to work with other agencies and with the Ministry regarding any further review of TOU prices that the Ministry may consider appropriate in the circumstances.

RECOMMENDATION 3

To ensure that ratepayer concerns are addressed properly and in a timely manner, and that clear, timely and accurate bills are issued to ratepayers, the Ministry of Energy should work with the Ontario Energy Board, Hydro One and other distribution companies to:

- improve tracking of the nature and details of ratepayer enquiries and complaints to identify and monitor common or recurring concerns;
- better educate ratepayers about the impacts of time-of-use (TOU) pricing and other factors on electricity bills, as well as the root causes of potential metering or billing issues and what is being done to address them; and
- identify and fix any problems with their billing systems and local communication systems on a timely basis, and monitor the performance of those systems over time to reduce ratepayer complaints triggered by these problems.

MINISTRY RESPONSE

In accordance with the *Ontario Energy Board Act, 1998*, the OEB is responsible for protecting the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

In line with these objectives, the OEB has made customer focus one of four principal outcomes for local distribution companies (LDCs) as part of its Renewed Regulatory Framework for Electricity.

The Ministry welcomes the introduction of specific metrics related to customer satisfaction as part of its scorecard to measure and benchmark LDC performance on an annual basis.

In particular, from 2014 on, LDCs will be required to report to the OEB on their effectiveness at addressing customer complaints, customer satisfaction survey results and performance with respect to targets for billing accuracy.

The Ministry will ask the OEB to consider whether any additions or revisions to its new framework are required in light of this recommendation.

HYDRO ONE RESPONSE

Hydro One serves over 1.2 million ratepayers across Ontario and issues over 1 million bills monthly. The implementation of Hydro One's new billing system in May 2013 has led to billing issues for about 6% of its customers. Hydro One has been working to communicate with ratepayers and make them aware of its plans to fix the technical issues and improve customer service. At the time of this audit, approximately 1.8% of customers were impacted. Since February 2014, Hydro One has taken several actions to improve its customer service, including:

- reducing the number of ratepayers who have not received a bill for a prolonged period of time to 0.8%, improved from 5%;
- decreasing the number of ratepayers who have received only estimated bills for a prolonged period of time (currently 1% of Hydro One's customer base);
- introducing a 10-day commitment for resolving customer issues, with a resolution within 10 days or by a promised date;
- changing call-centre training, increasing the number of customer-service-centre agents, and introducing new policies such as interest-free payment plans for customers who have received bills covering long billing periods and waived service charges for ratepayers affected by billing issues;
- adding a new section to Hydro One's website to improve ratepayer understanding of billing and metering issues; and answer ratepayers' common questions on high bills, the impact of cold weather on electricity consumption, meter readings, meter accuracy, smart meters and the smart-meter network;
- enhancing customer call tracking to identify and resolve emerging issues;
- exploring the implementation of a new customer commitment tracking and monitoring solution;
- establishing a Service Champion Advisory Panel; and inviting external experts to provide advice to Hydro One's president and CEO, review Hydro One's customer-service performance, and make performance results public; and
- continuing to fix and monitor the technical problems with its new billing system, improve call centre staff capabilities to address customer service needs, and resolve the associated complaints fairly and promptly by providing payment arrangement options and waiving late payment charges or any other penalties to ratepayers who were affected by these technical problems.

Billing Impacts of Delivery Charge on Ratepayers

There are three major types of costs associated with Smart Metering: capital costs (for meters, communication infrastructure, installation and data systems); ongoing operating costs for meter reading and services; and stranded costs for scrapping old analog meters. These costs are recovered from ratepayers though the Delivery Charge, which is the second largest component of a typical ratepayer electricity bill, and which varies from one distribution company to another, as illustrated in **Figure 7** and **Appendix 2**.

Variations in Delivery Charge between Distribution Companies

As illustrated in **Figure 7**, a typical residential electricity bill varies between $108 per month and $196 per month, depending on where the ratepayer lives and which distribution company provides the service. Of the four categories of charges (Electricity, Delivery, Regulatory and Debt Retirement) that make up the electricity bill, the Delivery Charge accounts for the largest variation in costs among distribution companies, ranging from about $25 a month to $111 a month, with the average at about $44 per month, as shown in **Figure 7** and **Appendix 2**.

In 2012, the Minister of Energy established the Ontario Distribution Sector Review Panel to advise the government on how to improve efficiency in the distribution companies with the aim of reducing the cost to ratepayers of electricity distribution. The panel's research and analysis showed that the current approach to delivering electricity has been costing ratepayers more than it should. In particular, compared to their larger counterparts, smaller distribution companies tended to have higher per capita operating costs, which were passed on to ratepayers through the Delivery Charge line on electricity bills. As a result, ratepayers of smaller distribution companies paid more for their electricity than ratepayers of larger distribution companies. Given the varying sizes of the distribution companies, and their varying Delivery Charge, the panel's key recommendation was to merge the existing distribution companies into eight to 12 larger ones to improve cost-efficiency and ensure price stability, fairness and value for money in the electricity-distribution sector. The panel expected that consolidation would help reduce sector-wide operating costs by 20% in areas such as customer service, billing, facilities maintenance and administration.

However, we noted that the panel excluded the two largest distribution companies with high costs, Hydro One and Toronto Hydro, when comparing the costs of different distribution companies. Given that these two distribution companies have Delivery Charges higher than the provincial average, it would be worthwhile for the Ministry, in conjunction with the OEB, to study the cost implication for ratepayers from consolidation to reduce the variations in distribution-company costs.

Variations in Smart-metering Costs between Distribution Companies

The distribution companies recover all costs associated with the implementation and operation of their smart-metering systems from ratepayers through the Delivery Charge line on electricity bills, as discussed in the section **Variations in Delivery Charge between Distribution Companies**. There are 73 distribution companies across Ontario, each responsible for procuring, installing and operating smart-meter systems. Each distribution company negotiated with different vendors to procure systems for their regions. As a result of the different costs incurred by distribution companies, we noted that the average cost per meter was about $190, but varied significantly, ranging from $81 per meter at one distribution company to $544 per meter at another. Such wide variation was due mainly to geographical issues in service areas and the degree of upfront expenses, such as project-management and system-integration costs. These two factors were particularly significant at Hydro One, Ontario's only provincially owned distribution company.

At the time of our audit, we noted that the costs incurred by Hydro One in implementing its smart-metering project were significant. In December 2006, Hydro One's Board of Directors approved $670 million for the project. By the end of 2013, Hydro One had spent over $660 million (including about $490 million on procurement and installation of smart meters and associated communication systems, and about $170 million on system development, integration and automation), which was about 50% of the $1.4-billion total province-wide implementation cost—and more than the other 72 distribution companies combined (see the section **Ineffective Implementation and Oversight of Smart Metering Initiative**). However, Hydro One installed 1.2 million smart meters, which represents only about 25% of the 4.8 million smart meters installed in Ontario. Of the $660 million spent by Hydro One, our review of the OEB's records noted that about $440 million has yet to be reviewed and approved by the OEB.

Hydro One's high costs were partly the result of installing smart meters and establishing communications infrastructure across its large and diverse geographic service area, which includes a mix of urban, rural and remote regions. Another factor was the high contract fee paid to a private-sector vendor for system integration.

In August 2007, the OEB also noted that the cost incurred by Hydro One at that time to implement its smart-metering project was already high compared to other distribution companies. The OEB indicated that a special comment was warranted with respect to Hydro One's substantial expenditures on a contract for project management with a private-sector vendor. In particular, the OEB reported a concern raised by one stakeholder group: Hydro One had substantial internal management resources and was likely the most experienced distribution company in dealing with big projects, so it was hard to understand why it had to retain the vendor at such a large contract cost. At the time of our audit, we reviewed the contracting process and noted the following:

In March 2005, Hydro One issued a Request for Proposals (RFP) to select vendors in four areas: smart meters, communications, meter-data management, and system integration (including project management and various consulting services associated with back-office functions and operations).

With respect to the system-integration contract, eight vendors bid on the contract, and Hydro One set up an RFP Evaluation Team to assess each proposal. We noted that Hydro One did not effectively manage its vendor-selection process, governance structure and contract costs. Specifically:

- The proposals submitted by different vendors were not comparable, and so it was inappropriate to assess them together. In particular, not all vendors submitted prices up to 2010. When we asked for more details and explanation, Hydro One management said they could provide only speculation and anecdotal responses, because the key employees in the RFP Evaluation Team who worked on the initial stage of the project were no longer with Hydro One. When we interviewed these former employees, they confirmed that, apart from the RFP Evaluation Team's scoring sheet, there was no other documentation on file to explain how the scores were assigned.
- The RFP Evaluation Team selected the system-integration vendor based on several criteria, including price. However, pricing evaluation was not based on the overall contract cost. Hydro One explained that since the smart-metering project would span multiple years based on new technology, the overall contract cost could not be fixed due to the "unknown nature of all the business requirements at the time of the RFP." An appropriate RFP process would require Hydro One to understand and know more about what it wants in its smart metering project, and to specify the requirements for the vendors in sufficient detail so that they could develop an approach to the project. Granting a contract through the RFP process without acquiring enough knowledge about the business requirements could lead to risks of significant cost increases due to change orders. Carrying out a Request for Information (RFI) process, which is designed to collect more information from a broad base of potential vendors prior to the RFP procedure, would help reduce such risks, particularly for a project of this size involving emerging technology.
- In April 2005, Hydro One selected the system-integration vendor. Since then, Hydro One entered into multiple contracts with this same vendor, and approved a number of change orders. The costs associated with these contracts have increased significantly, which in

turn contributed to Hydro One's higher cost per meter than other distribution companies. Specifically:

- At the time of our audit, the total contract cost paid by Hydro One to the vendor exceeded $125 million. Our review of Hydro One's board minutes noted that the board received no specific details on contract fees paid to this vendor. Hydro One explained that the board delegated the responsibility to oversee cost details to Hydro One management. Hydro One also indicated that it managed the contract and project execution according to a program governance plan. However, our review of this plan noted that it was developed by the vendor and did not include Hydro One's board in the governance structure.
- The initial contract set the fee at a maximum of about $1.1 million, and specified that the scope was to support the rollout of 25,000 smart meters, and to continue design, proof-of-concept and planning activities. The contract ended up supporting the deployment of just 2,000 smart meters, but the actual fee paid by Hydro One amounted to $1.7 million, which included additional costs arising from change requests and reimbursements for travel and other expenses.
- Hydro One, as a Crown corporation, is required to follow the government's procurement policy, which says that any contract between the organization and a successful vendor must be formally defined in a signed written document before goods or services are provided. However, Hydro One signed the initial contract with the vendor on April 25, 2006, three months after the vendor had already started work. Similarly, a second contract was signed on August 31, 2006, two months after the vendor had already commenced work.
- After the first two contracts, Hydro One signed multiple contracts with the same vendor from 2007 to 2010 without a competitive process, even though both the initial and second contracts stipulated that Hydro One had the option to look for other suppliers to complete subsequent work. If Hydro One did not use the same vendor again for subsequent work, both the initial and the second contracts specified that Hydro One would have to pay an additional $462,000 and $650,000 respectively that the vendor had initially offered to Hydro One as a discount, and could not use certain products delivered by the vendor for any RFP or other procurement processes in the future. Hydro One explained that the smart-metering project was a multiphase one, with each phase proceeding on completion of the previous phase and at the sole discretion of Hydro One. Hydro One further indicated that since the initial contract had been awarded through a competitive process, there was no requirement to conduct separate competitive processes for subsequent phases.

Additional Costs of Implementing Smart Metering

Apart from smart-meter capital and operating costs, there were other expenses relating to implementation of Smart Metering, including the disposal of analog meters and the future replacement of smart meters, that will have a significant impact on electricity bills.

The installation of about 4.8 million smart meters in Ontario rendered millions of conventional analog meters obsolete, making it necessary to retire and dispose of them sooner than planned. The distribution companies we consulted said the analog meters they had to scrap were still in good shape and could have been used for another five to 16 more years. The expense of scrapping analog meters became part of the so-called stranded costs, added to the costs of procuring, installing and operating smart-metering systems. The OEB allows distribution companies to fully recover stranded costs from ratepayers through the Delivery Charge on electricity bills. As of January 2011, total stranded costs would be about $400 million, which represents the net book value of the obsolete analog meters as reported in the 2005 OEB implementation plan. As such, this $400 million more reliably captures stranded costs than the $185-million amount in stranded costs that the distribution companies had reported in their smart-meter-cost-recovery applications to the OEB at the time of our audit. In our view, this $185-million amount is incomplete because it represents only the costs the distribution companies are recovering through the application process to the OEB but not the costs that they are recovering through other means, such as writing off the value of their analog meters outright and accelerating the depreciation of their analog meters.

Apart from the stranded cost, another additional cost is related to the replacement of smart meters, which will likely further increase the Delivery Charge on electricity bills because smart meters would be subject to earlier and more frequent replacement than analog meters. The estimated useful life for a typical smart meter is 15 years, compared to 40 years for an analog meter. The distribution companies we consulted said the 15-year estimate is overly optimistic because smart meters:

- are subject to significant technological changes, making it difficult to maintain hardware and software for the first-generation meters, which do not have the advanced functions of newer models;
- have complex features, such as radio communications and digital displays, which are subject to higher malfunction and failure rates;
- are similar to other types of information technology, computer equipment and electronic devices in that they are backed by short warranty periods and require significant upgrades or more frequent replacements as the technology matures; and
- will likely be obsolete by the time they are re-verified as required by the federal agency Measurement Canada every six to 10 years.

Costs relating to replacements will be subject to OEB review and approval. If the OEB does not allow the distribution company to recover these costs from ratepayers, the distribution company will seek recovery through other means (for example, passing the costs on to taxpayers and/or reducing the dividends that the distribution company pays to the municipality). At the distribution companies we visited, we noted cases of mass replacements of smart meters triggered by technological advances and malfunctions. For example:

- In 2013, one large distribution company notified the OEB that 96,000 first-generation smart meters installed in 2006 had to be replaced prior to their normal retirement date to take advantage of improved functionality provided by updated technology. The new meters have 10 times the memory retention of first-generation meters, and provide a "last gasp" function that allows them to detect imminent power outages. The distribution company forecast that 37,000 first-generation meters would be replaced by the end of 2020, and projected a $2.5-million loss on disposal of these older smart meters. The total cost of replacing these meters was set at $11 million.
- In 2012, another large distribution company identified a communication defect in a specific batch of 71,000 smart meters, and had to replace them all regardless of whether they malfunctioned, because they would eventually fail. The distribution company had already replaced about 62,000 of them and expected to complete the job by the end of 2014. From 2013 to April 2014, the distribution company incurred $8.7 million in replacement costs, but it expected to recover at least $2.3 million of that cost from the vendor under the commercial terms of the warranty.

RECOMMENDATION 4

To ensure that the unanticipated costs incurred by distribution companies in implementing the Smart Metering Initiative are justified, and that any significant cost variations among distribution companies are adequately explained, the Ontario Energy Board should perform detailed reviews of distribution-company costs, including an analysis of cost variations for similar services among different distribution companies.

OEB RESPONSE

The OEB has reviewed the prudence of smart-meter costs incurred by most distribution companies through the OEB's hearing process. These reviews took into account the requirements of Ontario Regulation 426/06, the costs incurred by the distribution companies seeking approval and the variations of the costs incurred by different distribution companies. Accordingly, the OEB does not anticipate undertaking additional analysis of those smart-meter costs that have already been reviewed through the OEB's hearing process. However, several distribution companies, including Hydro One, have not yet applied for recovery of all of the smart-meter costs they have incurred. Once those distribution companies apply for such recovery, the OEB will review the prudence of those costs in accordance with the factors set out above.

RECOMMENDATION 5

To improve cost-efficiency of the distribution companies and reduce variations in distribution companies' costs, the Ministry of Energy, in conjunction with the Ontario Energy Board, should formally conduct a cost-benefit analysis into consolidating distribution companies as recommended by the Ontario Distribution Sector Review Panel.

MINISTRY RESPONSE

The Minister of Energy has committed that government will not legislate or force consolidation within the distribution sector. The government is focused on delivering ratepayer savings through voluntary consolidation on a commercial basis and in the best interest of ratepayers.

The government sought input from the local distribution companies (LDCs) to create efficiencies and deliver savings to ratepayers while at the same time positioning the distribution sector to meet the challenges of the future. The government continues to challenge LDCs to do more to improve efficiency and reduce costs for ratepayers.

Hydro One and its large distribution customer base can act as a catalyst for consolidation by seeking acquisition and partnership opportunities. The government expects that Hydro One will only pursue opportunities that are economically viable and in the best interest of ratepayers.

Any change of ownership in the local distribution sector is subject to Ontario Energy Board approval.

OEB RESPONSE

The OEB has undertaken a number of initiatives to improve the cost-efficiency of distribution companies and to address any regulatory barriers to consolidate the distribution companies. The OEB would be pleased to work with the Ministry regarding any further cost-benefit analysis of distribution-company consolidation that the Ministry may consider appropriate in the circumstances.

RECOMMENDATION 6

To ensure that any future project is implemented cost-effectively and in compliance with sound business practices, Hydro One should review and improve its contracting and procurement activities, such as retaining adequate documentation to justify vendor selection and evaluation and acquiring enough knowledge about a project's business requirements before issuing a Request for Proposal, to minimize the risks of significant contract-cost increases.

HYDRO ONE RESPONSE

The Request for Proposal (RFP) process for Hydro One's smart-metering project was completed in April 2005. Subsequent to the RFP process and the Auditor General's audit on Hydro One's Acquisition of Goods and Services in 2006, Hydro One developed an evaluation guideline, which requires documentation of detailed notes to substantiate the evaluation scores.

Hydro One agrees that it is subject to the government's procurement directives. Hydro One has complied with such directives and associated amendments since the first directive was issued in July 2009. In 2009 and 2010, Hydro One also changed its internal policies to comply with the government's travel and expense and procurement directives. For example, Hydro One no longer reimburses its consultants for meals, hospitality or incidentals, and continues to reimburse expenses related to flights, train and car travel and hotel rooms only if such expenses are agreed to in the contracts and pre-approved by Hydro One.

Hydro One also agrees that a Request for Information (RFI) process is a useful tool to assess the market, determine business requirements, and/or estimate project costs. Responses to RFIs contribute to the content of an eventual RFP document. The RFI is a procurement tool that Hydro One now employs.

Smart-meter Data Processing Systems and Costs

Data collection and management is an important component of Smart Metering to ensure that accurate and timely meter-reading data is available from which to prepare TOU-based bills for ratepayers.

In July 2006, the government appointed the Independent Electricity System Operator (IESO) as co-ordinator of the Smart Metering System Implementation Program. A key IESO responsibility was to establish the Meter Data Management and Repository (provincial data centre), to provide a common and central platform for processing, storing and managing smart-meter data to support TOU pricing.

In July 2007, the government designated the IESO as a Smart Metering Entity, making it responsible to manage the development, implementation and operation of the provincial data centre, and to facilitate the integration of smart-meter data within the centre. The aim was to enable distribution companies to bill ratepayers accurately for consumption. The data flow between the distribution companies and the IESO within the smart-metering system is illustrated in **Figure 14**.

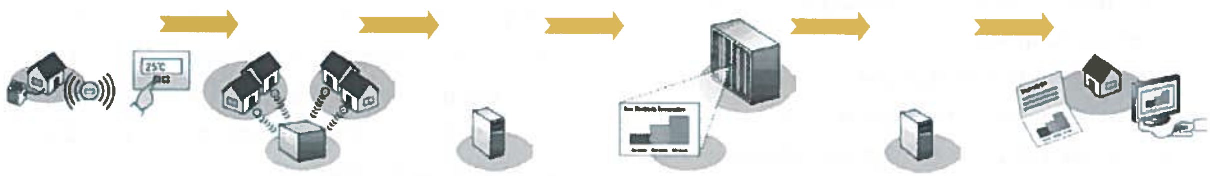
Ratepayers Charged for Redundant or Unused Provincial Data Centre Services

The *Energy Conservation Responsibility Act, 2006*, permits the IESO to recover costs associated with the development, implementation, and operation of the provincial data centre, as well as the integration of the distribution companies into the provincial data centre. In March 2013, the OEB approved an IESO application to recover from all residential and small-business ratepayers the $249-million cost for the period from 2006 to 2017 (including $100 million in actual costs from 2006 to 2012 and the $149-million projected costs from 2013 to 2017) through a new Smart Metering Charge (Charge) of 79¢ a month. This monthly Charge has been included in the Delivery Charge on electricity bills

Figure 14: Smart Metering System and Data Flow in Ontario

Source of data: Independent Electricity System Operator (IESO)

73 Local Distribution Companies			IESO	73 Local Distribution Companies	
Smart Meters	**Data Collector**	**Data Transfer**	**Data Processing***	**Billing System**	**Data Access**
Smart meters installed by a distribution company track hourly electricity usage data.	Data is sent by wireless connection, phone or power line to a regional collector owned by the distribution company.	Regional collector relays data to a system operated by the distribution company.	Provincial data centre collects data from distribution company and calculates electricity usage during on-peak, mid-peak and off-peak hours.	The distribution company receives data from the provincial data centre and prepares electricity bills from its billing system.	Ratepayers have access to their data through electricity bills and online through distribution company's website.



* Almost all of the distribution companies have also used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial data centre) for billing purposes, as illustrated in the section *Duplication of Systems and Costs.*

since May 1, 2013, and will continue until October 31, 2018.

About 4.8 million smart meters have been installed by distribution companies across Ontario, but approximately 812,000 of them, or about one in six, have not transmitted any data to the provincial data centre for processing. However, these 812,000 ratepayers still have to pay the monthly Charge of 79¢, totalling about $42.1 million up to October 2018. Specifically:

- In August 2008, one large distribution company implemented its own system to process smart-meter data, with functions similar to the provincial data centre. In April 2009, the Ministry and this distribution company signed a Letter of Understanding allowing the company to use its own system on an interim basis to accelerate the introduction of TOU pricing. The distribution company initially agreed to begin transmitting its smart-meter data to the provincial data centre by the end of 2010. In February 2013, the company deferred its plan for full integration with the provincial data centre to the end of 2015. Currently, this company has about 700,000 ratepayers with smart meters, but still has not transmitted any data to the provincial data centre. While these 700,000 ratepayers have never benefited from the provincial data centre, each still has to pay the 79¢-a-month Charge; they have paid a total of about $7.7 million up to mid-2014, and will pay $28.6 million more by October 2018. On top of the monthly Charge, these ratepayers also cover the cost of the distribution company's own data system.
- Another large distribution company has about 112,000 ratepayers with smart meters, but has not transmitted any data to the provincial data centre due to internal network connectivity issues with the company's smart-metering system. Although these 112,000 ratepayers have never benefited from the provincial data centre, they must also pay the monthly Charge of 79¢—a total of $1.2 million up to mid-2014 and another $4.6 million by October 2018.

Duplication of Systems and Costs

The *Energy Conservation Responsibility Act, 2006* and Ontario Regulation 393/07 designated the IESO as the Smart Metering Entity, with "exclusive authority" to carry out the following functions through development and operation of the provincial data centre:

- collect, manage and store meter data;
- perform validation, estimating and editing activities to identify and account for missed or inaccurate meter data;
- operate one or more databases to facilitate collecting, managing, storing and retrieving meter data; and
- prepare data that is ready for use by distribution companies to bill ratepayers.

In February 2007, the Program Definition Document, which established the responsibilities for the Ministry and the IESO in the design and delivery of provincial data centre functionality, also stated that "centralization of the [provincial data centre] functions will ensure a standardization of data validation, estimating and editing processes across the province and facilitate a cost-effective implementation of such processes."

However, when the IESO began developing the provincial data centre in 2007, some distribution companies had already procured and begun to install their own smart meters and associated systems, which varied from one company to another. As a result, we noted that the use of the provincial data centre as a central system has not been cost-effective, because most of the distribution companies have used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial meter data management system) for billing purposes.

In interviews with and surveys of distribution companies, we found that 96% have been using their own systems to process smart-meter data, and 88% said their own systems and the provincial data centre perform similar functions, resulting in redundancy. For example, before transmitting data to the provincial data centre, the distribution companies use their systems to perform data validation, estimating and editing services—all key functions of the provincial data centre.

The costs of this duplication—one system at the provincial level and another locally—are all being passed on to ratepayers. The monthly operating cost associated with each distribution company's own system, about 21¢ per meter on average, is being borne by ratepayers on top of the 79¢ monthly Smart Metering Charge (see the section **Ratepayers Charged for Redundant or Unused Provincial Data Centre Service**).

Based on our review of comments submitted by distribution companies and stakeholders in June 2006, during the Ministry's consultation, we noted consistent concern about system duplication. Examples of comments:

- "Centralization of part of the customer billing functions and accountabilities as proposed are unnecessary and incomprehensible given the complexities and issues that give rise to exceptions in determining meter reading and billing quantities on a daily basis."
- "Vesting that responsibility [validation, editing and estimating (VEE) function of smart-meter data] in the[provincial data centre] is tantamount to duplication of efforts and operational inefficiencies that will lead, in turn, to incremental costs."
- "The customers will call us when they have questions or problems. It is critical that the [local distribution companies] have free and open access to our customer data, the right to archive data for billing and operational usage, and continue to be the sole point of contact for our retail customers."
- "[Local distribution companies] have never been given a reasonable explanation as to why the data needs to be gathered, stored and redistributed back to [local distribution companies] from such a massive central storage base... Customers will be calling their local distributors for information that will be

primarily housed at a central [provincial data centre]."

- "Validation, editing and estimating (VEE) will be performed centrally. This central assumption is of great concern to [local distribution companies]. As the [local distribution company] has the local customer relationship and knowledge, it is in the best position to know the unique specifics of their individual customers and therefore provide the most accurate edits and estimations of customer data."
- "As the LDCs' Customer Information System (CIS) is the source of the relationship between customer, location and meter, CIS will now also have to manage that relationship including the new [provincial data centre]. This will require programming changes within CIS systems... This approach seems to be one which would result in significant duplication of data in order to maintain these relationships."

Significant System Development and Integration Challenges

Tight and aggressive timelines set by the government, as noted in the section **Governance and Oversight of Planning and Implementation**, along with the complex structure of Ontario's electricity sector involving numerous distribution companies, have created significant challenges in the system-development and integration aspects of implementation of Smart Metering.

Aggressive Smart Metering Implementation Timelines

According to the OEB's 2005 implementation plan for Smart Metering, many stakeholders expressed concern over an aggressive timetable that could lead to mistakes and higher costs. The OEB plan also warned that Smart Metering was both challenging and complex, requiring an intense and well-co-ordinated effort between key players over several years, plus the co-operation of ratepayers.

We found that aggressive timelines created challenges in the development of the provincial data centre and its integration with different systems at the distribution companies. For example, senior IESO management indicated that the timelines were tight from the start and that development of the provincial data centre was a large undertaking being done too quickly, especially in 2007 and 2008, when the IESO encountered software and technical issues. The IESO expressed concerns about the tight timelines to the Ministry, but there was no change to the original summer 2007 deadline. The IESO did not meet that deadline, and delivery of the provincial data centre was delayed to March 2008. Some distribution companies had started installing smart meters for ratepayers prior to 2007. The provincial data centre was not ready to process smart-meter data for TOU pricing when the first smart meter went online.

The OEB also indicated that 40 out of 73 distribution companies applied for extensions to their mandated implementation dates of TOU pricing due to operational or technical problems, including delays in integrating with the provincial data centre and data-quality issues with certain smart meters.

In addition, 40% of the distribution companies we consulted ranked "implementation timelines" as one of the top three challenges (see **Appendix 1**). Some of the distribution companies commented that:

- "The province should have provided more time for testing and implementation of smart meter technology as opposed to rushing unproven technology into service."
- "Integration with the [provincial data centre] presented challenges as the system design and timelines continued to evolve during the implementation."
- "Meeting timelines was difficult due mainly to integration challenges."
- "Implementation timelines were aggressive given all the testing and paper-work that was required."

Complicated Structure of Electricity Sector for Smart Metering Implementation

In other jurisdictions, mass deployment of smart meters was carried out by only a few distribution companies, or even just one. The challenge in Ontario was that 73 different distribution companies were each responsible to purchase, install, operate and maintain smart meters, as well as to bill ratepayers.

The fact that a relatively large number of distribution companies operate in Ontario's electricity sector has made it challenging to ensure cost-efficient implementation of Smart Metering, in part because it required significant system integration between the provincial data centre and different smart-metering systems as well as billing systems at individual distribution companies. To ensure compliance with system interface and data-transfer requirements, each distribution company had to upgrade its existing systems, or acquire new ones, and perform a series of hardware and software tests. Specifically, we noted that:

- Seventy-five per cent of the distribution companies we consulted ranked "data management and system integration" as one of the top three challenges, and 83% said it was difficult and costly to integrate their systems with the provincial data centre (see **Appendix 1**).
- Sixty per cent of distribution companies indicated that changes to the provincial data centre required them to implement "frequent system changes and upgrades." The IESO said that between 2009 and 2012, three major changes were made to the provincial data centre to correct defects, deliver new functions, and address the issue flagged by Measurement Canada (see section **Non-compliance with Measurement Canada's Data Requirements**). Apart from the three major changes, the provincial data centre was also modified during 2008 and 2009 to support changes to distribution company systems and operating practices. Distribution companies that tracked these costs reported spending a total of about $47 million to change their internal systems to ensure proper integration and compatibility with the provincial data centre (see **Figure 15**). Some of the distribution companies commented as follows:
  - "Integration with [the provincial data centre] required multiple upgrades and ongoing testing beyond testing required with the IESO."
  - "Testing with the [provincial data centre] was a very onerous task."
  - "Significant time and effort went into systems integration to ensure proper data flow between the [provincial data centre] and the distribution companies."
  - "This was a costly and time-consuming exercise to integrate the distribution companies' systems and the [provincial data centre]."

Figure 15: System-related Costs Incurred by Local Distribution Companies

Prepared by the Office of the Auditor General of Ontario

Date	Cost Description	Approx. Cost[1] ($ 000)	Report Section (if applicable)
2006–2013	Upgrading local systems to enable the implementation of TOU pricing	47,000[2]	Significant System Development and Integration Challenges
2006–2013	Developing web presentment portals to allow ratepayers to access their electricity use and billing data online	1,100	
2010–2012	Fixing local systems to comply with Measurement Canada's requirements	800	Non-compliance with Measurement Canada's Data Requirements

1. Amount understated because some of the distribution companies we interviewed and surveyed did not separately track these costs. Many of the distribution companies we consulted treated these smart metering-related costs as their normal operating costs and recovered these costs through their regular rate applications to the OEB rather than through their smart-meter-cost-recovery applications.
2. About $40 million of this $47-million amount was incurred by Hydro One.

Aggressive implementation timelines and a complex electricity sector made it challenging to implement Smart Metering smoothly and cost-effectively.

Insufficient Oversight of Provincial Data Centre Costs and Services

The IESO initially contracted in December 2006 with a private-sector vendor, following a competitive bidding process, for the development, implementation and operation of the provincial data centre. That initial contract was for the five years from December 2006 to March 2012, with an option for another two years to March 2014, which it exercised. In December 2012, following a competitive bidding process, the IESO entered into a new contract with the same vendor for another five years, to March 2019, with an option to extend for five more years, to March 2024. The IESO has already paid this vendor about $81.7 million for the period from January 2007 to March 2013. Apart from using personnel supplied by this vendor and internal staff, the IESO incurred about $16 million in costs by the end of 2013 for other consultants to develop, implement and operate the provincial data centre.

Contract Terms for Operating Fee of Provincial Data Centre Not Clear

Our review of the contract fee paid by the IESO to the vendor for operating the provincial data centre showed that the average annual fee of $13.4 million for the two-year extension period between 2012 and 2014 was almost double the $6.8-million-a-year rate of the original contract period for the five previous years.

The IESO attributed a portion of the fee increase to the additional costs associated with the changes made to the provincial data centre. However, we noted that these additional costs were mainly incurred prior to 2012, before the two-year extension, to deal with major changes made to the provincial data centre. The IESO also attributed a portion of the fee increase to the higher number of smart meters. However, the government had set the target of installing smart meters for all residential and small-business ratepayers, so the IESO should have been aware of the number of smart meters that had to be installed.

We noted that the IESO and the vendor negotiated and agreed upon the higher contract fee as a result of the ambiguity of contract terms for the two-year extension period. Specifically, when the IESO prepared in June 2011 to exercise the two-year extension option under the original contract, it discovered an error that resulted in an underestimation of the cost projection for the two-year extension period by $13.9 million. As a result, IESO management informed the Board of Directors that the error stemmed from an amendment that failed to clarify the contract fee applicable to the two-year extension. IESO management also informed its legal counsel that this was an oversight on the part of the vendor, the IESO and their counsels, and that since the vendor had incurred losses on the contract, the "ambiguity around contract extension offered opportunities to improve the vendor's commercial position and stem their losses going forward."

Continued to Contract for Service Not Being Used

Under the original contract, the IESO required the vendor to provide Interactive Voice Response (IVR) service that enables ratepayers to check their electricity usage by telephone. The IVR service was available for use in March 2008, when the provincial data centre began operating. However, only two of the 73 distribution companies chose to register and configure themselves for IVR, and they reported only limited ratepayer use of the service. For example, only 25 ratepayers at these two distribution companies used IVR from February 2012 to March 2013. Even though there has been very little use of IVR since its start-up in March 2008, the IESO still included IVR in the new contract signed with the vendor in December 2012.

While almost 80% of the distribution companies integrated their systems with the provincial data centre in 2011 and early 2012, the IESO indicated that it did not have sufficient information on the actual use of the IVR service prior to 2013. As such, the IESO did not retire IVR until September 2013, and it consequently negotiated a credit of $390,000 to be applied against future deliverables from this vendor. Adequate and proper monitoring of service usage on a timely basis would have terminated the IVR service sooner and eliminated the associated cost, which was not specified in the contracts and could not be estimated.

RECOMMENDATION 7

To ensure that ratepayers are not burdened with the duplicated and ongoing costs of system development and integration, the Ministry of Energy should work with the Independent Electricity System Operator (IESO), the Ontario Energy Board (OEB) and the distribution companies to re-evaluate options around operating the provincial data centre and/or having separate local systems at individual distribution companies in order to determine the cost-effectiveness of various options and avoid continued duplication of systems and costs.

MINISTRY RESPONSE

The Ministry has ensured that the necessary regulatory framework, in particular Ontario Regulations 393/07 and 426/06, is in place to restrict cost duplication for services which are within the exclusive authority of the Meter Data Management and Repository.

The Ministry will continue to investigate opportunities to build on the value already provided by the provincial data centre.

IESO RESPONSE

If requested by the Ministry of Energy, the IESO will work with the Ministry and the OEB to encourage distribution companies' compliance with existing regulation and reduce the reported duplication of the functions that the IESO has exclusive authority over, and that are fulfilled by the provincial data centre.

Similarly, if requested by the Ministry of Energy, the IESO will work with the Ministry and distribution companies to identify and evaluate opportunities for leveraging existing investments and economies of scale of the provincial data centre in order to reduce the operating costs of distributors and costs to the ratepayer.

OEB RESPONSE

The OEB would be pleased to work with the Ministry of Energy and others in any assessment that the Ministry may initiate in respect of options regarding the cost-effective use of the resources of the provincial meter data management system and the local distribution systems.

RECOMMENDATION 8

To ensure that any future province-wide project involving the complex electricity distribution sector is implemented cost-effectively, the Ministry of Energy should work with the relevant electricity sector organizations to set appropriate and reasonable implementation targets and timelines in order to minimize the costs and risks associated with system development and integration for numerous distribution companies.

MINISTRY RESPONSE

The smart meter and time-of-use (TOU) rollout was completed via a partnership approach. Each organization, namely the Ministry, the IESO, the OEB and local distribution companies were responsible for certain aspects of the rollout, and significant consultation took place along the way.

The Ministry will ensure that projects in the electricity distribution sector are rolled out in a prudent, collaborative and cost effective manner.

Smart-meter Data Accuracy and Quality

To minimize billing estimates and adjustments, as well as ratepayer complaints, smart-meter data has to be processed accurately and completely to produce correct and timely billing data.

Non-compliance with Measurement Canada's Data Requirements

Measurement Canada is the federal agency responsible for ensuring that ratepayers receive fair and accurate measurement in transactions involving goods and services, including measurement of electricity consumption and billing. Generally, electricity consumption and billing can be measured using two types of smart-meter data: "register read" or "interval read."

- "Register read," recorded by both analog and smart meters, is the meter's internal memory or external display showing the total cumulative consumption from the date it was installed, similar to a car odometer's record of kilometres travelled. Prior to installing smart meters, distribution company staff manually read analog meters by visiting ratepayer premises. The cumulative meter reading on electricity bills should match the numbers on the meters.
- "Interval read" is logged only by a smart meter, and is a time-based record of electricity usage (hourly or shorter period) by ratepayers.

Measurement Canada requires the cumulative meter reading to be used in calculating the billing amount, and to be displayed on both the meter and the bill. These requirements ensure transparency by providing information on electricity bills that enable ratepayers to look at their meter's display and then reconcile it to the amounts on their bills. However, Measurement Canada advised both the IESO and the Ministry in November 2009 that its requirements were not being met in Ontario, because the cumulative meter reading from smart meters was not being captured by the provincial data centre or by the distribution companies' systems. In January 2010, Measurement Canada reiterated its concerns and instructed the IESO to take corrective action by January 1, 2012. Consequently, both the IESO and the distribution companies changed their systems to address Measurement Canada's concern. The IESO spent $13.7 million to make necessary adjustments to the provincial data centre.

Apart from the IESO, the distribution companies also incurred costs to fix the problem at their end. In August 2010, the IESO indicated to the media that only about 150,000 ratepayers at five distribution companies were affected by this issue. However, we noted at the time of our audit that, in fact, all distribution companies were affected and had incurred additional costs to fix the problem. Of the distribution companies we consulted, only 20 of them tracked their costs for this—a collective total of more than $800,000 to correct the problem (see **Figure 15**). One distribution company noted that the Measurement Canada issue has "negatively impacted the costs associated with [provincial data centre] integration." Another said the billing systems of all distribution companies "had to be re-engineered to remove 'register reads' when the [provincial data centre] was first implemented and then re-engineered again to put the 'register reads' back ... there really seemed to have been a misunderstanding with the Ministry or IESO as the system should have been designed to show 'register reads' right from the beginning."

Questionable Quality and Usefulness of Meter-reading Data

Several limitations in processing smart-meter data by the provincial data centre and the business processes at the distribution companies have affected the quality and usefulness of smart-meter data. For example:

- When distribution companies change or replace meters, they must follow a proper business process that requires them to send two sets of consumption data to the provincial data centre: one set from the old meter and one from the new. Given that some distribution companies did not follow this process, there is no guarantee of the quality and completeness of data they submitted to the provincial data centre, creating a risk that incorrect billing data could be generated.

- Not all smart meters are equipped with technology to notify the provincial data centre when power outages occur. The Ministry also indicated that the provincial data centre is not intended to have a real-time outage management function to help identify blackouts. As a result, ratepayers who lose power during outages could still receive electricity bills based on estimates made by the provincial data centre or the distribution companies. In December 2013, for example, a severe ice storm caused massive power outages in southern Ontario. Based on our review of usage data from one large distribution company affected by the blackouts, some ratepayers with no power still had to pay electricity bills based on estimates of their historical consumption patterns, and the distribution company had to correct the bills in subsequent billing periods.
- Almost all distribution companies have their own systems as noted in section **Duplication of Systems and Costs**. Apart from using these internal systems to process smart-meter data, companies also use it to query and retrieve usage data for ratepayers and for internal analysis. According to half the distribution companies we consulted, they do this because the provincial data centre has limited capabilities for data retrieval and querying. In August 2013, the IESO also reported to its Board of Directors that the provincial data centre was able to manage data queries during its early stage of implementation, but it was not designed to support the expected increases in volume of data-retrieval requests. This has, in turn, reduced the value and usefulness of the provincial data centre, which had been expected to facilitate storage and retrieval of meter data when it was first developed.

RECOMMENDATION 9

To ensure the accuracy, quality and usefulness of smart-meter data, the Independent Electricity System Operator should:

- work with the distribution companies to review the limitations and the billing problems associated with the provincial data centre and the distribution companies' business processes, including improving the procedures of processing smart-meter data during meter replacements and power blackouts, as well as enhancing the data retrieval and querying capability of the provincial data centre; and
- educate the distribution companies about the proper business processes that have to be followed.

IESO RESPONSE

The IESO has provided training sessions for all distribution companies on processing meter replacements and power blackouts within the provincial data centre. The IESO will provide additional training sessions and assistance to those distribution companies that need such training to improve the procedures of processing smart-meter data.

Subsequent to the audit, the IESO enhanced the data retrieval and querying capability of the provincial data centre. Also, the IESO and the Ministry have been working together to develop a business case for a project that will support the evolving needs for data access and retrievals for research and analysis purposes.

Smart-meter Security and Safety Risks

The expanding use of smart meters has led to questions and concerns about possible security risks relating to privacy, and safety risks associated with fire hazards. As part of our audit, we examined these concerns in Ontario.

Insufficient Security and Access Controls on Meter-reading Data

The ability of smart meters to track electricity use on an hourly basis for residential and small-business ratepayers has raised security and privacy concerns regarding unauthorized access to and use of smart-meter data. Smart meters enable the collection of massive amounts of personal electricity-use data, allowing ratepayers and distribution companies—as well as anyone else with access to the data—to see exactly what makes up a ratepayer's electricity use. The smart-meter data could reveal when people are out, daily routines and changes in those routines. As a result, electricity-use patterns could be mined, for example, for marketing and advertising purposes.

In Ontario, about 800 distribution company employees and/or their agents have access to specific functions in the provincial data centre that include viewing and editing meter data through an encrypted interface from any computer connected to the Internet. The IESO's existing controls to prevent and detect unauthorized data access include an annual audit of the provincial data centre by external auditors and an annual risks-and-controls assessment by IESO staff. However, we noted that data security could be improved further. Specifically:

- The provincial data centre automatically grants access to users through a login process that requires a name and password. However, no additional authentication code is required. Based on our research, and consultation with an independent expert in information security and smart metering, the best practice for more secure remote access of privacy-sensitive information is two-step verification. This requires users to provide an authentication code generated by a security device issued to them, in addition to user name and password.
- The IESO has engaged external auditors to conduct an annual audit to provide reasonable assurance that its controls over the provincial data centre are suitably designed and operate effectively. Since this audit is not designed to cover the distribution companies, it is limited to provincial data centre operations and controls specified by the IESO. We noted that data from the provincial data centre could still be exposed to potential security risks at the distribution-company level because:
  - As noted in the section **Duplication of Systems and Costs**, almost all distribution companies we consulted use their own systems to process smart-meter data. Also, about 85% of them indicated that they have not performed any Privacy Impact Assessment (PIA), a formal risk-management tool used to identify the actual or potential effects that a proposed or existing system may have on ratepayer privacy. The PIA is considered a "best privacy practice" for organizations with significant existing or new systems containing personal information.
  - Our review of a sample of 200 staff at different distribution companies who had access to the provincial data centre found that eight who had left the distribution companies did not have their access revoked in a timely manner. The IESO indicated that it is up to distribution companies to advise it when access rights need to be modified or ended. The IESO also said it does not have the jurisdiction, responsibility or ability to review the appropriateness of users to whom distribution companies wish to grant access. Therefore, there

could be security risks at the distribution-company level that the IESO was not aware of and over which it had no control.

Lack of Tracking and Monitoring of Smart Meters-related Fire Incidents

At the time of our audit, we found instances of Ontario ratepayers reporting fires arising from smart meters. From our research, we also noted that other jurisdictions, such as British Columbia, Saskatchewan and Pennsylvania, also reported cases of smart meters catching fire. However, no accurate or complete information on smart meters-related fires was available in Ontario to determine the scope and extent of the problem across the province. Specifically:

- The Office of the Fire Marshal (OFM), Ontario's principal adviser on fire protection policy and safety issues, indicated that it is aware of fires involving smart meters in Ontario, elsewhere in Canada, and in the United States. However, some distribution companies and fire departments do not report such cases to the OFM, so more information is needed to assess the extent of the problem in Ontario. From May 2011 to March 2013, for example, the OFM recorded 14 fires involving either meters or the bases on which they were mounted. However, the OFM indicated that its incident-reporting system could not specifically identify what type of device was involved—analog or smart meter—because it did not collect specific details about the meters. Based on anecdotal evidence, the OFM identified three possible root causes for the fires:
  - old meter base connections may have been loose or otherwise unfit for a seamless exchange to a new smart meter;
  - new smart meters may have been improperly installed; or
  - new smart meters may have had defects that caused electrical failures or misalignment with the old meter base.
- The Electrical Safety Authority (ESA), the agency with a mandate to enhance public electrical safety in Ontario, is delegated by the government to be responsible for the regulation that applies to meter installation. Any meter failure resulting from incorrect installation by the distribution company falls under the ESA's regulatory oversight. In February 2007, and again in October 2012, the ESA indicated that it has been aware of potential fire risks in smart meters, and incidents of property damage involving smart meters and/or meter bases. To address these concerns, the ESA surveyed the distribution companies, asking them to provide information on such incidents. However, the ESA indicated that it has not received sufficient information to conclude on the severity of the issue or the types of meters causing problems. Due to recent smart meters-related fires in Saskatchewan, the ESA started reviewing those incidents in the summer of 2014 to determine if there could be any concerns in Ontario.

The federal Industry Canada department oversees the certification of radio communication devices, including smart meters, which must be tested and certified against Industry Canada standards before they can be sold in this country. At the provincial level, the ESA acts on behalf of the Ontario government, with specific responsibility for electrical safety. As part of its mandate, the ESA administers the Ontario Electrical Safety Code and regulations associated with electricity-distribution-system safety, electrical product safety and licensing of electricians. However, there has been a lack of clarity on the safety standards relating to smart meters at the provincial level. Specifically:

- The ESA indicated that according to an Ontario Electrical Safety Code bulletin in May 2012, federal legislation does not give ESA any jurisdiction over revenue billing devices (i.e., smart meters and associated transformers) and does not require the

revenue billing devices to be approved provincially as required by the Canadian Electrical Code or Ontario Electrical Safety Code.
- The ESA further noted that the Ontario Electrical Safety Code applies to meter bases and mounting devices, but not to revenue billing devices such as the actual smart meters. Therefore, smart meters and associated transformers are deemed acceptable if they have an approval number provided by Measurement Canada, a federal agency. However, we noted that Measurement Canada is mandated to ensure the integrity and accuracy of measurement, including electricity consumption and billing data, but not the safety, of measuring devices such as smart meters.

Insufficient tracking and monitoring of smart meters-related fire incidents has made it difficult to determine the scope and extent of the problem across the province as well as to address the problem accordingly, creating safety risks in Ontario.

RECOMMENDATION 10

To ensure that smart-meter data is processed and stored securely, the Independent Electricity System Operator should work with the distribution companies to improve their system and data-security controls in order to prevent and detect unauthorized access to smart-meter data.

IESO RESPONSE

Subsequent to the audit, the IESO introduced new capabilities in June 2014 to help distribution companies manage their users' access to the provincial data centre. The IESO provides the distribution companies with additional information that allows them to identify required changes to their users' access permissions. Based on this additional information, the distribution companies are to notify the IESO of any necessary changes.

In addition, the IESO will review the data-security controls in place at the IESO and the controls that should be in operation at the distribution companies to prevent and detect unauthorized access to smart-meter data. The IESO will also work with the distribution companies to review the "Building Privacy into Ontario's Smart Meter Data Management System" paper published by the IESO and the Information and Privacy Commission of Ontario.

RECOMMENDATION 11

To ensure that potential fire risks of smart meters are addressed appropriately and in a timely manner, the Ministry of Energy should work with relevant entities, such as the distribution companies, the Office of the Fire Marshal and the Electrical Safety Authority, to track and monitor information on smart meter-related fire incidents so as to identify and understand their causes in Ontario.

MINISTRY RESPONSE

The Ministry has not received information from the appropriate authorities or local distribution companies (LDCs) to indicate that there is a safety risk with smart meters in Ontario.

The Ministry will support efforts by the appropriate entities such as the Office of the Fire Marshal, the Electrical Safety Authority and LDCs to ensure that any concerns or incidents related to electricity meter safety are tracked and monitored accordingly.

The Ministry continues to monitor the concerns and actions related to meter safety in Saskatchewan and consider any implications for Ontario.

Appendix 1—Questions to and Responses from Distribution Companies in Ontario

Prepared by the Office of the Auditor General of Ontario

Selected Questions	Responses: % of Distribution Companies Responded "Yes"	Responses: % of Distribution Companies Responded "No"
Did your distribution company realize any net savings in operations since implementing the Smart Metering Initiative?	5	95
Did your distribution company conduct any study to examine the bill impact since the implementation of smart meters and time-of-use (TOU) rates?	9	91
Did your distribution company conduct any study to examine the changes of electricity consumption since the implementation of smart meters and TOU rates?	0	100
Does your distribution company have a system, performing similar functions as the central Meter Data Management and Repository, to process smart meter data?	96	4
Did your distribution company perform any Privacy Impact Assessment when implementing the Smart Metering Initiative?	15	85

	% of Distribution Companies Indicated as Concerns
Please indicate your distribution company's concerns with the Meter Data Management and Repository (provincial data centre)	88% – Redundant functionality with the systems at distribution company
	83% – Difficult and costly to integrate distribution companies' systems with the Meter Data Management and Repository
	60% – Frequent changes and upgrades of the Meter Data Management and Repository
	50% – Limited capacity or capability for data retrieval and query

	% of Distribution Companies Ranked as Top 3 Challenges
Please rank the challenges that your distribution company has faced in implementing the Smart Metering Initiative.	75% – Costly data management and system integration
	44% – Lengthy procurement process
	40% – Tight implementation timeline

	% of Distribution Companies Indicated as Top 3 "High Volume" Complaints
Please indicate the volume (High/Low) of ratepayer complaints relating to smart meters and TOU pricing since the implementation of Smart Metering Initiative in your distribution company.	51% – Increased bills with no savings
	33% – Limited understanding and information on TOU pricing
	24% – Limited or no ability to change electricity consumption

Appendix 2—Delivery Charge on Monthly Electricity Bill by Distribution Company[1]

Source of data: Ontario Energy Board

Distribution Company	Delivery Charge ($)
1. Algoma Power Inc.	59.4
2. Atikokan Hydro Inc.	65.5
3. Bluewater Power Distribution Corporation	45.8
4. Brant County Power Inc.	40.8
5. Brantford Power Inc.	31.8
6. Burlington Hydro Inc.	40.1
7. Cambridge and North Dumfries Hydro Inc.	36.5
8. Canadian Niagara Power Inc. (Fort Erie)[2]	52.6
Canadian Niagara Power Inc. (Port Colborne Hydro Inc.)[2]	53.8
9. Centre Wellington Hydro Ltd.	41.6
10. Chapleau Public Utilities Corporation	53.2
11. COLLUS PowerStream Corp.	34.9
12. Cooperative Hydro Embrun Inc.	39.7
13. E.L.K. Energy Inc.	30.9
14. Enersource Hydro Mississauga Inc.	36.8
15. Entegrus Powerlines Inc.	41.0
16. EnWin Utilities Ltd.	41.6
17. Erie Thames Powerlines Corporation	44.2
18. Espanola Regional Hydro Distribution Corporation	51.1
19. Essex Powerlines Corporation	43.6
20. Festival Hydro Inc. (Hensall)[2]	45.0
Festival Hydro Inc. (Main)[2]	45.6
21. Fort Frances Power Corporation	36.2
22. Greater Sudbury Hydro Inc.	37.9
23. Grimsby Power Incorporated	40.1
24. Guelph Hydro Electric Systems Inc.	41.9
25. Haldimand County Hydro Inc.	57.3
26. Halton Hills Hydro Inc.	39.0
27. Hearst Power Distribution Company Limited	31.7
28. Horizon Utilities Corporation	40.9
29. Hydro 2000 Inc.	43.6
30. Hydro Hawkesbury Inc.	28.0
31. Hydro One (Low Density)[2,3]	110.6
Hydro One (Medium Density)[2,3]	69.5
Hydro One (Urban High Density)[2,3]	54.2
32. Hydro One Brampton Networks Inc.	35.6
33. Hydro Ottawa Limited	40.1
34. Innisfil Hydro Distribution Systems Limited	49.6
35. Kenora Hydro Electric Corporation Ltd.	37.3
36. Kingston Hydro Corporation	41.4

Distribution Company	Delivery Charge ($)
37. Kitchener-Wilmot Hydro Inc.	35.0
38. Lakefront Utilities Inc.	36.7
39. Lakeland Power Distribution Ltd.	53.4
40. London Hydro Inc.	38.3
41. Midland Power Utility Corporation	48.7
42. Milton Hydro Distribution Inc.	40.3
43. Newmarket-Tay Power Distribution Ltd. (Newmarket)[2]	41.7
Newmarket-Tay Power Distribution Ltd. (Tay)[2]	24.9
44. Niagara Peninsula Energy Inc. (Niagara)[2]	39.6
Niagara Peninsula Energy Inc. (Peninsula)[2]	42.7
45. Niagara-on-the-Lake Hydro Inc.	41.8
46. Norfolk Power Distribution Inc.	53.1
47. North Bay Hydro Distribution Limited	40.4
48. Northern Ontario Wires Inc.	51.2
49. Oakville Hydro Electricity Distribution Inc.	43.5
50. Orangeville Hydro Limited	42.3
51. Orillia Power Distribution Corporation	41.3
52. Oshawa PUC Networks Inc.	33.8
53. Ottawa River Power Corporation	36.5
54. Parry Sound Power Corporation	61.0
55. Peterborough Distribution Incorporated	37.4
56. PowerStream Inc. (Barrie)[2]	35.5
PowerStream Inc. (South)[2]	35.1
57. PUC Distribution Inc.	31.7
58. Renfrew Hydro Inc.	37.5
59. Rideau St. Lawrence Distribution Inc.	43.1
60. Sioux Lookout Hydro Inc.	55.0
61. St. Thomas Energy Inc.	39.8
62. Thunder Bay Hydro Electricity Distribution Inc.	33.3
63. Tillsonburg Hydro Inc.	38.6
64. Toronto Hydro-Electric System Limited	46.9
65. Veridian Connections Inc. (Gravenhurst)[2]	52.8
Veridian Connections Inc. (Main)[2]	38.7
66. Wasaga Distribution Inc.	27.3
67. Waterloo North Hydro Inc.	38.0
68. Welland Hydro-Electric System Corp.	41.9
69. Wellington North Power Inc.	50.3
70. West Coast Huron Energy Inc.	55.2
71. Westario Power Inc.	43.8
72. Whitby Hydro Electric Corporation	44.4
73. Woodstock Hydro Services Inc.	45.3

1. This list of 73 distribution companies was based on 2013 Yearbook of Electricity Distributors issued by the OEB. The Delivery Charge data was based on 2014 data from the OEB website.
2. These distribution companies with larger geographic coverage have different Delivery Charge in different regions within their service areas.
3. Hydro One's Delivery Charge varies, depending on the location of ratepayers and the number of ratepayers in an area. The fewer people in the area, the higher the cost of delivering power to that area.