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4.0 OPERATING COSTS

4.1 OVERVIEW

4.1.1 Background

In this Exhibit, the operating costs consist of the required expenditures necessary for Energy+ to maintain and operate its distribution system safely and reliably, while achieving its strategic imperatives:

1. People – Develop and support our dedicated, talented team who embrace best practices, innovative solutions, and new technologies to deliver present and future energy needs to our communities;
2. Safety and Wellness – Always pursue excellence in safety and wellness;
3. Customers – Anticipate and exceed customer expectations regarding efficiency and reliable delivery of electricity;
4. Environmental Stewardship – Respect the environment in everything we do;
5. Community – Demonstrate our dedication to the well-being of our communities; and
6. Value – Invest in quality energy infrastructure while delivering optimal financial returns to our shareholders.

Energy+ believes that its strategic imperatives align to the achievement of the performance outcomes of: (i) Customer Focus; (ii) Operational Effectiveness; (iii) Public Policy Responsiveness; and (iv) Financial Performance, as outlined in the "*Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach"* ("RRFE"), dated October 18, 2012.

Operating costs include the operations and maintenance of the distribution assets, the costs associated with metering, billing, collecting from its customers, the costs

associated with ensuring all stakeholders' safety (public, employees, etc.) and costs to maintain the distribution business service quality and reliability standards in compliance with the Ontario Energy Board's ("OEB") Distribution System Code and other regulatory bodies (Independent Electricity System Operator ("IESO"), Ministry of Energy, the Electrical Safety Authority ("ESA"), etc.).

For the purpose of this Application, in 2017, a two year budget was prepared for the 2018 bridge year and the 2019 test year. This budget was approved by the Energy+ Board of Directors in December 2017. The budget provides a plan, against which actual results may be evaluated, and it underpins this Application. Once approved, the budget is only revised if a material change in plan is required and would require Board approval.

With respect to inflation rate assumptions, the 2019 Test Year expenditures were budgeted based on the actual expected costs, and not specifically based on an overall specified inflation rate. Assumptions with respect to labour rates are provided in Section 4.4 Compensation.

Energy+'s proposed 2019 Test Year total Operating, Maintenance and Administration ("OM&A") costs, excluding property taxes and Low Energy Assistance Program ("LEAP"), are $18,575,648, as summarized in Table 4-1, below.

Table 4-1: Summary of Operations, Maintenance and Administrative Expenditures

	Last Rebasing Year (Proxy 2014 Board Approved)	2019 Test Year
Operations	$ 3,228,515	$ 3,289,039
Maintenance	$ 2,661,929	$ 2,641,602
Billing and Collecting	$ 3,730,609	$ 3,945,340
Community Relations	$ 333,707	$ 98,215
Administrative and General	$ 8,456,671	$ 8,601,452
Total	**$ 18,411,431**	**$ 18,575,648**
2019 Test Year vs. 2014 Board Approved Proxy		$ 164,217
% Increase 2019 Test Year vs. 2014 Board Approved Proxy		0.9%

4.1.2 2014 Board Approved Proxy

On November 28, 2014, the former Cambridge and North Dumfries Hydro Inc. ("CND") acquired all of the shares of the former Brant County Power Inc. ("BCP"). On January 1, 2016 the former CND and BCP legally amalgamated to become Energy+ Inc.

The last Board Approved Operations, Maintenance and Administration amounts were established for each of these entities in the following Applications:

- Cambridge and North Dumfries Hydro Inc. – 2014 Rate Rebasing EB-2013-0116
- Brant County Power Inc. – 2011 Rate Rebasing EB-2010-0125

As a result of the acquisition and subsequent amalgamation, and in light of the fact that each of the former utilities had different rate rebasing years, Energy+ has

developed 2014 Board Approved Proxy figures for comparative purposes. The 2014 Board Approved Proxy was calculated as the aggregate of:

- Former CND Board Approved OM&A for 2014, as approved in EB-2013-0116; and

- Former BCP Board Approved OM&A for 2011, as approved in EB-2010-0125, as inflated for 2012, 2013, and 2014 utilizing the Board IRM inflation factors for each of those years.

Energy+ proposes to utilize the 2014 Board Approved Proxy to facilitate a comparison of OM&A amounts in a manner consistent with the current Energy+ corporate structure and Board Filing Requirements.

Table 4-2 below shows the calculation of the 2014 Board Approved Proxy figures.

Table 4-2: Computation of 2014 Board Approved Proxy

	Former CND 2014 Board Approved	Former BCP 2014 Board Approved Proxy	Energy+ 2014 Board Approved Proxy	Former BCP 2014 Board Approved Proxy			
				2011 Board Approved	Proxy 2012 IRM Factor 0.68%	Proxy 2013 IRM Factor 0.28%	Proxy 2014 IRM Factor 1.6%
Operations	$ 2,342,789	$ 885,726	$ 3,228,515	$ 863,472	$ 869,344	$ 871,778	$ 885,726
Maintenance	$ 1,995,344	$ 666,585	$ 2,661,929	$ 649,837	$ 654,256	$ 656,088	$ 666,585
Billing and Collecting	$ 2,944,585	$ 786,024	$ 3,730,609	$ 766,275	$ 771,486	$ 773,646	$ 786,024
Community Relations	$ 151,100	$ 182,607	$ 333,707	$ 178,019	$ 179,230	$ 179,731	$ 182,607
Administrative and General	$ 7,064,034	$ 1,392,637	$ 8,456,671	$ 1,357,646	$ 1,366,878	$ 1,370,705	$ 1,392,637
Total	**$ 14,497,852**	**$ 3,913,579**	**$ 18,411,431**	**$ 3,815,249**	**$ 3,841,193**	**$ 3,851,948**	**$ 3,913,579**

4.1.3 Presentation of Consolidated OM&A Expenditures

For comparative purposes, and throughout this Exhibit, the actual results for the 2014 and 2015 years represent the combined actual results for the former CND and BCP. The 2016 through 2019 Test Year figures represent Energy+ Inc.

In order for Energy+ to complete this Application and file on-time for April 27, 2018, the figures presented for the 2017 Year are based on Energy+'s 2017 Forecast for the year, which includes 11 months of actuals. The filing date of April 27, 2018 also precedes the timing of the filing of the RRR Filing, which is due April 30, 2018. Energy+ intends to update the 2017 Forecast for the 2017 Actuals upon completion and filing of the RRR Filing.

4.1.4 Accounting Policy Changes

4.1.4.1 Changes in Capitalization Policies and Depreciation

In accordance with the Board's letter dated July 12, 2012, each of the former CND and BCP adopted capitalization and depreciation policies under CGAAP that were compliant with International Financial Reporting Standards.

The former CND adopted the required accounting changes for depreciation and capitalization policies on January 1, 2012, which were included in the former CND's 2014 Cost of Service Application. As a result, there were no additional impacts to the expensing of overheads or amortization expense in the Cambridge and North Dumfries service territory.

The former BCP adopted the required accounting changes for depreciation and capitalization policies on January 1, 2013. The impact of the capitalization and depreciation changes related to the former BCP are detailed in Exhibit 9, Deferral and Variance Accounts (Account 1576).

Upon amalgamation on January 1, 2016, the accounting policies for depreciation and capitalization policies for Energy+ were harmonized to be consistent with the policies of the former CND.

4.1.4.2 Transition to Modified International Financing Reporting Standards ('MIFRS")

Both of the former CND and BCP followed Canadian Generally Accepting Accounting principles ("CGAAP") in 2013 and 2014. Each of the former utilities adopted International Financial Reporting Standards effective January 1, 2015 with restatement to January 1, 2014. Energy+ adopted Modified International Financial Reporting Standards ("MIFRS") for rate making purposes effective January 1, 2015 and follows the OEB's Accounting Procedures Handbook ("APH").

In this Application, where applicable, 2014 Actuals are presented under the former CGAAP (modified for changes in depreciation and capitalization policies) and the years 2015 through 2019 Test Year are presented under MIFRS.

The impact of the adoption to MIFRS are detailed in Exhibit 9, Deferral and Variance Accounts (Account 1575).

4.1.5 2019 Test Year OM&A Expense Summary and Cost Trends

Energy+'s 2019 Test Year OM&A expenses are $18,575,648 excluding expenditures relating to LEAP and property taxes. A summary of OM&A expenses from 2014 Board Approved Proxy to the 2019 Test Year is found in Table 4-3 below.

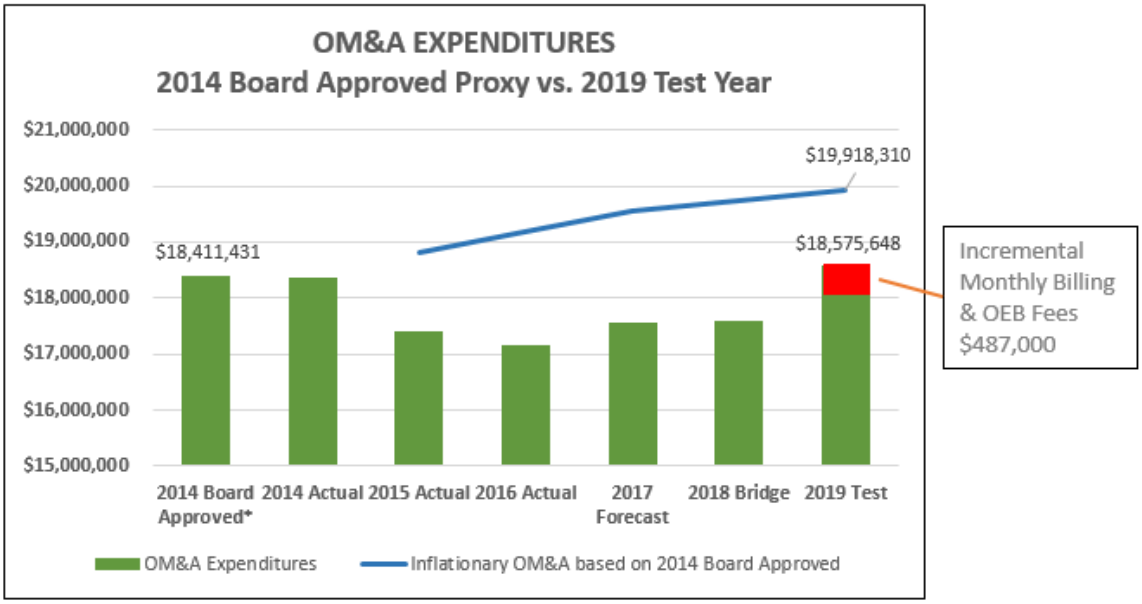
Table 4-3: 2019 Test Year OM&A Summary

	Last Rebasing Year (Proxy 2014 Board Approved)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Forecast	2018 Bridge Year	2019 Test Year
Operations	$ 3,228,515	$ 2,738,607	$ 2,880,615	$ 2,934,425	$ 2,975,027	$ 3,240,629	$ 3,289,039
Maintenance	$ 2,661,929	$ 3,118,876	$ 2,755,290	$ 2,671,173	$ 2,592,217	$ 2,674,678	$ 2,641,602
Billing and Collecting	$ 3,730,609	$ 3,477,666	$ 3,330,327	$ 3,548,298	$ 3,391,259	$ 3,372,867	$ 3,945,340
Community Relations	$ 333,707	$ 256,788	$ 117,727	$ 97,839	$ 90,720	$ 93,555	$ 98,215
Administrative and General	$ 8,456,671	$ 8,765,568	$ 8,309,038	$ 7,905,340	$ 8,512,531	$ 8,213,696	$ 8,601,452
Total	**$ 18,411,431**	**$ 18,357,504**	**$ 17,392,997**	**$ 17,157,075**	**$ 17,561,754**	**$ 17,595,425**	**$ 18,575,648**
2019 Test Year vs. 2014 Board Approved Proxy							$ 164,217
% Increase 2019 Test Year vs. 2014 Board Approved Proxy							0.9%

Energy+ would highlight that the proposed OM&A level of $18,575,648 for the 2019 Test Year is only $164,217 or 0.9% higher than the 2014 Board Approved Proxy of $18,411,431 and $218,144 higher or 1.2% higher than the 2014 Actuals.

Figure 4-1 illustrates the level of OM&A expenditures for the 2014 Board Approved Proxy, 2015 Actuals, 2016 Actuals, 2017 Forecast, 2018 Bridge and 2019 Test Year, and compares the actual and proposed levels of OM&A for Energy+ to the level of OM&A derived from taking the 2014 Board Approved Proxy OM&A and applying the OEB's inflation factor over the same period.

Figure 4-1: OM&A Expenditures 2014 Board Approved Proxy vs. 2019 Test Year



This illustrates that Energy+ has achieved significant operating efficiencies between 2014 and the 2019 Test Year.

The acquisition of the former BCP, and the subsequent amalgamation and integration of the operations, resulted in the achievement of approximately $1.2MM in sustained savings by the end of 2017. In the absence of this transaction, and the additional efforts undertaken by Energy+ to achieve operating synergies, OM&A expenditures in the 2019 Test Year could have been significantly higher than the level being proposed in this Application.

Figure 4-2 Year Over Year Change in OM&A Expenses

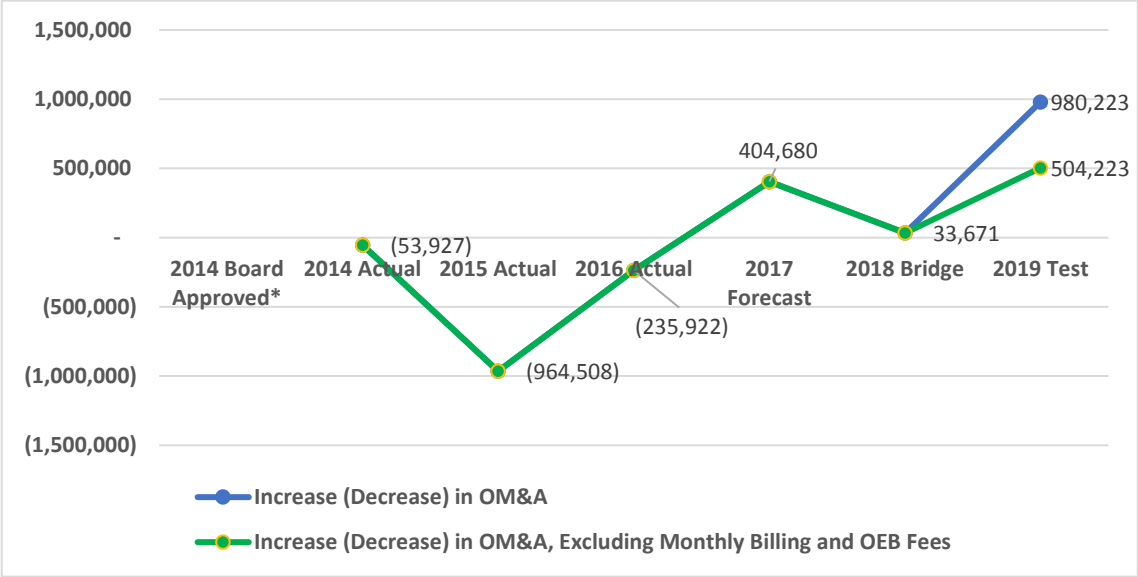


Figure 4-2 illustrates the year over year change in OM&A expenditures from 2014 Actual to the 2019 Test Year. As noted previously, the decreases in OM&A in 2015 and 2016 were a result of realized savings from the acquisition of the former BCP and subsequent legal amalgamation. The increase in OM&A in 2017 was principally due to increased costs associated with the preparation of the 2019 Cost of Service Application.

Included in the 2019 Test Year OM&A is $390,000 in incremental annual costs as a result of the transition to monthly billing. In accordance with the Amendments to the Distribution System Code on April 15, 2015 (EB-2014-0198), Energy+ was required to transition to monthly billing for all Residential and GS< 50 kW customers effective December 31, 2016. Energy+ completed its transition to monthly billing in the months of November and December, 2016, with all customers fully transitioned by January 1, 2017. Only the customers in the Cambridge and North Dumfries service territory were impacted by this change; Customers in the Brant service territory were already being billed on a monthly basis. Prior to 2019, the incremental expenditures associated with the transition to monthly billing were included in a Deferral Account and were not included in the annual OM&A expenditures prior to the 2019 Test Year.

In September, 2017, the Board issued the 2016 Benchmarking Update for Determination of 2017 Stretch Factor Rankings. Energy+ was assigned Cohort 3. Prior to the amalgamation, the former CND was in Cohort 3 and the former BCP was in Cohort 4. Based on the Report to the Energy Board "*Empirical Research in Support of Incentive Rate Settings: 2016 Benchmarking Update*", dated July 2017, Energy+'s OM&A Cost percentage change between 2016 and 2015 was -2.8% compared to the industry average of 3.23% and the median of 3.74%. Energy+'s cost performance for the 2014-2016 period was -9.9% in 2016 and -5.8% for the period 2014-2016, compared to the average of -2.82% and -2.64% respectively.

Based on the Efficiency Assessment benchmark, Energy+ ranked 28th out 68 LDCs. In the 2016 OEB yearbook, Energy+'s OM&A of $270.80 per customer ranks 27th and is approximately 13% lower than the average of $323.87.

Based on the 2019 Test Year OM&A per customer of $281.58, and assuming that the 2016 OM&A per customer for each utility was inflated by an IRM factor for 2017, 2018 and 2019 based on Group 3 Cohort (i.e. 1.6% for 2017, 0.9% for 2018, and 0.9% for 2019) Energy+ would continue to rank 27th. Based upon the Benchmarking_Spreadsheet_Forecast_Model ("PEG Model") completed and filed as part of this Application (Exhibit 1), Energy+ would remain in Cohort 3 based on the benchmarking forecast, and as summarized in Table 4-4.

Table 4-4: Summary of Cost Benchmarking Results

Cost Benchmarking Summary	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Bridge	2019 Test
Actual Total Cost	$ 39,796,552	$ 40,411,318	$ 40,964,591	$ 40,997,606	$ 41,999,147	$ 43,393,443	$ 45,302,047
Predicted Total Cost	$ 39,260,331	$ 41,324,910	$ 43,196,523	$ 45,263,215	$ 45,082,461	$ 47,858,436	$ 49,941,961
Difference	$ 536,221	$ (913,592)	$ (2,231,932)	$ (4,265,610)	$ (3,083,314)	$ (4,464,993)	$ (4,639,914)
Percentage Difference (Cost Performance)	1.36%	-2.24%	-5.30%	-9.90%	-7.08%	-9.79%	-9.75%
Three-Year Average Performance						-8.93%	-8.88%
Stretch Factor Cohort							
Annual Result				3	3	3	3
Three Year Average						3	3

Please refer to Table 4-5 for a summary of the changes to OM&A between Energy+'s 2014 Board Approved Proxy and the 2019 Test Year.

Table 4-5: Overall OM&A Cost Trends

2014 Board Approved Proxy OM&A (excluding LEAP and Property Taxes)	**$ 18,357,504**
Operating Synergies - Acquisition of former Brant County Power Inc.	(1,197,000)
Organizational Capacity - Increase/ (Decrease)	(157,000)
Distribution Maintenance Costs - (Increase)/Decrease - Increased Allocation to Capital Projects	(475,000)
Merit/Collective Agreement Increases	1,208,764
Incremental Monthly Billing Costs (Deferral Account prior to 2019)	390,000
Information Systems Technology (Licenses/Cyber Security)	219,000
Shared Services with Brantford Power Inc.	195,000
Transition to 24/7 Control Room (Load Dispatching)	168,445
Increase in OEB Fees (Deferral Account prior to 2019)	97,000
Other	(231,065)
2019 Test Year OM&A	**$ 18,575,648**

A more detailed analysis of these costs trends is provided in Section 4.2, as part of the analysis of Cost Drivers.

As noted in Section 4.1.4.1, the former CND adopted the required accounting changes for depreciation and capitalization policies on January 1, 2012, which were included in the former CND's 2014 Cost of Service Application. The former BCP adopted the required accounting changes for depreciation and capitalization policies on January 1, 2013. With respect to the former BCP, approximately $138,000 in labour costs for operations supervision were previously capitalized prior to 2013; as part of this Application these costs are expensed to OM&A. As this amount is below the materiality threshold, such amount was not identified separately as an overall OM&A Cost Driver.

Energy+ believes that the level of planned operating, maintenance and administrative ("OM&A") expenditures are appropriate and rational after taking into consideration customer feedback and preferences, productivity, reliability, service quality, government mandated obligations, and the objectives of the *Renewed Regulatory Framework for Electricity Distributors* ("RRFE").

4.2 SUMMARY AND COST DRIVER TABLES

4.2.1 Overview of Budgeting Process

Energy+ prepares an annual budget that is reviewed and approved by the Audit and Finance Committee and ultimately by the Board of Directors. In addition to the annual budget, Energy+ also prepares a multi-year forecast for the subsequent four years. The multi-year forecast is developed to provide a longer-term road map and to assess the longer-term outlook of the corporation, including the future financial position of the corporation and impacts on various stakeholders, including customers and the shareholder.

The budget process is initiated by the Chief Financial Officer ("CFO") in June of each year, and the process includes: (i) preparation of a current year forecast to identify any significant changes in the expected results which may impact the following year's budget; (ii) the preparation of department business plans, including consideration of expected regulatory requirements and feedback received through various ongoing customer engagement activities; (iii) the preparation of detailed departmental operating expenditure templates using a "bottom up approach" where all expenditures must be itemized and variance explanations and/or justification provided for the expenditures; (iv) the preparation of a detailed capital budget based on the Distribution System Plan ("DSP"), which includes inputs from the Asset Condition Assessment and input from customers and stakeholders (developers, municipalities, etc.), as well as detailed requests and justification for non-distribution expenditures includes transportation, tools, computer hardware and software, etc. and (v) the preparation of a labour budget using projected wage and benefit costs, and the identification and justification for any new hires proposed. The Leadership Team also works with the Vice President of Human Resources to review vacant positions and potential retirements, to determine potential areas for savings opportunities or opportunities to revise the position requirements to maximize capacity and skills in the organization without incremental hires.

The Energy+ Leadership Team (Vice Presidents and President and CEO) are very involved in the budget process. Significant effort is made to align the budget with the action items in the business plan in order that Energy+ can continue to advance in important areas such as customer service, distribution system reliability and productivity improvements.

For the purpose of this Application, in 2017, a two year budget was prepared for the 2018 bridge year and the 2019 test year. This budget was approved by the Energy+ Board of Directors in December 2017. The budget provides a plan, against which actual results may be evaluated, and it underpins this Application. Once approved, the budget is only revised if a material change in plan is required and would require Board approval.

With respect to inflation rate assumptions, the 2019 Test Year expenditures were budgeted based on the actual expected costs, and not specifically based on an overall specified inflation rate. Assumptions with respect to labour rates are provided in Section 4.4 Compensation.

4.2.2 Summary of Recoverable OM&A Expenses

Energy+ follows the OEB's Accounting Procedures Handbook ("APH") in distinguishing work performed between operations and maintenance. A summary of Energy+'s OM&A Expenses, excluding LEAP, for the 2014 Board Approved Proxy, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Forecast, 2018 Bridge, and 2019 Test Years is provided in Table 4-6, which is Board Appendix 2-JA.

4.2.3 OM&A Cost per Customer and Full-Time Equivalent

Table 4-7, Board Appendix 2-L is a summary of the OM&A Cost per Customer and per Full-Time Equivalent ("FTE"). The FTEs agree to the numbers shown in the Compensation Section 4.4. The number of customers is based on the annual average for each rate class of metered customers, and is consistent with the load forecast.

OM&A per Customer for the 2014 Board Approved Proxy was $289.54, comprised of the OM&A per Customer for the former CND of $270.31 and the former BCP of $393.12. In 2014, prior to the integration of the operations of the former CND and BCP and the subsequent amalgamation, the 2014 Actual OM&A per customer on a consolidated basis was $294.24. For the 2018 Bridge Year, the OM&A per customer is projected to be $269.93 or a $24.31 less than the 2014 Actuals. This represents an improvement of 8.3%. Although the 2019 Test Year OM&A per customer is projected to increase to $281.58 or $11.65 or 4.3%, Energy+ would highlight that approximately $7.38 of the increase is due to the transition to monthly billing and increased OEB Assessment Fees, further discussed in Section 4.2.4. Excluding these costs, the increase in OM&A per customer would have been $4.27 or 1.6%.

Table 4-6: Summary of Recoverable OM&A Expenses

Appendix 2-JA

Summary of Recoverable OM&A Expenses

Consolidated Former CND and BCP (2014-2015) and Energy+ Inc. (2016-2019)

	Last Rebasing Year (Proxy 2014 Board Approved)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Forecast	2018 Bridge Year	2019 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 3,228,515	$ 2,738,607	$ 2,880,615	$ 2,934,425	$ 2,975,027	$ 3,240,629	$ 3,289,039
Maintenance	$ 2,661,929	$ 3,118,876	$ 2,755,290	$ 2,671,173	$ 2,592,217	$ 2,674,678	$ 2,641,602
SubTotal	**$ 5,890,444**	**$ 5,857,483**	**$ 5,635,905**	**$ 5,605,598**	**$ 5,567,244**	**$ 5,915,308**	**$ 5,930,641**
%Change (year over year)				-0.5%			6.5%
%Change (Test Year vs Last Rebasing Year - Actual)							
Billing and Collecting	$ 3,730,609	$ 3,477,666	$ 3,330,327	$ 3,548,298	$ 3,391,259	$ 3,372,867	$ 3,945,340
Community Relations	$ 333,707	$ 256,788	$ 117,727	$ 97,839	$ 90,720	$ 93,555	$ 98,215
Administrative and General	$ 8,456,671	$ 8,765,568	$ 8,309,038	$ 7,905,340	$ 8,512,531	$ 8,213,696	$ 8,601,452
SubTotal	**$ 12,520,987**	**$ 12,500,022**	**$ 11,757,092**	**$ 11,551,476**	**$ 11,994,510**	**$ 11,680,117**	**$ 12,645,007**
%Change (year over year)				-1.7%			8.3%
%Change (Test Year vs Last Rebasing Year - Actual)							
Total	**$ 18,411,431**	**$ 18,357,504**	**$ 17,392,997**	**$ 17,157,075**	**$ 17,561,754**	**$ 17,595,425**	**$ 18,575,648**
%Change (year over year)				-1.4%			5.6%

	Last Rebasing Year (Proxy 2014 Board Approved)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Forecast	2018 Bridge Year	2019 Test Year
Operations	$ 3,228,515	$ 2,738,607	$ 2,880,615	$ 2,934,425	$ 2,975,027	$ 3,240,629	$ 3,289,039
Maintenance	$ 2,661,929	$ 3,118,876	$ 2,755,290	$ 2,671,173	$ 2,592,217	$ 2,674,678	$ 2,641,602
Billing and Collecting	$ 3,730,609	$ 3,477,666	$ 3,330,327	$ 3,548,298	$ 3,391,259	$ 3,372,867	$ 3,945,340
Community Relations	$ 333,707	$ 256,788	$ 117,727	$ 97,839	$ 90,720	$ 93,555	$ 98,215
Administrative and General	$ 8,456,671	$ 8,765,568	$ 8,309,038	$ 7,905,340	$ 8,512,531	$ 8,213,696	$ 8,601,452
Total	**$ 18,411,431**	**$ 18,357,504**	**$ 17,392,997**	**$ 17,157,075**	**$ 17,561,754**	**$ 17,595,425**	**$ 18,575,648**
%Change (year over year)			-5.3%	-1.4%	2.4%	0.2%	5.6%

Table 4-6: Summary of Recoverable OM&A Expenses (continued)

	Last Rebasing Year (2014 Board-Approved)	Last Rebasing Year (2014 Actuals)	Variance 2014 Board-approved – 2014 Actuals	2015 Actuals	Variance 2015 Actuals vs. 2014 Actuals	2016 Actuals	Variance 2016 Actuals vs. 2015 Actuals	2017 Forecast	Variance 2017 Actuals vs. 2016 Actuals	2018 Bridge Year	Variance 2018 Bridge vs. 2017 Actuals	2019 Test Year	Variance 2019 Test vs. 2018 Bridge
Operations	$ 3,228,515	$ 2,738,607	$ 489,908	$ 2,880,615	$ (347,900)	$ 2,934,425	$ 53,810	$ 2,975,027	$ 40,602	$ 3,240,629	$ 265,602	$ 3,289,039	$ 48,410
Maintenance	$ 2,661,929	$ 3,118,876	$ (456,947)	$ 2,755,290	$ 93,360	$ 2,671,173	$ (84,116)	$ 2,592,217	$ (78,956)	$ 2,674,678	$ 82,461	$ 2,641,602	$ (33,076)
Billing and Collecting	$ 3,730,609	$ 3,477,666	$ 252,943	$ 3,330,327	$ (400,282)	$ 3,548,298	$ 217,971	$ 3,391,259	$ (157,039)	$ 3,372,867	$ (18,392)	$ 3,945,340	$ 572,473
Community Relations	$ 333,707	$ 256,788	$ 76,919	$ 117,727	$ (215,980)	$ 97,839	$ (19,889)	$ 90,720	$ (7,119)	$ 93,555	$ 2,835	$ 98,215	$ 4,660
Administrative and General	$ 8,456,671	$ 8,765,568	$ (308,897)	$ 8,309,038	$ (147,633)	$ 7,905,340	$ (403,698)	$ 8,512,531	$ 607,192	$ 8,213,696	$ (298,836)	$ 8,601,452	$ 387,757
Total OM&A Expenses	$ 18,411,431	$ 18,357,504	$ 53,927	$ 17,392,997	$ (1,018,435)	$ 17,157,075	$ (235,922)	$17,561,754	$ 404,680	$ 17,595,425	$ 33,671	$18,575,648	$ 980,223
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)													
Total Recoverable OM&A Expenses	$ 18,411,431	$ 18,357,504	$ 53,927	$ 17,392,997	$ (1,018,435)	$ 17,157,075	$ (235,922)	$17,561,754	$ 404,680	$ 17,595,425	$ 33,671	$18,575,648	$ 980,223
Variance from previous year				$ (964,508)		$ (235,922)		$ 404,680		$ 33,671		$ 980,223	
Percent change (year over year)				(5.3%)		(1.3%)		2%		0.2%		6%	
Percent Change: Test year vs. Most Current Actual								5.77%					
Simple average of % variance for all years								1.19%					0.3%
Compound Annual Growth Rate for all years													0.2%
Compound Growth Rate (2017 Forecast vs. 2014 Actuals)								(1.47%)					

Table 4-7: Recoverable OM&A Per Customer and Per FTE – 2014 to 2019

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]
Consolidated Former CND and BCP (2014-2015) and Energy+ Inc. (2016-2019)

	Last Rebasing Year - 2014- Board Approved (Former CND)	Last Rebasing Year - 2014- Proxy Board Approved (Former BCP)	2014 Board Approved Proxy (Consolidated)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Forecast	2018 Bridge Year	2019 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs									
O&M	$ 4,338,133	$ 1,552,311	$ 5,890,444	$ 5,857,483	$ 5,635,905	$ 5,605,598	$ 5,567,244	$ 5,915,308	$ 5,930,641
Admin Expenses	$ 10,159,719	$ 2,361,268	$ 12,520,987	$ 12,500,022	$ 11,757,092	$ 11,551,476	$ 11,994,510	$ 11,680,117	$ 12,645,007
Total Recoverable OM&A	$ 14,497,852	$ 3,913,579	$ 18,411,431	$ 18,357,504	$ 17,392,997	$ 17,157,075	$ 17,561,754	$ 17,595,425	$ 18,575,648
Number of Customers [2,4,6]	53,634	9,955	63,589	62,389	62,923	63,651	64,408	65,184	65,970
Number of FTEs [3,4]	113	31	144	132	133	126	129	131	130
Customers/FTEs	475	321	442	473	473	505	499	498	507
OM&A cost per customer									
O&M per customer	$ 80.88	$ 155.93	$ 92.63	$ 93.89	$ 89.57	$ 88.07	$ 86.44	$ 90.75	$ 89.90
Admin per customer	$ 189.43	$ 237.19	$ 196.90	$ 200.36	$ 186.85	$ 181.48	$ 186.23	$ 179.19	$ 191.68
Total OM&A per customer	$ 270.31	$ 393.12	$ 289.54	$ 294.24	$ 276.42	$ 269.55	$ 272.66	$ 269.93	$ 281.58
OM&A cost per FTE									
O&M per FTE	$ 38,390.56	$ 50,074.56	$ 40,905.86	$ 44,374.87	$ 42,375.22	$ 44,488.88	$ 43,156.93	$ 45,155.02	$ 45,620.32
Admin per FTE	$ 89,909.02	$ 76,169.93	$ 86,951.30	$ 94,697.13	$ 88,399.19	$ 91,678.38	$ 92,980.70	$ 89,161.20	$ 97,269.28
Total OM&A per FTE	$ 128,299.58	$ 126,244.49	$ 127,857.16	$ 139,072.00	$ 130,774.41	$ 136,167.26	$ 136,137.63	$ 134,316.22	$ 142,889.60

4.2.4 Cost Drivers

Table 4-8, Board Appendix 2-JB provides a list of the cost drivers that affected Energy+'s OM&A year over year spending based on the materiality threshold, or, where the cost driver is common or a recurring expenditure that has impacted multiple years. The OM&A opening balance for the last rebasing year of $18,357,504, represents the 2014 Board Approved Proxy, as described previously.

As previously indicated, Energy+ would highlight that the proposed OM&A level of $18,575,648 for the 2019 Test Year is only $164,217 or 0.9% higher than the 2014 Actual of $18,411,431 and $218,144 higher or 1.2% higher than the 2014 Board Approved Proxy.

Energy+ has provided the OM&A details and variance analysis on a program basis using the Board's Appendix 2-JC. Please refer to Section 4.3.

Table 4-8: Cost Driver Table – OEB Appendix 2-JB

OM&A	Last Rebasing Year (2014 Actuals)	2015 Actuals	2016 Actuals	2017 Forecast	2018 Bridge Year	2019 Test Year
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance²	$ 18,411,431	$ 18,357,504	$ 17,392,997	$ 17,157,075	$ 17,561,754	$ 17,595,425
Integration Costs		255,000	(255,000)			
Operating Synergies - Acquisition		(427,000)	(546,000)	(224,000)		
Asset Management Review/Asset Condition Assessment			171,000	(76,000)		
Cost of Service Application Costs		(308,000)		445,995	(230,995)	(25,000)
Bad Debt Write-Offs		(218,957)	234,858	(245,585)		
Incremental Monthly Billing Costs (Deferral Account prior to 2019)						390,000
Transition to 24/7 Control Room (Load Dispatching)		83,000	(50,489)	25,934	110,000	
Shared Services with Brantford Power Inc.						195,000
Increase in OEB Fees (Deferral Account prior to 2019)						97,000
Impact of Vacant Positions - Timing	(272,000)	(110,000)	25,000			
Organizational Capacity - Increase/ (Decrease)			(120,000)	134,000	(119,000)	(52,000)
Merit/Collective Agreement Increases		240,904	232,596	239,264	241,000	255,000
Space/Facilities studies	100,000	30,000	(36,000)	(64,000)	-	-
Organizational Analysis (Succession Planning/Culture Survey/Structure)	92,000	(92,000)				
Distribution Maintenance Costs - (Increase)/Decrease - Increased Allocation to Capital Projects		(475,000)				
Tree trimming		111,095				
Information Systems Technology (Licenses/Cyber Security)			90,000	129,000		
Other	26,073	(53,549)	18,113	40,071	32,666	120,223
Closing Balance²	$ 18,357,504	$ 17,392,997	$ 17,157,075	$ 17,561,754	$ 17,595,425	$ 18,575,648

Note: Opening balance re Last Rebasing Year column represents the 2014 Board Approved Proxy; The Closing Balance represents the 2014 Actuals.

Table 4-9 Overall OM&A Cost Trends summarizes the material costs trends/ primary drivers that have influenced the change in Energy+'s OM&A expenditures since 2014 and up to and including the 2019 Test Year. Each driver is summarized by its net change between 2014 and 2019. All amounts in excess of the materiality of $175,000 are discussed.

Table 4-8: Overall OM&A Cost Trends

2014 Board Approved Proxy OM&A (excluding LEAP and Property Taxes)	**$ 18,357,504**
Operating Synergies - Acquisition of former Brant County Power Inc.	(1,197,000)
Organizational Capacity - Increase/ (Decrease)	(157,000)
Distribution Maintenance Costs - (Increase)/Decrease - Increased Allocation to Capital Projects	(475,000)
Merit/Collective Agreement Increases	1,208,764
Incremental Monthly Billing Costs (Deferral Account prior to 2019)	390,000
Information Systems Technology (Licenses/Cyber Security)	219,000
Shared Services with Brantford Power Inc.	195,000
Transition to 24/7 Control Room (Load Dispatching)	168,445
Increase in OEB Fees (Deferral Account prior to 2019)	97,000
Other	(231,065)
2019 Test Year OM&A	**$ 18,575,648**

Operating Synergies

Energy+ has realized approximately $1,197,000 in cumulative annual savings as a result of the acquisition of the former BCP and subsequent legal amalgamation. The savings achieved are consistent with the $1.0MM to $1.2MM of expected savings identified in the former CND's Section 86 Application for approval to acquire the former BCP (EB-2014-0217). Table 4-10 summarizes the nature of the achieved savings, which were principally related to wages and benefits due to reductions in the number of full-time employees. In total, 11 full-time positions were eliminated over a three year period and were achieved through: (i) the elimination of duplicate and/or vacant positions, (ii) realignment of existing positions; and (iii) natural attrition, including retirements.

Table 4-10: Summary of Operating Synergies

Summary of Cumulative Annual Operating Synergies	2015 Actuals	2016 Actuals	2017 Forecast	Cumulative
Wage/Salary Savings - Reduction in Full-Time Equivalent Positions/Elimination of Vacancies	(470,000)	(327,000)	(166,000)	(963,000)
Incremental wage increases to align Collective Agreements/Wage Grades	206,000	30,000	-	236,000
Reduction in Benefit Costs due to reduction in FTEs	(92,400)	(103,950)	(58,100)	(254,450)
	(356,400)	(400,950)	(224,100)	(981,450)
Reduction in Board of Directors fees	(49,000)			(49,000)
Other	(21,600)	(145,050)	100	(166,550)
	(427,000)	(546,000)	(224,000)	(1,197,000)

A portion of the operating synergies achieved in 2015 were offset by integration costs of approximately $255,000. Integration costs principally included: (i) Project Management consulting to facilitate the various aspects of integrating the two organizations; and consulting costs associated with labour relations, accounting, and information systems technology integration.

Organizational Capacity (Change in Employee Complement)

In addition to the reduction in the full-time positions as a result of the amalgamation, Energy+ further reduced the number of positions by the equivalent of 3 full-time positions between the 2014 Board Approved Proxy and the 2019 Test Year. The net change of 3 positions reflects the addition of 8 new positions, offset by the reduction of 11 positions. The net overall impact to OM&A expenditures is approximately $157,000, based on the allocation of certain positions between operating and capital (e.g. reductions in Powerline Technicians has an impact on both OM&A and capital expenditures as a portion of the wages and benefits are capitalized. Further details are as outlined in Section 4.4.2.

Distribution Maintenance Costs

Operations labour hours are allocated to projects based on work orders initiated for all projects, whether capital, operations, maintenance or recoverable from customers. In 2015, there was an increase of approximately $450,000 in labour costs allocated to capital projects, resulting in a decrease in OM&A. This is principally explained by an increase in the level of capital investments. As summarized in Exhibit 2, net capital

expenditures in 2014 were approximately $11.0MM and increased to $13.3MM in 2015. Energy+ does not anticipate any material change in the allocation of labour to capital projects in the 2019 Test Year. In the 2019 Test Year, capital expenditures are proposed to be $16MM.

Merit/Collective Agreement Increases

Energy+'s compensation cost driver of Merit/Collective Bargaining/Other Annual Wage increases comprise unionized wage progressions and annual negotiated pay increases, non-union merit increases, and non-union incentive payouts based on performance results. Energy+'s workforce is comprised of unionized and non-unionized employees. Since 2014, wage increases for merit, collective bargaining, and other wages have contributed $1,208,764 in increased operating costs for Energy+. These increased costs were substantially offset by the wage and benefit synergies realized as a result of the acquisition of the former BCP and subsequent amalgamation. In the absence of the acquisition, Energy+ submits that these wage and benefit expenditures would have been incremental to the OM&A expenditures that formed part of the 2014 Board Approved Proxy, with no corresponding reduction. Please refer to Section 4.4 Compensation with respect to further information with respect to Energy+'s Compensation.

Incremental Monthly Billing Costs

On April 15, 2015 the OEB announced that by the end of 2016, all electricity distributors in Ontario will be required to bill their customers on a monthly basis. In Energy+'s 2016 IRM application (EB-2015-0057), Energy+ (CND) indicated that it would be in a position to begin billing all customers on a monthly basis, beginning January 1, 2017 and requested an accounting order to establish a new deferral account to record the incremental costs associated with moving to the monthly billing method, as the former CND did not include the costs of monthly billing in its last (2014) Cost of Service application. In the OEB Decision and Rate Order in for this the IRM application (EB-2015-0057), the OEB approved the account as requested by Energy+. The OEB, in the Decision, also indicated that the costs recorded in this

account will be subject to a prudency review at the time of Energy+'s next rebasing application, expected for 2019 rates.

Customers of the former BCP were billed on a monthly basis prior to the acquisition by the former CND in 2014. As such, incremental costs associated with monthly billing for only those customers in the Energy+ Cambridge and North Dumfries (CND) service territory have and will be recorded in a deferral account up until December 31, 2018. For the 2019 Test Year, the annual costs incurred by Energy+ for monthly billing are recorded in OM&A and the incremental costs associated with the CND service territory are a specific driver of the increase in OM&A between the 2014 Board Approved Proxy and the 2019 Test Year.

Energy+ began moving CND customers to monthly billing in November and December 2016 with all customers transitioned by the billing period beginning January 3, 2017. Energy+ would note that it is proud of its accomplishments in integrating its Customer Information System ("CIS") to one common platform in 2016 for all customers, as well as transition to monthly billing.

The following Table 4-11 summarizes the incremental OM&A expenditures included in the 2019 Test Year with respect to monthly billing:

Table 4-11: Incremental Monthly Billing OM&A Expenditures

Description	Amount	Explanation
Incremental Customer Care/Billing Resources	140,000	Hiring of one additional Customer Care Clerk and 1 Billing Clerk
Incremental Postage and Bill Printing	225,000	Postage costs due to mailing of invoices every month
Other	25,000	Subcontractor costs, incremental Collection Notices; Processing of increased payments.
	$ 390,000	

Total annual costs of $390,000 is approximately $40,000 higher than the estimates made by the former CND in its IRM application (EB-2015-0057) in which it stated that an estimate of the recurring OM&A expenditures for the transition to monthly billing would be between $250,000 and $350,000 annually. In its original estimate, the former CND had anticipated a reduction in overall bad debt expense attributable to the transition to monthly billing of approximately $50,000. The 2019 Test Year bad debt has decreased by approximately $40,000 in total from the 2014 Board Approved Proxy, however, it is difficult to determine whether this decrease is directly attributable to the implementation of monthly billing. The reduction in bad debt expense has not been specifically reflected in the above table but is incorporated into the 2019 Test Year. Energy+ has continued to promote e-billing to all of its customers to mitigate the impact of increased billing, printing, and postage costs from the implementation of monthly billing. At the end of 2015, prior to the implementation of monthly billing for CND customers, 5,574 customers were enrolled in e-billing. At the end of 2017, 7,409 customers were enrolled. Although this was a 32% increase in two years, the number of customers enrolled in e-billing is still significantly lower than the number of residential and GS> 50kW customers who receive bills on a monthly basis.

As part of its augmented customer engagement activities, Energy+ asked customers how likely they would be to switch to paperless billing if they were to receive a bill credit of $0.75. As summarized in the Customer Engagement Executive Summary (Exhibit 1, Section 1.3.1), Residential and GS< 50kW

customers are largely split on whether they would be likely to sign up for Energy+'s e-billing program.

- Low-volume customers in Cambridge and North Dumfries are significantly more likely to express interest in switching to e-billing. 47% residential and 56% small business customers said they were likely to switch in the telephone surveys.

- Between 48%-52% of low-volume customers in the County of Brant say they are unlikely to switch to e-billing, knowing they would receive a $0.75 credit on their bills. Cambridge and North Dumfries customers (32%-35%) were unlikely to switch to e-billing knowing they would receive a $0.75 credit on their monthly bill.

Based upon customer feedback, Energy+ has not proposed a bill credit to customers to incent them to switch to e-billing, however, Energy+ will continue to promote e-billing as an alternative to customers, as well as encourage all new customers to sign up.

Information Systems Technology (Licenses/Cyber Security)

Information Systems Technology expenditures with respect to software maintenance and implementation of solutions to protect Energy+ from cyber security vulnerabilities has increased OM&A expenditures by approximately $219,000 between 2014 Board Approved and 2019 Test Year. Although expenditures have increased in this area, Energy+ submits that it has achieved operating efficiencies, as well as strengthened its information systems environment with the implementation of a Disaster Recovery solution and other cyber security measures. This was accomplished with no additional staff.

Table 4-12 provides a breakdown of the most significant changes in software maintenance costs:

Table 4-12: Information Systems Technology Expenditures

	Increase/(Decrease)	Explanation
Outage Management System License Fees	68,000	OMS Solution implemented in 2015
Customer Information System License Fees	45,000	Increased license costs for Energy+ CIS
Cyber Security Solutions	84,000	Implementation of software solutions to enhance the security over Energy+'s operating systems.
Enterprise License Agreements	39,000	Increase costs implemented by Vendor
Human Resources and Safety Solutions	26,000	Implementation of software solution for training, performance evaluations, and compliance.
Other	75,000	Various other/inflationary increases
	337,000	
Elimination of Customer Information System License Fee	(100,000)	Elimination of license fee due to intergration of CIS system to one common platform post acquisition and amalgamation.
Board of Directors Portal Solution	(18,000)	Savings realized from implementing an alternative solution for less cost.
	(118,000)	
Net increase	219,000	

Shared Services with Brantford Power Inc.

As outlined in Exhibit 2, Section 2.7.2 Land and Facilities Plan, in 2019, as part of a long-term lease agreement with Brantford Power Inc. ("BPI"), Energy+' will occupy approximately 13,255 sq. ft. of dedicated space at a new facility to be located at Garden Avenue and Highway 403 ("Garden Avenue") in Brantford, Ontario. This location will function as the Operations Centre to service customers in the Brant County Service territory. In addition to the leasing of dedicated space, Energy+ and BPI plan to enter into a Shared Services Agreement to achieve economies of scale from:

- Sharing space for mechanical/vehicle bays, stock room, and outdoor space;

- Exploring the option of sharing the services of a Purchasing Manager, reducing the combined requirement of 2 FTEs to 1 FTE.

- Sharing a stock room, allowing a reduction to the overall level of inventory required for either company, while offering greater flexibility and efficiency related to inventory management for both companies;

- BPI will provide mechanical services to Energy+. As neither utility would normally afford an in-house mechanic (there is currently only 1 mechanic in Energy+ principally servicing the vehicles in the CND service territory), this is expected to improve service levels to customers and reduce costs to third party mechanical services for each company.

The increase in operating costs of $195,000 is comprised of the following:

	Annual Cost
Shared Space Operating Lease Estimate	$255,000
Shared Mechanic (1/2 FTE)	40,000
Operating Costs (Exclusive Space)	35,000
	$330,000
Less: Current Operating Costs (Existing Facility)	(135,000)
Total Operating Costs	$195,000

As part of the augmented customer engagement activities, Energy+ asked all customer classes throughout the engagement about their views towards Energy+'s proposed building renovation. As outlined in the Customer Engagement Report (Exhibit 1, Appendix 1, Section 1.3.4), the following is a summary of those findings:

"In both the County of Brant and Cambridge and North Dumfries, a large majority of low-volume customers, either outright supported, or felt that the proposed facility investments and associated costs were necessary. Between 70% and 77% of low-volume customers felt that the estimated costs of facilities renovations were at least necessary.

Telephone & Online Results Capital Plan Priorities	Telephone				Online	
	Residential		Small Business		Residential	
	County of Brant	Cambridge and North Dumfries	County of Brant	Cambridge and North Dumfries	County of Brant	Cambridge and North Dumfries
General Plant Investment Preferences – Facilities Costs ($0.68 per month)						
Support	17%	29%	41%	33%	31%	27%
Don't like it, but find it necessary	53%	43%	36%	42%	46%	48%
Oppose	25%	24%	18%	22%	19%	18%

On average, small business customers were more likely to support these investments than residential customers. In the GS>50-999 kW mid-market workshops, five out of ten customers felt that the renovations were necessary, while five found the $0.68 per month bill impact to be unreasonable."

In addition to the specific feedback with respect to the proposed facility investments, customers also provided feedback with respect to their priorities, which, beyond delivering reasonable rates, customers prioritized reliable day-to-day electrical service, collaborating to reduce costs and preventing outages caused by extreme weather. The shared services with BPI is an example of collaboration that is expected to achieve operating synergies in the future that will benefit customers.

Transition to 24/7 Control Room

As outlined in the former CND's 2014 Rate Application (EB-2013-0116), a transition to a 24/7 Control Room was planned commencing in 2014 with the hiring of 3 additional System Control Room Apprentice operators ("SCO"). The transition to a full 24/7 operation was expected to take a few years due to the extensive training and experience required by the Apprentices to become fully qualified.

One Apprentice SCO was hired in 2015, however, the remaining two positions were not filled until early 2018. The hiring of qualified SCO's to transition to a 24/7 Control Room proved to be a challenge for Energy+. In early 2016, after the resignation of one of the Apprentice SCOs, Energy+ undertook an initiative to explore the opportunity to evaluate the advantages of combining and sharing a System Control Room with another LDC to build a single, 24/7 System Control Room. Energy+ considered that this could be a very good opportunity to achieve 24/7 operations to benefit customers, but also had the potential to achieve operating

synergies for both utilities. This initiative was ultimately not completed due to union contract issues as a result of separate and distinct union representation at both LDCs. Energy+ is committed to the implementation of a 24/7 Control Room.

As part of its Decision (EB-2013-0116), it is important to highlight that the Board reduced OM&A expenditures by $379,806 citing "increase in staffing levels which seems aggressive and a delay in implementing new hiring". As a result, the transition to a 24/7 System Control Room is expected to add incremental costs to the overall OM&A expenditure levels of Energy+.

A 24/7 control room provides faster response time to outages (i.e. avoids the "up to twenty minutes" for an SCO to get from home to the control room at 1500 Bishop Street to begin switching with SCADA switches), resulting in fewer Customer Hours lost. A 24/7 control room provides better service to customers calling Energy+ after hours. An SCO can more fully respond to customer calls than the answering service. A 24/7 control room provides improved monitoring of Energy+'s transformer station and facilitates immediate communication with Hydro One and the IESO, in the event of a contingency (e.g. opening breakers to reduce load, voltage reduction, etc.). A 24/7 control room will ensure that an SCO will always be available. Currently, the "on-call" SCO will time out (maximum 16 hours of work in a 24 hour period) for extended outages on weekends or holidays. There is not always another SCO available to fill in. SCO's were previously "on call" every third week and were often not available on the other two weeks due to other commitments. A larger group of SCOs avoids the requirement for our SCOs to be "on-call" every third week which is a significant burden and gives Energy+ a larger pool of SCOs to draw upon in the event of contingencies such as illness or early retirement.

With the hiring of additional Apprentices in early 2018, and as a result of negotiations with the IBEW, Energy+ has introduced extended hours for the Control Room. The transition to 24/7 will occur once the requisite training for the System Control Room Operators and Apprentices has been completed. As part of its augmented customer engagement initiatives, Energy+ requested feedback from customers with respect to the implementation of a 24/7 Control Room. Customers in all rate classes were supportive of 24/7 System Control Monitoring. As outlined in the Customer

Engagement Report (Exhibit 1, Section 1.3.5), the following is a summary of those findings:

"Energy+ is transitioning to a 24/7 real-time monitoring of the distribution system that is estimated to cost the average customer an additional $0.36 per month. Low-volume customers who participated in the telephone surveys were asked if they supported this transition, of which, a large majority did. Between 65% and 75% of low volume customers supported 24/7 real-time monitoring and the associated costs.

Telephone Results Capital Plan Priorities	Residential		Small Business	
	County of Brant	Cambridge and North Dumfries	County of Brant	Cambridge and North Dumfries
OM&A Preferences – 24/7 Real-Time Monitoring ($0.36 per month)				
Support (Definitely + Probably)	65%	69%	75%	75%
Oppose (Definitely + Probably)	31%	29%	23%	23%

Mid-market and large use customers who participated in the workshop sessions were somewhat surprised that Energy+ didn't currently have 24/7 System Control Centre capacity. These customers largely expect these types of service offerings from Energy+."

Increase in OEB Assessment Fees

Effective April 1, 2016, the OEB revised its Cost Assessment Model ("CAM"), the methodology used to apportion its costs under Section 26 of the *Ontario Energy Board Act, 1998 (Act).* As a result of this change in the CAM, Energy+ experienced a significant increase in its OEB Assessment Fees compared to the amounts previously approved in distribution rates. Table 4-13 summarizes the Board Approved OEB Assessment Fees compared to the 2017 Actuals and 2019 Test Year, and the resulting increase of $97,000 between the 2014 Board Approved amounts and the 2019 Test Year.

In accordance with the Board's letter dated February 9, 2016, for 2016 Actual, 2017 Forecast and 2018 Bridge Year, Energy+ has recorded the difference between the actual OEB Assessment amount in each year and the amount of OEB cost assessment currently built into rates as part of Account 1508, Other Regulatory Assets, Sub-Account OEB Cost Assessment Variance. The request for disposition of this variance account up to December 31, 2017 is included in Exhibit 9.

Table 4-13: Increase in OEB Assessment Fees

	Prior Board Approved					
	2014 CND	2011 BCP	Total	2017 Actual	2019 Test	Increase
Increase in OEB Assessment Fees	$156,000	$45,901	$201,901	$ 287,529	$298,912	$97,011

Bad Debt Expense

Bad debt expense is not a material driver of the OM&A cost trend between the 2019 Test Year and the 2014 Board Approved Proxy. Energy+ has incorporated material changes in the bad debt expense in the Cost Driver Table 4-8 in the 2015 Actual, 2016 Actual and 2017 Forecast Years.

Table 4-14 summarizes the bad debt expense for the 2014 Board Approved Proxy, 2015 to 2016 Actuals, 2017 Forecast, 2018 Bridge, and 2019 Test Year, and

provides a year over year variance. Table 4-14A provides the computation of the 2014 Board Approved Proxy amount. The 2019 Test Year bad debt expense is projected to be $249,424 or $39,509 less than the 2014 Board Approved Proxy.

Table 4-14: Bad Debt Expense

	2014 BA Former CND	2014 BA Former BCP	2014 BA Proxy	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Actual	2018 Actual
Bad Debt Expense	212,000	76,933	288,933	511,688	292,731	527,589	282,004	248,660	249,424
Year over Year Increase (Decrease)					(218,957)	234,858	(245,585)	(33,344)	764
Change in Bad Debt Expense - 2019 Test Year vs. 2014 Board Approved Proxy									(39,509)

Table 4-14A: 2014 Board Approved Proxy – Bad Debt Expense

	Former BCP 2014 Board Approved Proxy			
	2011 Board Approved	Proxy 2012 IRM Factor 0.68%	Proxy 2013 IRM Factor 0.28%	Proxy 2014 IRM Factor 1.6%
Bad Debt Expense	75,000	75,510	75,721	76,933

2014 Actual bad debt expenses were $511,688 or $222,755 higher compared to the 2014 Board Approved Proxy of $288,933. Approximately $160,000 of the increase was attributable to increased bad debt expense for the former BCP attributable to: (i)

bankruptcy of a commercial customer; (ii) the write-off of aged accounts receivable that the former BCP had accumulated prior to the acquisition by the former CND.

2015 Actual bad debts were $292,731 or $218,957 lower than 2014 Actuals, and consistent with the 2014 Board Approved Proxy of $288,933. As explained previously, 2014 bad debt expense included the write-off of old accounts.

2016 Actual bad debts were $527,589 or $234,858 higher than 2015 Actual and $238,656 higher than the 2014 Board Approved Proxy amount. The increase in bad debt expense in 2016 was explained by a bad debt expense of $230,000 due to a commercial customer filing for bankruptcy protection. Prior to filing for bankruptcy, this customer had a good payment history resulting in no requirement for a customer deposit.

2017 Forecast bad debts are $282,004, or $245,585 less than the 2016 Actuals; As explained previously, the 2016 bad debt expense included a large write-off of $230,000 for a commercial customer.

Other/Miscellaneous

Other miscellaneous expenses reflect non-material changes from one year to the next for items such as training costs, office supplies, facility cost and other miscellaneous administrative expenses.

4.3 PROGRAM DELIVERY COSTS WITH VARIANCE ANALYSIS

4.3.1 Materiality Threshold

The materiality threshold used by Energy+ to determine the OM&A accounts requiring analysis was computed based on the Chapter 2 Filing Requirements as 0.5% of the proposed distribution revenue requirement. Energy+ has adopted a threshold of $175,000 for variance analysis. The calculation of materiality is set out in Table 4-15.

Table 4-15: Materiality Threshold for Variance Analysis

VARIANCE ANALYSIS THRESHOLD	
	2019 TEST
Estimated Distribution Revenue Requirement	$35,170,323
0.5% of Proposed Distribution Revenue Requirement	$175,852
Materiality Threshold for Variance Analysis	$175,000

4.3.2 Overview

As part of the overall financial management of its operating costs, Energy+ produces monthly financial statements and operating variance analysis in comparison to the approved budget. The operating variance analysis, which reports significant variances by department, is distributed to the Energy+ Leadership Team on a monthly basis. An analysis of operating variances is also provided to the Audit Committee and Board of Directors as part of the monthly Financial Reports to the Board of Directors. As Energy+ manages and reports its operating costs based on departments, Program Costs and related variance analysis in this Exhibit align to Energy+'s department structure and the accountability of its management team.

For the years prior to 2015, subsequent to the acquisition of the former BCP, Energy+ has used its best efforts to categorize the OM&A expenditures into the Programs that best align to the categories previously established by the former CND and adopted by Energy+.

In Table 4-16 below, Board Appendix 2-JC, provides a summary of Operations, Maintenance, and Administration expenses for the 2014 Board Approved Proxy, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Forecast, 2018 Bridge, and 2019 Test Year by Program.

An analysis is provided on all material variances that exceed the materiality threshold for the 2019 Test year versus 2017 Forecast and 2019 Test Year versus 2014 Board Approved Proxy. All highlighted items in yellow in Table 4-15 exceed the materiality threshold and an explanation is provided.

Table 4-16: OM&A Programs Table (Appendix 2-JC)

Programs	Last Rebasing Year (2014 Board Approved Proxy)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Forecast	2018 Bridge Year	2019 Test Year	Variance (Test Year vs. 2017 Forecast)	Variance (Test Year vs. Last Rebasing Year (2014 Board Approved Proxy)
Reporting Basis									
Transformer Station	330,112	363,446	287,146	241,474	190,200	267,315	271,653	81,453	(58,459)
Sub-Total	330,112	363,446	287,146	241,474	190,200	267,315	271,653	81,453	(58,459)
Distribution Stations	59,752	7,582	4,326	4,277	8,729	5,184	5,018	(3,711)	(54,734)
Sub-Total	59,752	7,582	4,326	4,277	8,729	5,184	5,018	(3,711)	(54,734)
Overhead Maintenance	2,111,103	2,096,386	1,786,839	1,702,975	1,514,206	1,558,640	1,467,337	(46,869)	(643,766)
Sub-Total	2,111,103	2,096,386	1,786,839	1,702,975	1,514,206	1,558,640	1,467,337	(46,869)	(643,766)
Tree Trimming Maintenance	480,744	389,414	500,509	509,894	483,109	529,073	539,030	55,921	58,286
Sub-Total	480,744	389,414	500,509	509,894	483,109	529,073	539,030	55,921	58,286
Load Dispatching	645,251	552,686	636,092	585,603	611,537	806,301	828,219	216,682	182,968
Sub-Total	645,251	552,686	636,092	585,603	611,537	806,301	828,219	216,682	182,968
Underground Maintenance	928,460	885,959	751,296	858,908	887,815	928,027	915,192	27,377	(13,268)
Sub-Total	928,460	885,959	751,296	858,908	887,815	928,027	915,192	27,377	(13,268)
Distribution Transformer Operation	167,063	132,232	123,467	101,972	93,126	89,773	88,207	(4,919)	(78,856)
Sub-Total	167,063	132,232	123,467	101,972	93,126	89,773	88,207	(4,919)	(78,856)
	-								
Maintenance Line TS	97,577	119,275	175,957	186,093	182,278	187,382	188,321	6,043	90,744
Sub-Total	97,577	119,275	175,957	186,093	182,278	187,382	188,321	6,043	90,744
Meter Expense	725,512	853,087	946,345	1,040,768	910,219	873,045	941,713	31,494	216,201
Sub-Total	725,512	853,087	946,345	1,040,768	910,219	873,045	941,713	31,494	216,201
Customer Premises	161,915	185,746	163,849	6,481	12,594	7,128	6,859	(5,735)	(155,056)
Sub-Total	161,915	185,746	163,849	6,481	12,594	7,128	6,859	(5,735)	(155,056)
Billing and Settlement	1,358,695	1,147,299	1,367,997	1,401,715	1,433,398	1,405,215	1,811,807	378,409	453,112
Sub-Total	1,358,695	1,147,299	1,367,997	1,401,715	1,433,398	1,405,215	1,811,807	378,409	453,112
Meter Reading Expenses	426,648	275,704	277,680	374,157	393,948	420,594	467,742	73,794	41,094
Sub-Total	426,648	275,704	277,680	374,157	393,948	420,594	467,742	73,794	41,094
Collecting	830,312	1,036,708	861,846	739,435	622,042	568,961	657,803	35,761	(172,509)
Sub-Total	830,312	1,036,708	861,846	739,435	622,042	568,961	657,803	35,761	(172,509)
Office and Building	855,828	738,255	628,004	524,572	521,606	529,133	730,977	209,371	(124,851)
Sub-Total	855,828	738,255	628,004	524,572	521,606	529,133	730,977	209,371	(124,851)
Customer Care	1,167,742	1,063,377	803,692	915,899	923,271	954,097	983,988	60,717	(183,754)
Sub-Total	1,167,742	1,063,377	803,692	915,899	923,271	954,097	983,988	60,717	(183,754)
General Administration	5,521,979	5,913,339	5,305,536	4,976,948	5,614,189	5,135,305	5,295,626	(318,563)	(226,353)
Sub-Total	5,521,979	5,913,339	5,305,536	4,976,948	5,614,189	5,135,305	5,295,626	(318,563)	(226,353)
Engineering Supervision	-	57,333	23,490	170,726	-	-	-	-	-
Sub-Total	-	57,333	23,490	170,726	-	-	-	-	-
Operation Supervision	182,955	214,338	236,587	196,428	673,431	663,440	678,773	5,342	495,818
Sub-Total	182,955	214,338	236,587	196,428	673,431	663,440	678,773	5,342	495,818
Human Resources and Training	195,063	275,064	188,809	220,728	212,498	284,834	275,378	62,880	80,315
Sub-Total	195,063	275,064	188,809	220,728	212,498	284,834	275,378	62,880	80,315
Safety and Health	295,598	256,884	180,780	198,273	272,164	298,036	289,337	17,173	(6,261)
Sub-Total	295,598	256,884	180,780	198,273	272,164	298,036	289,337	17,173	(6,261)
Accounting	544,255	539,893	557,031	788,590	711,085	707,826	724,446	13,361	180,191
Sub-Total	544,255	539,893	557,031	788,590	711,085	707,826	724,446	13,361	180,191
Information Systems	1,127,247	1,107,023	1,213,973	1,346,832	1,224,079	1,299,241	1,327,552	103,473	200,305
Sub-Total	1,127,247	1,107,023	1,213,973	1,346,832	1,224,079	1,299,241	1,327,552	103,473	200,305
CIS and CDM Administration	135,048	96,019	10,878	-				-	(135,048)
Sub-Total	135,048	96,019	10,878	-		-	-	-	(135,048)
Integration Expenditures	-	-	254,986	-				-	-
Sub-Total	-	-	254,986	-		-	-	-	-
Communication and Corporate Sponsorship	62,572	50,455	13,965	64,327	66,230	76,875	80,670	14,440	18,098
Sub-Total	62,572	50,455	13,965	64,327	66,230	76,875	80,670	14,440	18,098
Miscellaneous	-		91,916						
Total	**18,411,431**	**18,357,504**	**17,392,997**	**17,157,075**	**17,561,754**	**17,595,425**	**18,575,648**	**1,013,894**	**164,217**

4.3.3 Variance Analysis – Programs

2019 Test Year vs. 2014 Board Approved Proxy

Overhead Maintenance – Decrease of $643,766

The primary reasons for the decline in overhead maintenance between the 2019 Test Year and 2014 Board Approved Proxy are: (i) a reduction in operations staff due to attrition, including retirements, further outlined in Section 4.4.2; and (ii) an increase in the labour hours allocated to capital projects, reflecting the focus on capital programs as outlined in Exhibit 2, particularly the increase in system renewal projects in the Brant Service territory. The increased allocation of labour hours predominantly occurred in 2015, as outlined in Section 4.2.4 Cost Drivers.

Load Dispatching (Control Room Operations) – Increase of $182,968

The increase in Load Dispatching is principally due to the addition of two additional System Control Room Operators to provide for the transition to a 24/7 Control Room. The former CND had incorporated the addition of 3 additional System Control Room Operators ("SCO") in its original plans in 2014. One Apprentice SCO was hired in 2015, however, the remaining two positions were not filled until 2018. As part of its Decision (EB-2013-0116), it is important to highlight that the Board reduced OM&A expenditures by $379,806 citing "increase in staffing levels which seems aggressive and a delay in implementing new hiring"[1]. The hiring of qualified SCO's to transition to a 24/7 Control Room proved to be a challenge for Energy+. In early 2016, after the resignation of one of the Apprentice SCOs, Energy+ undertook an initiative to explore the opportunity to evaluate the advantages of combining and sharing a System Control Room with another LDC to build a single, 24/7 System Control Room. Energy+ considered that this could be a very good opportunity to achieve 24/7 operations to benefit customers, but also had the potential to achieve operating synergies for both utilities. This initiative was ultimately not completed due to union contract issues as a result of separate and distinct union representation at both LDCs.

[1] Decision and Order (EB-2013-0116), August 14, 2014, Pg. 5

Energy+ is committed to the implementation of a 24/7 Control Room.

The increase in Load Dispatching of $182,968 from the 2014 Board Approved Proxy to the 2019 Test Year is lower than the increase of $216,682 between the 2019 Test Year and 2017 Forecast. This difference is due to the recognition in the 2019 Test Year that overtime costs for the Control Room are expected to decline with the extension of hours and ultimately the transition over time to the 24/7 Control Room.

Meter Expense – Increase of $216,201

The increase in meter expense is explained by: (i) increased AMI Network fees over the five year period of approximately $134,000 due to contracted CPI increases, US dollar exchange rates, and increase in the number of meters; and (ii) a reallocation of meter expenses for the former BCP that were included in other program costs to align to the Program Costs adopted by Energy+. As noted previously, for the years prior to 2015, subsequent to the acquisition of the former BCP, Energy+ has used its best efforts to categorize the OM&A expenditures into the Programs that best align to the categories previously established by the former CND and adopted by Energy+. The 2011 Board Approved amount for the former BCP that was classified as Meter Expense was $43,320, yet the AMI Network and Meter Service Provider expenses for the Brant service territory were approximately $100,000 at that time and included in General Administration (Outside Services expenditures).

Billing and Settlement – Increase of $453,112

As described in Section 4.4.2 Cost Drivers, the implementation of monthly billing for customers in the Cambridge and North Dumfries service territory has resulted in an increase of approximately $390,000 in the 2019 Test Year. As previously explained, the former CND did not include the costs of monthly billing in its last (2014) Cost of Service application. Prior to 2019, these incremental costs are being recorded in a deferral account.

The balance of the increase in the Billing and Settlement program costs is principally

explained by annual wage and benefit increases for the billing and settlement staff, as described in Section 4.4 Compensation, and reallocation of wages from Customer Care, as noted below.

Customer Care – Decrease of $183,754

The decrease in Customer Care expenditures is principally explained by: (i) reallocation of wages from Customer Care to the Billing and Settlement department (former BCP wages were all allocated to Customer Care); (ii) partially offset by increased wages and benefits due to annual wage increases, as explained in Section 4.4.1.2.

General Administration – Decrease of $226,353

The decrease in General Administration is explained by: (i) decrease in labour and benefit costs due to the reallocation of Operation Supervisors to the Operations Supervision department in 2017 Actual, 2018 Bridge and 2019 Test Year (see Operations Supervision explanation below); partially offset by increased salaries and benefits due to annual merit increases, as explained in Section 4.4.1.3.

Operations Supervision – Increase of $495,818

The increase in Operations Supervision is explained by a reallocation of labour and benefit costs for the Operations Supervisors, that prior to 2017, were included as part of Management wages in General and Administration.

Accounting – Increase of $180,191

The former BCP did not separate out its Accounting department expenditures. As a result, the 2014 Board Approved Proxy for the Accounting program costs only represent the 2014 Board Approved expenditures of the former CND for this category. In 2016, the financial systems were fully integrated and costs associated with the Accounting/Finance department were combined. The increase in Accounting

program expenditures therefore is principally explained by: (i) the wages and benefits of two additional Accounting staff of the former BCP; (ii) wage and benefit increases between the 2014 Board Approved and 2019 Test Year; partially offset by a reduction of one full-time Intermediate Accountant position realized as a result of the acquisition and subsequent amalgamation, as further summarized in Section 4.4.2.2.

Information Systems – Increase of $200,305

The increase in Information Systems is principally explained by increased costs associated with software license fees, and costs associated with Cyber Security initiatives, as explained in Section 4.2.4. Cost Drivers.

2019 Test Year vs. 2017 Forecast

Load Dispatching – Increase of $216,682

As explained in Section 4.3.3 2019 Test Year vs. 2014 Board Approved Proxy variance analysis, the increase in Load Dispatching is principally due to the addition of two additional System Control Room Operators to provide for the transition to a 24/7 Control Room.

Billing and Settlement – Increase of $378,409

The increase in Billing and Settlement costs is explained by the incremental costs from the implementation of monthly billing. As previously indicated, prior to 2019, the incremental costs have been included in a deferral and variance account. As a result, the annual incremental costs are reflected in the 2019 Test Year.

Office and Building – Increase of $209,371

The increase in Office and Building costs in 2019 Test Year compared to the 2017 Forecast is explained by $195,000 in annual operating costs associated with the shared services arrangement with Brantford Power Inc., as explained in Section 4.2.4.

General Administration – Decrease of $318,563

The decrease in General Administration costs is principally explained by a reduction in regulatory expenses related to the preparation of the 2019 Cost of Service Application. The 2017 forecast includes costs of approximately $446,000, compared to the $190,000 that is included in the 2019 Test Year. Please refer to Table 4-38 for details with respect to the 2019 Cost of Service Application Costs.

4.4 EMPLOYEE COMPENSATION

4.4.1 Compensation Philosophy

4.4.1.1 Overview

Energy+ recognizes the alignment of the contributions of its employees to the success of its business. Energy+ strives to pay competitively and equitably for employee performance, yet is cognizant of the budgetary and business constraints of operating in a regulated environment.

Energy+'s overall compensation for all employees is designed to be competitive and equitable in order to attract and retain qualified personnel in an industry that is facing an aging workforce and is competing for skilled resources. The compensation package includes a base wage and benefits package. Energy+'s workforce is comprised of both unionized and non-unionized management employees.

4.4.1.2 Unionized Employees

Energy+'s unionized workforce is represented by the International Brotherhood of Electrical Workers ("IBEW"), Local 636. There are two bargaining units that represent the unionized workforce. Inside Bargaining Unit represents: Customer Care Representatives, Billing Representatives, Clerical, Finance, and Engineering Staff. Outside Bargaining Unit represents: Powerline Technicians ("PLTs"), Mechanic, Truck Drivers, Stores/Stockroom, Customer Care Field Representative, Meter Technicians, Stations Technicians, System Control Operators, and Locator.

Energy+'s collective agreement with unionized staff provides for annual payroll increases and employee step progressions. Labour rates are adjusted annually based on negotiated percentages contained within the collective agreement.

Prior to the acquisition of the former BCP, the administrative employees of the former BCP were non-unionized and the outside employees (e.g. Powerline Technicians and

Metering Technicians) were represented by the Power Workers Union Local 1000 ("PWU"). In 2015, the inside employees of the former BCP were transitioned to the IBEW Inside Bargaining Unit and incorporated within the existing IBEW Inside Collective Agreement. For the period April 1, 2015 through March 31, 2017 the outside employees servicing the Brant service territory were represented by the PWU. In the latter part of 2017, a union representation vote was held, as directed by the Ontario Labour Relations Board, and IBEW became the sole bargaining agent for the Energy+ Outside Bargaining Unit.

Energy+ recently completed new Collective Agreements with the IBEW for the Inside and Outside Bargaining Units. The new Collective Agreements are for a six year period (April 1, 2018 to March 31, 2024). Labour wages are the result of a negotiated process and wage increases are based on factors such as recent settlements reached in the LDC sector, particularly in neighbouring LDCs, as well as the local cost of living inflation factor.

Table 4-17 summarizes the annual wage adjustments under the Collective Agreements for the historical years 2014 to 2017, as well as the negotiated increases for 2018 and 2019.

Table 4-17: IBEW and PWU Agreements Annual Wage Adjustments

	Notes	2014	2015	2016	2017	2018	2019
Inside Collective Agreement - IBEW (April 1)		2.30%	2.25%	2.25%	2.20%	2.0%	2.0%
Outside Collective Agreement - IBEW (April 1)		2.30%	2.25%	2.25%	2.20%	2.0%	2.0%
Outside Collective Agreement - PWU (April 1 up to March 31, 2017)	1, 2	2.85%	2.25%	2.25%	NA	NA	NA

Notes:
(1) April 1, 2015 to March 31, 2017 Agreement also included a one-time $1.50 adjustment for all PLTs and $0.75 for Meter Technicians to phase in to former CND rates.
(2) PWU Agreement expired in March, 2017. IBEW became the sole union effective October 19, 2017, as a result of a representation vote under the Ontario Labour Relations Board.

Agreement Dates
Inside IBEW - April 1, 2014 to March 31, 2018
Inside IBEW - April 1, 2018 to March 31, 2024
Outside IBEW - April 1, 2014 to March 31, 2018
Outside IBEW - April 1, 2018 to March 31, 2024
Outside PWU - April 1, 2012 to March 31, 2015
Outside PWU - April 1, 2015 to March 31, 2017

Each job classification at Energy+ has a wage rate progression scale that increases from a base rate to a maximum rate. The Hay Job Evaluation program is utilized by Energy+ in establishing the job classifications and wage rate progression scale. The Hay Job Evaluation program is a methodology utilized by many LDCs, uses a multi-factor system to rank job classifications, and generally evaluates positions based upon level of knowledge, problem solving, and accountability required for the position. The evaluation is then used to pay employees at an appropriate rate compared to other positions in the organization.

Energy+ maintains a collaborative approach with a mutual gains bargaining philosophy to labour relations. The compensation for unionized employees is negotiated through the collective bargaining process

4.4.1.3 Executive/Management/Non-Union Employees

Energy+'s total compensation philosophy is based on its desire to attract, retain and motivate an outstanding workforce. Energy+ provides a total compensation program that establishes and maintains competitive salary levels within relevant markets and

available resources, which is consistent with job content, responsibilities and expectations. The program emphasizes and encourages excellence by rewarding employee contributions, including performance that supports Energy+'s core values of Customer Focused, Teamwork, Dialogue, Safety and Wellness, Community, Accountability, Innovation, and Environmental Stewardship.

Energy+'s total compensation system is comprised of base salary, incentive pay, and a comprehensive benefit program.

Energy+'s total compensation program is reviewed and analyzed for its competitiveness against three market comparators:

Broader Public Sector (BPS) Ontario – excluding GTA

- Includes public sector and non-profit organizations

Industrial Sector (Industrial) Ontario – excluding GTA

- Includes private organizations in a variety of industries

LDC Sector

- Includes LDC's of similar size and scope, and those that Energy+ considers its market competition for talent.

Energy+ considers its primary competition for talent to be the LDC market, yet recognizes the requirement to maintain a balanced review and approach against both the private and public sector markets.

In setting its total compensation, Energy+ strives to maintain a 50th percentile position against the public and private sectors, with a primary focus on maintaining a 50th percentile position against its LDC market competition.

Salaries

Energy+ uses a pay grade system that includes 11 pay grades within the management group, with each pay grade having a higher base salary as the level of responsibility increases.

Energy+ maintains a base salary band of 85% to 115% for each position. Job rate (100%) is the rate at which a fully experienced and competent individual achieves or is expected to operate at. Below job rate, the individual is considered developing. Achieving above job rate is possible for individuals who have demonstrated mastery or consistent superior performance in one or more roles. The use of a salary band provides for:

- Opportunity to reward, retain and attract top talent beyond 100%;
- Opportunity to mitigate compression issues between unionized staff and management; and
- Opportunity to place individuals new to the position in a developmental salary range.

The use of a base salary band is also consistent with best practice and the LDC market comparators.

Annual increases in base salary are determined through Energy+'s performance management program, which provides a system for rewarding employees based on behavior and performance competencies.

Table 4-18 summarizes the annual salary adjustments for the Management and Non-Union employees, which was computed on an annual basis as a percentage of the total salary adjustment based on the annual merit review determined at the beginning of the year, as a percentage of salaries prior to the adjustment. Management staff includes the Leadership Team.

Table 4-18: Annual Salary Adjustment for Management/Non-Union Staff

Annual Salary Adjustment %	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Bridge
Management/Non-Union						
Energy+	NA	NA	3.04%	1.91%	2.00%	2.00%
Former CND	3.39%	2.02%				
Former BCP	0.00%	3.95%				

Incentive Pay:

Energy+ places considerable emphasis on a results-driven, performance-based system, which achieves success through the development of SMART (Specific, Measurable, Achievable, Relevant, Time-bound) objectives. Goals are intended to challenge the organization to consider how it can improve overall and individual skills to maximize its potential and further enhance its contribution to the shareholder and community.

Energy+'s incentive program utilizes a Balanced Score Card ("BSC") approach to goal setting and annually assigns a weighted goal to each of the following four categories: (i) Financial Performance; (ii) Service; (iii) People; and (iv) Community. The BSC and related objectives are aligned to Energy+'s Strategic Plan.

The objective of the BSC incentive is to recognize that management contributes materially to the success of the organization through their direct ability to impact the business, their ingenuity, drive, and leadership. The BSC incentive is awarded annually based on the achievement of weighted objectives that are established at the beginning of each performance year.

Table 4-18 Incentive Target provides a summary by position level of the potential BSC incentive on an annual basis.

Table 4-19: Incentive Target Weighting Between Corporate Performance and Personal Performance

Position	Variable % of Base	Maximum Payout 1.5 % of Target	Balanced Corporate Scorecard Weighting	Individual Objectives Weighting
President & CEO	36.7%	46.7	80%	20%
Leadership	25%	30.7	65%	35%
Directors	10%	15%	65%	35%
Management/Supervisors	8%		30%	70%

Pay for executives and management is reviewed annually by the President and CEO, Human Resources, Nominating & Governance Committee of the Board of Directors, and ultimately by the Board of Directors.

4.4.1.4 Employee Benefits Program

A comprehensive and competitive benefits package exists which includes health and dental benefits, life insurance, vacation, OMERS retirement plan contributions, Employer Health Tax, CPP and EI contributions and WSIB insurance. The plans are designed to address the health and welfare needs of employees, with similar plans for both union and management employees.

Energy+'s collective agreement with unionized staff provides for benefits which are a result of a collaborative and negotiated process, based on factors such as recent settlements in the LDC sector including neighbouring LDC's.

Please refer to Section 4.4.2.3.2 for further analysis of Employee Benefits.

4.4.2 Employee Costs and Variance Analysis

4.4.2.1 Overview

Table 4-20 Employee Costs (Board Appendix 2-K) summarizes the Employee complement, compensation and benefits for the 2014 Board Approved Proxy, 2014 Actuals, 2015 Actuals, 2016 Actuals 2017 Actuals, 2018 Bridge and 2019 Test Years. All compensation amounts have been included, whether expensed or capitalized. The number of employees ("FTEs") is based on the computation of the number of full-time equivalent positions throughout each of the fiscal years. Employees that were hired during the year or employees that left the organization were pro-rated based on the start date month. FTEs exclude Board of Directors, students and those employees who are funded through the IESO's Conservation First Framework (Energy Efficiency Department).

Table 4-21 Employee Costs – 2014 Board Approved Proxy provides the computation of the 2014 Board Approved Proxy, as described in Section 4.1.2.

Energy+ would note, however, that the 2014 Board Approved Appendix 2-K figures for the former CND is based on the latest version of the Appendix 2-K filed with that Application (EB-2013-0116, Response to Undertaking J1.7), which includes an adjustment for a $147,000 reduction in health and dental benefits identified in Response to Interrogatories 7.4 VECC 32. The amounts, however, were not adjusted to reflect the Decision and Order of the Board (EB-2013-0116), whereby the OM&A of the former CND was reduced by $379,806 citing "increase in staffing levels which seems aggressive and a delay in implementing new hiring"[2]. As the former CND did not provide a revised Appendix 2-K to reflect this Decision, the 2014 Board Approved

[2] Decision and Order (EB-2013-0116), August 14, 2014, Pg. 5

Proxy for purposes of Appendix 2-K may be overstated. Board of Directors honoraria and benefits have also not been included in the analysis below.

1

Table 4-20: Employee Costs (Board Appendix 2-K)

Energy+ Inc. (Consolidated)
Appendix 2-K
Employee Costs

	Last Rebasing Year Board Approved - 2014 Proxy	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Bridge Year	2019 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	31	26	30	25	27	26	27
Non-Management (union and non-union)	113	106	103	101	105	105	103
Total	144	132	133	126	132	131	130
Total Salary and Wages including overtime and incentive pay							
Management (including executive)	3,487,244	3,098,542	3,411,676	3,544,071	3,566,145	3,681,136	3,746,319
Non-Management (union and non-union)	7,985,237	8,183,816	8,409,187	8,668,084	8,512,927	8,473,012	8,339,516
Total	$ 11,472,481	$ 11,282,357	$ 11,820,863	$ 12,212,155	$ 12,079,072	$ 12,154,148	$ 12,085,835
Total Benefits (Current + Accrued) [2]							
Management (including executive)	921,349	788,757	805,117	813,831	903,903	890,409	903,912
Non-Management (union and non-union)	2,500,003	1,994,079	1,896,525	1,974,126	2,056,983	2,219,478	2,160,521
Total	$ 3,421,352	$ 2,782,837	$ 2,701,642	$ 2,787,957	$ 2,960,887	$ 3,109,887	$ 3,064,433
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 4,408,592	$ 3,887,299	$ 4,216,793	$ 4,357,903	$ 4,470,048	$ 4,571,544	$ 4,650,231
Non-Management (union and non-union)	$ 10,485,240	$ 10,177,895	$ 10,305,712	$ 10,642,210	$ 10,569,910	$ 10,692,490	$ 10,500,037
Total	$ 14,893,832	$ 14,065,194	$ 14,522,505	$ 15,000,112	$ 15,039,958	$ 15,264,035	$ 15,150,268

Note:

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

[2] Current employee benefits, plus Pension and Other Post-Employment Benefits costs, as recorded for recovery in distribution rates. Should be consistent with

Energy+ Notes and Assumptions:

1. 2014 Board Approved Proxy represents: 2014 Former CND Board Approved plus 2011 Former BCP Board Approved plus IRM Factor to 2014
2. 2014 Actuals and 2015 Actuals represent the consolidated results of former CND and former BCP.

2

3

Table 4-21: Employee Costs – 2014 Board Approved Proxy

	2014 Board Approved - Former CND	2014 Board Approved Proxy - Former BCP	2014 Board Approved Proxy - Energy+	2011 Board Approved - Former BCP	IRM 2012 0.68%	IRM 2013 0.28%	IRM 2014 1.60%
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	24	7	31	7			
Non-Management (union and non-union)	89	24	113	24			
Total	113	31	144	31			
Total Salary and Wages including overtime and incentive pay							
Management (including executive)	2,883,848	603,396	3,487,244	588,235	592,235	593,893	603,396
Non-Management (union and non-union)	6,490,209	1,495,028	7,985,237	1,457,465	1,467,376	1,471,484	1,495,028
Total	$ 9,374,057	$ 2,098,424	$ 11,472,481	$ 2,045,700	$2,059,611	$ 2,065,378	$ 2,098,424
Total Benefits (Current + Accrued) [2]							
Management (including executive)	721,843	199,506	921,349	194,493	195,816	196,364	199,506
Non-Management (union and non-union)	2,005,688	494,315	2,500,003	481,895	485,172	486,530	494,315
Total	$ 2,727,531	$ 693,821	$ 3,421,352	$ 676,388	$ 680,987	$ 682,894	$ 693,821
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 3,605,691	$ 802,901	$ 4,408,592	$ 782,728	$ 788,051	$ 790,257	$ 802,901
Non-Management (union and non-union)	$ 8,495,897	$ 1,989,343	$ 10,485,240	$ 1,939,360	$1,952,548	$ 1,958,015	$ 1,989,343
Total	$ 12,101,588	$ 2,792,244	$ 14,893,832	$ 2,722,088	$2,740,598	$ 2,748,272	$ 2,792,244

Note:

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

[2] Current employee benefits, plus Pension and Other Post-Employment Benefits costs, as recorded for recovery in distribution

Energy+ Notes and Assumptions:

1. 2014 Board Approved Proxy represents: 2014 Former CND Board Approved plus 2011 Former BCP Board Approved plus IRM Factor to 2014
2. 2014 Board Approved for CND based on Response to Undertaking J.1.7. Benefit expense was reduced by $147,000 based on Response to Interrogatory 7.4 VECC 32
3. 2011 Board Approved FTE for the former BCP was adjusted by -1 FTE to reflect 1 Employee dedicated to Energy Efficiency.
4. 2014 Actuals and 2015 Actuals represent the consolidated results of former CND and former BCP.
5. FTEs who are funded through IESO as part of Conservation Programs are excluded from totals.

4.4.2.2 Full Time Employees

Table 4-22 summarizes the number of full-time employees by department at year-end since 2014, as well as shows the 2014 Board Approved Proxy figures at the department level. The total number of full-time employees at year-end may be different from the FTEs provided in Table 4-11 due to: (i) timing of new hires; (ii) vacancies during the year; and (iii) timing of retirements.

Table 4-22: Number of Full Time Employees by Department, Year-End December 31

Departments	Board Approved Proxy (Note 1)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Forecast	2018 Bridge	2019 Test
Leadership Team	10	10	9	8	8	8	8
Administration	2	1	1	1	1	2	2
Accounting and Regulatory	9	8	8	9	8	8	8
Human Resources	1	1	1	1	1	1	1
Safety	0	0	1	1	1	1	1
Customer Care	21	22	22	19	21	22	22
Billing	12	9	10	10	10	9	9
Communications	1	0	1	1	1	1	1
Information Systems	5	5	5	3	4	4	4
Engineering Distribution	14	9	9	8	8	11	11
Engineering Services	10	12	9	11	13	13	13
Metering	6	6	7	5	4	4	4
Operations	49	42	46	45	44	43	42
Purchasing and Stores	4	4	4	4	4	4	4
TOTAL NUMBER OF EMPLOYEES (Regulated)	144	129	133	126	128	131	130
Vacant Positions at Year-End		15	3	4	-	-	-
TOTAL NUMBER OF APPROVED POSITIONS (Regulated)	144	144	136	130	128	131	130
CHANGE IN NUMBER OF POSITIONS BY YEAR			-8	-6	-2	3	-1
CUMULATIVE CHANGE IN NUMBER OF POSITIONS (2019 vs. 2014)							-14
Energy Efficiency (Funded through IESO)	5	6	7	4	5	5	5
TOTAL NUMBER OF EMPLOYEES (Regulated and Energy Efficiency)	149	150	143	134	133	136	135

Notes:
(1) Board Approved Proxy based on Former CND 2014 Cost of Service and Former BCP 2011 Cost of Service
(2) Year-end number of employees may vary from Full Time Equivalent (FTE) used in Appendix 2-L due to: (i) timing of hires; (ii) timing of retirements; (iii) vacant positions.

Table 4-23 summarizes the computation of the 2014 Board Approved Proxy at the department level. The 2014 Board Approved Proxy is derived from the 2014 Board Approved for the former CND and the 2011 Board Approved for the former BCP. Energy+ submits that by utilizing the 2011 Board Approved Proxy for the former BCP as the basis for the approved 2014 headcount, there is an implied assumption that the former BCP would not have added any new positions between 2011 and 2014, which may not be the case. Energy+ submits, however, that it provides a reasonable proxy upon which to analyze the change in full-time employees.

Table 4-23: Number of Full-Time Employees by Department, 2014 Board Approved Proxy

Departments	As Filed - Last Rebasing Year			2014 Board Approved
	2014 CND	2011 BCP	Total	Proxy
Leadership Team	8	2	10	10
Administration	1	1	2	2
Accounting and Regulatory	7	2	9	9
Human Resources	1	0	1	1
Safety	0	0	0	0
Customer Care	17	4	21	21
Billing	8	4	12	12
Communications	1	0	1	1
Information Systems	5	0	5	5
Engineering Distribution	12	2	14	14
Engineering Services	10	0	10	10
Metering	5	1	6	6
Operations	34	15	49	49
Purchasing and Stores	4	0	4	4
TOTAL NUMBER OF EMPLOYEES (Regulated)	113	31	144	144

For purposes of the variance analysis with respect to the change in full-time employees, Table 4-24 summarizes the net change in full-time employees between the 2019 Test Year and 2014 Board Approved Proxy. The net change in the number of employees includes the reduction and/or elimination of certain positions, as well as new positions that were added during the same period. In certain cases, a position may have been eliminated/reduced in one year, but subsequently added in another year. Explanations are provided for the overall change in full-time employees.

Table 4-24: Changes in Number of Full-Time Employees by Year, 2019 Test Year vs. 2014 Board Approved Proxy

New Hires/Positions	2015	2016	2017	2018	2019	Cumulative
ITS Supervisor			1			1
Regulatory Analyst		1				1
Customer Care - Monthly Billing				1		1
Director, Engineering			1			1
System Control Room Operators				2		2
GIS Technician				1		1
Manager, Business Solutions				1		1
	-	1	2	5	-	8

Positions Eliminated	2015	2016	2017	2018	2019	Cumulative
Acquisiton/Amalgamation						
Chief Financial Officer	(1)					(1)
Intermediate Accountant	(1)					(1)
VP Energy Efficiency	(1)					(1)
GIS Technician	(1)					(1)
Director, Customer Care	(1)					(1)
Lines Superintendent	(1)					(1)
Executive Assistant	(1)					(1)
Customer Care Clerk	(1)	(1)				(2)
Operations Clerk		(1)				(1)
Meter Technician		(1)				(1)
	(8)	(3)	-	-	-	(11)
Other						
Sync Operator			(1)			(1)
Intermediate Accountant		(1)				(1)
Supervisor, Metering			(1)			(1)
Business Analyst		(1)				(1)
ITS Programmer Analyst		(1)				(1)
Powerline Technician			(1)	(2)	(1)	(4)
Stations Technician		(1)				(1)
Engineering Distribution (Department Restructuring)			(1)			(1)
	-	(4)	(4)	(2)	(1)	(11)
Total Reductions	(8)	(7)	(4)	(2)	(1)	(22)
Net Change	**(8)**	**(6)**	**(2)**	**3**	**(1)**	**(14)**

As highlighted in Section 4.2.4 Cost Drivers, as a result of the acquisition of the former BCP and subsequent legal amalgamation, Energy+ achieved significant savings principally related to wages and benefits due to reductions in the number of full-time employees. In total, 11 full-time positions were eliminated over a two year period and were achieved through: (i) the elimination of duplicate and/or vacant positions, (ii) realignment of existing positions; and (iii) natural attrition, including retirements.

In addition to the reduction in the full-time positions as a result of the amalgamation, Energy+ further reduced the number of positions by the equivalent of 3 full-time positions. The net change of 3 positions reflects the addition of 8 new positions, offset by the reduction of 11 positions.

When an existing position with Energy+ becomes vacant due to a retirement or employee turnover, Energy+ initiates an internal review and analysis to determine whether: (i) the position should be filled based on the existing job requirements; (ii) the position should be updated and/or changed to reflect the changing environment, industry landscape, or changing business conditions; or (iii) there is an opportunity to eliminate the position. At the same time, Energy+ evaluates and assesses where there may be current capacity constraints, and/or technical or competency gaps in the organization that should be considered for the hiring of a new position. Requests for any new hire must follow a formal process that includes documenting the justification for the position and the consideration of alternatives. All new hires are approved by the President and CEO. As part of the annual budget process, the Board of Directors reviews the changes in full-time employees.

4.4.2.2.1 Number of Employees Benchmarking

Table 4-25 below compares the Number of Employees, Number of Customers, and the Number of Customers per Employee for the 2014 Board Approved Proxy, 2019 Test Year, as well as a comparison to Energy+ peer group based on geography, as well as to the Industry based on the 2016 OEB Yearbook.

Table 4-25: Comparison to Other LDCs

	Energy+ 2014 Board Approved Proxy	Energy+ 2019 Test Year	Energy+ 2016 Actual	2016 Guelph Hydro	2016 Kitchener Wilmot	2016 Waterloo North Hydro	Industry (2016)
Number of Employees	144	130	126	124	187	136	
Number of Customers	63,589	65,970	64,123	54,414	94,058	56,230	5,106,528
Number of Customers per Employee	442	508	509	439	503	413	458

The number of customers per employee served by Energy+ was 442 based on the 2014 Board Approved Proxy and has improved to 509 in 2016 Actual, and is expected to be 508 in the 2019 Test Year. The improvement in the number of customers per employee from the 2014 Board Approved Proxy demonstrates the efficiencies achieved by Energy+. Energy+ compares favourably to its peers in 2016, as well as the Industry as a whole.

4.4.2.3 Wages and Benefits Variance Analysis

4.4.2.3.1 Year over Year Variance Analysis – FTEs and Wages

Table 4-26 – Change in FTEs by Category summarizes the net change in FTEs from the 2014 Board Approved Proxy to the 2019 Test Year.

Table 4-26: Change in FTEs by Category

	2014 Actual vs. 2014 Board Approved Proxy	2015 Actual vs. 2014 Actual	2016 Actual vs. 2015 Actual	2017 Actual vs. 2016 Actual	2018 Bridge vs. 2017 Actual	2019 Test vs. 2018 Bridge
Number of Employees (FTEs including Part-Time)1						
Management (including executive)	(5)	4	(4)	2	(1)	1
Non-Management (union and non-union)	(7)	(3)	(3)	4	-	(2)
Total	(12)	1	(7)	6	(1)	(1)

A summary of the overall net decrease of 14 FTEs between the 2014 Board Approved Proxy and 2019 Test Year is provided in Section 4.4.2.2. Differences between change in FTEs and the Change in Full Time Positions at year-end reflects the timing of: (i) vacancies; (ii) retirements; and (iii) hiring of new positions.

Table 4-27 summarizes the year over year variance in the salary and wages, benefits and total compensation.

Table 4-27: Year over Year Variance in Salary and Wages

	2014 Actual vs. 2014 Board Approved Proxy	2015 Actual vs. 2014 Actual	2016 Actual vs. 2015 Actual	2017 Actual vs. 2016 Actual	2018 Bridge vs. 2017 Actual	2019 Test vs. 2018 Bridge
Total Salary and Wages including overtime and incentive pay						
Management (including executive)	(388,702)	313,134	132,396	22,073	114,991	65,184
Non-Management (union and non-union)	198,579	225,371	258,897	(155,157)	(39,915)	(133,496)
Total	(190,123)	538,505	391,293	(133,083)	75,076	(68,312)
Total Benefits (Current + Accrued)						
Management (including executive)	(132,591)	16,360	8,714	90,072	(13,495)	13,503
Non-Management (union and non-union)	(505,923)	(97,554)	77,601	82,857	162,495	(58,957)
Total	(638,515)	(81,194)	86,315	172,929	149,000	(45,454)
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	(521,293)	329,494	141,110	112,145	101,496	78,687
Non-Management (union and non-union)	(307,345)	127,817	336,498	(72,300)	122,580	(192,453)
Total	(828,638)	457,311	477,607	39,846	224,076	(113,767)

2014 Actual vs. 2014 Board Approved Proxy

The variance between the 2014 Actuals and 2014 Board Approved Proxy is attributable to lower than planned full time employees for each of the former CND and BCP. In May, 2014, the former CND and the County of Brant entered into a purchase and sale agreement whereby the former CND would acquire the former BCP. During 2014, both the former CND and former BCP had a number of full-time positions that were vacant during the year. As illustrated in Table 4-21, at the end of December 31, 2014, there were 15 positions vacant. As a result of the pending acquisition and planned integration of the two organizations, both organizations deferred the replacement of certain vacant positions in order to achieve the expected savings from the transaction. It was also during this time that the former CND was actively hiring for new System Control Room operators, as described previously, as well as certain of the new positions identified and approved as part of the 2014 Application.

2015 Actual vs. 2014 Actuals

The increase in salaries and wages in 2015 of $538,505 was explained by: (i) merit increases for management staff, including an adjustment to align the wages of staff from the former BCP based on the compensation philosophy of the former CND, and as adopted for Energy+ (refer to Table 4-17); (ii) wage increases for union staff based on collective bargaining increases (refer to Table 4-16); (iii) increase in the FTEs compared to 2014 as a result of filling vacant positions (i.e. 15 vacant positions as per 2014 Actuals less 11 reductions due to acquisition is 4 incremental FTEs in 2015, with 3 vacancies at the end of 2015); and (iv) retirement incentives.

2016 Actual vs. 2015 Actuals

The increase in salaries and wages in 2016 of $391,293 was explained by: (i) merit increases for management staff (refer to Table 4-17); (ii) wage increases for union staff based on collective bargaining increases (refer to Table 4-16), and (iii) targeted retirement incentives.

2017 Actual vs. 2016 Actual

The decrease in salaries and wages in 2017 of $133,083 was explained by: (i) realization of a full year of salary and wage savings due to the reduction in the number of full-time positions; partially offset by the: (ii) merit increases for management staff (refer to Table 4-17); and (iii) wage increases for union staff based on collective bargaining increases (refer to Table 4-16).

2018 Bridge vs. 2017 Actual

The increase in salaries and wages in 2018 Bridge Year of $75,076 is principally explained by: (i) merit increases for management staff (refer to Table 4-17); (ii) wage increases for union staff based on collective bargaining increases (refer to Table 4-16); partially offset by: (iii) a full-year of realized savings on eliminated positions; and (iv) lower overtime costs as a result of transitioning to a 24/7 Control Room. In 2018, Energy+ introduced expanded hours in 2018 in advance of transitioning to a 24/7 Control Room to provide extended control room coverage to customers, while at the same time providing adequate training time for new personnel prior to transition to 24/7 operations.

2019 Test vs. 2018 Bridge

The decrease in salaries and wages in 2019 Test Year of $68,312 is principally explained by: (i) merit increases for management staff (refer to Table 4-17); (ii) wage increases for union staff based on collective bargaining increases (refer to Table 4-16); offset by (iii) a reduction in one full-time position; and (iv) further reduction in overtime costs as a result of transitioning to a 24/7 Control Room.

4.4.2.3.2 Year Over Year Variance Analysis - Benefits

The following Table 4-28 summarizes the OMERS, CPP, EI and EHT contribution rates that have been used for the 2019 Test Year, as well as a comparison to 2018 Actual rates:

Table 4-28: Benefit Contribution Rates

Contributions	Actual 2018 Rates Maximum	Actual 2018 Rates Rates	2019 Test Year Rates Maximum	2019 Test Year Rates Rates
Omers Tier 1 Upto CPP Max	55900	9%	57200	9%
Omers Tier 2/3 Over CPP Max	>55900	14.60%	>57200	14.60%
EHT		1.95%		1.95%
WSIB	90300	1.12%	91400	1.07%
CPP Employer Portion		4.95%		4.95%
EI Employer Portion		1.273%		1.245%

A detailed summary of Energy+'s actual benefit program costs are presented in Table 4-29 below.

Table 4-29: Benefit Expenses

Benefit	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Test Year
CPP - Employer's Portion	316,063	335,442	332,756	328,016	334,091	329,669
EI - Employers' Portion	154,269	135,861	164,207	138,067	153,026	148,169
Employee Health Tax	219,992	229,152	234,330	232,546	236,773	235,429
WSIB	102,940	106,361	107,682	138,251	111,003	110,405
Total Statutory	793,263	806,816	838,976	836,879	834,893	823,672
OMERS	1,100,209	1,143,622	1,151,834	1,163,343	1,309,816	1,222,598
Health and Dental Benefits	504,105	457,206	481,369	514,556	562,412	597,984
LTD Insurance	80,092	83,140	77,378	86,450	132,077	140,414
Life Insurance	45,648	45,909	41,663	37,451	34,585	30,986
Employee Future Benefits	205,396	110,785	137,625	261,567	172,308	182,354
Other	54,124	54,165	59,112	60,641	63,795	66,423
Total Company	1,989,574	1,894,826	1,948,981	2,124,007	2,274,994	2,240,760
Total Benefits	**2,782,837**	**2,701,642**	**2,787,957**	**2,960,887**	**3,109,887**	**3,064,433**

The following Table 4-30 below summarizes the year over year variance analysis with respect to benefit expenses. With the exception of OMERS expense in the 2018 Bridge Year (highlighted in grey in the table), there are no variances that exceed Energy+'s materiality threshold of $175,000. The increase in OMERS expense in 2018 Bridge Year includes an amount of $86,000 that represents an OMERS retirement payment that formed part of a negotiated employment settlement agreement. This payment is not included in the 2019 Test Year, resulting in a decrease in the OMERS benefit expense in the 2019 Test Year.

Table 4-30: Benefit Expense Variance Analysis

	Variance Analysis - Benefits				
Benefit	**2015 v 2014**	**2016 v 2015**	**2017 v 2016**	**2018 v 2017**	**2019 v 2018**
CPP - Employer's Portion	19,379	(2,686)	(4,740)	6,075	(4,422)
EI - Employers' Portion	(18,407)	28,346	(26,141)	14,960	(4,857)
Employee Health Tax	9,160	5,179	(1,784)	4,227	(1,344)
WSIB	3,421	1,321	30,568	(27,248)	(598)
Total Statutory	13,553	32,160	(2,097)	(1,986)	(11,221)
OMERS	43,413	8,212	11,509	146,473	(87,218)
Health and Dental Benefits	(46,899)	24,163	33,187	47,856	35,573
LTD Insurance	3,048	(5,762)	9,072	45,627	8,337
Life Insurance	261	(4,246)	(4,212)	(2,866)	(3,599)
Employee Future Benefits	(94,611)	26,840	123,942	(89,259)	10,046
Other	41	4,947	1,529	3,155	2,628
Total Company	(94,747)	54,154	175,026	150,987	(34,233)
Total Benefits	**(81,194)**	**86,315**	**172,929**	**149,000**	**(45,454)**

4.4.2.3.3 OMERS and Post-Employment Benefits

OMERS Pension Plan

Energy+ employees are members of the Ontario Municipal Employees Retirement System ("**OMERS**"). OMERS is a multi-employer pension plan that most LDC's participate in, therefore the pension benefit provided to Energy+ employees is consistent with that of other LDC's. The plan is a contributory defined pension plan which is financed by equal contributions from the employer and employee based on the employee's contributory earnings. For the 2019 Test Year, Energy+ assumed OMERS rates of 9% on earnings up to CPP earning limits and 14.6% on earnings over CPP earnings limit as per the OMER's website. Table-31 provides a summary of the annual OMERS contributions for the 2014 Actual, 2015 Actual, 2016 Actual, 2017 Actual, 2018 Bridge and 2019 Test Years.

Table 4-31: OMERS Contribution Costs

OMERS Contributions	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Test Year
OMERS	1,100,209	1,143,622	1,151,834	1,163,343	1,309,816	1,222,598

Post-employment and other actuarial defined benefits

Energy+ pays certain health, dental, and life insurance benefits under defined benefits plans on behalf of its retired employees. The cost of these benefits is expensed as earned by employees through employment service. The accrued benefit obligations and current service cost are actuarially determined by applying the projected benefits method pro-rated on service and based on assumptions that reflect management's best estimates. The amount of the obligation is determined from actuarial valuations performed every three years. In the years between valuations, an extrapolation is used.

Energy+ also provides a short-term non-vesting sick-leave benefit to its employees. Actuarial gains and losses on accumulated sick-leave credits are recognized in the statements of income in the period in which they arise.

Table 4-32 below summarizes the amount of post-retirement benefits and sick-leave benefit expense, based on the actuarial expense, that are included in benefit costs for the 2014 Actual, 2015 Actual, 2016 Actual, 2017 Actual, 2018 Bridge Year and 2019 Test Year. Table 4-33 provides the reconciliation of the post-retirement and sick leave benefits liability at the end of each year for the 2014 Actual, 2015 Actual, 2016 Actual, 2017 Actual, 2018 Bridge Year and 2019 Test Year.

The accounting for post-employment benefits is on an accrual basis and the approach has not changed from the former CND and BCP's last rebasing.

Energy+ confirms that the Pension and Other Post-Employment Benefits ("OPEBs") costs treatment proposed in the Application is consistent with the *Report of the Board: Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs.*

Table 4-32: Post-Employment and Other Benefits – Actuarial Expense

Post Retirement/Other Benefits Expense	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Test Year
Actuarial Expense						
Post Retirement Benefits	172,826	162,510	147,625	173,567	172,308	182,354
Sick Leave	32,570	(51,725)	(10,000)	88,000	-	-
	205,396	110,785	137,625	261,567	172,308	182,354

Table 4-33: Post-Employment and Other Benefits Liability

Post Retirement Benefits Liability	2014 Actual (MIFRS)	2015 Actual	2016 Actual	2017 Actual	2018 Bridge	2019 Test Year
Opening Balance						
Post Retirement Benefits	2,470,249	2,606,885	2,623,510	2,838,526	2,983,986	2,983,986
Sick Leave	324,155	356,725	305,000	295,000	383,000	383,000
	2,794,404	2,963,610	2,928,510	3,133,526	3,366,986	3,366,986
Actuarial Expense						
Post Retirement Benefits	172,826	162,510	147,625	173,567	172,308	182,354
Sick Leave	32,570	(51,725)	(10,000)	88,000	-	-
	205,396	**110,785**	**137,625**	**261,567**	**172,308**	**182,354**
Premiums Paid	(143,966)	(145,885)	(125,215)	(142,734)	(172,308)	(182,354)
Valuation Adjustment - OCI	107,776		192,606	114,627		
Closing Balance	2,963,610	2,928,510	3,133,526	3,366,986	3,366,986	3,366,986

The latest copy of the Actuarial Valuation has been provided as Appendix 4-1.

4.4.2.3.4 Allocation of Benefits to OM&A and Capital

Please refer to Exhibit 2, Section 2.7.4.2 for a description of Energy+'s capitalization of overhead policy, including the allocation of the payroll burden, which includes benefits. Table 2-45, which is the OEB's Appendix2-D, in that Exhibit provides the amount of direct labour, including benefits, that is allocated to capital.

4.5 SHARED SERVICES/CORPORATE COST ALLOCATION

Energy+ provides accounting services to Cambridge and North Dumfries Energy Plus Inc. ("Energy Plus") and Cambridge and North Dumfries Energy Solutions Inc. ("CND Energy Solutions") for a fixed monthly fee, which represents an allocation of all Accounting department expenditures of approximately 1% and 2% respectively. Commencing in 2017, Energy+ also provides accounting services for Grand River Energy Solutions Corp. ("GRE"), which is 1/3 owned by CND Energy Solutions.

Energy Plus is a holding company, with a limited number of transactions each year. CND Energy Solutions currently completes streetlight maintenance services for the Region of Waterloo, the City of Cambridge, and the Township of North Dumfries. GRE is an unregulated generation and renewable energy solutions company, which is in an early development stage, with limited transactions.

All direct costs incurred by Energy Plus, CND Energy Solutions, and GRE have been recorded directly to Energy Plus, CND Energy Solutions, and GRE accounting records.

Energy+ provides the coordination and material relating to street light maintenance to CND Energy Solutions on a full cost recovery basis which includes labour, benefits, materials, overheads and all other identifiable costs.

Energy+ recovers Board of Directors' costs from Energy Plus and CND Energy Solutions on a full cost recovery basis.

Tables 4-34 provides a summary of the Shared Services and Corporate Cost Allocations for the 2014 Board Approved Proxy, 2018 Bridge Year and 2019 Test Year.

Table 4-34: Shared Services and Corporate Cost Allocation Summary

		2014 Board Approved		2019 Test Year		2018 Bridge Year	
	Service Provided	Price	Cost	Price	Cost	Price	Cost
Shared Services - Provided To							
Energy Solutions	Street Light Maintenance	376,745	376,745	213,000	213,000	213,000	213,000
Energy Plus	Board of Directors	11,100	11,100	11,100	11,100	11,100	11,100
Energy Solutions	Board of Directors	11,100	11,100	11,100	11,100	11,100	11,100
		398,945	398,945	235,200	235,200	235,200	235,200
Corporate Cost Allocation							
Energy Plus	Accounting	6,000	1.0%	6,120	1.0%	6,120	1.1%
Energy Solutions	Accounting	12,000	2.0%	12,240	2.0%	12,240	2.1%
Grand River Energy Solutions Corp	Accounting	-	NA	10,000	1.7%	10,000	1.7%
		18,000		28,360		28,360	
TOTAL		$ 416,945	$ 398,945	$ 263,560	$ 235,200	$ 263,560	$ 235,200

With the exception of Streetlight maintenance services provided to Energy Solutions, there are no material variances between the 2014 Board Approved Proxy, 2018 Bridge Year, and 2019 Test Year. The Streetlight Maintenance services provided to Energy Solutions in the 2018 Bridge Year and 2019 Test Year are projected to be $163,745 lower than the 2014 Board Approved Proxy. The conversion of streetlights to LED lighting in 2016 and 2017 by the City of Cambridge and the Region of Waterloo has resulted in a reduction in the maintenance services projected to be provided by Energy+ to Energy Solutions.

Tables 4-35A and 4-35B provide a summary of charges for services projected for the 2018 Bridge and 2019 Test Year. Included in Appendix 4-2 are the historical Appendix 2-N Shared Services and Corporate Cost Allocation for the historical years 2014, 2015, 2016, and 2017 Forecast.

Table 4-35A: Shared Services/Corporate Cost Allocation – 2018 Bridge

Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2018

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Energy+ Inc.	Energy Solutions	Street Light Maintenance	Cost	213,000	213,000
Energy+ Inc.	Energy Plus	Board of Directors	Cost	11,100	11,100
Energy+ Inc.	Energy Solutions	Board of Directors	Cost	11,100	11,100

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Energy+	Energy Plus	Accounting	Cost		6,120
Energy+	Energy Solutions	Accounting	Cost		12,240
Energy+	GRE Corporation	Accounting	Cost		10,000

Table 4-35B: Shared Services/Corporate Cost Allocation – 2019 Test Year

Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Energy+ Inc.	Energy Solutions	Street Light Maintenance	Cost	213,000	213,000
Energy+ Inc.	Energy Plus	Board of Directors	Cost	11,100	11,100
Energy+ Inc.	Energy Solutions	Board of Directors	Cost	11,100	11,100

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Energy+	Energy Plus	Accounting	Cost		6,120
Energy+	Energy Solutions	Accounting	Cost		12,240
Energy+	GRE Corporation	Accounting	Cost		10,000

4.6 PURCHASES OF PRODUCTS AND SERVICES OF NON-AFFILIATES

Energy+ purchases products and services from a variety of vendors. Suppliers provide operating expense and/or capital expense goods and services. Energy+ has a Purchasing and Contracts Policy which outlines the governing principles and procedures to be followed by all employees of Energy+ when purchasing a product or service. The Purchasing and Contracts Policy is attached as Appendix 4-3. Energy+ confirms that it is in compliance with the Purchasing Policy.

Table 4-36 provides a summary of Energy+'s purchases by vendor for 2014 to 2017 where the actual total expenditures exceed $175,000, the materiality threshold used in this Application. The table also identifies the method of selecting the vendor.

For 2018 and 2019, Energy+ anticipates that many of the same vendors will be used as was used in prior years. However, Energy+ continually searches for new suppliers in order to purchase new services and material at prices, terms and quality of products and services that will benefit Energy+ and ultimately, the customers.

Table 4-36: Products and Services of Non Affiliates

VendorName	Product/Service	Method	2014	2015	2016	2017
ANIXTER (formerly HD SUPPLY)	Inventory & Transformers	INV quoteTX partnership/alliance	796,028	1,238,655	1,930,751	2,099,312
D.L. HANNON INC.	Construction Services	Tender	328,026	129,500	560,570	1,204,126
UNDERGROUND CONDUIT SOLUTIONS INC.	Construction Services	Tender	50,050		25,102	1,003,822
MEARIE GROUP (Benefits)	Employee Benefits	Tender	720,649	762,537	870,752	938,733
STELLA-JONES (formerly GUELPH UTILITY POLE)	Poles	Sole Source	454,489	898,388	696,093	807,605
DAVEY TREE EXPERT CO.	Tree Trimming Services	Tender	532,763	693,065	650,302	727,508
NETWORK UNDERGROUND UTILITIES INC.	Construction Services	Tender			182,715	478,457
FOLMUR CONSTRUCTION (2004) LTD	Construction Services	Tender	731,925	1,187,888	1,431,200	445,941
NEXANS CANADA INC.	Inventory	Tender	236,511	444,385	456,546	438,562
SENSUS METERING SYSTEMS	Monitoring Services & AMI Network	Tender	337,744	284,811	295,835	422,156
HARRIS COMPUTER SYSTEMS	Software/Support/Meter Maint.	Sole Source	246,794	530,362	336,663	369,383
CARTE INTERNATIONAL INC.	Transformers	Partnership/Alliance			675,994	345,265
STANTEC CONSULTING LIMITED	Engineering Services	Quote	364,293	375,078	273,642	307,490
MEARIE GROUP (Insurance)	Insurance	Sole Source	319,857	269,623	250,013	275,920
SUPER SUCKER HYDRO VAC SERVICE	Hydrovac Services	Quote	84,535	123,335	209,900	261,270
HY-LINE UTILITY SOLUTIONS	Construction Services	Tender		48,192	550,193	257,956
NBM ENGINEERING INC.	Engineering Services	Quote	44,455	25,826	15,469	257,119
BADGER DAYLIGHTING INC.	Hydrovac Services	Quote	175,879	285,087	229,381	233,576
WESTBURNE RUDDY	Inventory	Quote	171,336	168,624	201,956	216,469
BEL VOLT SALES LTD.	Inventory	Quote	147,732	140,526	180,005	205,967
ITRON CANADA INC.	Meters	Sole Source	135,780	47,169	46,200	184,000
THOMAS & BETTS	Switches	Sole Source	86,000	380,776	164,315	172,743
COMPUGEN INC.	Hardware/Software	Partnership/Alliance	273,182	134,465	143,444	164,366
UTILISMART CORPORATION	Settlement Services	Sole Source	161,329	174,338	181,076	157,998
KTI LIMITED	Meters/Parts	Sole Source	91,283	41,765	206,699	148,183
UTS CONSULTANTS INC.	Engineering Services	Quote	38,000	39,566	225,234	138,591
LONG VIEW SYSTEMS	Hardware/Software/Support	Partnership/Alliance	257,472	65,080	80,152	119,155
ADVANCED CONTROL SYSTEMS	Software/Support	Sole Source	132,879	290,380	214,558	91,705
BRANTFORD POWER	Transformer Station Expenses	Tender	29,793	425,652	3,688	45,163
S & C ELECTRIC CANADA LTD	Switches	Sole Source	202,710	765,892	253,094	43,709
VALARD CONSTRUCTION LP	Construction Services	Tender	339,048	1,157,234	62,974	28,859
BLACK & MCDONALD LIMITED	Construction Services	Tender	287,375			8,995
ACUMEN ENGINEERED SOLUTIONS INTL	Consulting Services	Quote	15,960	16,787	174,701	2,841
PA CONSULTING GROUP	Consulting Services	Quote	378,164	142,505		
POWERTEL UTILITIES CONTRACTORS LIMITED	Construction Services	Tender			260,867	
SOUTHWEST POWER CORPORATION	Construction Services	Tender	266,481	587,835	91,662	
WESTMORE POLELINE & ELECTRIC INC.	Construction Services	Tender	187,166	342,341		
MOLONEY ELECTRIC	Transformers	Sole Source	1,308,989	1,069,699	291,568	
POSI-PLUS TECHNOLOGIES INC.	Vehicles	Sole Source	402,628			
TIMBERLAND EQUIPMENT LIMITED	Stringing Machine (Asset)	Quote			290,835	
WAJAX EQUIPMENT	Vehicles	Quote	247,675	426,075		

The following methods of procurement are used to acquire goods and services throughout the year to best suit the needs of the Company.

Methods of Procurement:

Tendered – Invited qualified vendors are sent a formal document and are asked to bid with a predetermined closing date. Low bid is awarded the contract, unless unique circumstances dictate otherwise, as approved by the CEO.

Quoted – Obtain quotes for a specific product from qualified vendors. Business is awarded to vendor based on price, service and lead times.

RFP – Request for Proposals is sent to vendors. Business is awarded to the vendor that best suits the needs of Energy+ and its customers.

Quoted/Negotiated – Obtain quotes/pricing from a vendor then work with them to negotiate pricing that is agreeable to both parties.

- The advantage of this method is there is the opportunity to obtain both better service and reliability of product availability. For example, wood poles pricing stays constant for 2 years, they are dropped on-site and Energy+ does not have to deal with rail cars/unloading/transporting and both parties agree on price.

Invoiced – Invoice is sent to us, pricing is not negotiated, i.e. municipal taxes, energy costs.

Quoted – Single Source Purchase – these products are specified by the department involved and are a single source purchase, i.e. specific types of switches, line trucks.

The reason why this method is utilized is to ensure the quality of the product or service, and to ensure it performs to the specific operational and engineering requirements as set by the department.

Partnership/Alliance – Obtain pricing for the year, sometimes 2 years, and negotiate this pricing at an amount agreeable to both parties. Spot check pricing is done to ensure pricing is in line with market levels, i.e. transformers, some types of power cable.

- Reasons for this Method:

1. Steady supply of material at predetermined lead times, regardless of the market, i.e. market at various periods indicate delivery lead times of 20 to 40 weeks and the partnership agreement states 8 to 10 weeks. For example, reliable supply of transformers and power cable are vital to ensure timely repairs and improvements, and therefore a partnership agreement is a most efficient manner of conducting business.

2. Fixed pricing for a 1 or 2 year period, lower lead times, valuable engineering services from vendor, faster turnaround on returns and repairs that are required.

4.7 ONE TIME COSTS AND REGULATORY EXPENSES

4.7.1 One-time Costs

The only noteworthy one-time costs relate to the costs associated with the preparation of the 2019 Cost of Service ("COS") Rate Application.

Energy+ estimates that the total incremental costs associated with the COS application will be $850,000. Details are provided under Regulatory Expenses in Section 4.7.2 and are as summarized in Table 4-37 and Table 4-38, Board Approved Appendix 2-M. One fifth of the cost or $190,000 has been included in the 2019 Test Year. This represents an increase of approximately $62,000 over the 2014 Board Approved Proxy amount included in the 2014 Revenue Requirement computation on a consolidated basis ($190,000 versus $128,000).

Table 4-39 provides a summary of the 2014 Board Approved Proxy-Regulatory Expenses computation.

4.7.2 Regulatory Expenses

4.7.2.1 Staffing

Energy+'s Manager, Regulatory Affairs and Financial Planning is primarily responsible for preparing regulatory filings and rate applications, completing audits, ensuring regulatory and legislative compliance and providing input to the various regulatory agencies. A Regulatory and Financial Analyst reports to the Manager. Due to the complexity and work load involved in completing the above tasks, other members of the Management team are required on an on-going basis to ensure regulatory and legislative compliance and also to provide assistance in preparing rate applications. The Manager, Accounting and Accounting Staff also perform regulatory accounting and assist with the preparation of the Cost of Service Application, including variance analysis.

The staffing costs for the Finance department, including the regulatory staff noted above, are included in Accounting and General Administrative Program Costs.

4.7.2.2 OEB Assessments

Energy's other regulatory expenses include annual assessment fees paid to the OEB, cost awards for hearings, proceedings and other matters before the regulatory body and costs associated with consultants providing regulatory compliance assistance.

As previously documented in Section 4.2.4, the OEB Assessment fees for Energy+ have increased significantly ($97,000) from the 2014/2011 Board Approved amounts for the former CND and BCP. Prior to 2019, the increase in OEB Assessment Fees has been recorded in a deferral account. In 2019, the increased OEB Assessment Fees are included in OM&A.

4.7.2.3 Regulatory Applications

Regulatory expenses continue to increase with the demand for reporting, ensuring compliance in a complex environment and the completion of annual incentive rate mechanism filings and cost of service applications. The filing requirements for the 2019 cost of service application are more extensive than those experienced in 2014 (and in 2011 for the former BCP).

Energy+ will incur significant costs for preparing, processing and approval of this Application. The costs include consulting and legal fees, incremental expenses related to staff resources, and intervenor cost awards as identified in Table 4-38, Board Appendix 2-M. The total cost for this application is forecasted to be $850,000. OEB and Intervenor expenses have been forecasted at $100,000. Energy+ requests approval of these costs to be recovered over a five-year period.

As part of the preparation of the Application, Energy+ has incurred incremental costs associated with the preparation of a consolidated Distribution System Capital Plan, augmented customer engagement initiatives to ensure that customers have been engaged and feedback considered in the Application, and additional regulatory and legal support due to certain complexities associated with the Application as a result of the acquisition and subsequent legal amalgamation, including load forecasting, cost allocation, and rate harmonization. Energy+ has not included the costs associated with the preparation of the Asset Condition Assessment undertaken in 2017 as it considers this expenditure to form part of the on-going Asset Management Planning process.

Table 4-37: Regulatory Cost Schedule

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (Board Approved Proxy)	Most Current Actuals Year 2017	2018 Bridge Year	Annual % Change	2019 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 201,901	$ 287,529	$ 291,329	1.32%	$ 298,912	2.60%
2	OEB Section 30 Costs (Applicant-originated)			One-Time	$ -				$ 35,000	
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 12,000	$ 6,415	$ 14,000	118.24%	$ 14,000	0.00%
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters	5655		One-Time		$ 66,556	$ 125,000	87.81%	$ 50,000	-60.00%
5	Legal costs for regulatory matters			On-Going	$ 29,474					
6	Consultants' costs for regulatory matters	5655		One-Time		$ 262,861	$ 80,000	-69.57%	$ 5,000	-93.75%
6	Consultants' costs for regulatory matters			On-Going	$ 45,000					
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		One-Time		$ 107,538		-100.00%		
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments			On-Going	$ 800	$ 800	$ 800	0.00%	$ 800	0.00%
10	Any other costs for regulatory matters (please define) - Public Meetings	5655		One-Time		$ 9,040	$ 10,000	10.62%		-100.00%
10	Any other costs for regulatory matters (please define) - Amortization of CoS Costs			One-Time	$ 127,920					
11	Intervenor costs	5655		One-Time		$ 833		-100.00%	$ 100,000	
12	Sub-total - Ongoing Costs [3]		$ -		$ 289,175	$ 294,744	$ 306,129	3.86%	$ 313,712	2.48%
13	Sub-total - One-time Costs [4]		$ -		$ 127,920	$ 446,828	$ 215,000	-51.88%	$ 190,000	-11.63%
14	Total		$ -		$ 417,095	$ 741,572	$ 521,129	-29.73%	$ 503,712	-3.34%

Table 4-38: Cost of Service Application Costs

		Historical Year(s)	2018 Bridge Year	2019 Test Year
2	OEB Section 30 Costs (Applicant-originated)			$ 35,000
4	Expert Witness costs			
5	Legal costs	$ 66,556	$ 125,000	$ 50,000
6	Consultants' costs	$ 262,861	$ 80,000	$ 5,000
7	Incremental operating expenses associated with staff resources allocated to this application.	$ 107,538		
8	Incremental operating expenses associated with other resources allocated to this application. [1]			
10	Other - Public Meetings	$ 9,040	$ 10,000	
11	Intervenor costs			$ 100,000
Total		$ 445,995	$ 215,000	$ 190,000
Cumulative Total				$ 850,995

Table 4-39: 2014 Board Approved Proxy – Regulatory Expenses

		Board Approved		
Regulatory Cost Category		Former CND	Former BCP	Board Approved
		2014	2011	Proxy
1	OEB Annual Assessment	$ 156,000	$ 45,901	$ 201,901
2	OEB Section 30 Costs (Applicant-originated)			$ -
3	OEB Section 30 Costs (OEB-initiated)	$ 12,000		$ 12,000
4	Expert Witness costs for regulatory matters			$ -
5	Legal costs for regulatory matters		$ 29,474	$ 29,474
6	Consultants' costs for regulatory matters		$ 45,000	$ 45,000
7	Operating expenses associated with staff resources allocated to regulatory matters			$ -
8	Operating expenses associated with other resources allocated to regulatory matters 1			$ -
9	Other regulatory agency fees or assessments	$ 800		$ 800
10	Any other costs for regulatory matters (please define) - Public Meetings			$ -
11	Intervenor costs			$ -
12	Sub-total - Ongoing Costs 3	$ 168,800	$ 120,375	$ 289,175
13	Sub-total - One-time Costs 4	$ 98,295	$ 29,625	$ 127,920
14	Total	$ 267,095	$ 150,000	$ 417,095

Note: Summary of One-Time Costs

Cost of Service Preparation Costs (2014/2011)	$ 491,476	$ 118,500	$ 609,976
Annual Cost - Amortized over 5 Years	$ 98,295	$ 29,625	$ 127,920

4.8 LOW INCOME ENERGY ASSISTANCE PROGRAM ("LEAP") AND DONATIONS

4.8.1 Low-Income Emergency Assistance Program ("LEAP")

Energy+ continues to participate in the Low Income Emergency Assistance Program (LEAP). As set out in the March, 2009 *Report of the Board: Low Income Energy Assistance Program,* the Board has determined that the greater of 0.12% of a distributor's Board approved distribution revenue requirement or $2,000 is a reasonable commitment of all distributors to emergency financial assistance. The LEAP amount must be calculated based on total distribution revenues and is to be recovered from all rate classes based on the respective distribution revenue of each of those classes. Energy+ has partnered with the Waterloo Region Social Services and Family Counselling of Brant to assist in the LEAP program and is intended to provide emergency relief to eligible low-income customers who may be experiencing difficulty paying current arrears amounts to Energy+. Energy+ has budgeted an amount of $42,000 based on the 2019 proposed distribution revenue requirement. The LEAP amount will be adjusted to account for changes resulting from the Board's Decision on Energy+'s 2019 Test Year distribution revenue requirement. For purposes of this Application, the LEAP amount has been included in USoA Account 6205 Donations to ensure that it is captured appropriately in the Revenue Requirement.

4.8.2 Charitable and Political Donations

Energy+ confirms that it has not included the recovery of charitable donations for the purpose of setting rates, with the exception of the LEAP program, summarized above in Section 4.8.1. Energy+ does not make political donations and therefore confirms that no political donations are included for recovery.

4.9 DEPRECIATION, AMORTIZATION AND DEPLETION

4.9.1 Overview

Energy+ amortizes its capital assets available for use on a straight-line basis over their estimated useful lives of each significant component. Amortization is recorded at one-half of the annual rate for assets placed into service or acquired in the current year, in accordance with Section 2.7.4 of Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. Depreciation of an asset begins in the year when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended.

Construction in progress assets are not amortized until the project is complete and the asset is available for use.

Costs incurred to remove an existing asset from service are recorded as removal costs and the expense is grouped with depreciation and amortization expense.

At this time, Energy+ does not have any Asset Retirement Obligations, and therefore no associated depreciation.

Energy+'s accounting policy is to expense borrowing costs. Energy+ does not capitalize interest on capital projects unless they meet the IFRS criteria of a qualifying asset, which is defined in the Board's "Report of the Board EB-2008-0408 Transition to International Financial Reporting Standards, June 28, 2009" as an "asset that necessarily takes a substantial period of time to get ready for its intended use or sale". Energy+ does not have any capitalized borrowing costs forecast in its 2018 Bridge or 2019 Test Year.

Energy+'s Capitalization Policy is fully described in Exhibit 2, Section 2.7.4.

Table 4-40 provides a summary of Energy+'s amortization expense for 2014 Board Approved Proxy, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Forecast, 2018 Bridge, and 2019 Test Year. Table 4-41 provides the computation of Energy+'s 2014 Board Approved Proxy.

Details of Energy+'s depreciation expense and amortization expense are provided in Section 4.9.3.2 Depreciation Expense. Fixed Asset Continuity Schedules are provided in Exhibit 2, Section 2.3.

Table 4-40: Summary of Depreciation and Amortization Expense

USoA	Description	2014 Board Approved Proxy	2014 Actual (GCAAP)	2015 Actual (MIFRS)	2016 Actuals	2017 Forecast	2018 Bridge	2019 Test
1611	Computer Software (Formally known as Account 1925)	698,074	613,532	746,850	839,876	701,000	766,258	813,708
1805	Land	-	-	-	-	-	-	-
1808	Buildings	38,069	34,673	34,026	30,957	20,000	32,798	32,798
1815	Transformer Station Equipment >50 kV	429,815	421,725	426,041	433,366	283,000	267,755	268,828
1820	Distribution Station Equipment <50 kV	17,667	-	-	-	-	-	-
1830	Poles, Towers & Fixtures	712,431	657,245	727,444	454,414	694,000	818,619	884,662
1835	Overhead Conductors & Devices	825,091	719,376	773,213	815,866	995,000	1,061,136	1,148,256
1840	Underground Conduit	235,457	218,535	237,821	233,373	290,000	297,714	315,267
1845	Underground Conductors & Devices	626,454	560,687	602,471	611,390	736,000	762,717	807,234
1850	Line Transformers	808,976	762,120	805,421	695,098	888,000	941,504	985,261
1855	Services (Overhead & Underground)	92,065	49,653	51,034	8,452	42,000	42,514	42,514
1860	Meters/Smart Meters	774,382	882,252	888,959	1,114,982	811,000	852,257	895,267
1905	Land	-	-	-	-	-	-	-
1908	Buildings & Fixtures	164,129	184,100	178,174	204,937	160,000	167,005	183,563
1910	Leasehold Improvements	-	-	8,674	15,851	-	-	-
1915	Office Furniture & Equipment	58,847	44,658	50,954	60,456	56,000	59,933	57,274
1920	Computer Equipment (Hardware)	550,880	553,837	468,079	370,475	384,000	253,071	257,215
1930	Transportation Equipment	397,456	358,564	417,100	335,578	461,000	460,451	462,769
1935	Stores Equipment	414	516	989	1,463	1,000	1,463	1,463
1940	Tools, Shop & Garage Equipment	105,678	169,745	87,348	112,984	94,000	99,093	96,433
1945	Measurement & Testing Equipment	7,670	3,306	11,306	(3,553)	-	-	-
1950	Power Operated Equipment	302	1,672	2,946	1,768	3,000	2,549	-
1955	Communication Equipment	4,514	338	8,058	(7,884)	-	-	-
1960	Miscellaneous Equipment	3,297	13,074	103,677	8,568	66,000	501	501
1995	Contributions & Grants	(500,489)	(494,244)	(508,037)	(376,445)	(417,000)	(435,509)	(435,509)
2010	Electric Plant Purchased or Sold	-	1,213	1,212	-	-	-	-
2440	Deferred Revenue	-	-	(70,270)	(146,349)	(189,000)	(203,765)	(234,498)
Total		**6,051,180**	**5,756,577**	**6,053,491**	**5,815,622**	**6,079,000**	**6,248,064**	**6,583,006**
Less:	**Fully allocated depreciation**							
	Transportation Equipment	(397,456)	(358,564)	(417,100)	(335,578)	(461,000)	(460,451)	(462,769)
	Stores Equipment	(32,668)	(112,906)	(24,519)				
	Stranded Meter Adjustment	-	312,120					
	Removal Costs	472,884	354,855	457,428	511,155	568,000	316,160	348,600
	Deferred Revenue included in Other Revenue	-			146,349	189,000	203,765	234,498
	Miscellaneous Adjustments	(3,297)		(26,639)	(23,387)			
Total Depreciation for Rate Setting Purposes		**6,090,643**	**5,952,082**	**6,042,661**	**6,114,161**	**6,375,000**	**6,307,538**	**6,703,335**

Table 4-41: Summary of Depreciation and Amortization Expense – 2014 Board Approved Proxy

USoA	Description	2014 Board Approved CND	2014 Board Approved Proxy BCP	2014 Board Approved Proxy	2011 Board Approved Proxy BCP	IRM Factor 0.68%	IRM Factor 0.28%	IRM Factor 1.60%
1611	Computer Software (Formally known as Account 1925)	677,095	20,979	698,074	20,452	20,591	20,649	20,979
1805	Land		-	-		-	-	-
1808	Buildings	21,351	16,718	38,069	16,298	16,409	16,455	16,718
1815	Transformer Station Equipment >50 kV	365,445	64,370	429,815	62,753	63,180	63,357	64,370
1820	Distribution Station Equipment <50 kV		17,667	17,667	17,223	17,340	17,389	17,667
1830	Poles, Towers & Fixtures	502,914	209,517	712,431	204,253	205,642	206,218	209,517
1835	Overhead Conductors & Devices	684,064	141,027	825,091	137,484	138,419	138,806	141,027
1840	Underground Conduit	210,456	25,001	235,457	24,373	24,539	24,607	25,001
1845	Underground Conductors & Devices	528,980	97,474	626,454	95,025	95,671	95,939	97,474
1850	Line Transformers	647,510	161,466	808,976	157,409	158,479	158,923	161,466
1855	Services (Overhead & Underground)		92,065	92,065	89,752	90,362	90,615	92,065
1860	Meters/Smart Meters	717,254	57,128	774,382	55,693	56,072	56,229	57,128
1905	Land		-	-		-	-	-
1908	Buildings & Fixtures	155,304	8,825	164,129	8,603	8,662	8,686	8,825
1915	Office Furniture & Equipment	40,396	18,451	58,847	17,987	18,109	18,160	18,451
1920	Computer Equipment (Hardware)	514,213	36,667	550,880	35,746	35,989	36,090	36,667
1930	Transportation Equipment	233,631	163,825	397,456	159,709	160,795	161,245	163,825
1935	Stores Equipment		414	414	404	407	408	414
1940	Tools, Shop & Garage Equipment	85,910	19,768	105,678	19,271	19,402	19,456	19,768
1945	Measurement & Testing Equipment		7,670	7,670	7,477	7,528	7,549	7,670
1950	Power Operated Equipment		302	302	294	296	297	302
1955	Communication Equipment		4,514	4,514	4,401	4,431	4,443	4,514
1960	Miscellaneous Equipment		3,297	3,297	3,214	3,236	3,245	3,297
1995	Contributions & Grants	(425,260)	(75,229)	(500,489)	(73,339)	(73,838)	(74,044)	(75,229)
Total		**4,959,263**	**1,091,917**	**6,051,180**	**1,064,482**	**1,071,720**	**1,074,721**	**1,091,917**
Less:	**Fully allocated depreciation**							
	Transportation Equipment	(233,631)	(163,825)	(397,456)	(159,709)	(160,795)	(161,245)	(163,825)
	Stores Equipment		(32,668)	(32,668)	(31,847)	(32,064)	(32,153)	(32,668)
	Removal Costs	472,884	-	472,884		-	-	-
	Miscellaneous Adjustments		(3,297)	(3,297)	(3,214)	(3,236)	(3,245)	(3,297)
Total Depreciation for Rate Setting Purposes		**5,198,516**	**892,127**	**6,090,643**	**869,712**	**875,626**	**878,078**	**892,127**

4.9.2 Accounting Changes

4.9.2.1 Changes in Capitalization Policies and Depreciation

As described in Exhibit 2, Section 2.1.4 Accounting Policy Changes, in accordance with the Board's letter dated July 12, 2012, each of the former CND and BCP adopted capitalization and depreciation policies under CGAAP that were compliant with International Financial Reporting Standards. The former CND adopted the required accounting changes for depreciation and capitalization policies on January 1, 2012, which were included in the former CND's 2014 Cost of Service Application. The former BCP adopted the required accounting changes for depreciation and capitalization policies on January 1, 2013. The impact of the capitalization and depreciation changes related to the former BCP are detailed in Exhibit 9, Deferral and Variance Accounts (Account 1576).

Upon amalgamation on January 1, 2016, the accounting policies for depreciation and capitalization policies for Energy+ were harmonized to be consistent with the policies of the former CND.

4.9.2.2 Transition to Modified International Financial Reporting Standing ("MIFRS")

Both of the former CND and BCP followed Canadian Generally Accepting Accounting principles ("CGAAP") in 2013 and 2014. Each of the former utilities adopted International Financial Reporting Standards effective January 1, 2015 with restatement to January 1, 2014 ("transition date"). Energy+ adopted Modified International Financial Reporting Standards ("MIFRS") for rate making purposes effective January 1, 2015 and follows the OEB's Accounting Procedures Handbook ("APH").

4.9.3 Depreciation Rates and Methodology

4.9.3.1 Useful Lives and Componentization

The following outlines the depreciation practices used by Energy+ in this Application and provides a summary of changes since the last Cost of Service Application.

As indicated previously, the former CND adopted the required accounting changes for depreciation and capitalization policies on January 1, 2012, which were included in the former CND's 2014 Cost of Service Application. The former BCP adopted the required accounting changes for depreciation and capitalization policies on January 1, 2013. Upon legal amalgamation on January 1, 2016, the accounting policies for depreciation and capitalization policies for Energy+ were harmonized to be consistent with the policies of the former CND. As a result, during the years 2013, 2014, and 2015, the former BCP's useful lives were different in certain classes of assets.

Energy+'s estimated useful lives ("UL") were determined using the Kinectrics Useful Life Study ("CND Kinectrics Study") that was conducted on behalf of the former CND, Kitchener-Wilmot Hydro, and Guelph Hydro, which was incorporated into the former CND's 2014 Cost of Service Application (EB-2013-0116, Exhibit 4). A copy of the CND Kinectrics Study is provided in Appendix 4-8. With the exception of the useful lives utilized by the former BCP in the years 2013-2015, and the adoption of the former CND depreciation practices, Energy+ has not made any other changes to the depreciation expense policy or changes in asset services lives.

Table 4-42 summarizes the UL and depreciation rates for the Energy+ capital assets.

In selecting the useful life ("UL") of its assets, Energy+ utilized the following principles:

- Range for asset life expectancy based on the former CND Kinectrics Study;
- Local conditions, experiences and practices;
- Practical replacement strategy, which incorporates the replacement of more than one asset at the same time with different ranges of useful lives (i.e.. if an

asset with a longer life (e.g. duct structure) supports an asset with a shorter life (e.g. cable), then the typical life chosen for both assets will be based on the typical life of the asset with a shorter life expectancy); and

- Consideration of other factors that may shorten an asset's UL (e.g. the frequency of road rebuilding projects).

Table 4-43 summarizes the UL and depreciation rates for the former BCP capital assets for the years 2013 to 2015, and the adopted Energy+ rates effective January 1, 2016.

Energy+ has provided explanations for those assets where the UL used for purposes of amortization is outside of the minimum or maximum Typical Useful Lives ("TUL") in the OEB-sponsored Kinectrics Study.

Table 4-42: Service Life Comparison – Energy+ Inc.

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]
Energy+ Inc.

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	50	2%	50	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers and Fixtures	35	3%	35	3%	Yes	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	30	3%	30	3%	No	No
	5	OH Line Switch Motor			15	25	25	1835	Overhead Conductors and Devices	20	5%	20	5%	No	No
	6	OH Line Switch RTU			15	20	20	1835	Overhead Conductors and Devices	15	7%	15	7%	No	No
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	50	2%	50	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60	1835	Overhead Conductors and Devices	20	5%	20	5%	Yes	No
	10	OH Shunt Capacitor Banks			25	30	40	1850	Line Transformers	25	4%	25	4%	No	No
	11	Reclosers			25	40	55	1835	Overhead Conductors and Devices	50	2%	50	2%	No	No
TS & MS	12	Power Transformers	Overall		30	45	60	1815	TS Equipment	55	2%	55	2%	No	No
			Bushing		10	20	30			30	3%	30	3%	No	No
			Tap Changer		20	30	60			30	3%	30	3%	No	No
	13	Station Service Transformer			30	45	55	1850	Line Transformers	50	2%	50	2%	No	No
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30	1815	TS Equipment	30	3%	30	3%	No	No
			Battery Bank		10	15	15	1815	TS Equipment	15	7%	15	7%	No	No
			Charger		20	20	30	1815	TS Equipment	20	5%	20	5%	No	No
	16	Station Metal Clad Switchgear	Overall		30	40	60	1815	TS Equipment	60	2%	60	2%	No	No
			Removable Breaker		25	40	60	1815	TS Equipment	40	3%	40	3%	No	No
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60	1815	TS Equipment	30	3%	30	3%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20	1815	TS Equipment	15	7%	15	7%	No	No
	22	Rigid Busbars			30	55	60	1815	TS Equipment	55	2%	55	2%	No	No
	23	Steel Structure			35	50	90	1815	TS Equipment	80	1%	80	1%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	28	Primary TR XLPE Cables Direct Buried			25	30	35	1845	UG Conductors and Devices	35	3%	35	3%	No	No
	29	Primary TR XLPE Cables in Duct			35	40	55	1845	UG Conductors and Devices	50	2%	50	2%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1845	UG Conductors and Devices	60	2%	60	2%	No	Yes
	32	Secondary Cables in Duct			35	40	60	1845	UG Conductors and Devices	60	2%	60	2%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	50	2%	50	2%	No	Yes
	35	Submersible/Vault Transformers			25	35	45	1850	Line Transformers	25	4%	25	4%	No	No
	36	UG Foundation			35	55	70	1840	UG Conduit	60	2%	60	2%	No	No
	37	UG Vaults	Overall		40	60	80	1840	UG Conduit	60	2%	60	2%	No	No
			Roof		20	30	45	1850	Line Transformers	40	3%	40	3%	No	No
	38	UG Vault Switches			20	35	50	1845	UG Conductors and Devices	30	3%	30	3%	No	No
	39	Pad-Mounted Switchgear			20	30	45	1845	UG Conductors and Devices	30	3%	30	3%	No	No
	40	Ducts			30	50	85	1840	UG Conduit	75	1%	75	1%	No	No
	41	Concrete Encased Duct Banks			35	55	80	1840	UG Conduit	80	1%	80	1%	No	No
	42	Cable Chambers			50	60	80	1840	UG Conduit	60	2%	60	2%	No	No
S	43	Remote SCADA			15	20	30	1980	System Supervisory Equipment	15	7%	15	7%	No	No

Table F-2 from Kinetrics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Transportation Equipment	12	8%	12	8%	No	No
		Trailers	5	20	1930	Transportation Equipment	20	5%	20	5%	No	No
		Vans	5	10	1930	Transportation Equipment	8	13%	8	13%	No	No
3	Administrative Buildings - New		50	75	1908	Buildings and Fixtures	60	2%	60	2%	No	No
4	Administrative Buildings - Old		50	75	1908	Buildings and Fixtures	80	1%	80	1%	No	Yes
5	Leasehold Improvements		Lease dependent									
6	Station Buildings	Station Buildings	50	75	1908	Buildings and Fixtures	80	1%	80	1%	No	Yes
		Parking	25	30	1908	Buildings and Fixtures	25	4%	25	4%	No	No
		Fence	25	60	1908	Buildings and Fixtures	35	3%	35	3%	No	No
		Roof	20	30	1908	Buildings and Fixtures	20	5%	20	5%	No	No
7	Computer Equipment	Hardware	3	5	1920	Computer Hardware	3	33%	3	33%	No	No
		Software	2	5	1925	Computer Software	5	20%	5	20%	No	No
8	Equipment	Power Operated	5	10	1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
		Stores	5	10	1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop and Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10								
9	Communication	Towers	60	70								
		Wireless	2	10								
10	Residential Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
11	Industrial/Commercial Energy Meters		25	35	1860	Meters	25	4%	25	4%	No	No
12	Wholesale Energy Meters		15	30	1860	Meters	20	5%	20	5%	No	No
13	Current & Potential Transformer (CT & PT)		35	50	1860	Meters	45	2%	45	2%	No	No
14	Smart Meters		5	15	1860	Meters	15	7%	15	7%	No	No
15	Repeaters - Smart Metering		10	15								
16	Data Collectors - Smart Metering		15	20								

Table 4-43: Service Life Comparison – Former BCP

Table F-1 from Kinetrics Report[1]
Energy+ (Former Brant County Power Inc.)

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Prior to 2013		Up to Dec. 31, 2015		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	25	4%	35	3%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55								
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors and Devices	25	4%	55	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60								
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1850	Distribution Transformers	25	4%	40	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1815	Transformer Station	40	3%	45	2%	No	No
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30	1820	Substation Equipment	25	4%	5	20%	Yes	No
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60								
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90	1808	Building	30	3%	50	2%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40								
	32	Secondary Cables in Duct			35	40	60	1845	UG Conductors and Devices	25	4%	60	2%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45								
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70								
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45								
	40	Ducts			30	50	85	1840	UG Conduit	25	4%	40	3%	No	No
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30								

Table F-2 from Kinetrics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture and Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Rolling Stock (Transportation Equipment)	8	13%	10	10%	No	No
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings		50	75	1908	Buildings	30	3%	30	3%	Yes	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Hardware	5	20%	4	25%	No	No
		Software	2	5	1925	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10	1950	Power Equipment	10	10%	5	20%	No	No
		Stores	5	10	1935	Stores Equipment	5	20%	5	20%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools Shop Garage	10	10%	5	20%	No	No
			5	10	1960	Misc. Equipment	10	10%	5	20%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement and Testing Equipment	10	10%	5	20%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35								
11	Wholesale Energy Meters		15	30								
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Distribution Meters	25	4%	10	10%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

Fully Dressed Concrete Poles: Energy+ has used a UL of 35 years, based upon the former CND Kinectrics Study, compared to the TUL of 60 years in the Board's Kinectrics Report. Within Energy+'s service territory, concrete poles are located near major roadways and, based upon Energy+'s experience, are subject to higher levels of road salt, which causes faster degradation.

OH Voltage Regulators: Energy+ has used the UL of 20 years, based on the former CND Kinectrics Study, which is lower than the Board's Kinectrics Report TUL of 40. In Energy+'s experience, the voltage regulators wear out earlier than overhead transformers; the voltage regulators have internal parts that are moving thousands of times per year, which degrades the oil within the unit.

Secondary Cable Direct Buried: Energy+ has used a UL of 60 years as compared to the OEB Kinectrics Study TUL of 35 years. Energy+ is no longer using the direct buried methodology. Based upon past experience and in consideration of its rebuild strategy, Energy+ has used 60 years.

Padmount Transformers: Energy+ has used a UL of 50 years, which is between the TUL and MAX TUL of the former CND's Kinectrics Study. The Board's Kinectrics Report TUL is 40 years. Based on Energy+'s experience, including its rebuild history, the majority of transformers are expected to exceed the TUL of 40 years.

Administrative Building: Energy+ has used a UL of 80 years for its administrative building. The UL of 80 years is 5 years greater than the MAX UL in the Board's Kinectrics Report. CND's Kinectrics Study did not include this component.

Station Building: Energy+ has used a UL of 80 years, which is between the TUL and MAX UL in the former CND Kinectrics Study. This compares to the Board's Kinectrics Report TUL of 50 years. Energy+ believes that its transformer station, constructed in 2002, has an estimated useful life of 80 years.

For the former BCP between the years 2013 to 2015, there were two asset components whereby the UL used for purposes of amortization was outside of the minimum or maximum Typical Useful Lives in the OEB-sponsored Kinectrics Study.

Substation Equipment: The former BCP used a UL of 5 years for its substation equipment subsequent to the adoption of new useful lives under GCAAP in 2013. Prior to 2013, the UL was 25 years. As the former BCP was in the process of decommissioning its substations, the UL of 5 years was used to reflect the expected remaining life for these substations.

Administrative Building: The former BCP used a UL of 30 years for its administrative building, which was lower than the Kinectrics minimum UL of 50 years. The operations centre building located in Paris, ON is forecast to be sold in 2018 and therefore has been recognized as a disposition in the 2018 fixed asset continuity schedules.

4.9.3.2 Depreciation Expense

In accordance with the Filing Requirements, Energy+ has completed depreciation and amortization expense tables in Accordance with Appendix 2C: Depreciation and Amortization Expense for the following years:

- Table 4-44: 2014 Revised CGAAP, which accounts for the changes to service lives and componentization.
- Table 4-45: 2015 Actuals MIFRS
- Table 4-46: 2016 Actuals MIFRS
- Table 4-47: 2017 Forecast MIFRS
- Table 4-48: 2018 Bridge Year MIFRS
- Table 4-49: 2019 Test Year MIFRS

Energy+ does not have any material differences on the transition to MIFRS from Revised CGAAP, and therefore a 2014 MIFRS Appendix 2-C was not required.

Table 4-44: 2014 Revised CGAAP – Appendix 2-C Depreciation and Amortization Expense

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 1,544,106	$ 631,436	$ 912,670	$ 1,162,984	$ 13,670	$ 1,149,314	$ 948,115	5.24	19.08%	5.00	20.00%	$ 174,133	**$ 229,863**	**$ 94,812**	**$ 498,807**	$ 613,532	**$ 114,725**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1805	Land	$ 347,843	$ -	$ 347,843	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1808	Buildings	$ 1,498,548	$ -	$ 1,498,548	$ 248	$ -	$ 248	$ -	52.75	1.90%	80.00	1.25%	$ 28,408	**$ 3**	**$ -**	**$ 28,411**	$ 34,673	**$ 6,262**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 9,459,698	$ -	$ 9,459,698	$ 276,030	$ -	$ 276,030	$ -	37.30	2.68%	33.00	3.03%	$ 253,634	**$ 8,365**	**$ -**	**$ 261,999**	$ 421,725	**$ 159,726**
1820	Distribution Station Equipment <50 kV	$ 54,619	$ 54,619	-$ 0	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 18,129,972	$ -	$ 18,129,972	$ 4,389,337	$ 248,310	$ 4,141,027	$2,466,213	37.40	2.67%	50.00	2.00%	$ 484,819	**$ 82,821**	**$ 24,662**	**$ 592,301**	$ 657,245	**$ 64,943**
1835	Overhead Conductors & Devices	$ 19,587,572	$ -	$ 19,587,572	$ 5,731,752	$ -	$ 5,731,752	$2,381,987	40.05	2.50%	40.00	2.50%	$ 489,117	**$ 143,294**	**$ 29,775**	**$ 662,185**	$ 719,376	**$ 57,190**
1840	Underground Conduit	$ 13,025,017	$ -	$ 13,025,017	$ 2,091,299	$ -	$ 2,091,299	$ 561,403	71.71	1.39%	80.00	1.25%	$ 181,630	**$ 26,141**	**$ 3,509**	**$ 211,280**	$ 218,535	**$ 7,254**
1845	Underground Conductors & Devices	$ 19,080,475	$ -	$ 19,080,475	$ 4,253,678	$ -	$ 4,253,678	$1,201,122	46.57	2.15%	44.00	2.27%	$ 409,702	**$ 96,674**	**$ 13,649**	**$ 520,025**	$ 560,687	**$ 40,662**
1850	Line Transformers	$ 24,270,286	$ -	$ 24,270,286	$ 3,582,324	$ 617,504	$ 2,964,820	$1,875,606	39.92	2.50%	38.00	2.63%	$ 607,908	**$ 78,022**	**$ 24,679**	**$ 710,609**	$ 762,120	**$ 51,511**
1855	Services (Overhead & Underground)	$ 1,366,549	$ -	$ 1,366,549	$ 61,753	$ -	$ 61,753	$ 59,973	43.00	2.33%	40.00	2.50%	$ 31,780	**$ 1,544**	**$ 750**	**$ 34,074**	$ 49,653	**$ 15,579**
1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1860	Meters	$ 2,552,455	$ -	$ 2,552,455	$ 9,365,219	$ 221,915	$ 9,143,304	$ 295,527	10.94	9.14%	15.00	6.67%	$ 233,282	**$ 609,554**	**$ 9,851**	**$ 852,686**	$ 882,252	**$ 29,565**
1905	Land	$ 301,592	$ -	$ 301,592	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ 16,548	**$ 16,548**
1908	Buildings & Fixtures	$ 2,860,379	$ -	$ 2,860,379	$ 909,731	$ -	$ 909,731	$ 229,629	29.39	3.40%	50.00	2.00%	$ 97,326	**$ 18,195**	**$ 2,296**	**$ 117,817**	$ 167,552	**$ 49,736**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 79,789	$ -	$ 79,789	$ 206,814	$ -	$ 206,814	$ 51,558	8.74	11.44%	10.00	10.00%	$ 9,129	**$ 20,681**	**$ 2,578**	**$ 32,388**	$ 34,100	**$ 1,711**
1915	Office Furniture & Equipment (5 years)	$ 72,254	$ -	$ 72,254	$ 1,140	$ -	$ 1,140	$ -	5.00	20.00%	5.00	20.00%	$ 14,451	**$ 228**	**$ -**	**$ 14,679**	$ 10,558	**-$ 4,121**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 702,016	$ -	$ 702,016	$ 1,233,822	$ 631,436	$ 602,386	$ 598,258	3.38	29.58%	3.00	33.33%	$ 207,639	**$ 200,795**	**$ 99,710**	**$ 508,144**	$ 553,837	**$ 45,693**
1930	Transportation Equipment	$ 1,927,696	$ -	$ 1,927,696	$ 552,770	$ 213,577	$ 339,193	$ 848,074	8.43	11.87%	12.00	8.33%	$ 228,768	**$ 28,266**	**$ 35,336**	**$ 292,370**	$ 358,564	**$ 66,194**
1935	Stores Equipment	$ 1,290	$ -	$ 1,290	$ -	$ -	$ -	$ -	2.00	50.00%	5.00	20.00%	$ 645	**$ -**	**$ -**	**$ 645**	$ 516	**-$ 129**
1940	Tools, Shop & Garage Equipment	$ 822,096	$ -	$ 822,096	$ 134,103	$ -	$ 134,103	$ 55,129	6.23	16.05%	10.00	10.00%	$ 131,955	**$ 13,410**	**$ 2,756**	**$ 148,121**	$ 169,745	**$ 21,624**
1945	Measurement & Testing Equipment	$ 14,467	$ -	$ 14,467	$ -	$ -	$ -	$ -	3.45	28.99%	-	0.00%	$ 4,193	**$ -**	**$ -**	**$ 4,193**	$ 3,306	**-$ 887**
1950	Power Operated Equipment	$ 406	$ -	$ 406	$ -	$ -	$ -	$ 12,742	1.00	100.00%	10.00	10.00%	$ 406	**$ -**	**$ 637**	**$ 1,043**	$ 1,672	**$ 629**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%	-	0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1955	Communication Equipment	$ 1,140	$ -	$ 1,140	$ -	$ -	$ -	$ -	3.00	33.33%	-	0.00%	$ 380	**$ -**	**$ -**	**$ 380**	$ 338	**-$ 42**
1960	Miscellaneous Equipment	$ 156,583	$ -	$ 156,583	$ 87,500	$ 125,771	-$ 38,271	$ -	6.30	15.87%	10.00	10.00%	$ 24,854	**-$ 3,827**	**$ -**	**$ 21,027**	$ 13,074	**-$ 7,953**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 13,618,905	$ -	-$ 13,618,905	-$ 3,306,993	$ -	-$ 3,306,993	-$ 500,449	40.12	2.49%	43.57	2.30%	-$ 339,421	**-$ 75,901**	**-$ 5,743**	**-$ 421,065**	-$ 494,244	**-$ 73,179**
2005	Property under Finance Leases	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
2010	Electric Plant Purchased or Sold	$ 27,880	$ -	$ 27,880	$ -	$ -	$ -	$ -	27.00	3.70%	-	0.00%	$ 1,033	**$ -**	**$ -**	**$ 1,033**	$ 1,213	**$ 180**
2440	Deferred Revenue5	$ -	$ -	$ -	$ -	$ -	$ -	-$ 255,698		0.00%	43.57	2.30%	$ -	**$ -**	**-$ 2,934**	**-$ 2,934**	$ -	**$ 2,934**
	Total	**$ 104,265,823**	**$ 686,055**	**$ 103,579,768**	**$ 30,733,510**	**$ 2,072,183**	**$ 28,661,327**	**$ 10,829,190**					**$ 3,275,770**	**$ 1,478,127**	**$ 336,322**	**$ 5,090,220**	**$ 5,756,577**	**$ 666,357**

Table 4-45: 2015 MIFRS – Appendix 2-C Depreciation and Amortization Expense

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 1,544,106	$ 631,436	$ 912,670	$ 2,111,099	$ 194,951	$ 1,916,148	$ 1,362,426	4.28	23.34%	5.00	20.00%	$ 213,051	**$ 383,230**	**$ 136,243**	**$ 732,523**	$ 746,850	**$ 14,327**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1805	Land	$ 347,843	$ -	$ 347,843	$ -	$ -	$ -	$ -	-	0.00%	-	0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1808	Buildings	$ 1,498,548	$ -	$ 1,498,548	$ 248	$ -	$ 248	$ 9,430	52.75	1.90%	80.00	1.25%	$ 28,408	**$ 3**	**$ 59**	**$ 28,470**	$ 34,026	**$ 5,555**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 9,459,698	$ -	$ 9,459,698	$ 276,030	$ -	$ 276,030	$ 385,942	37.30	2.68%	33.00	3.03%	$ 253,634	**$ 8,365**	**$ 5,848**	**$ 267,847**	$ 426,041	**$ 158,195**
1820	Distribution Station Equipment <50 kV	$ 54,619	$ 54,619	-$ 0	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 18,129,972	$ -	$ 18,129,972	$ 6,855,550	$ 621,808	$ 6,233,742	$ 3,614,591	37.40	2.67%	50.00	2.00%	$ 484,819	**$ 124,675**	**$ 36,146**	**$ 645,639**	$ 727,444	**$ 81,805**
1835	Overhead Conductors & Devices	$ 19,587,572	$ -	$ 19,587,572	$ 8,113,739	$ -	$ 8,113,739	$ 2,801,781	40.05	2.50%	40.00	2.50%	$ 489,117	**$ 202,843**	**$ 35,022**	**$ 726,983**	$ 773,213	**$ 46,231**
1840	Underground Conduit	$ 13,025,017	$ -	$ 13,025,017	$ 2,652,702	$ -	$ 2,652,702	$ 1,322,950	71.71	1.39%	80.00	1.25%	$ 181,630	**$ 33,159**	**$ 8,268**	**$ 223,057**	$ 237,821	**$ 14,764**
1845	Underground Conductors & Devices	$ 19,080,475	$ -	$ 19,080,475	$ 5,454,800	$ -	$ 5,454,800	$ 2,314,666	46.57	2.15%	44.00	2.27%	$ 409,702	**$ 123,973**	**$ 26,303**	**$ 559,977**	$ 602,471	**$ 42,494**
1850	Line Transformers	$ 24,270,286	$ -	$ 24,270,286	$ 5,457,929	$ 1,367,778	$ 4,090,151	$ 2,460,360	39.92	2.50%	38.00	2.63%	$ 607,908	**$ 107,636**	**$ 32,373**	**$ 747,917**	$ 805,421	**$ 57,504**
1855	Services (Overhead & Underground)	$ 1,366,549	$ -	$ 1,366,549	$ 121,726	$ -	$ 121,726	$ 71,241	43.00	2.33%	40.00	2.50%	$ 31,780	**$ 3,043**	**$ 891**	**$ 35,714**	$ 51,034	**$ 15,320**
1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1860	Meters	$ 2,552,455	$ -	$ 2,552,455	$ 9,660,745	$ 268,771	$ 9,391,974	$ 242,967	10.94	9.14%	15.00	6.67%	$ 233,282	**$ 626,132**	**$ 8,099**	**$ 867,512**	$ 888,959	**$ 21,447**
1905	Land	$ 301,592	$ -	$ 301,592	$ -	$ -	$ -	$ -	-	0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 2,860,379	$ -	$ 2,860,379	$ 1,139,360	$ -	$ 1,139,360	$ 90,179	29.39	3.40%	50.00	2.00%	$ 97,326	**$ 22,787**	**$ 902**	**$ 121,015**	$ 178,174	**$ 57,159**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,525		0.00%	1.50	66.67%	$ -	**$ -**	**$ 8,175**	**$ 8,175**	$ 8,674	**$ 499**
1915	Office Furniture & Equipment (10 years)	$ 79,789	$ -	$ 79,789	$ 258,372	$ -	$ 258,372	$ -	8.74	11.44%	10.00	10.00%	$ 9,129	**$ 25,837**	**$ -**	**$ 34,966**	$ 40,418	**$ 5,452**
1915	Office Furniture & Equipment (5 years)	$ 72,254	$ -	$ 72,254	$ 1,140	$ -	$ 1,140	$ 107,443	5.00	20.00%	5.00	20.00%	$ 14,451	**$ 228**	**$ 10,744**	**$ 25,423**	$ 10,536	**-$ 14,887**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 702,016	$ -	$ 702,016	$ 1,802,360	$ 1,105,910	$ 696,450	$ 227,887	3.38	29.58%	3.00	33.33%	$ 207,639	**$ 232,150**	**$ 37,981**	**$ 477,770**	$ 468,079	**-$ 9,691**
1930	Transportation Equipment	$ 1,927,696	$ -	$ 1,927,696	$ 1,375,666	$ 735,164	$ 640,502	$ 596,194	8.43	11.87%	10.00	10.00%	$ 228,768	**$ 64,050**	**$ 29,810**	**$ 322,628**	$ 417,100	**$ 94,473**
1935	Stores Equipment	$ 1,290	$ -	$ 1,290	$ -	$ -	$ -	$ 14,625	2.00	50.00%	5.00	20.00%	$ 645	**$ -**	**$ 1,463**	**$ 2,108**	$ 989	**-$ 1,118**
1940	Tools, Shop & Garage Equipment	$ 822,096	$ -	$ 822,096	$ 189,232	$ 181,023	$ 8,209	$ 66,211	6.23	16.05%	10.00	10.00%	$ 131,955	**$ 821**	**$ 3,311**	**$ 136,086**	$ 87,348	**-$ 48,738**
1945	Measurement & Testing Equipment	$ 14,467	$ -	$ 14,467	$ -	$ -	$ -	$ -	3.45	28.99%	10.00	10.00%	$ 4,193	**$ -**	**$ -**	**$ 4,193**	$ 11,306	**$ 7,113**
1950	Power Operated Equipment	$ 406	$ -	$ 406	$ 12,742	$ -	$ 12,742	$ -	1.00	100.00%	10.00	10.00%	$ 406	**$ 1,274**	**$ -**	**$ 1,680**	$ 2,946	**$ 1,266**
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%	-	0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1955	Communication Equipment	$ 1,140	$ -	$ 1,140	$ -	$ -	$ -	$ -	3.00	33.33%	3.00	33.33%	$ 380	**$ -**	**$ -**	**$ 380**	$ 8,058	**$ 7,678**
1960	Miscellaneous Equipment	$ 156,583	$ -	$ 156,583	$ 87,500	$ 71,441	$ 16,059	$ 179	6.30	15.87%	10.00	10.00%	$ 24,854	**$ 1,606**	**$ 9**	**$ 26,469**	$ 103,677	**$ 77,208**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 13,618,905	$ -	-$ 13,618,905	-$ 3,807,442	$ -	-$ 3,807,442	$ -	40.12	2.49%	43.57	2.30%	-$ 339,421	**-$ 87,387**	**$ -**	**-$ 426,808**	-$ 508,037	**-$ 81,229**
2005	Property under Finance Leases	$ -	$ -	$ -	$ -	$ -	$ -	$ -		0.00%		0.00%	$ -	**$ -**	**$ -**	**$ -**	$ -	**$ -**
2010	Electric Plant Purchased or Sold	$ 27,880	$ -	$ 27,880	$ -	$ -	$ -	$ -	27.00	3.70%	-	0.00%	$ 1,033	**$ -**	**$ -**	**$ 1,033**	$ 1,212	**$ 180**
2440	Deferred Revenue5	$ -	$ -	$ -	-$ 255,698	$ -	-$ 255,698	-$ 4,496,481		0.00%	43.57	2.30%	$ -	**-$ 5,869**	**-$ 51,601**	**-$ 57,469**	-$ 70,270	**-$ 12,801**
	Total	**$ 104,265,823**	**$ 686,055**	**$ 103,579,768**	**$ 41,507,801**	**$ 4,546,846**	**$ 36,960,955**	**$ 11,217,114**					**$ 3,314,688**	**$ 1,868,556**	**$ 330,045**	**$ 5,513,288**	**$ 6,053,491**	**$ 540,203**

Table 4-46: 2016 MIFRS – Appendix 2-C Depreciation and Amortization Expense

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 1,544,106	$ 631,436	$ 912,670	$ 3,473,525	$ 729,283	$ 2,744,242	$ 1,069,386	4.82	20.75%	5.00	20.00%	$ 189,415	$ 548,848	$ 106,939	$ 845,201	$ 839,876	-$ 5,325
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 347,843	$ -	$ 347,843	$ -	$ -	$ -		-	0.00%	-	0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 1,498,548	$ -	$ 1,498,548	$ 9,678	$ -	$ 9,678	$ 20	52.75	1.90%	80.00	1.25%	$ 28,408	$ 121	$ 0	$ 28,529	$ 30,957	$ 2,428
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 9,459,698	$ -	$ 9,459,698	$ 661,972	$ -	$ 661,972	$ 61,985	37.30	2.68%	33.00	3.03%	$ 253,634	$ 20,060	$ 939	$ 274,633	$ 433,366	$ 158,733
1820	Distribution Station Equipment <50 kV	$ 54,619	$ 54,619	-$ 0	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 18,129,972	$ -	$ 18,129,972	$ 10,470,140	$ 896,800	$ 9,573,340	$ 4,001,764	37.40	2.67%	50.00	2.00%	$ 484,819	$ 191,467	$ 40,018	$ 716,303	$ 454,414	-$ 261,889
1835	Overhead Conductors & Devices	$ 19,587,572	$ -	$ 19,587,572	$ 10,915,520	$ -	$ 10,915,520	$ 3,652,752	40.05	2.50%	40.00	2.50%	$ 489,117	$ 272,888	$ 45,659	$ 807,664	$ 815,866	$ 8,202
1840	Underground Conduit	$ 13,025,017	$ -	$ 13,025,017	$ 3,975,652	$ -	$ 3,975,652	$ 1,641,358	71.71	1.39%	80.00	1.25%	$ 181,630	$ 49,696	$ 10,258	$ 241,584	$ 233,373	-$ 8,212
1845	Underground Conductors & Devices	$ 19,080,475	$ -	$ 19,080,475	$ 7,769,466	$ -	$ 7,769,466	$ 2,241,115	46.57	2.15%	44.00	2.27%	$ 409,702	$ 176,579	$ 25,467	$ 611,748	$ 611,390	-$ 358
1850	Line Transformers	$ 24,270,286	$ -	$ 24,270,286	$ 7,918,289	$ 2,032,602	$ 5,885,687	$ 2,420,999	39.92	2.50%	38.00	2.63%	$ 607,908	$ 154,887	$ 31,855	$ 794,650	$ 695,098	-$ 99,552
1855	Services (Overhead & Underground)	$ 1,366,549	$ -	$ 1,366,549	$ 192,967	$ -	$ 192,967		43.00	2.33%	40.00	2.50%	$ 31,780	$ 4,824	$ -	$ 36,604	$ 8,452	-$ 28,152
1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters	$ 2,552,455	$ -	$ 2,552,455	$ 9,903,713	$ 372,934	$ 9,530,779	$ 266,979	10.94	9.14%	15.00	6.67%	$ 233,282	$ 635,385	$ 8,899	$ 877,566	$ 1,114,982	$ 237,415
1905	Land	$ 301,592	$ -	$ 301,592	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,860,379	$ -	$ 2,860,379	$ 1,229,539	$ -	$ 1,229,539	$ 26,750	29.39	3.40%	50.00	2.00%	$ 97,326	$ 24,591	$ 267	$ 122,184	$ 204,937	$ 82,753
1910	Leasehold Improvements	$ -	$ -	$ -	$ 24,525	$ -	$ 24,525			0.00%	1.50	66.67%	$ -	$ 16,350	$ -	$ 16,350	$ 15,851	-$ 499
1915	Office Furniture & Equipment (10 years)	$ 79,789	$ -	$ 79,789	$ 258,372	$ -	$ 258,372		8.74	11.44%	10.00	10.00%	$ 9,129	$ 25,837	$ -	$ 34,966		-$ 34,966
1915	Office Furniture & Equipment (5 years)	$ 72,254	$ -	$ 72,254	$ 108,582	$ -	$ 108,582	$ 31,289	5.00	20.00%	5.00	20.00%	$ 14,451	$ 21,716	$ 3,129	$ 39,296	$ 60,456	$ 21,160
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 702,016	$ -	$ 702,016	$ 2,030,247	$ 1,545,681	$ 484,566	$ 191,364	3.38	29.58%	3.00	33.33%	$ 207,639	$ 161,522	$ 31,894	$ 401,055	$ 370,475	-$ 30,580
1930	Transportation Equipment	$ 1,927,696	$ -	$ 1,927,696	$ 1,971,859	$ 853,279	$ 1,118,580	$ 417,159	8.43	11.87%	10.00	10.00%	$ 228,768	$ 111,858	$ 20,858	$ 361,484	$ 335,578	-$ 25,906
1935	Stores Equipment	$ 1,290	$ -	$ 1,290	$ 14,625	$ -	$ 14,625		2.00	50.00%	5.00	20.00%	$ 645	$ 2,925	$ -	$ 3,570	$ 1,463	-$ 2,108
1940	Tools, Shop & Garage Equipment	$ 822,096	$ -	$ 822,096	$ 255,442	$ 181,023	$ 74,419	$ 87,827	6.23	16.05%	10.00	10.00%	$ 131,955	$ 7,442	$ 4,391	$ 143,788	$ 112,984	-$ 30,804
1945	Measurement & Testing Equipment	$ 14,467	$ -	$ 14,467	$ -	$ -	$ -		3.45	28.99%	10.00	10.00%	$ 4,193	$ -	$ -	$ 4,193	$ 3,553	-$ 7,747
1950	Power Operated Equipment	$ 406	$ -	$ 406	$ 12,742	$ -	$ 12,742		1.00	100.00%	10.00	10.00%	$ 406	$ 1,274	$ -	$ 1,680	$ 1,768	$ 88
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment	$ 1,140	$ -	$ 1,140	$ -	$ -	$ -		3.00	33.33%	3.00	33.33%	$ 380	$ -	$ -	$ 380	$ 7,884	-$ 8,264
1960	Miscellaneous Equipment	$ 156,583	$ -	$ 156,583	$ 87,679	$ 71,441	$ 16,238		6.30	15.87%	10.00	10.00%	$ 24,854	$ 1,624	$ -	$ 26,478	$ 8,568	-$ 17,910
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 13,618,905	$ -	-$ 13,618,905	-$ 3,807,442	$ -	-$ 3,807,442	$ 63,478	40.12	2.49%	43.57	2.30%	-$ 339,421	-$ 87,387	$ 728	-$ 426,079	-$ 376,445	$ 49,634
2005	Property under Finance Leases	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2010	Electric Plant Purchased or Sold	$ 27,880	$ -	$ 27,880	$ -	$ 24,243	-$ 24,243		27.00	3.70%	-	0.00%	$ 1,033	$ -	$ -	$ 1,033	$ -	-$ 1,033
2440	Deferred Revenue5	$ -	$ -	$ -	-$ 4,752,178	$ -	-$ 4,752,178	-$ 2,826,535		0.00%	43.57	2.30%	$ -	-$ 109,070	-$ 32,437	-$ 141,507	-$ 146,349	-$ 4,842
	Total	**$ 104,265,823**	**$ 686,055**	**$ 103,579,768**	**$ 52,724,915**	**$ 6,707,286**	**$ 46,017,629**	**$ 13,347,691**					**$ 3,291,052**	**$ 2,233,437**	**$ 298,867**	**$ 5,823,356**	**$ 5,815,622**	**-$ 7,733**

Table 4-47: 2017 MIFRS – Appendix 2-C Depreciation and Amortization Expense

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 1,544,106	$ 631,436	$ 912,670	$ 4,542,910	$ 2,610,235	$ 1,932,675	$ 603,006	4.82	20.75%	5.00	20.00%	$ 189,415	$ 386,535	$ 60,301	$ 636,250	$ 701,000	$ 64,750
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 347,843	$ -	$ 347,843	$ -	$ -	$ -		-	0.00%	-	0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 1,498,548	$ -	$ 1,498,548	$ 9,698	$ -	$ 9,698		52.75	1.90%	80.00	1.25%	$ 28,408	$ 121	$ -	$ 28,529	$ 20,000	-$ 8,529
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 9,459,698	$ -	$ 9,459,698	$ 723,957	$ -	$ 723,957		37.30	2.68%	33.00	3.03%	$ 253,634	$ 21,938	$ -	$ 275,572	$ 283,000	$ 7,428
1820	Distribution Station Equipment <50 kV	$ 54,619	$ 54,619	-$ 0	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 18,129,972	$ -	$ 18,129,972	$ 14,471,904	$ 1,138,510	$ 13,333,394	$ 1,924,298	37.40	2.67%	50.00	2.00%	$ 484,819	$ 266,668	$ 19,243	$ 770,729	$ 694,000	-$ 76,729
1835	Overhead Conductors & Devices	$ 19,587,572	$ -	$ 19,587,572	$ 14,568,272	$ -	$ 14,568,272	$ 4,360,352	40.05	2.50%	40.00	2.50%	$ 489,117	$ 364,207	$ 54,504	$ 907,828	$ 995,000	$ 87,172
1840	Underground Conduit	$ 13,025,017	$ -	$ 13,025,017	$ 5,617,010	$ -	$ 5,617,010	$ 2,159,645	71.71	1.39%	80.00	1.25%	$ 181,630	$ 70,213	$ 13,498	$ 265,341	$ 290,000	$ 24,659
1845	Underground Conductors & Devices	$ 19,080,475	$ -	$ 19,080,475	$ 10,010,581	$ -	$ 10,010,581	$ 3,044,319	46.57	2.15%	44.00	2.27%	$ 409,702	$ 227,513	$ 34,595	$ 671,809	$ 736,000	$ 64,191
1850	Line Transformers	$ 24,270,286	$ -	$ 24,270,286	$ 10,339,288	$ 2,680,377	$ 7,658,911	$ 2,504,142	39.92	2.50%	38.00	2.63%	$ 607,908	$ 201,550	$ 32,949	$ 842,407	$ 888,000	$ 45,593
1855	Services (Overhead & Underground)	$ 1,366,549	$ -	$ 1,366,549	$ 192,967	$ -	$ 192,967		43.00	2.33%	40.00	2.50%	$ 31,780	$ 4,824	$ -	$ 36,604	$ 42,000	$ 5,396
1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters	$ 2,552,455	$ -	$ 2,552,455	$ 10,170,691	$ 644,304	$ 9,526,387	$ 780,488	10.94	9.14%	15.00	6.67%	$ 233,282	$ 635,092	$ 26,016	$ 894,391	$ 811,000	-$ 83,391
1905	Land	$ 301,592	$ -	$ 301,592	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,860,379	$ -	$ 2,860,379	$ 1,256,289	$ -	$ 1,256,289	$ 110,965	29.39	3.40%	50.00	2.00%	$ 97,326	$ 25,126	$ 1,110	$ 123,561	$ 160,000	$ 36,439
1910	Leasehold Improvements	$ -	$ -	$ -	$ 24,525	$ -	$ 24,525			0.00%	1.50	66.67%	$ -	$ 16,350	$ -	$ 16,350		-$ 16,350
1915	Office Furniture & Equipment (10 years)	$ 79,789	$ -	$ 79,789	$ 258,372	$ -	$ 258,372		8.74	11.44%	10.00	10.00%	$ 9,129	$ 25,837	$ -	$ 34,966		-$ 34,966
1915	Office Furniture & Equipment (5 years)	$ 72,254	$ -	$ 72,254	$ 139,872	$ -	$ 139,872	$ 49,537	5.00	20.00%	5.00	20.00%	$ 14,451	$ 27,974	$ 4,954	$ 47,379	$ 56,000	$ 8,621
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 702,016	$ -	$ 702,016	$ 2,221,611	$ 2,168,925	$ 52,686	$ 342,966	3.38	29.58%	3.00	33.33%	$ 207,639	$ 17,562	$ 57,161	$ 282,362	$ 384,000	$ 101,638
1930	Transportation Equipment	$ 1,927,696	$ -	$ 1,927,696	$ 2,389,018	$ 853,279	$ 1,535,739	$ 359,000	8.43	11.87%	10.00	10.00%	$ 228,768	$ 153,574	$ 17,950	$ 400,292	$ 461,000	$ 60,708
1935	Stores Equipment	$ 1,290	$ -	$ 1,290	$ 14,625	$ -	$ 14,625		2.00	50.00%	5.00	20.00%	$ 645	$ 2,925	$ -	$ 3,570	$ 1,000	-$ 2,570
1940	Tools, Shop & Garage Equipment	$ 822,096	$ -	$ 822,096	$ 343,270	$ 181,023	$ 162,247	$ 159,500	6.23	16.05%	10.00	10.00%	$ 131,955	$ 16,225	$ 7,975	$ 156,154	$ 94,000	-$ 62,154
1945	Measurement & Testing Equipment	$ 14,467	$ -	$ 14,467	$ -	$ -	$ -		3.45	28.99%	10.00	10.00%	$ 4,193	$ -	$ -	$ 4,193		-$ 4,193
1950	Power Operated Equipment	$ 406	$ -	$ 406	$ 12,742	$ -	$ 12,742		1.00	100.00%	10.00	10.00%	$ 406	$ 1,274	$ -	$ 1,680	$ 3,000	$ 1,320
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment	$ 1,140	$ -	$ 1,140	$ -	$ -	$ -		3.00	33.33%	3.00	33.33%	$ 380	$ -	$ -	$ 380		-$ 380
1960	Miscellaneous Equipment	$ 156,583	$ -	$ 156,583	$ 87,679	$ 71,441	$ 16,238		6.30	15.87%	10.00	10.00%	$ 24,854	$ 1,624	$ -	$ 26,478	$ 66,000	$ 39,522
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 13,618,905	$ -	-$ 13,618,905	-$ 3,743,964	$ -	-$ 3,743,964		40.12	2.49%	43.57	2.30%	-$ 339,421	-$ 85,930	$ -	-$ 425,351	-$ 417,000	$ 8,351
2005	Property under Finance Leases	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2010	Electric Plant Purchased or Sold	$ 27,880	$ -	$ 27,880	$ -	$ 24,243	-$ 24,243		27.00	3.70%	-	0.00%	$ 1,033	$ -	$ -	$ 1,033	$ -	-$ 1,033
2440	Deferred Revenue5	$ -	$ -	$ -	-$ 7,578,713	$ -	-$ 7,578,713	-$ 1,182,000		0.00%	43.57	2.30%	$ -	-$ 173,943	-$ 13,564	-$ 187,508	-$ 189,000	-$ 1,492
	Total	**$ 104,265,823**	**$ 686,055**	**$ 103,579,768**	**$ 66,072,606**	**$ 10,372,337**	**$ 55,700,269**	**$ 15,216,218**					**$ 3,291,052**	**$ 2,207,260**	**$ 316,691**	**$ 5,815,002**	**$ 6,079,000**	**$ 263,998**

Table 4-48: 2018 MIFRS – Appendix 2-C Depreciation and Amortization Expense

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 1,544,106	$ 631,436	$ 912,670	$ 5,145,916	$ 2,957,918	$ 2,187,998	$ 612,200	4.82	20.75%	5.00	20.00%	$ 189,415	$ 437,600	$ 61,220	$ 688,234	$ 766,258	$ 78,024
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 347,843	$ -	$ 347,843	$ -	$ -	$ -		-	0.00%	-	0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 1,498,548	$ -	$ 1,498,548	$ 9,698	$ -	$ 9,698		52.75	1.90%	80.00	1.25%	$ 28,408	$ 121	$ -	$ 28,529	$ 32,798	$ 4,269
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 9,459,698	$ -	$ 9,459,698	$ 723,957	$ -	$ 723,957	$ 35,000	37.30	2.68%	33.00	3.03%	$ 253,634	$ 21,938	$ 530	$ 276,103	$ 267,755	-$ 8,348
1820	Distribution Station Equipment <50 kV	$ 54,619	$ 54,619	-$ 0	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 18,129,972	$ -	$ 18,129,972	$ 16,396,202	$ 1,388,510	$ 15,007,692	$ 3,106,118	37.40	2.67%	50.00	2.00%	$ 484,819	$ 300,154	$ 31,061	$ 816,034	$ 818,619	$ 2,585
1835	Overhead Conductors & Devices	$ 19,587,572	$ -	$ 19,587,572	$ 18,928,624	$ -	$ 18,928,624	$ 3,617,082	40.05	2.50%	40.00	2.50%	$ 489,117	$ 473,216	$ 45,214	$ 1,007,546	$ 1,061,136	$ 53,590
1840	Underground Conduit	$ 13,025,017	$ -	$ 13,025,017	$ 7,776,655	$ -	$ 7,776,655	$ 1,285,479	71.71	1.39%	80.00	1.25%	$ 181,630	$ 97,208	$ 8,034	$ 286,873	$ 297,714	$ 10,841
1845	Underground Conductors & Devices	$ 19,080,475	$ -	$ 19,080,475	$ 13,054,900	$ -	$ 13,054,900	$ 1,812,061	46.57	2.15%	44.00	2.27%	$ 409,702	$ 296,702	$ 20,592	$ 726,995	$ 762,717	$ 35,721
1850	Line Transformers	$ 24,270,286	$ -	$ 24,270,286	$ 12,843,430	$ 3,130,377	$ 9,713,053	$ 1,891,075	39.92	2.50%	38.00	2.63%	$ 607,908	$ 255,607	$ 24,883	$ 888,397	$ 941,504	$ 53,107
1855	Services (Overhead & Underground)	$ 1,366,549	$ -	$ 1,366,549	$ 192,967	$ -	$ 192,967		43.00	2.33%	40.00	2.50%	$ 31,780	$ 4,824	$ -	$ 36,604	$ 42,514	$ 5,910
1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters	$ 2,552,455	$ -	$ 2,552,455	$ 10,951,179	$ 944,304	$ 10,006,875	$ 824,242	10.94	9.14%	15.00	6.67%	$ 233,282	$ 667,125	$ 27,475	$ 927,882	$ 852,257	-$ 75,625
1905	Land	$ 301,592	$ -	$ 301,592	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,860,379	$ -	$ 2,860,379	$ 1,367,254	$ -	$ 1,367,254	$ 14,500	29.39	3.40%	50.00	2.00%	$ 97,326	$ 27,345	$ 145	$ 124,816	$ 167,005	$ 42,189
1910	Leasehold Improvements	$ -	$ -	$ -	$ 24,525	$ -	$ 24,525			0.00%	1.50	66.67%	$ -	$ 16,350	$ -	$ 16,350		-$ 16,350
1915	Office Furniture & Equipment (10 years)	$ 79,789	$ -	$ 79,789	$ 258,372	$ -	$ 258,372		8.74	11.44%	10.00	10.00%	$ 9,129	$ 25,837	$ -	$ 34,966		-$ 34,966
1915	Office Furniture & Equipment (5 years)	$ 72,254	$ -	$ 72,254	$ 189,409	$ -	$ 189,409	$ 9,200	5.00	20.00%	5.00	20.00%	$ 14,451	$ 37,882	$ 920	$ 53,253	$ 59,933	$ 6,680
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 702,016	$ -	$ 702,016	$ 2,564,577	$ 2,396,812	$ 167,765	$ 211,700	3.38	29.58%	3.00	33.33%	$ 207,639	$ 55,922	$ 35,283	$ 298,844	$ 253,071	-$ 45,773
1930	Transportation Equipment	$ 1,927,696	$ -	$ 1,927,696	$ 2,748,018	$ 853,279	$ 1,894,739	$ 100,000	8.43	11.87%	10.00	10.00%	$ 228,768	$ 189,474	$ 5,000	$ 423,242	$ 460,451	$ 37,209
1935	Stores Equipment	$ 1,290	$ -	$ 1,290	$ 14,625	$ -	$ 14,625		2.00	50.00%	5.00	20.00%	645	$ 2,925	$ -	$ 3,570	$ 1,463	-$ 2,107
1940	Tools, Shop & Garage Equipment	$ 822,096	$ -	$ 822,096	$ 502,770	$ 181,023	$ 321,747	$ 108,500	6.23	16.05%	10.00	10.00%	$ 131,955	$ 32,175	$ 5,425	$ 169,554	$ 99,093	-$ 70,461
1945	Measurement & Testing Equipment	$ 14,467	$ -	$ 14,467	$ -	$ -	$ -		3.45	28.99%	10.00	10.00%	$ 4,193	$ -	$ -	$ 4,193		-$ 4,193
1950	Power Operated Equipment	$ 406	$ -	$ 406	$ 12,742	$ -	$ 12,742		1.00	100.00%	10.00	10.00%	$ 406	$ 1,274	$ -	$ 1,680	$ 2,549	$ 869
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment	$ 1,140	$ -	$ 1,140	$ -	$ -	$ -		3.00	33.33%	3.00	33.33%	$ 380	$ -	$ -	$ 380		-$ 380
1960	Miscellaneous Equipment	$ 156,583	$ -	$ 156,583	$ 87,679	$ 71,441	$ 16,238		6.30	15.87%	10.00	10.00%	$ 24,854	$ 1,624	$ -	$ 26,478	$ 501	-$ 25,977
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 13,618,905	$ -	-$ 13,618,905	-$ 3,743,964	$ -	-$ 3,743,964		40.12	2.49%	43.57	2.30%	-$ 339,421	-$ 85,930	$ -	-$ 425,351	-$ 435,509	-$ 10,158
2005	Property under Finance Leases	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2010	Electric Plant Purchased or Sold	$ 27,880	$ -	$ 27,880	$ -	$ 24,243	-$ 24,243		27.00	3.70%	-	0.00%	$ 1,033	$ -	$ -	$ 1,033		-$ 1,033
2440	Deferred Revenue5	$ -	$ -	$ -	-$ 8,760,713	$ -	-$ 8,760,713	-$ 2,132,910		0.00%	43.57	2.30%	$ -	-$ 201,072	-$ 24,477	-$ 225,549	-$ 203,765	$ 21,784
	Total	**$ 104,265,823**	**$ 686,055**	**$ 103,579,768**	**$ 81,288,824**	**$ 11,947,907**	**$ 69,340,917**	**$ 11,494,247**					**$ 3,291,052**	**$ 2,658,300**	**$ 241,305**	**$ 6,190,657**	**$ 6,248,064**	**$ 57,407**

Table 4-49: 2019 MIFRS – Appendix 2-C Depreciation and Amortization Expense

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1611	Computer Software (Formally known as Account 1925)	$ 1,544,106	$ 631,436	$ 912,670	$ 5,758,116	$ 3,274,597	$ 2,483,519	$ 526,500	4.82	20.75%	5.00	20.00%	$ 189,415	$ 496,704	$ 52,650	$ 738,768	$ 813,708	$ 74,940
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 347,843	$ -	$ 347,843	$ -	$ -	$ -		-	0.00%	-	0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ 1,498,548	$ -	$ 1,498,548	$ 9,698	$ -	$ 9,698		52.75	1.90%	80.00	1.25%	$ 28,408	$ 121	$ -	$ 28,529	$ 32,798	$ 4,269
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 9,459,698	$ -	$ 9,459,698	$ 758,957	$ -	$ 758,957	$ 55,000	37.30	2.68%	33.00	3.03%	$ 253,634	$ 22,999	$ 833	$ 277,466	$ 268,828	-$ 8,638
1820	Distribution Station Equipment <50 kV	$ 54,619	$ 54,619	-$ 0	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 18,129,972	$ -	$ 18,129,972	$ 19,502,320	$ 1,638,510	$ 17,863,810	$ 2,407,644	37.40	2.67%	50.00	2.00%	$ 484,819	$ 357,276	$ 24,076	$ 866,171	$ 884,662	$ 18,491
1835	Overhead Conductors & Devices	$ 19,587,572	$ -	$ 19,587,572	$ 22,545,706	$ -	$ 22,545,706	$ 2,803,706	40.05	2.50%	40.00	2.50%	$ 489,117	$ 563,643	$ 35,046	$ 1,087,806	$ 1,148,256	$ 60,450
1840	Underground Conduit	$ 13,025,017	$ -	$ 13,025,017	$ 9,062,134	$ -	$ 9,062,134	$ 1,452,741	71.71	1.39%	80.00	1.25%	$ 181,630	$ 113,277	$ 9,080	$ 303,987	$ 315,267	$ 11,281
1845	Underground Conductors & Devices	$ 19,080,475	$ -	$ 19,080,475	$ 14,866,961	$ -	$ 14,866,961	$ 2,047,840	46.57	2.15%	44.00	2.27%	$ 409,702	$ 337,885	$ 23,271	$ 770,858	$ 807,234	$ 36,376
1850	Line Transformers	$ 24,270,286	$ -	$ 24,270,286	$ 14,734,505	$ 3,580,377	$ 11,154,128	$ 2,025,885	39.92	2.50%	38.00	2.63%	$ 607,908	$ 293,530	$ 26,656	$ 928,094	$ 985,261	$ 57,167
1855	Services (Overhead & Underground)	$ 1,366,549	$ -	$ 1,366,549	$ 192,967	$ -	$ 192,967		43.00	2.33%	40.00	2.50%	$ 31,780	$ 4,824	$ -	$ 36,604	$ 42,514	$ 5,910
1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters	$ 2,552,455	$ -	$ 2,552,455	$ 11,775,421	$ 2,675,086	$ 9,100,335	$ 751,092	10.94	9.14%	15.00	6.67%	$ 233,282	$ 606,689	$ 25,036	$ 865,007	$ 895,267	$ 30,260
1905	Land	$ 301,592	$ -	$ 301,592	$ -	$ -	$ -		-	0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 2,860,379	$ -	$ 2,860,379	$ 1,381,754	$ -	$ 1,381,754	$ 4,400,000	29.39	3.40%	50.00	2.00%	$ 97,326	$ 27,635	$ 44,000	$ 168,961	$ 183,563	$ 14,602
1910	Leasehold Improvements	$ -	$ -	$ -	$ 24,525	$ -	$ 24,525			0.00%	1.50	66.67%	$ -	$ 16,350	$ -	$ 16,350		-$ 16,350
1915	Office Furniture & Equipment (10 years)	$ 79,789	$ -	$ 79,789	$ 258,372	$ -	$ 258,372		8.74	11.44%	10.00	10.00%	$ 9,129	$ 25,837	$ -	$ 34,966		-$ 34,966
1915	Office Furniture & Equipment (5 years)	$ 72,254	$ -	$ 72,254	$ 198,609	$ -	$ 198,609	$ 3,600	5.00	20.00%	5.00	20.00%	$ 14,451	$ 39,722	$ 360	$ 54,533	$ 57,274	$ 2,741
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 702,016	$ -	$ 702,016	$ 2,776,277	$ 2,588,176	$ 188,101	$ 240,700	3.38	29.58%	3.00	33.33%	$ 207,639	$ 62,700	$ 40,117	$ 310,456	$ 257,215	-$ 53,241
1930	Transportation Equipment	$ 1,927,696	$ -	$ 1,927,696	$ 2,848,018	$ 853,279	$ 1,994,739	$ 105,000	8.43	11.87%	10.00	10.00%	$ 228,768	$ 199,474	$ 5,250	$ 433,492	$ 462,769	$ 29,277
1935	Stores Equipment	$ 1,290	$ -	$ 1,290	$ 14,625	$ -	$ 14,625		2.00	50.00%	5.00	20.00%	$ 645	$ 2,925	$ -	$ 3,570	$ 1,463	-$ 2,107
1940	Tools, Shop & Garage Equipment	$ 822,096	$ -	$ 822,096	$ 611,270	$ 181,023	$ 430,247	$ 66,700	6.23	16.05%	10.00	10.00%	$ 131,955	$ 43,025	$ 3,335	$ 178,314	$ 96,433	-$ 81,881
1945	Measurement & Testing Equipment	$ 14,467	$ -	$ 14,467	$ -	$ -	$ -		3.45	28.99%	10.00	10.00%	$ 4,193	$ -	$ -	$ 4,193		-$ 4,193
1950	Power Operated Equipment	$ 406	$ -	$ 406	$ 12,742	$ -	$ 12,742		1.00	100.00%	10.00	10.00%	$ 406	$ 1,274	$ -	$ 1,680		-$ 1,680
1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%	-	0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communication Equipment	$ 1,140	$ -	$ 1,140	$ -	$ -	$ -		3.00	33.33%	3.00	33.33%	$ 380	$ -	$ -	$ 380		-$ 380
1960	Miscellaneous Equipment	$ 156,583	$ -	$ 156,583	$ 87,679	$ 71,441	$ 16,238		6.30	15.87%	10.00	10.00%	$ 24,854	$ 1,624	$ -	$ 26,478	$ 501	-$ 25,977
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 13,618,905	$ -	-$ 13,618,905	-$ 3,743,964	$ -	-$ 3,743,964		40.12	2.49%	43.57	2.30%	-$ 339,421	-$ 85,930	$ -	-$ 425,351	-$ 435,509	-$ 10,158
2005	Property under Finance Leases	$ -	$ -	$ -	$ -	$ -	$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
2010	Electric Plant Purchased or Sold	$ 27,880	$ -	$ 27,880	$ -	$ 24,243	-$ 24,243		27.00	3.70%	-	0.00%	$ 1,033	$ -	$ -	$ 1,033		-$ 1,033
2440	Deferred Revenue5	$ -	$ -	$ -	-$ 10,893,623	$ -	-$ 10,893,623	-$ 817,000		0.00%	43.57	2.30%	$ -	-$ 250,026	-$ 9,376	-$ 259,402	-$ 234,498	$ 24,904
	Total	**$ 104,265,823**	**$ 686,055**	**$ 103,579,768**	**$ 92,783,071**	**$ 14,886,732**	**$ 77,896,339**	**$ 16,069,408**					**$ 3,291,052**	**$ 2,881,558**	**$ 280,335**	**$ 6,452,945**	**$ 6,583,006**	**$ 130,060**

4.10 TAXES OR PAYMENTS IN LIEU OF TAXES AND PROPERTY TAXES

4.10.1 PILS and Capital Taxes

Energy+ makes payments in lieu (PILs) of corporate taxes calculated in accordance with the rules for computing taxable income, taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario), as modified by the Electricity Act, 1998, and related regulations. Energy+ does not pay Section 89 proxy taxes, and is exempt from the payment of incomes taxes under the *Income Tax Act* (Canada) and the Ontario Corporations Tax Act. Energy+ is projecting a profit for tax purposes in the 2019 Test year of $2,208,420, and therefore, has included $796,233 for the recovery of PILs in this Application.

Table 4-51 below provides a summary of the 2014, 2015, and 2016 Actuals, 2017 Forecast and the 2018 Bridge Year and 2019 Test Year PIL's estimates. These estimates are based on the rates prescribed by the Board in the Board's Income Tax/PILs Work form for 2018 Filers (the 2019 Workform was not available at time of completing this Application) and as provided in Appendix 4-4. The 2019 Test Year PILs have been determined by applying substantively enacted 2017 rates against taxable income.

Table 4-51: Income Tax Summary

	2014 Board Approved Proxy	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Bridge	2019 Test
Current PILs	48,753	226,986	442,631	669,321	1,250,864	855,536	796,233

At the time of filing this Application, Energy+ has not filed its 2017 corporate income tax returns. Energy+ does not expect significant changes between the final 2017 corporate income tax returns and the 2017 forecast income tax provision. Energy+ will provide a copy of the final 2017 tax returns as soon as they are available, and updated the Board's Income Tax/PILs Work form model for the 2017 Actuals.

A copy of the 2016 Federal T2 and Ontario C23 tax return for 2016 has been provided in Appendix 4-5. Income tax amounts included in the 2016 audited financial statements are based on estimates and differ from the actual tax return. The difference between actual and estimated tax provision for 2016 is recorded in the 2017 financial statements. In accordance with the Filing Requirements, Energy+ has completed and submitted the Board's Income Tax/PILs Work form model, which is consistent with the PILs included in the 2019 revenue requirement.

The following Table 4-52 presents the calculation of taxable income for the 2019 Test Year. Tax adjustments are made for both temporary and permanent differences and reserves. The most significant temporary differences include are:

- The difference between depreciation for accounting purposes versus capital cost allowance (CCA) for tax purposes; and

- The difference between opening and closing reserves from financial statements. The reserves represent Energy+'s post-employment benefit liability. Please refer to table 4-33 for the Actuarial Expense and Post-Retirement Benefits Liability balances.

Table 4-52: Computation of Taxable Income 2019 Test Year

		Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	6,162,890
	T2 S1 line #		
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets2-4 ADJUSTED ACCOUNTING DATAP489	104		6,583,006
Non-deductible meals and entertainment expense	121		10,000
Reserves from financial statements- balance at end of year	126	T13	3,332,000
Total Additions			**9,943,006**
Deductions:			
Capital cost allowance from Schedule 8	403	T8	10,630,476
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	3,267,000
Total Deductions		calculated	**13,897,476**
NET INCOME FOR TAX PURPOSES		calculated	**2,208,420**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	0
Net-capital losses of preceding taxation years (Please show calculation)	332	T4	0
REGULATORY TAXABLE INCOME		calculated	**2,208,420**

4.10.1.1 Loss Carry Forwards

Energy+ does not have any loss carry forwards for regulatory purposes.

4.10.1.2 Other Additions and Deductions

In accordance with the Filing Requirements, Energy+ has excluded the deferral and variance accounts for Regulatory Assets and Liabilities from the reserve balances for 2018 Bridge Year and 2019 Test Year.

4.10.1.3 Tax Credits

Energy+ takes advantage of the tax credits where available to minimize taxes payable. Table 4-53 summarizes the tax credits for the historical years 2014-2016 Actuals, and 2017 Forecast. Energy+ has not forecasted tax credits for the 2018 Bridge and 2019 Test Year as Energy+ is not anticipating the hiring of Apprentices.

4.10.1.4 Non-recoverable and Disallowed Expenses

Energy+ has not included donations, other than LEAP, in the calculation of the revenue requirement. Energy+ does not have any additional expenses that are deductible for general tax purposes, but for which recovery in 2019 distribution rates would be partially or fully disallowed.

4.10.1.5 Detailed Tax Calculations

Table 4-54 below summarizes the detailed tax calculation for the 2014 to 2016 Actuals, 2017 Forecast, 2018 Bridge and 2019 Test Year. The 2014 Board Approved Proxy was computed as the 2014 Board Approved PILs amount for the former CND plus the 2011 Board Approved PILs for the former BCP increased for the IRM factors for 2012, 2013, and 2014.

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Table 4-53: Tax Credits

				2014 Actuals			2015 Actuals						
Schedule of Tax Credits	2014 Board Approved CND	2014 Board Approved Proxy BCP	2014 Board Approved Proxy	Former CND	Former BCP	Total 2014 Actuals	Former CND	Former BCP	Total 2015 Actuals	2016 Actual	2017 Forecast	2018 Bridge	2019 Test
CMT Carryforward	-	-	-	(108,636)	-	(108,636)	10,907	-	10,907	(17,054)		-	-
Apprentice Credits/Co-Operative	(77,500)	-	(77,500)	(64,014)	-	(64,014)	(60,000)	-	(60,000)	(70,000)	(57,360)	-	-
	(77,500)	-	(77,500)	(172,650)	-	(172,650)	(49,093)	-	(49,093)	(87,054)	(57,360)	-	-

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Table 4-54: Detailed Income Tax Calculation

	2014 Board Approved CND	2014 Board Approved Proxy BCP	2014 Board Approved Proxy	2014 Actuals Former CND	2014 Actuals Former BCP	Total 2014 Actuals	2015 Actuals Former CND	2015 Actuals Former BCP	Total 2015 Actuals	2016 Actual	2017 Forecast	2018 Bridge	2019 Test
Net Income before Taxes	**4,936,779**	**868,345**	**5,805,124**	**5,765,376**	**1,343,142**	**7,108,518**	**7,622,693**	**990,889**	**8,613,582**	**7,196,447**	**9,283,669**	**7,150,170**	**6,162,890**
Additions:													
Amortization of tangible assets	4,959,263	892,126	5,851,389	4,897,819	1,170,876	6,068,695	4,912,905	1,166,585	6,079,490	6,052,297	5,990,687	6,248,064	6,583,006
Tax reserves deducted in prior year			-	-	-	-	-		-	-	-		
Reserves from financial statements	2,068,000		2,068,000	2,101,279	771,617	2,872,896	2,189,796	805,816	2,995,612	3,140,004	3,373,594	3,267,000	3,332,000
Charitable donations			-	4,700	-	4,700	8,200	-	8,200	-	30,346		
Non-deductible club dues and fees			-	-	-	-	-	-	-	550	681		
Non-deductible Meals and Entertainment	10,000		10,000	12,351	-	12,351	13,542	4,839	18,381	9,970	10,810	10,000	10,000
Loss on disposal of assets			-	-	-	-	337,000	-	337,000	269,006	420,157	300,000	
Other			-										
Recapture of SR&ED expenditures from Form T661			-	-	21,378	21,378	66,161	-	66,161	-	-		
Capital items expensed			-	77,811	-	77,811	54,412	-	54,412	56,328	48,396		
Financing fees deducted in books			-	7,141	-	7,141	29,693	-	29,693	27,062	27,062	18,000	18,000
Non-deductible legal and accounting fees			-	420,199	-	420,199	78,564	-	78,564	-	-		
Inducement under - ITA 12(1) (x) - Apprentices	77,500		77,500	28,957	-	28,957	59,969	-	59,969	68,794	76,000		
Net change in regulatory accounts			-	-	462,391	462,391	-	178,084	178,084	330,886	-		
Taxable capital gain			-	-	23,551	23,551	-	-	-	-	-		
Other additions and deductions			-	-	-	-	-	27,507	27,507	-	-		
Total Additions	**7,114,763**	**892,126**	**8,006,889**	**7,550,257**	**3,219,030**	**10,000,070**	**7,750,242**	**2,182,831**	**9,933,073**	**9,954,897**	**9,977,733**	**9,843,064**	**9,943,006**
Deductions:													
Capital cost allowance from Schedule 8	(9,566,337)	(1,429,247)	(10,995,584)	(8,840,407)	(1,543,109)	(10,383,516)	(8,963,023)	(1,561,952)	(10,524,975)	(10,884,450)	(10,907,413)	(10,624,790)	(10,630,476)
Cumulative eligible capital from Schedule 10	(102,891)	(98,811)	(201,702)	(102,891)	(74,541)	(177,432)	(99,813)	(69,755)	(169,568)	(157,698)			
Reserves from financial statements	(2,156,000)		(2,156,000)	(2,126,383)	(769,217)	(2,895,600)	(2,259,095)	(771,617)	(3,030,712)	(2,928,514)	(3,140,004)	(3,140,004)	(3,267,000)
Gain on disposal of assets			-	(2,525)	(55,078)	(57,603)	(37,760)	-	(37,760)	-	-		
Non-taxable OCI			-	-	-	-	-	-	-	-	(30,000)		
Other			-										
Charitable donations			-	(4,700)	-	(4,700)	(8,200)	-	(8,200)	-	-		
SR&ED expenditures claimed in the year from Form T661 (line 460)			-	-	-	-	-	-	-	-	-		
Financing fees			-	(17,139)	-	(17,139)	(133,830)	-	(133,830)	(133,830)	(133,830)		
Regulatory balance adjustments			-	-	(2,858,562)	(2,858,562)	(2,567,945)	-	(2,567,945)	-	-		
Change in opening EFB, not through P&L			-	-	-	-	-	-	-	(192,606)	(114,627)		
Total Deductions	**(11,825,228)**	**(1,528,059)**	**(13,353,287)**	**(11,094,045)**	**(6,056,396)**	**(16,394,552)**	**(14,069,666)**	**(2,403,324)**	**(16,472,990)**	**(14,297,098)**	**(14,325,874)**	**(13,764,794)**	**(13,897,476)**
Taxable Income	**226,314**	**232,412**	**458,726**	**2,221,588**	**(1,494,224)**	**714,036**	**1,303,269**	**770,396**	**2,073,665**	**2,854,246**	**4,935,528**	**3,228,440**	**2,208,420**
Tax Rate	15.50%	21.00%	18.27%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Taxes	35,079	48,753	83,832	718,721	(414,807)	303,914	345,443	242,003	587,446	756,375	1,308,224	855,536	796,233
Tax Credits	(77,500)	-	(77,500)	(172,650)	-	(172,650)	(49,093)		(49,093)	(87,054)	(57,360)		
Tax recovery from non-capital losses carried forward					95,722	95,722		(95,722)	(95,722)				
Total Income Taxes	**-**	**48,753**	**48,753**	**546,071**	**(319,085)**	**226,986**	**296,350**	**146,281**	**442,631**	**669,321**	**1,250,864**	**855,536**	**796,233**

Note: The 2017 Forecast income tax expense will be adjusted for regulatory purposes as part of the RRR filing for the year as the pre-tax income for the year includes the recognition of $1,514,000 in incentive revenue under the Conservation First Framework which will be excluded from regulated net income. The tax impact at 26.5% is a reduction in income tax expense of approximately $401,000.

4.10.1.6 Integrity Checks

Energy+ has completed the integrity checks for the following information as detailed in the filing requirements.

- The depreciation and amortization added back in the PIL's model agree with the numbers disclosed in the rate base section of the Application.

- The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for Historical, Bridge and Test years.

- Schedule 8 of the most recent federal T2 tax return filed as a closing December 31, 2016 agrees with the opening 2017 Forecast Bridge Year UCC. Energy+ confirms that there were no non-distribution tax amounts on Schedule 8 on the December 31, 2016 tax return.

- The CCA deductions in the PILs tax model for Historic, Bridge and Test years agree with the numbers in the UCC schedules for the same years filed in the Application.

- Energy+ does not have any loss carry-forwards.

- CCA is maximized since Energy+ does not have any loss carry-forwards.

- Post-retirement benefit obligations added back on Schedule 1, the reconciliation of accounting income to net income for tax purposes, agree with the amounts provided in the OM&A analysis for compensation.

- The income tax rate used to calculate the tax expense is consistent with the Energy+'s actual tax facts and the evidence filed in the application.

4.10.2 Property Taxes

Energy+ pays property taxes to the City of Cambridge and the County of Brant. In addition, Energy+ makes annual payments to the Ontario Electricity Financial Corporation for Payments in Lieu of Property Taxes. Property taxes for the 2014 Board Approved Proxy, 2014 Actual, 2015 Actual, 2016 Actual, 2017 Forecast, 2018 Bridge and 2019 Test Year are provided in Table 4-55 below. Table 4-xx provides the computation of the 2014 Board Approved Proxy, as described in Section 4.1.2.

Table 4-55: Property Taxes

	2014 Board Approved Proxy	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Bridge	2019 Test
Property Taxes	161,819						
1500 Bishop St N, Cambridge		136,011	133,139	131,742	133,062	157,164	170,690
Grand Ave S, Cambridge		2,621	2,784	2,760	2,964	2,702	2,770
Water St S, Cambridge		2,072	2,050	-	-	-	-
65 Dundas St E, Paris/New Operations Centre		33,962	28,224	27,644	27,921	27,167	27,251
Total	161,819	174,666	166,197	162,147	163,946	187,033	200,710

As described in Exhibit 2, Energy+ intends to sell the property located at 65 Dundas St. Paris, Ontario in 2018. Energy+ has entered into a sale-leaseback arrangement whereby it will continue to lease the property until 2019, when Energy+ is expected to relocate to the shared Operations Centre with BPI. For purposes of the 2019 Test Year, Energy+ has assumed that its portion of the property taxes for the shared Operations Centre with BPI will approximate the property taxes on the Dundas St. property.

Table 4-56: 2014 Board Approved Proxy for Property Taxes

				Former BCP 2014 Board Approved Proxy			
					Proxy 2012	Proxy 2013	Proxy 2014
	2014 Board Approved CND	2014 Board Approved Proxy BCP	2014 Board Approved Proxy	2011 Board Approved	IRM Factor 0.68%	IRM Factor 0.28%	IRM Factor 1.6%
Property Taxes	155,664	6,155	161,819	6,000	6,041	6,058	6,155

4.11 CONSERVATION AND DEMAND MANAGEMENT

4.11.1 Lost Revenue Adjustment Mechanism ("LRAM")

On March 31, 2011, the Minister of Energy and Infrastructure issued a directive (the "Directive") to the OEB regarding electricity Conservation and Demand Management ("CDM") targets to be met by licensed electricity distributors. The Directive required that the OEB amend the licenses of distributors to add, as a condition of licence, the requirement for distributors to achieve reductions in electricity demand through the delivery of CDM programs over a four-year period beginning January 1, 2011. Section 12 of the Directive required that the OEB have regard to the objective that lost revenues that result from CDM Programs should not act as a disincentive to a distributor.

On April 26, 2012, the OEB issued Guidelines for Electricity Distributor Conservation and Demand Management ("CDM Guidelines"). In keeping with the Directive, the OEB adopted a mechanism to capture the difference between the results of actual, verified impacts of authorized CDM activities undertaken by distributors between 2011 and 2014 and the level of activities embedded into rates through the distributors load forecast in an LRAM variance account.

On May 19, 2016, the OEB issued the "Report of the OEB: *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs"* to update its policy on how peak demand savings from energy efficiency and demand response programs should be treated for LRAM Variance Account ("LRAMVA") purposes.

4.11.2 Disposition of LRAMVA

In accordance with the Filing Guidelines, a distributor must apply for the clearance of its LRAMVA balances attributable to energy efficiency programs in a Cost of Service Application. The OEB established Account 1568 as the LRAMVA to capture the

variance between the OEB-approved CDM forecast and the actual CDM results at the customer rate class level. Distributors must continue to track the variances between the OEB-approved LRAMVA threshold and actual CDM results in the LRAMVA for the 2015-2020 period, as noted in the OEB's *"Conservation and Demand Management Requirement Guidelines for Electricity Distributors"* issued December 19, 2014 (EB-2014-0278).

Energy+ is requesting approval with this Application a claim for the recovery of the balance in its LRAMVA account (USoA Account 1568), as at December 31, 2017 (and associated carrying charges). As Energy+ is submitting this Application before final verified results are available for 2017 CDM programs and 2016 adjustments, the LRAMVA value has been based on unverified results from the IESO as of January 2018. Energy+ intends to update these values once the IESO final results are available.

The former CND submitted a Cost of Service Application in 2013 for rate year 2014 (EB-2013-0116) that accounted for CDM programs offered in 2014, and that forecast applied through 2018. Prior to 2014, forecasts for the former CND did not account for CDM. The former BCP submitted a Cost of Service Application in 2010 for rate year 2011 (EB-2010-0125) that included in the load forecast estimated losses associated with CDM programs offered in 2011. This same forecast applied through 2018.

Energy+ submitted a claim for lost revenues in the former CND 2015 IRM Rate Application (EB-2014-0060) for CDM programs offered in 2011 through 2013 (including persistence of 2011 and 2012 results). In 2016, Energy+ submitted a claim for lost revenue variances in the Energy+(Brant) service territory for variances between the CDM results in 2011-2015, including persistence through 2015, and what was included in the 2011 rate year forecast.

Energy+ engaged Indeco Strategic Consulting Inc. ("Indeco") to assist with the calculations. The calculations in support of Energy+'s LRAM and LRAMVA claims and associated report ("Indeco Report") are included in Appendix 4-6. In its

calculations, Indeco has used the most recent reports from the IESO (formerly the OPA). The following IESO reports are included in Appendix 4-7 to this Exhibit:

- Final 2016 Annual Verified Results Report – Energy+
- Final 2015 Annual Verified Results Report – Brant County Power Inc.
- Final 2015 Annual Verified Results Report – Cambridge and North Dumfries Hydro Inc.
- 2011-2014 Final Results Report – Brant County Power Inc.
- 2011-2014 Final Results Report – Cambridge and North Dumfries Hydro Inc.
- January 2018 Participation and Cost Report – Energy+

Energy+ has completed the OEB's LRAMVA work form separately for each service territory as the IESO reported results for each of the former BCP and CND separately until the legal amalgamation in 2016. Copies of these reports, in working Microsoft Excel format, have been included as part of the Application material filed.

- Energy+(CND) OEB_LRAMVA_Work_Form; and
- Energy+(Brant) OEB_LRAMVA_Work_Form.

The tables and calculations by rate class required under the Filing Requirements can be found in the supporting calculations to the Indeco Report.

Please refer to Exhibit 9 for the calculation of Energy+'s recovery of its LRAMVA balance, and corresponding rate riders. The amounts requested for recovery have been included in the EDDVAR model and summarized in Table 4-57 below by rate class.

Table 4-57: Summary of Requested LRAM Amounts

	Energy+ (CND)			Energy+ (BCP)			Energy+		
	LRAMVA	Carrying charges	Total	LRAMVA	Carrying charges	Total	LRAMVA	Carrying charges	Total
Residential	(42,017)	(4,950)	(46,967)	73,874	1,979	75,853	31,857	(2,971)	28,886
GS<50	(53,105)	(3,057)	(56,162)	94,146	2,507	96,653	41,041	(550)	40,491
GS 50-999	630,471	24,167	654,638			-	630,471	24,167	654,638
GS 1000-4999	41,943	1,184	43,128			-	41,943	1,184	43,128
GS 50-4999			-	60,778	1,582	62,359	60,778	1,582	62,359
Large users	308,108	7,579	315,687			-	308,108	7,579	315,687
Scattered load	(2,374)	(91)	(2,465)			-	(2,374)	(91)	(2,465)
Sentinel lighting			-			-	-	-	-
Street lighting	(44,004)	(1,659)	(45,663)	101,105	2,286	103,391	57,101	627	57,728
Total	839,023.26	23,173.00	**862,196.26**	329,901.91	8,353.92	**338,255.83**	1,168,925.17	31,526.92	**1,200,452.09**

APPENDIX 4-1: 2017 ACTUARIAL VALUATION REPORT

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December 21, 2017

BY E-MAIL: kculver@energyplus.ca

Ms. Kelly Culver
Manager, Accounting
Energy + Inc.
1500 Bishop St., P.O. Box 1060
Cambridge, ON N1R 5X6

Dear Ms. Culver:

Re: Energy+ Inc. ("the Corporation") Actuarial Valuation Report as at December 31, 2017: Post-Retirement Non-Pension Benefits

This letter provides you with our calculation of the CY 2017 defined benefit cost and December 31, 2017 present value of defined benefit obligation ("PV DBO") for the above-noted plan.

The intended users of this letter and attachments include the Corporation and its auditors for financial reporting in compliance with the International Financial Reporting Standards ("IFRS") guidelines in respect of its post-retirement non-pension benefit plan for FY 2017. The calculations were performed in accordance with the IFRS guidelines for post-retirement non-pension benefits as outlined in International Accounting Standard IAS 19 – Employee Benefits ("IAS 19").

For post-retirement non-pension benefits, the FY 2017 defined benefit cost to be recognized in the income statement is approximately $173,500, the FY 2017 defined benefit cost to be recognized in other comprehensive income is approximately $114,600, and the December 31, 2017 PV DBO is approximately $2,990,600. The supporting calculations are summarized in the corresponding accounting schedule hereby attached.

Our calculations are based on the same benefit plan provisions, data, assumptions, and methodology as summarized in our Report of the Actuarial Valuation of Post-Retirement Non-Pension Benefits for the Corporation as at December 31, 2016, dated February 6, 2017. The only exception is the discount rate assumption of 3.25% per annum used to calculate the PV DBO at December 31, 2017, which was derived based on the Corporation's projected benefit cash flows for post-retirement non-pension benefits and the December 15, 2017 spot rate curve published by Fiera Capital. You will recall that the discount rate assumption was 3.70% in the valuation at December 31, 2016.

RSM Canada Consulting LP is a limited partnership that provides consulting services and is an affiliate of RSM US LLP, a member firm of RSM International, a global network of independent audit, tax and consulting firms. Visit rsmcanada.com/aboutus for more information regarding RSM Canada Consulting LP and RSM International.

Also included in the attached accounting exhibits are extrapolations for fiscal years ending December 31, 2018 and December 31, 2019 which are based on the same data, benefit provisions and assumptions as used in the December 31, 2017 extrapolation. We note that if there are significant changes to the information during these years, revised projections or a full actuarial review may be required. Significant changes to information would include re-negotiated benefits, increased benefit costs, changes in valuation assumptions and significant swings in demographics, for example.

We have also performed the following sensitivity tests the PV DBO at December 31, 2017 in accordance with the Corporation's IFRS reporting purposes:

	PV DBO at Dec. 31, 2017	Difference from Base
Base	2,990,600	
Retirement Age 58	3,379,000	+13%
Cost Trends +1%	3,124,500	4%
Cost Trends -1%	2,871,100	-4%
Discount Rate 2.25%	3,279,000	+10%
Discount Rate 4.25%	2,747,700	-8%

We are not aware of any subsequent events that would have a significant impact on our calculations.

If you have any questions regarding the above or the attached accounting schedules, please do not hesitate to give us a call.

Yours truly,

Stanley Caravaggio, FSA, FCIA
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SC/MH:ecs

Encls.

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Energy Plus
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Actual CY 2017	Projected * CY 2018	Projected * CY 2019
Discount Rate at January 1	3.70%	3.25%	3.25%
Discount Rate at December 31	3.25%	3.25%	3.25%
Health Benefit Cost Trend Rate at December 31			
Initial Rate	5.99%	5.78%	5.57%
Ultimate Rate	4.50%	4.50%	4.50%
Year Ultimate Rate Reached	2025	2025	2025
Dental Benefit Cost Trend Rate at December 31	4.50%	4.50%	4.50%
Salary Scale Rate at December 31	2.10%	2.10%	2.10%
Assumed Increase in Employer Contributions	actual	expected **	expected **

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

Net Defined Benefit Liability/(Asset) as at January 1	2,845,134	2,990,594	2,943,645
Defined Benefit Cost Recognized in Income Statement	173,567	168,155	168,990
Defined Benefit Cost Recognized in Other Comprehensive Income	114,627	-	-
Benefits Paid by the Employer	(142,734)	(215,103)	(226,163)
Net Defined Benefit Liability/(Asset) as at December 31	2,990,594	2,943,645	2,886,472

B. Determination of Defined Benefit Cost

B1. Determination of Defined Benefit Cost Recognized in Income Statement

Service Cost			
- Current Service Cost	70,937	78,181	80,722
- Past Service Cost	-	-	-
Net Interest Cost	102,629	89,973	88,268
Defined Benefit Cost Recognized in Income Statement	173,567	168,155	168,990

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	114,627	-	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-	-	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments			
Return on Plan Assets (excluding amounts included in net interest cost)	-	-	-
Change in effect of asset ceiling	-	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	114,627	-	-
Total Defined Benefit Cost	288,194	168,155	168,990

* Projected CY 2018 and CY 2019 results are provided for informational purposes only. Signficant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

** Based on expected benefits to be paid to those eligible for benefits.

Energy Plus
ESTIMATED BENEFIT EXPENSE (IAS 19)
FINAL

	Actual CY 2017	Projected * CY 2018	Projected * CY 2019
Discount Rate at January 1	3.70%	3.25%	3.25%
Discount Rate at December 31	3.25%	3.25%	3.25%
Health Benefit Cost Trend Rate at December 31			
Initial Rate	5.99%	5.78%	5.57%
Ultimate Rate	4.50%	4.50%	4.50%
Year Ultimate Rate Reached	2025	2025	2025
Dental Benefit Cost Trend Rate at December 31	4.50%	4.50%	4.50%
Salary Scale Rate at December 31	2.10%	2.10%	2.10%
Assumed Increase in Employer Contributions	actual	expected **	expected **

C. Change in the Present Value of Defined Benefit Obligation

Present Value of Defined Benefit Obligation as at January 1	2,845,134	2,990,594	2,943,645
Current Service Cost	70,937	78,181	80,722
Past Service Cost	-	-	-
Interest Cost	102,629	89,973	88,268
Benefits Paid	(142,734)	(215,103)	(226,163)
Net Actuarial Loss/(Gain)	114,627	-	-
Present Value of Defined Benefit Obligation as at December 31	2,990,594	2,943,645	2,886,472

D. Calculation of Component Items

Service Cost			
- Current Service Cost	70,937	78,181	80,722
- Past Service Cost	-	-	-
Interest Cost			
- Net Defined Benefit Liability/(Asset) as at January 1	2,845,134	2,875,967	2,829,018
- Benefits Paid	(71,367)	(107,552)	(113,081)
- Accrued Benefits	2,773,767	2,768,415	2,715,937
- Interest Cost	102,629	89,973	88,268
Expected Present Value of Defined Benefit Obligation as at December 31			
- Present Value of Defined Benefit Obligation as at January 1	2,845,134	2,875,967	2,829,018
- Current Service Cost	70,937	78,181	80,722
- Interest Cost	102,629	89,973	88,268
- Benefits Paid	(142,734)	(215,103)	(226,163)
- Expected Present Value of Defined Benefit Obligation as at December 31	2,875,967	2,829,018	2,771,845

E. Net Actuarial Loss/(Gain)

Net Actuarial Loss/(Gain) on Present Value of Defined Benefit Obligation as at December 31			
- Expected Present Value of Defined Benefit Obligation	2,875,967	2,829,018	2,771,845
- Past Service Cost	-	-	-
- Expected Present Value of Defined Benefit Obligation (after Past Service Cost)	2,875,967	2,829,018	2,771,845
- Actual Present Value of Defined Benefit Obligation	2,990,594	2,829,018	2,771,845
- Net Actuarial Loss/(Gain) on Present Value of Defined Benefit Obligation	114,627	-	-

* Projected CY 2018 and CY 2019 results are provided for informational purposes only. Signficant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

** Based on expected benefits to be paid to those eligible for benefits.

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Memorandum

Date: December 21, 2017

To: Kelly Culver (Energy + Inc.)

From: Stanley Caravaggio, Matthew Haymes

Subject: Energy + Inc. (the "Corporation") –
Accumulated Non-Vested Sick Leave Analysis as at December 31, 2017

EXECUTIVE SUMMARY

This memo provides the results of our analysis in regards to the Corporation's request for assistance with:

a) Analyzing the experience of the utilization of accumulated sick leave bank hours by its employees; and

b) Developing a method to estimate the future payments that are expected to be made as a result of employees' sick leave bank accruals.

These estimates are prepared for the Corporation to assist management in assessing the potential liability of its accumulating non-vested sick leave benefits for financial statement reporting purposes under the IAS 19 based accounting standards.

Based on the experience, which is detailed in the following section, the sick leave bank utilization experience for the Corporation's Union (Inside and Outside) employees has been significantly different than for the Corporation's Management employees over the period from 2012 to 2017. As a result of this experience, in calculating an estimate of the present value of the future payments to be made as a result of the Corporation's employees' unused sick leave bank hours at December 31, 2017, the Union employees have been analyzed separately from the Management employees. Furthermore, due to the low number of Management using sick leave bank hours, we have not included them in the present value calculation of the banked sick leave liability. Other comments based on our analysis of the experience of the group over the last six years are as follows:

Utilization by Year – The number of Union employees utilizing sick leave bank hours has been somewhat consistent from 2012 to 2017 (roughly six to ten employees annually over the period). The amount of banked sick leave used by these Union employees, however, was much more variable, with the highest average level per employee used in the YTD 2017 figures up to October 31st, and the lowest experience in 2013. For the Management group there was very little sick leave bank usage aside from 2015, in which one Management employee used approximately 250 sick leave bank hours. In 2016 and 2017 there has been an increase in the amount of banked sick leave hours used by Union employees, however Management's usage remains immaterial. Should Management's sick leave bank usage levels increase in future the figures may become material.

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Utilization by Age – Based on an analysis by the age of Union employees, the vast majority of employees who used sick leave bank hours from 2012 to 2017 were between 45 and 60.

A detailed breakdown of our calculations is provided in Appendix A attached to this memo. As you will see, the results indicate an estimated value of approximately **$383,000** for the expected future payments to be made as a result of the Corporation's employees' unused sick leave bank hours as at December 31, 2017. For reference, we calculated a value of $295,000 at December 31, 2016. The change in the liability from December 31, 2016 to December 31, 2017 can be attributed to the following:

- Increase of the frequency and severity assumptions due to the addition of final 2016 and year to date 2017 experience ($26,000 increase);
- Change in discount rate assumption ($15,000 increase);
- Change in demographics and other miscellaneous factors ($47,000 increase).

The calculations have been performed on a present value basis. A detailed description of the data, methodology and assumptions used in our calculations is provided in the following sections.

RESULTS OF EXPERIENCE ANALYSIS

The following table summarizes the Corporation's experience over the 2012 to 2017 period with regard to the number of individuals who used sick leave bank hours each year and the number of bank hours utilized by these same individuals. For clarity, the analysis focuses only on the amount of sick leave hours taken each year by employees that are in excess of the sick leave hours accrued by the employees during the same year. In other words, employees who did not use all of their sick leave hours accrued during the year and who actually added some amount of hours to their sick leave bank at the end of the year (for potential future use), would be excluded from the utilization figures below.

As you can see in Table 1, based on the experience data provided, the Union employees' average utilization over the 6 years, in regards to the number of employees who use the sick leave bank hours yearly, has been far greater than the experience of the Management employees. Based on these results, we have developed a utilization assumption for the Union employees for the estimates of the present value of future amounts to be paid for current sick leave bank accruals. For the Management group, due to their low utilization levels and consistent with the analysis performed in previous years, we have excluded them from the calculations at this time.

While there are a larger percentage of Outside employees utilizing their banked sick leave compared to Inside employees, the average amount of banked sick leave used by an individual is higher for Inside employees than for Outside employees by approximately 100 percent.

Table 1 – Utilization Experience by Calendar Year

Employee Group: A) Energy+ Inc. employees			Calendar Year YTD 2017	2016	2015	2014	2013	2012
Employee Group:								
i)	MANAGEMENT							
	a) Employees at beg of year		20	18	18	16	29	27
	b) Number of individuals who used sick leave bank hours in year		1	2	2	0	1	1
	c) Amount of bank hours used by individuals in b) above		8	60	252	0	58	16
ii)	INSIDE							
	a) Employees at beg of year		45	48	39	40	39	34
	b) Number of individuals who used sick leave bank hours in year		4	3	3	1	2	2
	c) Amount of bank hours used by individuals in b) above		651	107	423	716	150	322
iii)	OUTSIDE							
	a) Employees at beg of year		48	52	42	37	39	35
	b) Number of individuals who used sick leave bank hours in year		2	7	3	7	5	6
	c) Amount of bank hours used by individuals in b) above		399	826	63	534	205	368
iv)	INSIDE and OUTSIDE							
	a) Employees at beg of year		93	100	81	77	78	69
	b) Number of individuals who used sick leave bank hours in year		6	10	6	8	7	8
	c) Amount of bank hours used by individuals in b) above		1050	933	486	1250	355	690
	d) Average bank used per individual who used bank		175	93	81	156	51	86

From the experience data above, we have calculated the following metrics based on the average experience of the Union group as a whole over the period from 2012 to October 31st, 2017. We have used these experience figures in our calculations to estimate the additional amount that the Corporation expects to pay as a result of the unused sick leave bank hours accrued by its employees at December 31, 2017.

Table 2 – Utilization Experience for Management and Union Employees

Group	Average Percentage of Individuals Using Sick Leave Bank Per Year (2012-2017)	Average Amount of Sick Leave Bank Hours Used Per Individual Per Year (2012-2017)
MANAGEMENT	5.5%	57
INSIDE	6.0%	158
OUTSIDE	12.1%	79
INSIDE+OUTSIDE	9.1%	104

Additional experience analysis was done based on the age of employees at the beginning of each year of experience. Attached, as Appendix B, is a summary of the experience data on a 5-year grouped age basis for the Union and the Management employee groups. From the experience data, it is evident that both Union groups show higher utilization at older ages.

We have not used age specific assumptions in our calculations.

DATA

The following data was provided by the Corporation. We have performed some consistency checks on the data (for example, comparing it with previous data files provided), however, we have relied on the Corporation to confirm the accuracy, reliability and completeness of the data provided.

- Sick leave bank usage experience data for active and former employees for calendar years from 2012 to October 31, 2017, including:
  - Amount of sick leave bank hours earned by year
  - Amount of sick leave bank hours used by year
  - Group indicator
- Active employee data at October 31, 2017, including:
  - Age
  - Annual salary
  - Amount of unused sick leave bank hours
  - Group indicator

METHODOLOGY AND ASSUMPTIONS

Our calculations have been done using grouped employee data. We have grouped the active Union (Inside and Outside) employee data at October 31, 2017 by 5-year age bands. As indicated above, the Management group has not been included in our calculations.

The assumptions used in our calculations are listed below and based on the utilization experience analysis above as well as management's best estimates of future experience. The salary increase rate, withdrawal rate, and retirement age assumptions are the same as those used in the calculation completed as at December 31, 2016.

- Salary Increase Rate: 2.10% per annum
- Withdrawal Rate:

AGE BUCKET	CURRENT WITHDRAWAL RATE PER ANNUM
18 – 29	3.50%
30 – 34	2.50%
35 – 39	2.15%
40 – 49	1.75%
50 – 54	1.40%

- Discount Rate: 3.25% per annum (Previously 3.70%)
- Retirement Age: 60
- No mortality or long term disability prior to retirement
- Utilization of Sick Leave (based on Inside and Outside experience)
  - Average Percentage of Individuals Using Sick Leave Bank Per Year: 9.1%
  - Average Amount of Sick Leave Bank Hours Used Per Individual Per Year: 104 hours

APPENDIX A

Analysis Performed by Age-Band
Inside + Outside - Management not included

				Calculations of Estimated Expected Cost of Accumulating Non-Vested Sick Leave Bank Hours at December 31, 2017									
Inside + Outside		**Average Salary (Oct 31, 2017)**		# Active Employees	Sum of Accrued Sick	Capped Sick	Capped	Avg Age of		Estimated # of Individuals	Estimated 2018 Annual Total Payment for Individuals Over	Accumulation	Estimated Total Future
Age Band	# of Employees	Annual	Hourly*	at Val Date	Leave Bank Hrs	Leave Bank Hrs	Years	Actives	Avg Yrs to Ret	Over Accrual Per Year	Accrual	Factor**	Payments for Sick Leave
15	0	n.a	n.a.	0	-	-	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
20	1	$ 75,587.20	$ 37.76	1	308	335	32	25	35	0.09	$359	19.9	$7,129
25	18	$ 79,571.56	$ 39.75	18	6,927	5,626	33	27	33	1.64	$6,804	20.6	$140,118
30	8	$ 75,490.35	$ 37.71	8	5,249	2,045	27	33	27	0.73	$2,869	18.7	$53,754
35	5	$ 64,873.12	$ 32.40	5	2,411	1,048	22	38	22	0.46	$1,541	16.8	$25,862
40	8	$ 77,814.75	$ 38.87	8	8,571	1,299	17	43	17	0.73	$2,957	13.8	$40,866
45	15	$ 73,361.77	$ 36.64	15	15,196	1,751	12	48	12	1.37	$5,228	10.6	$55,461
50	20	$ 70,525.60	$ 35.23	20	19,583	1,391	7	53	7	1.82	$6,701	6.8	$45,316
55	13	$ 79,047.60	$ 39.48	13	17,044	377	3	57	3	1.19	$4,882	3.0	$14,701
60	5	$ 76,390.08	$ 38.16	5	8,334	-	-	62	0	0.46	$1,814	0.0	$0

Energy+ Inc. Total Estimated Future Payments due to Unused Sick Leave Bank Accrued at December 31, 2017: **$383,206**

* Average hourly rate of pay is calculated using annual salary rate for the group and assuming employees work 52 weeks each year and 38.5 hours per week

** Accumulation factor used to calculate value of future stream of payments and reflects the assumed salary increase rate, withdrawal rate and discount rate for future years. The factor also reflects the period over which benefits are expected to be paid, which is impacted by the level of bank hours accrued at the date of the calculation.

APPENDIX B

Mgmt	2012			2013			2014			2015			2016			YTD 2017		
Age Band	Employees at Beginning of Year	# of Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# of Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	1	0	0	1	0	0	1	0	0	0	0	0	0	0	0
25	1	0	0	1	0	0	0	0	0	1	0	0	2	0	0	3	0	0
30	0	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0
35	4	0	0	3	0	0	3	0	0	3	0	0	1	0	0	0	0	0
40	2	0	0	1	0	0	2	0	0	2	0	0	3	0	0	4	0	0
45	7	0	0	10	0	0	4	0	0	3	1	247	2	0	0	3	0	0
50	9	1	16	8	1	58	2	0	0	4	0	0	6	1	4	6	0	0
55	3	0	0	5	0	0	2	0	0	2	0	0	3	1	56	1	1	8
60	1	0	0	0	0	0	1	0	0	1	1	5	1	0	0	3	0	0
Total	27	1	16	29	1	58	16	0	0	18	2	252	18	2	60	20	1	8

Inside	2012			2013			2014			2015			2016			YTD 2017		
Age Band	Employees at Beginning of Year	# of Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	2	0	0	5	0	0	4	0	0	4	0	0	3	0	0	1	0	0
25	2	0	0	3	0	0	4	0	0	4	1	35	3	0	0	4	0	0
30	1	0	0	0	0	0	0	0	0	0	0	0	4	0	0	4	1	46
35	3	0	0	3	0	0	2	0	0	1	0	0	3	0	0	5	0	0
40	9	0	0	10	1	149	8	0	0	7	1	326	6	0	0	3	0	0
45	10	2	322	9	1	1	9	0	0	9	0	0	11	0	0	11	2	67
50	3	0	0	5	0	0	8	0	0	8	1	63	11	3	107	12	1	539
55	4	0	0	4	0	0	5	1	716	6	0	0	6	0	0	3	0	0
60	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	2	0	0
Total	34	2	322	39	2	150	40	1	716	39	3	423	48	3	107	45	4	651

Outside	2012			2013			2014			2015			2016			YTD 2017		
Age Band	Employees at Beginning of Year	# of Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual	Employees at Beginning of Year	# Employees who used sick leave bank hours	Amount of bank hours used over annual accrual
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	4	1	3	6	0	0	5	0	0	8	0	0	7	0	0	5	0	0
25	3	0	0	3	0	0	5	0	0	6	1	14	6	0	0	9	1	32
30	1	0	0	2	0	0	1	0	0	0	0	0	4	0	0	4	0	0
35	5	0	0	3	0	0	3	0	0	2	0	0	3	0	0	1	0	0
40	3	0	0	6	0	0	4	1	4	4	0	0	6	0	0	7	1	367
45	7	1	97	7	2	91	5	1	376	6	0	0	7	1	78	5	0	0
50	7	2	141	8	2	106	9	4	151	8	1	37	11	5	712	8	0	0
55	5	2	128	3	0	0	4	0	0	6	0	0	5	1	37	6	0	0
60	0	0	0	1	1	8	1	1	4	2	1	13	3	0	0	3	0	0
Total	35	6	368	39	5	205	37	7	534	42	3	63	52	7	826	48	2	399

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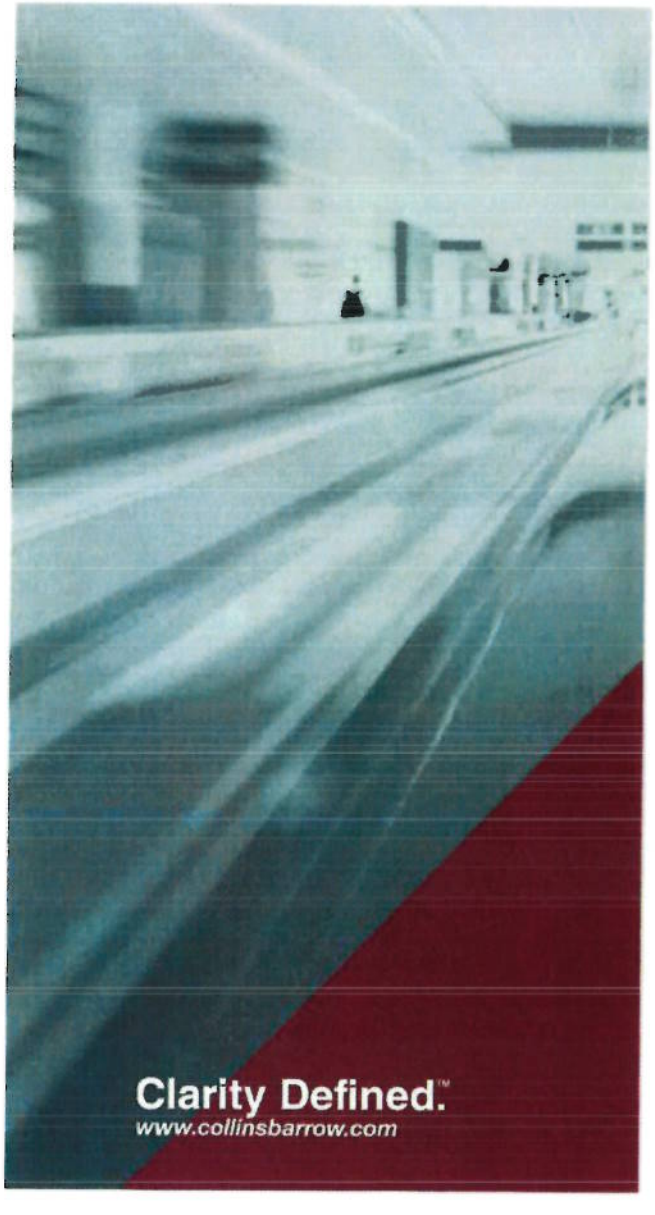

ENERGY+ INC.

Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits

As at December 31, 2016

February 6, 2017 – Final

COLLINS BARROW

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EXECUTIVE SUMMARY

PURPOSE

Collins Barrow Toronto Actuarial Services Inc. was engaged by Energy+ Inc. ("the Corporation") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2016. The nature of these benefits is defined benefit.

This report is prepared in accordance with the International Financial Reporting Standards (the "IFRS") guidelines for post-retirement non-pension benefits as outlined in the International Accounting Standard 19 – Employee Benefits ("IAS 19") in effect January 1, 2016. The Corporation began reporting on the basis of IFRS for the fiscal year ending December 31, 2015.

The most recent full valuation for former Cambridge and North Dumfries Hydro employees was prepared as at January 1, 2014. The previous valuation for all former Brant County Power employees was prepared as at November 28, 2014, both valuations based on the then appropriate assumptions.

The purpose of this valuation is threefold:

i) To determine the Corporation's liabilities in respect of post-retirement non-pension benefits at December 31, 2016;

ii) To determine the expense to be recognized in the income statement for fiscal year 2016; and

iii) To provide all other pertinent information necessary for compliance with IAS 19.

The intended users of this report include the Corporation and its auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

SUMMARY OF KEY RESULTS

The key results of this actuarial valuation as at December 31, 2016 with comparative results from the previous valuations are shown below, in thousands of dollars:

	Cambridge and North Dumfries Hydro January 1, 2014	Brant County Hydro November 28, 2014	Energy+ Inc. December 31, 2016
Present Value of Defined Benefit Obligation (PV DBO)			
a) People in Receipt of Benefits	1,070	434	1,574
b) Fully Eligible Actives*	230	111	442
c) Not Fully Eligible Actives	481	161	829
Total PV DBO	**1,781**	**706**	**2,845**

	Cambridge and North Dumfries Hydro CY 2014	Brant County Hydro 2014 Nov 28 - Dec 31	Energy+ Inc. CY 2016
Current Service Cost	47	1	72
Interest Cost	76	2	94
Defined Benefit Cost Recognized in Income Statement	**123**	**3**	**166**
Defined Benefit Cost Recognized in Other Comprehensive Income	**108**	**3**	**193**

**Fully Eligible refers to those employees who are eligible for post-retirement non-pension benefits at the valuation date*

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by Energy+ Inc. ("the Corporation") as at December 31, 2016, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations) and we express no opinion on them;
3. All known legal and constructive obligations with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
4. This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are not aware of any subsequent events after December 31, 2016 that would have a significant effect on our valuation.

The latest date on which the next actuarial valuation should be performed is December 31, 2019. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,
COLLINS BARROW TORONTO ACTUARIAL SERVICES INC.

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Toronto, Ontario

February 6, 2017

SECTION A—
VALUATION RESULTS

Table A - 1 shows the key valuation results for the prior valuation and the current valuation.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 60 to 58, an increase/decrease in the health and dental claims cost trend rates by 1% per annum, and an increase/decrease in the discount rate by 1% per annum.

Table A - 3 presents the development of changes in the present value of defined benefit obligation as a result of the re-measurement at December 31, 2016.

VALUATION RESULTS

Table A.1—Valuation Results
(in thousands of dollars)

	Cambridge and North Dumfries Hydro January 1, 2014	Brant County Hydro November 28, 2014	Energy+ Inc. December 31, 2016
Present Value of Defined Benefit Obligation (PV DBO)			
a) People in Receipt of Benefits	1,070	434	1,574
b) Fully Eligible Actives	230	111	442
c) Not Fully Eligible Actives	481	161	829
Total PV DBO	**1,781**	**706**	**2,845**

	Cambridge and North Dumfries Hydro CY 2014	Brant County Hydro 2014 Nov 28 - Dec 31	Energy+ Inc. December 31, 2016
Current Service Cost	47	1	72
Interest Cost	76	2	94
Defined Benefit Cost Recognized in Income Statement	**123**	**3**	**166**
Actuarial (Gains)/Losses	108	-	193
Defined Benefit Cost Recognized in Other Comprehensive Income	**108**	**-**	**193**
Total Defined Benefit Cost	**231**	**3**	**359**
Expected Benefit Payments	**110**	**4**	**125**

The benefit payments for CY 2016 are based on the actual payments made for those eligible for benefits in 2016. These amounts were provided by the Corporation.

SENSITIVITY ANALYSIS

Table A.2—Sensitivity Analysis
(in thousands of dollars)

	PV DBO at December 31, 2016				CY 2017	
	People in Receipt of Benefits	Fully Eligible Actives	Not Fully Eligible Actives	Total PV DBO	Current Service Cost	Interest Cost
Valuation Results	1,574	442	829	2,845	71	101
Retirement Age 58	1,574	521	1,027	3,122	84	111
Cost Trends +1%	1,578	456	869	2,903	73	104
Cost Trends -1%	1,570	428	746	2,744	63	98
Discount Rate 2.7%	1,699	466	955	3,121	82	81
Discount Rate 4.7%	1,466	420	726	2,612	62	118

DEVELOPMENT OF CHANGES IN THE DEFINED BENEFIT OBLIGATION

Table A.3—Development of Changes in the Present Value of Defined Benefit Obligation (in thousands of dollars)

PV DBO at December 31, 2015	2,611
2016 Current Service Cost	72
2016 Benefit Payments	(125)
2016 Interest Cost	94
Expected PV DBO at December 31, 2016	**2,652**
Actuarial (Gain)/Loss at December 31, 2016	193
PV DBO at December 31, 2016	**2,845**

The increase indicated above of $193,000 in the PV DBO from the expected PV DBO at December 31, 2016 is due to the re-measurement of the liability; a breakdown of the changes is as follows:

- A change in the claim cost trend rate assumption (an increase of approximately $15,000)
- A change in the mortality improvement assumption (an increase of approximately $4,000)
- A change in the withdrawal rate assumption (a decrease of approximately $1,000)
- A change in the salary growth rate (a decrease of approximately $1,000)
- A change in the health and dental benefit cost level assumptions (a decrease of approximately $134,000)
- Deviations from the expected demographic changes due to factors such as the difference between expected and actual group experience, changes in coverage type, changes in employee status, and new hires (an increase of approximately $310,000)

Pursuant to IAS 19, the re-measurement of the PV DBO at December 31, 2016 based on the changes in the assumptions and experience is recognized immediately as an adjustment to other comprehensive income at December 31, 2016.

SECTION B—
PLAN PARTICIPANTS

Table B – 1 sets out the summary information with respect to the plan participants valued in the report, with data as of October 31, 2016.

Table B – 2 reconciles the number of participants in the last valuation to the number of participants in the current valuation.

PARTICIPANT DATA

Table B.1—Participant Data

Membership data as at October 31, 2016 was received from the Corporation via e-mail and included information such as name, sex, age, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

Although the data provided reflected status and benefit information as at October 31, any changes in status and other member data occurring from October 31 to December 31 are not expected to be material to the valuation results.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of hire prior to date of birth;
- Ages under 18 or over 100;
- Abnormal levels of benefits and/or premiums; and
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

Active Employees

	October 31, 2016		
	Male	Female	Total
Number of Employees	83	48	131
Avg. Length of Service	13.7	13.4	13.6

Count as of October 31, 2016

	Active Lives - Not Fully Eligible			Active Lives - Fully Eligible		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	19	4	23	-	-	-
30 - 35	6	3	9	-	-	-
36 - 40	4	3	7	-	-	-
41 - 45	10	7	17	-	-	-
46 - 50	11	9	20	-	-	-
51 - 55	13	14	27	3	-	3
56 - 60	5	2	7	8	5	13
61 - 65	1	-	1	2	1	3
66 - 70	1	-	1	-	-	-
71 - 75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**70**	**42**	**112**	**13**	**6**	**19**

Average Service as of October 31, 2016

	Active Lives - Not Fully Eligible			Active Lives - Fully Eligible		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	3.1	2.0	2.9	-	-	-
30 - 35	7.7	6.7	7.4	-	-	-
36 - 40	13.2	9.0	11.4	-	-	-
41 - 45	12.5	10.9	11.8	-	-	-
46 - 50	11.4	14.1	12.6	-	-	-
51 - 55	21.2	13.7	17.3	28.3	-	28.3
56 - 60	10.5	12.5	11.1	30.0	25.6	28.3
61 - 65	11.9	-	11.9	29.4	41.2	33.3
66 - 70	1.9	-	1.9	-	-	-
71 - 75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**10.7**	**11.3**	**10.9**	**29.5**	**28.2**	**29.1**

People in Receipt of Benefits (includes people on LTD)

	October 31, 2016		
	Male	Female	Total
Number of Members	45	13	58

Expected Annual Benefit Payments for CY 2016

Age Band	Male	Female	Total
Less than 30	-	-	-
30 - 35	-	-	-
36 - 40	-	-	-
41 - 45	-	-	-
46 - 50	-	-	-
51 - 55	-	-	-
56 - 60	31,228	212	31,440
61 - 65	12,270	5,102	17,372
66 - 70	1,930	-	1,930
71 - 75	2,481	-	2,481
Greater than 75	101,767	11,517	113,284
Total	**149,676**	**16,831**	**166,507**

PARTICIPATION RECONCILIATION

Table B.2—Participation Reconciliation

Participant Reconciliation

	Actives	Retired
As at Jan 1, 2014*	**102**	**55**
Transfer from Brant County Power at Nov 28 2014	25	19
Adjustment**		1
New Entrants	20	
Active		
LTD		
Terminated	(10)	
Deceased		(1)
Retired	(4)	4
Retired and Ineligible for benefits***	(2)	
No Longer Eligible***		(20)
As at Oct. 31, 2016	**131**	**58**

** Jan 1, 2014 figures include former Cambridge and North Dumfries employees only*

*** As noted by the Corporation, 1 retiree was not included in the previous valuation by mistake but has been included in this valuation*

**** Retirees who have reached the maximum benefit age of 65*

SECTION C—
SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions for discount rates, and mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The Present Value of the Defined Benefit Obligation and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by IAS 19 when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. IAS 19 stipulates that the attribution period commences on the date when service by the employee first leads to post-retirement non-pension benefits under the plan and ends on the date when further service by the employee will lead to no material amount of further post-retirement non-pension benefits under the plan, other than from further salary increases.

For each employee not yet fully eligible for benefits, the Present Value of the Defined Benefit Obligation is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

For health and dental benefits, the Corporation has selected the funding levels charged for retiree benefits as management's best estimate of the benefits costs to be incurred. The total monthly premium rates, inclusive of premium taxes, used are as follows:

Health Single	Health Family	Dental Single	Dental Family
$ 97.67	$ 257.52	$ 63.43	$ 146.00

The above premium rates are effective January 1, 2017 to December 31, 2017, provided by the Corporation, and represent the rates at 100%, prior to any cost-sharing provisions.

The PV DBO at December 31, 2016 is based on membership data as at October 31, 2016 and management's best estimate assumptions as at December 31, 2016.

MANAGEMENT'S BEST ESTIMATE ASSUMPTIONS

The following are management's best estimate economic and demographic assumptions as at December 31, 2016.

ECONOMIC ASSUMPTIONS

Consumer Price Index

The consumer price index is assumed to be 2.00% per annum, which remains unchanged from the previous valuation.

Discount Rate

The rate used to discount future benefits is assumed to be 3.70% per annum as at December 31, 2016. This rate reflects the Corporation's expected projected benefit cash flows for post-retirement non-pension benefits and the market yields on high quality bonds at December 31, 2016.

This is unchanged from the assumption used in the previous valuations.

Salary Increase Rate

The rate used to increase salaries is assumed to be 2.10% per annum. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion adjusted for company-specific information.

This assumption used in the previous valuations was 2.25%.

Claims Cost Trend Rate

The rates used to project health benefit costs into the future are assumed to be as follows:

	Current Valuation		Previous Valuation	
End of Year	Health	Dental	Health	Dental
2017	6.20%	4.50%	5.97%	4.60%
2018	5.99%	4.50%	5.63%	4.60%
2019	5.78%	4.50%	5.29%	4.60%
2020	5.56%	4.50%	4.94%	4.60%
2021	5.35%	4.50%	4.60%	4.60%
2022	5.14%	4.50%	4.60%	4.60%
2023	4.93%	4.50%	4.60%	4.60%
2024	4.71%	4.50%	4.60%	4.60%
2025 and Thereafter	4.50%	4.50%	4.60%	4.60%

DEMOGRAPHIC ASSUMPTIONS

Mortality Table

The mortality tables used are as per the Canadian Institute of Actuaries Canadian Pensioners' Mortality Pension Experience Subcommittee final report dated February 11, 2014 (CIA Report). More specifically, the Canada Pensioners Mortality ("CPM") Table Public Sector (CPM2014 PUBL) has been used with the generational projection of mortality improvement based upon CPM Improvement Scale B-2014.

Mortality rates are applied on a sex-distinct basis.

The assumption used in the previous valuation was the draft version of the above-noted CPM table, along with the one-dimensional version of the corresponding mortality improvement table, CPM-B 2014.

Rates of Withdrawal

Termination of employment is assumed to be in accordance with the following withdrawal table:

Age Bucket	Current Valuation	Previous Valuation
18 – 29	3.50%	2.75%
30 – 34	2.50%	2.25%
35 – 39	2.15%	2.00%
40 – 49	1.75%	1.50%
50 – 54	1.40%	1.50%

Retirement Age

All active employees are assumed to retire at age 60 (or immediately if currently over age 60), which was based on the Corporation's retirement experience as well as the experience of other similar companies for which data was available. The retirement age was extended to the benefit eligibility age for active employees who are subject to the 20 year service provision and projected to reach benefit eligibility between 60 and 65.

This assumption remains unchanged from the previous valuation.

Disability

No provision was made for future disability. It was assumed that individuals on LTD would remain disabled until retirement at age 65.

This assumption remains unchanged from the previous valuation.

Family/Single Coverage

It is assumed that the coverage type as at December 31, 2016, as provided by the Corporation, will remain the same until the employee reaches the assumed retirement age. For family coverage, it is assumed that the retiree has a spouse of opposite gender and no other dependents. Male spouses are assumed to be three years older than female spouses.

These assumptions remain unchanged from the previous valuation.

Expenses and Taxes

We have assumed 10% of benefits is required for the cost of sponsoring the program for life insurance. We have assumed taxes and expenses are included in the premium rates for health benefits.

These assumptions remain unchanged from the previous valuation.

SECTION D—
SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation, based on information provided by and discussions with the Corporation.

GOVERNING DOCUMENTS

The program is governed by the following documents and agreements:

- Collective Agreement Between Cambridge and North Dumfries Hydro Inc. and Local Union 636 of the International Brotherhood of Electrical Workers for Office Unit #4, effective April 1, 2014 to March 31, 2018
- Collective Agreement Between Cambridge and North Dumfries Hydro Inc. and Local Union 636 of the International Brotherhood of Electrical Workers for Outside Unit #13, effective April 1, 2014 to March 31, 2018
- Energy+ Inc. Employee Benefit Booklet for Inside Union Employees, prepared January 2016
- Energy+ Inc. Employee Benefit Booklet for PWU Workers, prepared January 2016
- Energy+ Inc. Employee Benefit Booklet for Outside Union Employees, prepared January 2016
- Energy+ Inc. Employee Benefit Booklet for Management Employees, prepared January 2016
- Energy+ Inc. Employee Benefit Booklet for Early Retirees of Brant County, prepared January 2016
- Agreement between Brant County Power Incorporated and Power Workers Union (CUPE Local 1000), effective April 1, 2015 to March 31, 2017

What follows is only a summary of the post retirement non-pension benefits program. For a complete description, please refer to the above-noted documents.

ELIGIBILITY

Former Cambridge and North Dumfries Hydro Employees:

All employees who retired from the Corporation on or before December 31, 1999 are eligible for post-retirement life insurance benefits. In addition, employees age 55 or older with a minimum of 20 years of active service are eligible for extended health and dental benefits.

Former Brant County Hydro Employees:

Employees hired before October 1, 2010

All employees who retire from the Corporation and are receiving an OMERS pension are eligible for post-retirement life insurance.

Employees hired after October 1, 2010

All union employees who retire from the Corporation and are receiving an OMERS pension are eligible for post-retirement life insurance. For clarity, non-union employees hired after October 2010 are not eligible for post-retirement life coverage.

Employees hired before August 1, 2003

All employees who retire from the Corporation with a minimum of 20 years of active service and are receiving an OMERS pension are eligible for post-retirement health and dental benefits.

Employees hired after August 1, 2003

All employees who retire from the Corporation are eligible for post-retirement health and dental benefits.

PARTICIPANT CONTRIBUTIONS

For previous employees of Brant County Power who were hired after August 1, 2003 the Corporation shall pay 50% of the cost of the post-retirement health and dental benefits and 100% of the cost of the post-retirement life benefits for eligible retirees. For all other employees, the Corporation shall pay 100% of the cost of the post-retirement life, health and dental benefits for the eligible retirees.

PAST SERVICE

Past service is defined as continuous service prior to joining the plan if the participant was employed by another electrical distribution company/hydro prior to joining the Corporation.

LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

SUMMARY OF BENEFITS

Post-Retirement Life Insurance

All eligible employees who retire from the Corporation are entitled to lifetime post-retirement life insurance, as per the MEARIE plan administered by Great West Life, based upon the following table:

Plan Option	Amount of Coverage	Eligibility
1	Flat $2,000.	If employee retires with less than 10 years of service in the Plan.
2	50% of final annual earnings reducing by 2.5% of final annual earnings each year thereafter for 10 years, to a final benefit equal to 25.0% of final annual earnings. Reduction occurs on anniversary date of retirement.	If employee was ever insured under Employee Plan options 2, 3 or 4, or if employee retires with 10 or more years of service in Plan but was never in superseded plan.
3	50% of final annual earnings	If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only.
4	70% of the final amount insured for under the life plan immediately prior to retirement.	If employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under Option 1 only.

In addition, one retiree is entitled to 50% of his previous active life insurance coverage under a unique circumstance.

Health and Dental Benefits

Eligible employees are entitled to post-retirement health and dental benefits to age 65. Coverage for health and dental benefits continue to the dependents of a deceased retiree for a maximum of two years or the date the former employee would have turned age 65.

A detailed description of the life, health, and dental benefits covered under the post-retirement non-pension benefits can be found in the above-noted governing documents.

SECTION E—
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Energy+ Inc.
Actuarial Valuation as at December 31, 2016

I hereby confirm, as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Energy+ Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the membership data summarized in Section B is accurate and complete;

ii) the assumptions upon which this report is based as summarized in Section C, are management's best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on December 31, 2016.

ENERGY+ INC.

January 23, 2017
Date

Signature

Sarah J. Hughes, CPA, CA
Chief Financial Officer
ENERGY+ INC.

Name

Title

APPENDIX 4-2: HISTORICAL APPENDIX 2-N SHARED SERVICES

File Number:	EB-2018-0028
Exhibit:	1
Tab:	
Schedule:	
Page:	
Date:	27-Apr-18

Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2014

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Energy+ Inc. (former CND)	Energy Solutions	Street Light Maintenance	Cost	334,225	334,225
Energy+ Inc. (former CND)	Energy Plus	Board of Directors	Cost	11,100	11,100
Energy+ Inc. (former CND)	Energy Solutions	Board of Directors	Cost	11,100	11,100
Energy+ Inc. (former BCP)	County of Brant	Water/Waste Water Billing	Cost	194,810	194,810

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Energy+ Inc. (former CND)	Energy Plus	Accounting	Cost	1.4%	6,000
Energy+ Inc. (former CND)	Energy Solutions	Accounting	Cost	2.8%	12,000

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

· ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

· ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

· ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

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Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2015

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Energy+ Inc. (former CND)	Energy Solutions	Street Light Maintenance	Cost	283,335	283,335
Energy+ Inc. (former CND)	Energy Plus	Board of Directors	Cost	11,100	11,100
Energy+ Inc. (former CND)	Energy Solutions	Board of Directors	Cost	11,100	11,100
Energy+ Inc. (former CND)	Energy Solutions	Business Development	Cost	47,000	47,000
Energy+ Inc. (former CND)	Energy+ Inc. (former BCP)	Business Development	Cost	46,500	46,500
Energy+ Inc. (former CND)	Energy+ Inc. (former BCP)	Management Fees	Cost	93,000	93,000

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Energy+ Inc. (former CND)	Energy Plus	Accounting	Cost	1.4%	6,120
Energy+ Inc. (former CND)	Energy Solutions	Accounting	Cost	2.8%	12,240
Energy+ Inc. (former CND)	Energy+ Inc. (former BCP)	Interest IESO Prudential	Cost	100%	356,348
Energy+ Inc. (former CND)	Energy+ Inc. (former BCP)	Pole Change Out	Cost	100%	48,609
Energy+ Inc. (former CND)	Energy+ Inc. (former BCP)	Inventory Materials	Cost	100%	14,194

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Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2016

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Energy+ Inc.	Energy Solutions	Street Light Maintenance	Cost	219,000	219,000
Energy+ Inc.	Energy Plus	Board of Directors	Cost	11,100	11,100
Energy+ Inc.	Energy Solutions	Board of Directors	Cost	11,100	11,100
Energy+ Inc.	Energy Solutions	Business Development	Cost	23,000	23,000
Energy+ Inc.	Grand River Energy Solutions Corp	Management Fees	Cost	48,914	48,914

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Energy+	Energy Plus	Accounting	Cost	1.2%	6,120
Energy+	Energy Solutions	Accounting	Cost	2.4%	12,240

Note:

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Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2017

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Energy+ Inc.	Energy Solutions	Street Light Maintenance	Cost	212,978	212,978
Energy+ Inc.	Energy Plus	Board of Directors	Cost	11,100	11,100
Energy+ Inc.	Energy Solutions	Board of Directors	Cost	12,100	12,100
Energy+ Inc.	Grand River Energy Solutions Corp	Management Fees	Cost	26,487	26,487

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Energy+	Energy Plus	Accounting	Cost	1.1%	6,120
Energy+	Energy Solutions	Accounting	Cost	2.2%	12,240

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

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Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2018

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Energy+ Inc.	Energy Solutions	Street Light Maintenance	Cost	213,000	213,000
Energy+ Inc.	Energy Plus	Board of Directors	Cost	11,100	11,100
Energy+ Inc.	Energy Solutions	Board of Directors	Cost	11,100	11,100

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Energy+	Energy Plus	Accounting	Cost	1.0%	6,120
Energy+	Energy Solutions	Accounting	Cost	2.0%	12,240
Energy+	Grand River Energy Solutions Corp	Accounting	Cost	1.7%	10,000

Note:

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Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

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- ***% Allocation:***

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Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Energy+ Inc.	Energy Solutions	Street Light Maintenance	Cost	213,000	213,000
Energy+ Inc.	Energy Plus	Board of Directors	Cost	11,100	11,100
Energy+ Inc.	Energy Solutions	Board of Directors	Cost	11,100	11,100

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Energy+	Energy Plus	Accounting	Cost	1.1%	6,120
Energy+	Energy Solutions	Accounting	Cost	2.1%	12,240
Energy+	Grand River Energy Solutions Corp	Accounting	Cost	1.7%	10,000

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

APPENDIX 4-3: PURCHASING AND CONTRACTS

1.0 PURPOSE AND SCOPE

This policy outlines the guidelines and procedures that will be used by Energy+ Inc. (the "Company") and its affiliate companies to purchase equipment, materials, supplies, and services required by our Company. The Purchasing Department has primary responsibility for procurement. Any employee or agent acting on behalf of the Company that engages in or supports the purchase or goods or services for use by the Company must follow the procedures outlined in this document.

2.0 GOVERNING PRINCIPLES

Goods and services shall be purchased with proper authorization and on the basis of quality, service, and price, while considering key environmental and social benefits over the entire life-cycle of the product or service including:

- Complies with the latest environmental, health and safety legislation, where applicable;
- Reduces waste and/or conserve natural resources;
- Can be recycled or re-used;
- Produced from recycled materials; and
- Product has a long service-life, can be economically and effectively repaired, refurbished or upgraded.

The Company will maintain an open and competitive process with respect to the purchase of goods and services. The Company reserves the right to purchase from a singularly approved vendor as outlined in Section 5.2.5.

3.0 PURCHASING DEPARTMENT RESPONSIBILITIES

The Purchasing Department shall provide and be held responsible for providing the following services necessary to ensure that the Company's purchasing objectives are met:

- Procure supplies, services, materials and equipment of specified quality and quantity at the best price, using recognized methods in securing competitive prices;

- Issue most Company-related invitations to tenders and obtain quotations. No formal negotiations with potential suppliers should be carried out without at least informing the Purchasing Department.

  From time to time, vendors or suppliers may be contacted to provide materials or services that are deemed confidential and these transactions need not be disclosed to the Purchasing Department upon approval by the Leadership Team.

- To group, correlate and unify, so far as possible, requirements of the various departments and, by standardization, to reduce the kinds of goods used to the smallest number based upon the needs of the various departments affected. This program shall be an on-going joint enterprise among the various departments.

- Estimates of requirements for future periods of time shall be collected to determine the quantities of goods, which should be contracted for in advance of actual current need.

- Assist in providing estimates of cost for budgeting and project study documents.

- All pricing, deliveries, terms and conditions, etc. should be left to the purchasing group. Engineering, Information Systems and Leadership Team may, of necessity, contact suppliers and sales representatives for technical information and similar type needs.

- A copy of all correspondence affecting purchasing, or a purchase order or product supply or approval between the using department and the suppliers should be forwarded to purchasing. Purchasing will obtain suppliers' catalogues and arrange demonstrations upon request.

    0 Departments who wish to arrange demonstrations for their department's specialized needs may check with Purchasing for the appropriate contact person at the supplier. Purchasing should be advised as to the time and place of the demonstration as others may be interested.

- To visit suppliers, when necessary, to create goodwill and/or to expedite deliveries.

- Source potential suppliers, interview sales representatives, inform all applicable departments of the information received regarding new or existing materials, equipment, processes and techniques, and retain data on file for reference.

- Complete the purchase transaction by ensuring that all purchases follow the requisition approval process and a purchase order is issued with each order in excess of $500. Purchasing will follow-up and/or expediting to ensure deliveries and schedules are met.

- Operate and maintain a stores warehouse and maintain inventory levels consistent with the needs and schedules of the various departments.

4.0 AUTHORIZATION

4.1 Cheque Requisitions

Cheque requisition approval limits are based on the individual signing authority indicated in the Purchasing Requisition section.

The President and CEO or CFO has the authority to approve cheque requisitions for the following expenditures: corporate tax remittances, including HST, income taxes, and property taxes; payroll related remittances, including statutory deductions, OMERS, EHT, and group insurance, and investments.

4.2 Inventory Requisitions

All issues from the stockroom must occur in conjunction with the properly completed material requisition form. Stores personnel are responsible for ensuring that the material issued matches to the material requisition form.

Contractors and/or Sub-contractors must sign material requisition forms to acknowledge receipt and/or return of project materials. Stores Personnel must obtain signatures “before” the requisition forms are forwarded to Purchasing for processing.

4.3 Personal Expense Reports

Employee expense reports will be approved by the employee’s direct Management Team Member. This approval will indicate that authorization was given for the expenses claimed and that Company policy has been complied with. Expense reports containing travel expenses are to be approved by the Vice President, CFO, or President and CEO in accordance with Policy COR-004 Travel Expenses.

Expense reports for the President & CEO or Member of the Board of Director’s must be authorized by the Board Chair or Vice Chair.

Employee expense reports in excess of $25 will be paid through payroll direct deposit; expense reports less than $25 will be paid through the petty cash fund.

4.4 Petty Cash Payments

Management Team staff must approve petty cash vouchers prior to payment by a custodian of a petty cash fund. Approval limits must follow the guidelines set in the Requisitioning Authority and Personal Expense Reports sections of this policy. Payments from the petty cash fund for expenses or cash purchases are limited to $200.

4.5 Purchasing Requisitions

4.5.1 Requisition Process:

Requisitions must be completed for most type of purchases except in the area of blanket purchase orders or inventory restocking requirements. Requisitions are required to be completed prior to the purchase or the goods or service, and prior to the commencement of the work (if possible) for items such as surveying, sub-contracting for field projects, major vehicle repairs, etc.

Annually, Purchasing will establish authorized vendors for items such as sod, automotive parts, building supplies, etc. Employees will then be able to purchase items (pick up) subject to their requisition dollar limit.

All low voltage non-distribution type equipment (i.e. power tools, battery chargers, and extension cords) purchased on behalf of the Company and not approved by the Engineering Department shall meet the requirements of the Electrical Safety Code (ESC). Equipment must be approved to Canadian standards. The CSA mark or a “C” outside the Entela, ETL, FM, MET signifies this, OMNI, TUV America, TUV Rheinland and UL marks. See ESC Bulletin 2-7-22 for more information. All items shall be checked upon receipt to ensure compliance with the above.

Any purchase requisitions for safety related goods and services (e.g. P.P.E., gas detectors, ‘ergonomic’ chairs, ladders etc.) must be approved by the requisitioning department Vice-President with input from the Department Management Team and the Safety and Training Management Team and/or the Joint Health and Safety Committee (“JHSC”) to ensure that the goods or services meet all the requirements and standards specified in applicable regulations, legislation and/or standards documentation. Please refer to Appendix I for further details regarding the procedure to be followed.

4.5.2 Approval

It is the responsibility of the requisitioner to prepare/enter the requisition and provide all pertinent information, including general ledger account coding, department, project/work order reference, and references to drawings/specifications, if applicable. The requisitioner is also responsible to acquire the necessary approvals

4.5 Purchasing Requisitions (Continued)

4.5.2 Approval

4.5.2.1 All goods and services, excluding inventory and consulting services

All Purchase Requisitions, excluding inventory and consulting services, are to be approved based on the following authority limits:

Position	Authority Limits Budgeted Operating and Capital Expenses	Authority Limits Non-budgeted Operating and Capital Expenses
Sub-Foreperson	<= $500	Nil
Executive Assistant	<= $1,000	Nil
Management Team	<= $5,000	Nil
Director	>= $5,000 and <= $25,000	Nil
Vice President	Up to $75,000; Up to $100,000 with CFO	<= $10,000
Chief Financial Officer	<= $100,000	Up to $25,000 jointly with another Vice President; Up to $50,000 jointly with CEO
President and CEO	> $100,000 and <= $1MM	>= $10,000 and <= $100,000
Board Chair	> $1MM	>= $100,000 and <= $1MM
Board of Directors	> $1MM	> $1MM

4.5.2.2 Inventory

All inventory related Purchase Requisitions, except for inventory purchases required to maintain approved minimum inventory levels, are to be approved based on the following authority limits:

Position	Authority Limits - Inventory
Management Team	<= $25,000
Director	> $25,000 and <= $50,000
Vice President	<= $100,000
Chief Financial Officer	<= $100,000; Up to $250,000 jointly with the President and CEO
President and CEO	> $100,000 <= $1MM
Board Chair	> $1MM

4.5 Purchasing Requisitions (Continued)

4.5.2 Approval (Continued)

4.5.2.3 Consulting Services

Only Leadership Team Members may authorize consulting service expenditures, in accordance with the following authority limits:

Position	Authority Limits - Consulting
Vice President	<= $10,000
Chief Financial Officer	<= $10,000
President and CEO	> $10,000 and <= $50,000
Board	> $50,000

4.5.2.4 Delegation of Authority

The President and CEO is authorized to delegate approval authority to an employee in accordance with the approval limits set out in this policy. The President and CEO or the Board Chair is authorized to delegate the approval authority of the President and CEO to the Chief Financial Officer in the case of an emergency, extended absence, or vacation.

5.0 PURCHASING AND TENDERING PRACTICES

5.1 General

All purchasing activities will be conducted through the Purchasing Department to ensure cost effective procurement of goods and services in a timely manner. Purchase orders must be issued for all purchases in excess of $500. Purchase requisitions are to be prepared by the department requisitioning the goods or services and approved in accordance with the authority limits outlined in Section 4.0.

Purchase orders will be prepared by the Purchasing Department from the authorized purchase requisitions and sent to the appropriate supplier.

5.0 PURCHASING AND TENDERING PRACTICES (Continued)

5.2 Purchasing Process

The following purchasing process shall be applied to the purchase of goods and services with corresponding monetary limits and authorization levels:

$ Expenditure Limit	Purchasing Process
$10,000 or less	Informal Purchasing Method – Verbal or written quotation.
>$10,000 <= $50,000	Written Quotations – 3 or more suppliers.
> $50,000	Request for Tender/Proposal

The determination of the dollar limits, reflect the actual purchase or, in the case of on-going purchase commitments, the estimated annual expenditure would apply.

5.2.1 Informal Purchasing Methods

The informal purchasing methods will be used for smaller value goods and services that are used on a regular basis. The Purchasing Management Team will obtain offers from suppliers verbally or in writing. With assistance from and in agreement with the requisitioning department, an official purchase order will be issued to the lowest bidder meeting the specifications.

5.2.2 Verbal or Written Quotations

The Purchasing Management Team will obtain three competitive quotations (by fax, telephone or email), if possible. A record of quotation must be maintained. With assistance from and in agreement with the requisitioning department, an official purchase order will be issued to the successful bidder based upon price, specifications, and in accordance with the governing principles.

5.2.3 Request for Tender/Proposal

A formal Request for Tender ("RFT") or Request for Proposal ("RFP") will be issued for all purchases in excess of $50,000. The RFT or RFP will provide complete scope of work, specifications, and evaluation criteria.

All specifications shall be reasonable, clear, without ambiguity, and shall be designed to allow submission of tenders and quotations by the maximum number of responsible vendors. The requisitioning department shall be responsible for the technical accuracy of the specifications. Any correspondence arising should include both the requisitioning department and the Purchasing Department, to maintain full co-ordination. Sufficient drawings and instructions should accompany each request for tender.

5.2 Purchasing Process (Continued)

5.2.3 Request for Tender/Proposal (Continued)

The Purchasing Management Team is responsible for ensuring that all components of the tender are included in the package, and that sufficient bidding time is allowed and, further, that all qualified bidders have an opportunity to submit a tender.

The Purchasing Management Team will invite sealed tenders, or advertise for sealed tenders, and request sealed documents be addressed to the Company by the deadline and time. Any tender received after the deadline will not be accepted, except in unusual circumstances, and will be returned unopened to the supplier. The sealed tenders will be opened by the Purchasing Department with the requisitioning department present.

The Purchasing Management Team and the Vice President of the Department shall reach agreement on the recommendation of award. Where the total value of the RFP exceeds the approval limits as outlined in Section 4.5.2, or in the event a recommendation cannot be reached, a purchasing report is to be prepared for approval by the President and CEO.

In all cases, the Company reserves the right not to issue a Purchase Order following the purchase processes outlined in Section 5.2.1, 5.2.2, and 5.2.3.

5.2.4 Negotiating Prices

In special cases where negotiation will result in better prices or better deliveries, the Purchasing Management Team will have the authority to do so after consultation with and under the direction of the appropriate Vice President.

5.2.5 Singularly Approved Vendor

On singularly approved material and equipment and items of standardization, the Purchasing Management Team may purchase these items without competition when the price is considered fair, under proper evaluation. Singularly approved contractor situations may occur when other related business transactions require the use of that contractor without competitive tenders. The pricing will be reviewed by Engineering and Purchasing to ensure that the pricing is appropriate, fair and reasonable.

5.2 Purchasing Process (Continued)

5.2.6 Prequalification of Contractors

Where pre-qualified contractors form the bidders list, it will be the responsibility of the Engineering Department to conduct pre-qualification. The Purchasing Management Team will have the right to submit names of contractors for consideration of pre-qualification.

Any additions, deletions, or any other changes should be reported at once to the Purchasing Management Team for tendering information.

5.2.7 Computer Equipment and Software

Departments requiring the acquisition of computer equipment and software shall contact the Information Systems ("IS") Department for instruction, research, assistance in system configuration, and approval. The IS Department shall prepare the appropriate specifications for use in obtaining competitive pricing.

5.2.8 Revealing of Prices

Prices will only be revealed to those who tendered a competitive quote. The price revealed will be the total price only of the bids received.

5.3 Purchase Order Approval Levels

All Purchase Orders are to be approved based upon the following authority limits:

5.3.1 Inventory Items

The Purchasing Management Team is authorized to approve a Purchase Order for inventory items up to the amount of $100,000 to an individual vendor. A Purchase Order shall not be split into two separate Purchase Orders to avoid going to the next level for approval. The Vice President of Operations, or the Vice President of Engineering, or the Chief Financial Officer, or the President must approve Purchase Orders in excess of $100,000 for inventory items.

Inventory levels are to be maintained at the lowest possible level to reduce stock on hand, yet still meet the needs of the Corporation to have material on hand when required. On an annual basis, the Management Team, Purchasing and Stores is to prepare an inventory listing of recommended Minimum and Maximum levels. The inventory listing is to be reviewed and approved by the Vice President, Operations, the Vice President, Engineering, and Chief Financial Officer.

5.3 Purchase Order Approval Levels (Continued)

5.3.2 Non-Inventory Items

The Purchasing Management Team is authorized to approve a Purchase Order for non- inventory items up to the amount of $50,000 to an individual vendor. A Purchase Order shall not be split into two separate Purchase Orders to avoid going to the next level for approval. The Vice President of Operations, or the Vice President of Engineering, or the Chief Financial Officer, or the President must approve Purchase Orders in excess of $50,000 for non-inventory items, providing that they have not originated or approved the requisition.

5.3.3 Emergency Purchase

Due to extra-ordinary and emergency circumstances, purchasing policies and procedures may be difficult to adhere to. An emergency shall be defined as any situation which, if not corrected immediately, would result in a hazard to persons or property, create improper working conditions, could result in damage to buildings or facilities, would result in a violation of law, statute or ordinance established by government regulation, or any other fashion, if not acted upon, would be seriously detrimental to the interest of the Company or its customers.

The Leadership Team may authorize any expenditure in the case of an emergency. The President and CEO should be consulted, as soon as practical, on all emergency purchases that exceed the approval limits as outlined in this policy.

If an emergency purchase is made during non-business hours, all supporting documentation must be forwarded to the appropriate approval authority the next business day, in order that a Purchase Order, if required, may be issued to the vendor. All special situations or deviations from policy should be documented on the paperwork.

6.0 CONTRACTS

6.1. Contracts for Goods and Services

All contracts for the purchase of goods and services, including equipment maintenance agreements, will be approved based on the following:

Position	Authority Limits - Contracts
Vice President	<= $75,000
Chief Financial Officer	<= $100,000
President and CEO	> $100,000 and <= $1MM
Board Chair	> $1MM

The value of the contract, for purposes of the authority limits, will be based on the actual amount of the contract over the term of the contract.

6.2 Agreements

Any one of the Chair, Vice-Chair or Chief Financial Officer, along with the President & CEO, or in his absence the designate where applicable, be authorized to sign and affix the Corporate Seal to all agreements on behalf of the Company.

Agreements would include, but are not limited to the following:

- Subdivision Agreements
- Easements
- Railway Crossings
- Joint Trench and Pole Attachment Agreements
- Property Sales and Purchase Agreements

7.0 PURCHASING CARDS

7.1 General

Use of Purchase Cards ("P-Card") is encouraged for small purchases in order to reduce the number of cheques which are issued.

P-Cards will be issued to employees based upon a recommendation and approval by the department Vice President. Requests for P-Cards should be forwarded to the CFO. The CFO will be responsible for authorizing the request, in accordance with the terms of the Company's credit agreements.

The P-Card is not be used for any non-business related expenditures. Employees who receive a P-Card will be required to sign a Corporate Credit Card Assignment Form.

7.2 Process

All purchases using the P-Card are to be supported by invoices and/or receipts. Receipts are to be forwarded to Accounting (Attention: Accounts Payable) and should include the proper account coding, including cost centre, general ledger, and project number, if applicable.

7.3 Approvals

The monthly P-Card statement is to be approved by the Department management based upon the authority limits outlined in Section 4.0.

APPENDIX 4-4: INCOME TAX/PILS WORKFORMS

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Version 1.00

Utility Name	Energy Plus Inc. - Cambridge and North Dumfries
Assigned EB Number	EB-2018-0028
Name and Title	Sarah Hughes, Chief Financial Officer
Phone Number	519-621-8405, Ext. 2638
Email Address	shughes@energyplus.ca
Date	27-Apr-18
Last COS Re-based Year	2014

Note: Drop-down lists are shaded blue; Input cells are shaded green.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your rate application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Instructions

Purpose
The purpose of this workbook is to calculate the estimated Payment in Lieu of Taxes (PILs) for the Test Year. The calculation of PILs for the Test Year is on tab T0 and is based on the inputs on the other tabs.

Tab S Summary is a summary of the amounts to be transferred to the Data Input Sheet of the Revenue Requirement Workform.

Tab S1 Integrity Checks must be completed after the completion of the PILS calculation in this workbook.

Methodology
To calculate the PILs for the Test Year:

1) input the balances from the income tax return of the Historical Year in tabs H1 to H13.
2) input the balances for the Bridge Year and the Test Year.
Inputs should include:
- non-deductible expenses (Schedule 1 - B1 and T1)
- loss carryforward (Schedule 4 - B4 and T4)
- capital cost allowance (Schedule 8 - B8 and T8)
- non-deductible reserves (Schedule 13 - B13 and T13)

3) make any other adjustments and inputs required so that the PILs amount calculated for the Test Year on tab T0 is reasonable.

Other Notes
Tabs H1 to H13 relate to the Historical Year.
Tabs B1 to B13 relate to the Bridge Year.
Tabs T1 to T13 relate to the Test Year.

The amounts on tabs H1 to H13 should agree to the tax return filed with the Canada Revenue Agency. Any CRA audit adjustments or corrections should also be reflected.

It is assumed the net income before tax for the Test Year is equal to the Return on Equity. Return on Equity is calculated on tab A.

On tab "A. Data Input Sheet", input the "Rate Base" amount and "Return on Rate Base" amounts.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

1. Info
S. Summary
A. Data Input Sheet
B. Tax Rates & Exemptions

Historical Year

H0 - PILs, Tax Provision Historical Year
H1 - Adj. Taxable Income Historical Year
H4 - Schedule 4 Loss Carry Forward Historical Year
H8 - Schedule 8 Historical
H10 - Schedule 10 CEC Historical Year
H13 - Schedule 13 Tax Reserves Historical

Bridge Year

B0 - PILs,Tax Provision Bridge Year
B1 - Adj. Taxable Income Bridge Year
B4 - Schedule 4 Loss Carry Forward Bridge Year
B8 - Schedule 8 CCA Bridge Year
B10 - Schedule 10 CEC Bridge Year
B13 - Schedule 13 Tax Reserves Bridge Year

Test Year

T0 PILs, Tax Provision Test Year
T1 Taxable Income Test Year
T4 Schedule 4 Loss Carry Forward Test Year
T8 Schedule 8 CCA Test Year
T13 Schedule 13 Reserve Test Year

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

No inputs required on this worksheet.

Income Tax/PILs Workform for 2018 Filers

Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	Confirmed in Exhibit 4
2	The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	Confirmed in Exhibit 4
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non- distribution tax amounts on Schedule 8.	Y	Confirmed in Exhibit 4
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the UCC schedules for the same years filed in the application	Y	Confirmed in Exhibit 4
5	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	Y	Confirmed in Exhibit 4
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Y	Confirmed in Exhibit 4
7	CCA is maximized even if there are tax loss carry-forwards	Y	Confirmed in Exhibit 4
8	Accounting OPEB and pension amounts added back on Schedule 1 to reconcile accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations.	Y	Confirmed in Exhibit 4
9	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the application.	Y	Confirmed in Exhibit 4

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

			Test Year	Bridge Year	
Rate Base		S	**$ 171,191,397**	**$ 175,218,729**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$ 6,847,656	*W = S * T*	
Deemed Long Term Debt %	56.00%	U	$ 95,867,182	*X = S * U*	
Deemed Equity %	40.00%	V	$ 68,476,559	*Y = S * V*	
Short Term Interest Rate	2.29%	Z	$ 156,811	*AC = W * Z*	
Long Term Interest	4.37%	AA	$ 4,187,687	*AD = X * AA*	
Return on Equity (Regulatory Income)	9.00%	AB	**$ 6,162,890**	*AE = Y * AB*	T1
Return on Rate Base			**$ 10,507,388**	*AF = AC + AD + AE*	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	Yes	No
4. Does the applicant have any Capital Leases?	No	No	Yes
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Tax Rates Federal & Provincial As of May 16, 2016	Effective January 1, 2013	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016	Effective January 1, 2017	Effective January 1, 2018
Federal income tax						
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business						
Federal small business threshold	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	10.50%	10.50%	10.50%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. Regarding the small business deduction, if applicable,
   a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
   b. If taxable capital is below $10 million, the small business rate would be applicable.
   c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

				Wires Only	
Regulatory Taxable Income			H1	$ -	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)		**B**		
	Federal tax rate (Maximum 15%)		**C**		
	Combined tax rate (Maximum 26.5%)			0.00%	**D = B+C**
Total Income Taxes				**$ -**	**E = A * D**
	Investment Tax Credits				**F**
	Miscellaneous Tax Credits				**G**
Total Tax Credits				**$ -**	**H = F + G**
Corporate PILs/Income Tax Provision for Historical Year				**$ -**	**I = E - H**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A			0
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104			0
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121			0
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126			0
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0
				0
				0
				0
				0
				0
				0
				0
				0

				0
Total Additions		**0**	**0**	**0**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403			0
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414			0
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
				0
				0
				0
				0
				0
				0
Total Deductions		**0**	**0**	**0**
Net Income for Tax Purposes		**0**	**0**	**0**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**0**	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Distribution System - post 1987	##########		##########
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	##########		$ 1,154,583.20
2	Distribution System - pre 1988	##########		##########
8	General Office/Stores Equip	##########		$ 2,011,196.50
10	Computer Hardware/ Vehicles	##########		$ 1,649,828.80
10.1	Certain Automobiles			$ -
12	Computer Software	$ 301,503.00		$ 301,503.00
13 1	Lease # 1			$ -
13 2	Lease #2			$ -
13 3	Lease # 3			$ -
13 4	Lease # 4			$ -
14	Franchise			$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 137,678.92		$ 137,678.92
42	Fibre Optic Cable			$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment			$ -
43.2	Certain Clean Energy Generation Equipment			$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 210.10		$ 210.10
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -
47	Distribution System - post February 2005	##########		##########
50	Data Network Infrastructure Equipment - post Mar 2007	$ 160,107.75		$ 160,107.75
52	Computer Hardware and system software			$ -
95	CWIP	##########		$ 4,001,218.00
6	Buildings - after 1990	$ 16,300.80		$ 16,300.80
3	Buildings - pre 1990	$ 484,177.00		$ 484,177.00
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				0
	SUB-TOTAL - UCC	134,362,884	0	134,362,884

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filer

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**2,095,134**
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**2,095,134**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**2,095,134**
Current Year Deduction		**2,095,134**	**x 7% =**	**146,659**
Cumulative Eligible Capital - Closing Balance				#########

Ontario Energy Board

Income Tax/PILs Workform for 2

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:	3,140,004		3,140,004
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**3,140,004**	**0**	**3,140,004**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

PILS Tax Provision - Bridge Year

Wires Only

	Reference		
Regulatory Taxable Income	B1	$ 3,228,440	**A**

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate	
Ontario (Max 11.5%)	11.5%	11.5%	$ 371,271	11.5%	**B**
Federal (Max 15%)	15.0%	15.0%	$ 484,266	15.0%	**C**

Combined effective tax rate (Max 26.5%)	26.5%	**D = B + C**
Total Income Taxes	**$ 855,536**	**E = A * D**
Investment Tax Credits		**F**
Miscellaneous Tax Credits		**G**
Total Tax Credits	**$ -**	**H = F + G**
Corporate PILs/Income Tax Provision for Bridge Year	**$ 855,536**	**I = E - H**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	A		7,150,170
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		6,248,064
Amortization of intangible assets	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		300,000
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		10,000
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	3,267,000
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		18,000
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
	294		
	295		

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Bridge Year

ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**9,843,064**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	10,624,790
Terminal loss from Schedule 8	404		
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	3,140,004
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Adjusted Taxable Income - Bridge Year

Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**13,764,794**
Net Income for Tax Purposes		calculated	**3,228,440**
Charitable donations from Schedule 2	311		
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320		
Non-capital losses of preceding taxation years from Schedule 4	331	B4	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	B4	0
Limited partnership losses of preceding taxation years from Schedule 4	335		
TAXABLE INCOME		calculated	**3,228,440**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		Total	
Actual Historical	H4	0	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	0	
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Net Capital Loss Carry Forward Deduction		Total	
Actual Historical	H4	0	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	Working Paper Reference	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA		UCC End of Bridge Year
1	Distribution System - post 1987	H8	$ 30,401,521.92			$ 30,401,522	$ -	$ 30,401,522	4%	$ 1,216,061		$ 29,185,461
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	H8	$ 1,154,583.20			$ 1,154,583	$ -	$ 1,154,583	6%	$ 69,275		$ 1,085,308
2	Distribution System - pre 1988	H8	$ 18,258,422.76			$ 18,258,423	$ -	$ 18,258,423	6%	$ 1,095,505		$ 17,162,917
8	General Office/Stores Equip	H8	$ 2,011,196.50	$ 117,700		$ 2,128,897	$ 58,850	$ 2,070,047	20%	$ 414,009		$ 1,714,887
10	Computer Hardware/ Vehicles	H8	$ 1,649,828.80	$ 311,700		$ 1,961,529	$ 155,850	$ 1,805,679	30%	$ 541,704		$ 1,419,825
10.1	Certain Automobiles	H8				$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	H8	$ 301,503.00	$ 612,200		$ 913,703	$ 306,100	$ 607,603	100%	$ 607,603		$ 306,100
13 1	Lease # 1	H8				$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	H8				$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	H8				$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	H8				$ -	$ -	$ -		$ -		$ -
14	Franchise	H8				$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	H8	$ 137,678.92			$ 137,679	$ -	$ 137,679	8%	$ 11,014		$ 126,665
42	Fibre Optic Cable	H8				$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	H8				$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	H8				$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	H8	$ 210.10			$ 210	$ -	$ 210	45%	$ 95		$ 116
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8				$ -	$ -	$ -	30%	$ -		$ -
47	Distribution System - post February 2005	H8	$ 75,786,134.76	$ 10,452,647	-$ 1,544,100	$ 84,694,682	$ 4,454,274	$ 80,240,408	8%	$ 6,419,233		$ 78,275,449
50	Data Network Infrastructure Equipment - post Mar 2007	H8	$ 160,107.75			$ 160,108	$ -	$ 160,108	55%	$ 88,059		$ 72,048
52	Computer Hardware and system software	H8				$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	H8	$ 4,001,218.00			$ 4,001,218	$ -	$ 4,001,218	0%	$ -		$ 4,001,218
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)[1]	H10	$ 1,948,474.62			$ 1,948,475	$ -	$ 1,948,475	7%	$ 136,393		$ 1,812,081
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)[1]		$ -			$ -	$ -	$ -	5%	$ -		$ -
6	Buildings - after 1990		$ 16,300.80			$ 16,301	$ -	$ 16,301	10%	$ 1,630		$ 14,671
3	Buildings - pre 1990		$ 484,177.00			$ 484,177	$ -	$ 484,177	5%	$ 24,209		$ 459,968
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
	TOTAL		$ 136,311,358	$ 11,494,247	-$ 1,544,100	$ 146,261,505	$ 4,975,074	$ 141,286,432		$ 10,624,790	B1	$ 135,636,715

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	0		0				0	T13	0	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13	0	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & Share Issue Expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	B1	**0**	**0**	**0**	B1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General reserve for bad debts	H13	0		0				0	T13	0	
Accrued Employee Future Benefits:	H13	3,140,004		3,140,004		126,996		3,267,000	T13	126,996	
- Medical and Life Insurance	H13	0		0				0	T13	0	
-Short & Long-term Disability	H13	0		0				0	T13	0	
-Accmulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	0		0				0	T13	0	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**3,140,004**	**0**	**3,140,004**	B1	**126,996**	**0**	**3,267,000**	B1	**126,996**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income						T1	$ 2,208,420	**A**
	Tax Rate	Small Business Rate (If Applicable)		Taxes Payable	Effective Tax Rate			
Ontario (Max 11.5%)	11.5%	11.5%	$	253,968	11.5%	**B**		
Federal (Max 15%)	15.0%	15.0%	$	331,263	15.0%	**C**		
Combined effective tax rate (Max 26.5%)							26.50%	**D = B + C**
Total Income Taxes							**$ 585,231**	**E = A * D**
Investment Tax Credits								**F**
Miscellaneous Tax Credits								**G**
Total Tax Credits							**$ -**	**H = F + G**
Corporate PILs/Income Tax Provision for Test Year							**$ 585,231**	**I = E - H** S. Su
Corporate PILs/Income Tax Provision Gross Up [1]					73.50%	**J = 1-D**	**$ 211,002**	**K = I/J-I**
Income Tax (grossed-up)							**$ 796,233**	**L = K + I** S. Su

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Taxable Income - Test Year

		Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	6,162,890
	T2 S1 line #		
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		6,583,006
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		10,000
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	3,332,000
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		18,000
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions: (please explain in detail the nature of the item)			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
	294		
	295		
	296		
	297		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			

Total Additions			**9,943,006**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	10,630,476
Terminal loss from Schedule 8	404		
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	3,267,000
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
	395		
	396		
	397		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**13,897,476**
NET INCOME FOR TAX PURPOSES		calculated	**2,208,420**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	0
Net-capital losses of preceding taxation years (Please show calculation)	332	T4	0
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**2,208,420**

T0

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years	T1	0		0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	calculated	0		0
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments				0
Balance available for use in Future Years	calculated	0		0

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 8 CCA - Test Year

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	Distribution System - post 1987	B8	$ 29,185,461			$ 29,185,461	$ -	$ 29,185,461	4%	$ 1,167,418		$ 28,018,043
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	B8	$ 1,085,308			$ 1,085,308	$ -	$ 1,085,308	6%	$ 65,118		$ 1,020,190
2	Distribution System - pre 1988	B8	$ 17,162,917			$ 17,162,917	$ -	$ 17,162,917	6%	$ 1,029,775		$ 16,133,142
8	General Office/Stores Equip	B8	$ 1,714,887	70,300		$ 1,785,187	$ 35,150	$ 1,750,037	20%	$ 350,007		$ 1,435,180
10	Computer Hardware/ Vehicles	B8	$ 1,419,825	345,700		$ 1,765,525	$ 172,850	$ 1,592,675	30%	$ 477,803		$ 1,287,723
10.1	Certain Automobiles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	B8	$ 306,100	526,500		$ 832,600	$ 263,250	$ 569,350	100%	$ 569,350		$ 263,250
13 1	Lease # 1	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	B8	$ -			$ -	$ -	$ -		$ -		$ -
14	Franchise	B8	$ -			$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	B8	$ 126,665			$ 126,665	$ -	$ 126,665	8%	$ 10,133		$ 116,531
42	Fibre Optic Cable	B8	$ -			$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	B8	$ -			$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	B8	$ 116			$ 116	$ -	$ 116	45%	$ 52		$ 64
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
47	Distribution System - post February 2005	B8	$ 78,275,449	15,126,908	-2,430,782	$ 90,971,575	$ 6,348,063	$ 84,623,512	8%	$ 6,769,881		$ 84,201,694
50	Data Network Infrastructure Equipment - post Mar 2007	B8	$ 72,048			$ 72,048	$ -	$ 72,048	55%	$ 39,627		$ 32,422
52	Computer Hardware and system software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	B8	$ 4,001,218			$ 4,001,218	$ -	$ 4,001,218	0%	$ -		$ 4,001,218
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)1	B8	$ 1,812,081			$ 1,812,081	$ -	$ 1,812,081	7%	$ 126,846		$ 1,685,236
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)1	B8	$ -			$ -	$ -	$ -	5%	$ -		$ -
6	Buildings - after 1990		$ 14,671			$ 14,671	$ -	$ 14,671	10%	$ 1,467		$ 13,204
3	Buildings - pre 1990		$ 459,968			$ 459,968	$ -	$ 459,968	5%	$ 22,998		$ 436,970
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
	TOTAL		$ 135,636,715	$ 16,069,408	-$ 2,430,782	$ 149,275,341	$ 6,819,313	$ 142,456,028		$ 10,630,476	T1	$ 138,644,865

1. New CCA class 14.1 effective January 1, 2017. The class includes property that was eligible capital property immediately before January 1, 2017. For tax years that end prior to 2027, transitional rules apply to class 14.1 that were acquired before January 1, 2017

Ontario Energy Board

Income Tax/PILs Workform for 2018 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0		0	0	0		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	T1	**0**	**0**	**0**	T1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	0		0				0		0	
Accrued Employee Future Benefits:	B13	3,267,000		3,267,000		65,000		3,332,000		65,000	
- Medical and Life Insurance	B13	0		0				0		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	0		0				0		0	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**3,267,000**	**0**	**3,267,000**	T1	**65,000**	**0**	**3,332,000**	T1	**65,000**	**0**

APPENDIX 4-5: 2016 CORPORATE TAX RETURNS

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2017-12-31

Business number 86569 7585 RC0002

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Canada Revenue Agency. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. Payment may be made by cheque or money order payable to the Receiver General either at an authorized financial institution or filed with **the appropriate remittance voucher at the following address**:

Ministry of Finance
HYDRO PILS DIVISION
33 King St
Oshawa ON L1H 8E9

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2017-01-31	53,147		208,944	-155,797	
2017-02-28	53,147		0	-102,650	
2017-03-31	53,147		0	-49,503	
2017-04-30	53,147		0	3,644	
2017-05-31	53,147		0	56,791	
2017-06-30	53,147				109,938
2017-07-31	53,147				53,147
2017-08-31	53,147				53,147
2017-09-30	53,147				53,147
2017-10-31	53,147				53,147
2017-11-30	53,147				53,147
2017-12-31	53,142				53,142
Totals	637,759		208,944		428,815

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Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see cra.gc.ca or Guide T4012, *T2 Corporation - Income Tax Guide*.

055 **Do not use this area**

Identification

Business number (BN) 001 86569 7585 RC0002

Corporation's name
002 ENERGY + INC.

Address of head office
Has this address changed since the last time we were notified? 010 1 Yes ☐ 2 No ☒
If **yes**, complete lines 011 to 018.
011 1500 BISHOP ST N
012 PO BOX 1060
City: 015 CAMBRIDGE
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal or ZIP code: 018 N1R 5X6

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? 020 1 Yes ☐ 2 No ☒
If **yes**, complete lines 021 to 028.
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal or ZIP code: 028

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? 030 1 Yes ☒ 2 No ☐
If **yes**, complete lines 031 to 038.
031 1500 BISHOP ST N
032 PO BOX 1060
City: 035 CAMBRIDGE
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal or ZIP code: 038 N1R 5X6

040 **Type of corporation at the end of the tax year** (tick one)
- ☒ 1 Canadian-controlled private corporation (CCPC)
- ☐ 2 Other private corporation
- ☐ 3 Public corporation
- ☐ 4 Corporation controlled by a public corporation
- ☐ 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change 043 Year Month Day

To which tax year does this return apply?
Tax year start: 060 Year Month Day 2016-01-01
Tax year-end: 061 Year Month Day 2016-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? 063 1 Yes ☐ 2 No ☒
If **yes**, provide the date control was acquired 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? 070 1 Yes ☐ 2 No ☒
Amalgamation? 071 1 Yes ☒ 2 No ☐
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? 078 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 1 Yes ☒ 2 No ☐
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- ☐ 1 Exempt under paragraph 149(1)(e) or (l)
- ☐ 2 Exempt under paragraph 149(1)(j)
- ☐ 3 Exempt under paragraph 149(1)(t)
- ☐ 4 Exempt under other paragraphs of section 149

Do not use this area

095 096 898

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Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the *Income Tax Regulations*?	170		29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), or f) business limit assigned under subsection 125(3.2); or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

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Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes X	2 No
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 (Year Month Day)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		2,767,920	A
Deduct:				
Charitable donations from Schedule 2	311	10,137		
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		10,137 ▶	10,137	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			2,757,783	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		2,757,783	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			2,757,783	Z
Taxable income for the year from a personal services business**				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

** For a taxation year that ends after 2015.

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Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** 2,767,920 A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** 2,757,783 B

Business limit (see notes 1 and 2 below) . . . . . **410** C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C _____ x **415** *** 309,701 / 11,250 D = ... E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** F

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . G

Amount F **minus** amount G . . . . . **427** H

Small business deduction

Amount A, B, C, or H, whichever is the least _____ x Number of days in the tax year before January 1, 2016 / Number of days in the tax year 366 x 17 % = 1

Amount A, B, C, or H, whichever is the least _____ x Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366 x 17.5 % = 2

Total of amounts 1 and 2 (enter amount I on line J on page 8) **430** I

***** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

****** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Specified corporate income and assignment under subsection 125(3.2)

Applicable to tax years that begin after March 21, 2016

Except that, if the tax year of your corporation started before **and** ends on or after March 22, 2016 and in the tax year of a CCPC, you can make an assignment of business limit to that other CCPC if its tax year started after March 21, 2016.

	J1 Name of corporation receiving the income and assigned amount	J Business number of the corporation receiving the assigned amount **490**	K Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column J [3] **500**	L Business limit assigned to corporation identified in column J [4] **505**
1.				

Total **510** _____ Total **515** _____

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column K in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 425.

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General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)			2,757,783 A
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			B
Amount K13 from Part 13 of Schedule 27			C
Personal services business income	432		D
Amount used to calculate the credit union deduction (amount F from Schedule 17)			E
Amount from line 400, 405, 410, or 427 on page 4, whichever is the least			F
Aggregate investment income from line 440 on page 6*			G
Subtotal (**add** amounts B to G)		▶	H
Amount A **minus** amount H (if negative, enter "0")			2,757,783 I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by	13 %		358,512 J

Enter amount J on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			K
Lesser of amounts B9 and H9 from Part 9 of Schedule 27			L
Amount K13 from Part 13 of Schedule 27			M
Personal services business income	434		N
Amount used to calculate the credit union deduction (amount F from Schedule 17)			O
Subtotal (**add** amounts L to O)		▶	P
Amount K **minus** amount P (if negative, enter "0")			Q
General tax reduction – Amount Q **multiplied** by	13 %		R

Enter amount R on line 639 on page 8.

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Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . **440** A

Amount A x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) = (_____ / 366) x 26 2/3 % = 1

Amount A x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) = (366 / 366) x 30 2/3 % = 2

Subtotal (amount 1 **plus** amount 2) ▶ B

Foreign investment income from Schedule 7 . . . . . **445** C

Amount C x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) = (_____ / 366) x 9 1/3 % = 3

Amount C x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) = (366 / 366) x 8 % = 4

Subtotal (amount 3 **plus** amount 4) D

Foreign non-business income tax credit from line 632 on page 8 **minus** amount D (if negative, enter "0") . . . . . E

Amount B **minus** amount E (if negative, enter "0") . . . . . F

Foreign non-business income tax credit from line 632 on page 8 . . . . . G

(Number of days in the tax year before January 1, 2016 / Number of days in the tax year) = (_____ / 366) x 35 = ... 5

(Number of days in the tax year after December 31, 2015 / Number of days in the tax year) = (366 / 366) x 38 2/3 = ... 38.66667 6

Subtotal (amount 5 **plus** amount 6) 38.6667 H

Amount G x (100 / H) = (100 / 38.6667) = ... I

Taxable income from line 360 on page 3 . . . . . 2,757,783 J

Deduct:

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . . . K

Amount I L

Foreign business income tax credit from line 636 on page 8 . . . . . x 4 = M

Subtotal (total of amounts K to M) ▶ N

Subtotal (amount J **minus** amount N) 2,757,783 O

Amount O 2,757,783 x (Number of days in the tax year before January 1, 2016 / Number of days in the tax year) = (_____ / 366) x 26 2/3 % = 7

Amount O 2,757,783 x (Number of days in the tax year after December 31, 2015 / Number of days in the tax year) = (366 / 366) x 30 2/3 % = 845,720 8

Subtotal (amount 7 **plus** amount 8) 845,720 ▶ 845,720 P

Part I tax payable **minus** investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . . 407,668 Q

Refundable portion of Part I tax – Amount F, P, or Q, whichever is the least . . . . . **450** R

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Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460		
Deduct:			
Dividend refund for the previous tax year	465		
		▶	A
Add:			
Refundable portion of Part I tax from line 450 on page 6			B
Total Part IV tax payable from Schedule 3			C
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480		
Subtotal (add amounts B, C, and line 480)		▶	D
Refundable dividend tax on hand at the end of the tax year – Amount A **plus** amount D	485		

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 3 of Schedule 3 — 2,780,237 E

Amount E 2,780,237 × (Number of days in the tax year before January 1, 2016 ____ / Number of days in the tax year 366) × 33 1/3 % = 1

Amount E 2,780,237 × (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) × 38 1/3 % = 1,065,758 2

Subtotal (amount 1 **plus** amount 2) 1,065,758 ▶ 1,065,758 F

Refundable dividend tax on hand at the end of the tax year from line 485 above — G

Dividend refund – Amount F or G, whichever is less — H

Enter amount H on line 784 on page 9.

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Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % **550** 1,047,958 A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business **555** _____ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 5 % = **560** _____ B

Recapture of investment tax credit from Schedule 31 . . . . . **602** _____ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . . _____ D

Taxable income from line 360 on page 3 . . . . . 2,757,783 E

Deduct:

Amount from line 400, 405, 410, or 427 on page 4, whichever is the least . . . . . _____ F

Net amount (amount E **minus** amount F) 2,757,783 ▶ 2,757,783 G

Amount D or G, whichever is less _____ x (Number of days in the tax year before January 1, 2016 _____ / Number of days in the tax year 366) x 6 2 / 3 % = _____ 1

Amount D or G, whichever is less _____ x (Number of days in the tax year after December 31, 2015 366 / Number of days in the tax year 366) x 10 2 / 3 % = _____ 2

Refundable tax on CCPC's investment income (amount 1 **plus** amount 2) . . . . . **604** _____ ▶ _____ H

Subtotal (**add** amounts A, B, C, and H) 1,047,958 I

Deduct:

Small business deduction from line 430 on page 4 . . . . . _____ J

Federal tax abatement **608** 275,778

Manufacturing and processing profits deduction from Schedule 27 . . . . . **616**

Investment corporation deduction **620**

Taxed capital gains **624** _____

Additional deduction – credit unions from Schedule 17 . . . . . **628**

Federal foreign non-business income tax credit from Schedule 21 . . . . . **632**

Federal foreign business income tax credit from Schedule 21 . . . . . **636**

General tax reduction for CCPCs from amount J on page 5 . . . . . **638** 358,512

General tax reduction from amount R on page 5 . . . . . **639**

Federal logging tax credit from Schedule 21 . . . . . **640**

Eligible Canadian bank deduction under section 125.21 . . . . . **641**

Federal qualifying environmental trust tax credit **648**

Investment tax credit from Schedule 31 . . . . . **652** 6,000

Subtotal 640,290 ▶ 640,290 K

Part I tax payable – Amount I **minus** amount K . . . . . 407,668 L

Enter amount L on line 700 on page 9.

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Privacy statement

Personal information is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source cra.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html, personal information bank CRA PPU 047.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	407,668
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		407,668

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	230,091
Total tax payable	770	637,759 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount H on page 7	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	668,631	
Total credits	890	668,631 ▶	668,631 B

Refund code 894 1 Overpayment 30,872

Balance (amount A **minus** amount B) -30,872

If the result is positive, you have a **balance unpaid**. If the result is negative, you have an **overpayment**. Enter the amount on whichever line applies. Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

For information on how to make your payment, go to cra.gc.ca/payments.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920 A6698

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PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 HUGHES (Last name) 951 SARAH (First name) 954 CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2017-06-26 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (519) 621-3530 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name of other authorized person 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end (Year Month Day)
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125			6,422,000 A
Add:			
Provision for income taxes – current	101	669,000	
Provision for income taxes – deferred	102	1,212,000	
Amortization of tangible assets	104	6,114,000	
Loss on disposal of assets	111	269,000	
Charitable donations and gifts from Schedule 2	112	10,137	
Non-deductible club dues and fees	120	550	
Non-deductible meals and entertainment expenses	121	9,970	
Reserves from financial statements – balance at the end of the year	126	3,140,004	
Subtotal of additions		11,424,661 ▶	11,424,661
Other additions:			
Capital items expensed	206	71,186	
Financing fees deducted in books	216	26,810	
Taxable/non-deductible other comprehensive income items	239	141,000	

Miscellaneous other additions:

	1 Description 605	2 Amount 295			
1	Inducement under 12(1)(x) ITA	68,794			
2	12(1)(a) Customer Deposits	12,433,512			
3	Capital contributions received 12(1)(x)	2,826,533			
4	Net change in reg. accounts (BCP)	330,886			
	Total of column 2	15,659,725 ▶	296	15,659,725	
	Subtotal of other additions		199	15,898,721 ▶	15,898,721
	Total additions		500	27,323,382 ▶	27,323,382 B
Amount A **plus** amount B					33,745,382 C
Deduct:					
Capital cost allowance from Schedule 8			403	10,910,168	
Cumulative eligible capital deduction from Schedule 10			405	157,698	
Reserves from financial statements – balance at the beginning of the year			414	2,928,510	
Subtotal of deductions				13,996,376 ▶	13,996,376
Other deductions:					

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	20(1)(m) Customer Deposits	12,433,512
2	Financing Fees	133,830
3	Tax recovery incl. in net movements in reg. balance on P&L	1,248,256
4	Change in EFB, not in P&L	192,606
5	Amortization of deferred capital contributions	146,349

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	1 Description **705**	2 Amount **395**				
6	ITA 13(7.4) Election - capital contributions received	2,826,533				
	Total of column 2	16,981,086 ▶	**396**	16,981,086		
	Subtotal of other deductions		**499**	16,981,086 ▶	16,981,086	
	Total deductions		**510**	30,977,462 ▶	30,977,462	D
Net income (loss) for income tax purposes (amount C **minus** amount D)					2,767,920	E

Enter amount E on line 300 of the T2 return.

Canada

T2 SCH 1 E (16)

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Attached Schedule with Total

Line 206 – Capital items expensed

Title Line 206 – Capital items expensed

Explanatory note

per S-08.1

Description	Operator (Note)	Amount
GL# 5620-520		10,686 00
GL# 5620-521	+	5,694 41
Various - see S-08.1	+	56,328 57
see S08.4; amounts not capital	+	-1,523 00
	+	
	Total	71,185 98

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

Line 216 – Financing fees deducted in books

Title Line 216 – Financing fees deducted in books

Description	Operator (Note)	Amount
acct 2-6000-6010-595		18,606 00
acct 2-6000-6010-598	+	8,204 00
	+	
	Total	26,810 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) of the ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Select this check box to add all the amounts to income calculated in Schedule 1. . . . . ☐

Federal

A		
☒	Investment tax credit from apprenticeship job creation expenditures	12,000
☐	Investment tax credit from child care spaces expenditures	
☐	Canadian film or video production tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Film or video production services tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☒	Investment tax credit claimed on contributions made to SR&ED farming organizations	

Ontario

A		
☒	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☐	Ontario co-operative education tax credit	
☒	Ontario apprenticeship training tax credit	56,794
☐	Ontario computer animation and special effects tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario film and television tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario production services tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario interactive digital media tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario sound recording tax credit*	
	* Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
☐	Ontario book publishing tax credit	
☐	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
☐	Ontario business-research institute tax credit	
☐	Ontario community food program donation tax credit for farmers	

Tax credits whose amount should reduce the capital cost of property

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Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees;
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers;
  - the eligible amount of gifts of certified cultural property;
  - the eligible amount of gifts of certified ecologically sensitive land; or
  - the additional deduction for gifts of medicine.
- All legislative references are to the federal *Income Tax Act*, unless otherwise specified.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward. Please note that the provincial food donation tax credits must be applied in the current tax year.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
United Way	5,000
Womens Crisis Services of Waterloo	427
Cambridge Memorial Hospital Foundation	1,400
Lisaard House	332
MLSE Foundation	200
Cambridge Self Help Food Bank	730
Children's Safety Village of Brant	700
Send'em off Smiling	100
Grand Erie District School Board	500
Salvation Army	348
Subtotal	9,737
Add: Total donations of less than $100 each	400
Total donations in current tax year	10,137

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Part 1 – Charitable donations

		Federal		Québec	Alberta
Charitable donations at the end of the previous tax year			A		
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year	240		B		
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1)	210	10,137		10,137	10,137
Subtotal (line 250 **plus** line 210)		10,137	C	10,137	10,137
Subtotal (amount B **plus** amount C)		10,137	D	10,137	10,137
Deduct: Adjustment for an acquisition of control	255				
Total charitable donations available (amount D **minus** amount on line 255)		10,137	E	10,137	10,137
Deduct: Amount applied in the current year against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260	10,137		10,137	10,137
Charitable donations closing balance (amount E **minus** amount on line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) **262**

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) 1

Enter amount 1 on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) **263**

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) 2

Enter amount 2 on line 570 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia *Income Tax Act*.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016 and before January 1, 2019) **265**

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) 3

Enter amount 3 on line 683 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia *Income Tax Act*.

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

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Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2014-12-31			
3rd prior year	2013-12-31			
4th prior year	2012-12-31			
5th prior year	2011-12-31			
6th prior year*	2010-12-31			
7th prior year	2009-12-31			
8th prior year	2008-12-31			
9th prior year	2007-12-31			
10th prior year	2006-12-31			
11th prior year	2005-12-31			
12th prior year	2004-12-31			
13th prior year	2003-12-31			
14th prior year	2002-12-31			
15th prior year	2001-12-31			
16th prior year	2000-12-31			
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % ..... 2,075,940 F

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** ..... 225 G

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) ..... 227 H

The amount of the recapture of capital cost allowance in respect of charitable donations 230

Proceeds of disposition, **less** outlays and expenses** I

Capital cost** ..... J

Amount I or J, whichever is less 235

Amount on line 230 or 235, whichever is less ..... K

Subtotal (**add** amounts G, H, and K) L

Amount L **multiplied** by 25 % M

Subtotal (amount F **plus** amount M) 2,075,940 N

Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less) ..... 10,137 O

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

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Part 3 – Gifts of certified cultural property

			Federal		Québec		Alberta
Gifts of certified cultural property at the end of the previous tax year		A		A			
Deduct: Gifts of certified cultural property expired after five tax years*	439						
Gifts of certified cultural property at the beginning of the current tax year	440	B		B			
Add:							
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450						
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410						
Subtotal (line 450 **plus** line 410)		C		C			
Subtotal (amount B **plus** amount C)		D		D			
Deduct:							
Adjustment for an acquisition of control	455						
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460						
Subtotal (line 455 **plus** line 460)		E		E			
Gifts of certified cultural property closing balance (amount D **minus** amount E)	480						

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2014-12-31			
3rd prior year	2013-12-31			
4th prior year	2012-12-31			
5th prior year	2011-12-31			
6th prior year*	2010-12-31			
7th prior year	2009-12-31			
8th prior year	2008-12-31			
9th prior year	2007-12-31			
10th prior year	2006-12-31			
11th prior year	2005-12-31			
12th prior year	2004-12-31			
13th prior year	2003-12-31			
14th prior year	2002-12-31			
15th prior year	2001-12-31			
16th prior year	2000-12-31			
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

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Part 4 – Gifts of certified ecologically sensitive land

		Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			F		
Deduct: Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year	540		G		
Add:					
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014 (include this amount on line 112 of Schedule 1)	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014 (include this amount on line 112 of Schedule 1)	520				
Subtotal (**add** lines 550, 510, and 520)			H		
Subtotal (amount G **plus** amount H)			I		
Deduct:					
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			J		
Gifts of certified ecologically sensitive land closing balance (amount I **minus** amount J)	580				

* For the federal and Alberta, gifts made before February 11, 2014 , expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made during a tax year that ended after March 23, 2006 expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2014-12-31			
3rd prior year	2013-12-31			
4th prior year	2012-12-31			
5th prior year	2011-12-31			
6th prior year*	2010-12-31			
7th prior year	2009-12-31			
8th prior year	2008-12-31			
9th prior year	2007-12-31			
10th prior year	2006-12-31			
11th prior year*	2005-12-31			
12th prior year	2004-12-31			
13th prior year	2003-12-31			
14th prior year	2002-12-31			
15th prior year	2001-12-31			
16th prior year	2000-12-31			
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to determine the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years.
For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

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Part 5 – Additional deduction for gifts of medicine

		Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			K		
Deduct: Additional deduction for gifts of medicine expired after five tax years*	639				
Additional deduction for gifts of medicine at the beginning of the current tax year	640		L		
Add:					
Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650				
Additional deduction for gifts of medicine for the current year:					
Proceeds of disposition	602		1	1	1
Cost of gifts of medicine	601		2	2	2
Subtotal (line 1 **minus** line 2)			3	3	3
Line 3 **multiplied** by 50 %			4	4	4
Eligible amount of gifts	600		5	5	5

Federal

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year 610 _____

Québec

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year _____

Alberta

a _____ x (b _____ / c) = Additional deduction for gifts of medicine for the current year _____

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)			M	
Subtotal (amount L **plus** amount M)			N	
Deduct:				
Adjustment for an acquisition of control	655			
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660			
Subtotal (line 655 **plus** line 660)			O	
Additional deduction for gifts of medicine closing balance (amount N **minus** amount O)	680			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made before March 19, 2007, expire after five tax years and gifts made after March 18, 2007, expire after twenty tax years.

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Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2015-12-31			
2nd prior year	2014-12-31			
3rd prior year	2013-12-31			
4th prior year	2012-12-31			
5th prior year	2011-12-31			
6th prior year*	2010-12-31			
7th prior year	2009-12-31			
8th prior year	2008-12-31			
9th prior year	2007-12-31			
10th prior year	2006-12-31			
11th prior year	2005-12-31			
12th prior year	2004-12-31			
13th prior year	2003-12-31			
14th prior year	2002-12-31			
15th prior year	2001-12-31			
16th prior year	2000-12-31			
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, gifts made before March 19, 2007, expire after five tax years and gifts made after March 18, 2007, expire after twenty tax years.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

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Amounts carried forward – Gifts of musical instruments

Year of origin:		
1st prior year	2015-12-31	
2nd prior year	2014-12-31	
3rd prior year	2013-12-31	
4th prior year	2012-12-31	
5th prior year	2011-12-31	
6th prior year*	2010-12-31	
7th prior year	2009-12-31	
8th prior year	2008-12-31	
9th prior year	2007-12-31	
10th prior year	2006-12-31	
11th prior year	2005-12-31	
12th prior year	2004-12-31	
13th prior year	2003-12-31	
14th prior year	2002-12-31	
15th prior year	2001-12-31	
16th prior year	2000-12-31	
17th prior year		
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

Canada

T2 SCH 2 E (17)

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Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculations

Schedule 3

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a),(a.1), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- All legislative references are to the federal *Income Tax Act*.
- The calculations in this schedule apply only to private or subject corporations.
- A recipient corporation is **connected** with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- Column A1 – Enter "X" if dividends received from a foreign source.
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H and I **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing column J and K use the **special calculations provided in the notes**.

A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business Number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividends under section 83 230

Total of column E (enter amount on line 402 of Schedule 1)

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F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1] 240	F1 Eligible dividends (included in column F)	F2	G Dividends included in column F that was received **before** 2016 241	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) 250	I Dividend refund of the **connected** payer corporation (for tax year in column D)[note 2] 260	J Part IV tax before deductions. Dividends (from column G) received **before** 2016 **multiplied** by 33 1/3%[note 3] 270	K Part IV tax before deductions. Dividends received **after** 2015 (column F **minus** column G) **multiplied** by 38 1/3%[note 4] 275
Total of column F (include this amount on line 320 of the T2 Return)						**Total of column J** (enter amount on line a in Part 2)	**Total of column K** (enter amount on line b in Part 2)

1 If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270 or column 275 as applicable according to the date received. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For dividends received **before** 2016 from **connected** corporations, Part IV tax on dividends is equal to: column G **multiplied** by column I **divided** by column H.

4 For dividends received **after** 2015 from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by the result of column F **minus** column G.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received **before** 2016, before deductions (total of column J in part 1) . . . . . a

Part IV tax on dividends received **after** 2015, before deductions (total of column K in part 1) . . . . . b

Part IV tax before deductions (amount a **plus** amount b) . . . . . ▶ L

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) 320

Subtotal (amount L **minus** line 320) M

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax . . . . . 330 c

Non-capital losses from previous years claimed to reduce Part IV tax . . . . . 335 d

Current-year farm loss claimed to reduce Part IV tax . . . . . 340 e

Farm losses from previous years claimed to reduce Part IV tax . . . . . 345 f

Total losses applied against Part IV tax (total of amounts c to f) g

If your tax year begins after December 31, 2015:

Amount g **multiplied** by 38 1 / 3 % . . . . . h

If your tax year begins before January 1, 2016:

Amount b or M whichever is less

_____ ÷ 38 1 / 3 % . . . = 1

Amount 1 or g, whichever is less 2

Amount g **minus** amount 2 3

Amount 2 _____ x 38 1 / 3 % = i

Amount 3 _____ x 33 1 / 3 % = j

Subtotal (amount i **plus** amount j) k

Amount h or amount k, whichever applies depending on your tax year start date . . . . . N

Part IV tax payable (amount M **minus** amount N, if negative enter "0") 360

(enter amount on line 712 of the T2 return)

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Energy+ Inc.
EB-2018-0028
Exhibit 4
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Filed: April 30, 2018

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	O Name of connected recipient corporation 400	P Business Number 410	Q Tax year-end of connected recipient corporation in which the dividends in column R were received YYYY/MM/DD 420	R Taxable dividends paid to connected corporations 430	R1 Eligible dividends (included in column R)
1	CAMBRIDGE & NORTH DUMFRIES ENERGY PLUS INC.	88102 0127 RC0001	2016-12-31	2,780,237	

Total of column R 2,780,237

Total taxable dividends paid in the tax year to other than connected corporations **450**

Eligible dividends (included in line 450) 450a

Total taxable dividends paid in the tax year that qualify for a dividend refund
(total of column R **plus** line 450) **460** 2,780,237

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above) 2,780,237

Other dividends paid in the tax year (total of 510 to 540) . . . . .

Total dividends paid in the tax year **500** 2,780,237

Deduct:

Dividends paid out of capital dividend account **510**

Capital gains dividends **520**

Dividends paid on shares described in subsection 129(1.2) **530**

Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year **540**

Subtotal (total of lines 510 to 540) ▶ S

Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount S) 2,780,237 T

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Canada

T2SCH3 E (16)

Canada Revenue Agency / Agence du revenu du Canada

Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

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Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes . . . . . 2,767,920 A

Deduct: (increase a loss)

Net capital losses deducted in the year (enter as a positive amount) . . . . . a

Taxable dividends deductible under section 112 or subsections 113(1) or 138(6) . . . . . b

Amount of Part VI.1 tax deductible under paragraph 110(1)(k) c

Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2) . . . . . d

Subtotal (total of amounts a to d) ▶ B

Subtotal (amount A **minus** amount B; if positive, enter "0") C

Deduct: (increase a loss)

Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions . . . . . D

Subtotal (amount C **minus** amount D) E

Add: (decrease a loss)

Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss) . . . . . F

Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0") . . . . . G

If amount G is negative, enter it on line 110 as a positive.

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year . . . . . e

Deduct: Non-capital loss expired (note 1) . . . . . 100 f

Non-capital losses at the beginning of the tax year (amount e **minus** amount f) . . . . . 102 ▶ H

Add:

Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation . . . . . 105 g

Current-year non-capital loss (from amount G) . . . . . 110 h

Subtotal (amount g **plus** amount h) ▶ I

Subtotal (amount H **plus** amount I) J

Note 1: A non-capital loss expires as follows:

- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i
Section 80 – Adjustments for forgiven amounts	140		j
Subsection 111(10) – Adjustments for fuel tax rebate			j.1
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130		k
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3)	135		l
Subtotal (total of amounts i to l)		▶	K
Non-capital losses before any request for a carryback (amount J **minus** amount K)			L

Deduct – **Request to carry back non-capital loss to:**

First previous tax year to reduce taxable income	901		m
Second previous tax year to reduce taxable income	902		n
Third previous tax year to reduce taxable income	903		o
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		▶	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180		N

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		a
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205	138,126	b
Subtotal (amount a **plus** amount b)		138,126 ▶	138,126 A

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	250		c
Section 80 – Adjustments for forgiven amounts	240		d
Subtotal (amount c **plus** amount d)		▶	B
Subtotal (amount A **minus** amount B)			138,126 C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	210		D
Unused non-capital losses that expired in the tax year (note 4)			e
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5)			f
Enter amount e or f, whichever is less	215		g
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220		E
Subtotal (total of amounts C to E)			138,126 F

Note

If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

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Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (note 6) . . . . . 225 _____ G

Capital losses before any request for a carryback (amount F **minus** amount G) 138,126 H

Deduct – **Request to carry back capital loss to** (note 7):

	Capital gain (100%)		Amount carried back (100%)	
First previous tax year	_____	951	_____	h
Second previous tax year	_____	952	_____	i
Third previous tax year	_____	953	_____	j
Subtotal (total of amounts h to j)			_____ ▶	_____ I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)		280	138,126	J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year . . . . . _____ a

Deduct: Farm loss expired (note 8) . . . . . 300 _____ b

Farm losses at the beginning of the tax year (amount a **minus** amount b) . . . . . 302 _____ ▶ _____ A

Add:

Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation . . . 305 _____ c

Current-year farm loss (amount F in Part 1) . . . . . 310 _____ d

Subtotal (amount c **plus** amount d) _____ ▶ _____ B

Subtotal (amount A **plus** amount B) _____ C

Deduct:

Other adjustments (includes adjustments for an acquisition of control) . . . . . 350 _____ e

Section 80 – Adjustments for forgiven amounts . . . . . 340 _____ f

Farm losses of previous tax years applied in the current tax year . . . . . 330 _____ g

Enter amount g on line 334 of the T2 Return.

Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9) . . . . . 335 _____ h

Subtotal (total of amounts e to h) _____ ▶ _____ D

Farm losses before any request for a carryback (amount C **minus** amount D) _____ E

Deduct – **Request to carry back farm loss to:**

First previous tax year to reduce taxable income . . . . . 921 _____ i

Second previous tax year to reduce taxable income . . . . . 922 _____ j

Third previous tax year to reduce taxable income . . . . . 923 _____ k

First previous tax year to reduce taxable dividends subject to Part IV tax . . . . . 931 _____ l

Second previous tax year to reduce taxable dividends subject to Part IV tax . . . . . 932 _____ m

Third previous tax year to reduce taxable dividends subject to Part IV tax . . . . . 933 _____ n

Subtotal (total of amounts i to n) _____ ▶ _____ F

Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F) 380 _____ G

Note 8: A farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

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Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business . . . . . 485 _____ A

Minus the deductible farm loss:

(amount A above _____ – $2,500) **divided** by 2 = _____ a

Amount a or $ 15,000 (note 10), whichever is less . . . . . _____ ▶ _____ b

2,500 c

Subtotal (amount b **plus** amount c) 2,500 ▶ 2,500 B

Current-year restricted farm loss (amount A **minus** amount B) _____ C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year . . . . . _____ d

Deduct: Restricted farm loss expired (note 11) . . . . . 400 _____ e

Restricted farm losses at the beginning of the tax year (amount d **minus** amount e) . . . . . 402 _____ ▶ _____ D

Add:

Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation . . . . . 405 _____ f

Current-year restricted farm loss (from amount C) . . . . . 410 _____ g

Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.

Subtotal (amount f **plus** amount g) _____ ▶ _____ E

Subtotal (amount D **plus** amount E) _____ F

Deduct:

Restricted farm losses from previous tax years applied against current farming income . . . . . 430 _____ h

Enter amount h on line 333 of the T2 return.

Section 80 – Adjustments for forgiven amounts . . . . . 440 _____ i

Other adjustments . . . . . 450 _____ j

Subtotal (total of amounts h to j) _____ ▶ _____ G

Restricted farm losses before any request for a carryback (amount F **minus** amount G) _____ H

Deduct – Request to carry back restricted farm loss to:

First previous tax year to reduce farming income . . . . . 941 _____ k

Second previous tax year to reduce farming income . . . . . 942 _____ l

Third previous tax year to reduce farming income . . . . . 943 _____ m

Subtotal (total of amounts k to m) _____ ▶ _____ I

Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I) 480 _____ J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

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Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year		a	
Deduct: Listed personal property loss expired after 7 tax years	500	b	
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502	▶	A
Add: Current-year listed personal property loss (from Schedule 6)	510		B
Subtotal (amount A **plus** amount B)			C

Deduct:

Listed personal property losses from previous tax years applied against listed personal property gains. Enter amount c on line 655 of Schedule 6.	530	c	
Other adjustments	550	d	
Subtotal (amount c **plus** amount d)		▶	D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)			E

Deduct – Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961	e	
Second previous tax year to reduce listed personal property gains	962	f	
Third previous tax year to reduce listed personal property gains	963	g	
Subtotal (total of amounts e to g)		▶	F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)	580		G

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Part 7 – Limited partnership losses

Current-year limited partnership losses

	1 Partnership account number	2 Tax year ending yyyy/mm/dd	3 Corporation's share of limited partnership loss	4 Corporation's at-risk amount	5 Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	6 Column 4 **minus** column 5 (if negative, enter "0")	7 Current-year limited partnership losses (column 3 **minus** column 6)
	600	**602**	**604**	**606**	**608**		**620**
1.							

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1 Partnership account number	2 Tax year ending yyyy/mm/dd	3 Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary	4 Corporation's at-risk amount	5 Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	6 Column 4 **minus** column 5 (if negative, enter "0")	7 Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
	630	**632**	**634**	**636**	**638**		**650**
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1 Partnership account number	2 Limited partnership losses at the end of the previous tax year	3 Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary	4 Current-year limited partnership losses (from line 620)	5 Limited partnership losses applied in the current year (must be equal to or less than line 650)	6 Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5)
	660	**662**	**664**	**670**	**675**	**680**
1.						

Total (enter this amount on line 335 of the T2 return)

Note

If you need more space, you can attach more schedules.

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Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

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Tax Calculation Supplementary – Corporations

Schedule 5

Corporation's name	Business Number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 _____ Enter the Regulation that applies (402 to 413).

A Jurisdiction. Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year.*		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia Offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in subsection 400(2).

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

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Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.
3. If the corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
2,757,783		2,757,783	317,145

Ontario basic income tax (from Schedule 500) **270** 317,145

Deduct: Ontario small business deduction (from Schedule 500) **402**

Subtotal 317,145 ▶ 317,145 A6

Add:

Ontario additional tax re Crown royalties (from Schedule 504) **274**

Ontario transitional tax debits (from Schedule 506) **276**

Recapture of Ontario research and development tax credit (from Schedule 508) **277**

Subtotal ▶ B6

Subtotal (amount A6 **plus** amount B6) 317,145 C6

Deduct:

Ontario resource tax credit (from Schedule 504) **404**

Ontario tax credit for manufacturing and processing (from Schedule 502) **406**

Ontario foreign tax credit (from Schedule 21) **408**

Ontario credit union tax reduction (from Schedule 500) **410**

Ontario political contributions tax credit (from Schedule 525) **415**

Subtotal ▶ D6

Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") 317,145 E6

Deduct: Ontario research and development tax credit (from Schedule 508) **416**

Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0") 317,145 F6

Deduct:

Ontario corporate minimum tax credit (from Schedule 510) **418** 17,054

Ontario community food program donation tax credit for farmers (from Schedule 2) **420**

Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0") 300,091 G6

Add:

Ontario corporate minimum tax (from Schedule 510) **278**

Ontario special additional tax on life insurance corporations (from Schedule 512) **280**

Subtotal ▶ H6

Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) 300,091 I6

Deduct:

Ontario qualifying environmental trust tax credit **450**

Ontario co-operative education tax credit (from Schedule 550) **452**

Ontario apprenticeship training tax credit (from Schedule 552) **454** 70,000

Ontario computer animation and special effects tax credit (from Schedule 554) **456**

Ontario film and television tax credit (from Schedule 556) **458**

Ontario production services tax credit (from Schedule 558) **460**

Ontario interactive digital media tax credit (from Schedule 560) **462**

Ontario sound recording tax credit (from Schedule 562) **464**

Ontario book publishing tax credit (from Schedule 564) **466**

Ontario innovation tax credit (from Schedule 566) **468**

Ontario business-research institute tax credit (from Schedule 568) **470**

Subtotal 70,000 ▶ 70,000 J6

Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) **290** 230,091 K6

(if a credit, enter a negative amount) Include this amount on line 255.

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Energy+ Inc.
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Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	**255**	230,091

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Adjustments and transfers** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **212**	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1				32,987,763	0		32,987,763	4	0	0	1,319,511	31,668,252
2.	1b	New Buildings		26,750	1,279,077	0	13,375	1,292,452	6	0	0	77,547	1,228,280
3.	2				20,663,675	0		20,663,675	6	0	0	1,239,821	19,423,854
4.	3				536,484	0		536,484	5	0	0	26,824	509,660
5.	6				20,124	0		20,124	10	0	0	2,012	18,112
6.	8			414,788	2,489,582	95,718	159,535	2,649,117	20	0	0	529,823	2,278,829
7.	10			417,159	1,650,051	6,012	205,574	1,855,624	30	0	0	556,687	1,504,511
8.	12			1,096,552	702,647	0	536,779	1,262,420	100	0	0	1,262,420	536,779
9.	17				162,664	0		162,664	8	0	0	13,013	149,651
10.	45				694	0		694	45	0	0	312	382
11.	47			11,363,232	63,892,183	0	5,681,616	69,573,799	8	0	0	5,565,904	69,689,511
12.	50			202,050	465,130	0	101,025	566,155	55	0	0	311,385	355,795
13.	95	WIP (BCP)			1,692,219	0		1,692,219	0	0	0		1,692,219
14.	95	WIP net of Transformers		92,325	2,216,674	0	46,163	2,262,836	0	0	0		2,308,999
15.	13				22,090	0		22,090	NA	0	0	4,909	17,181
		Totals		13,612,856	128,781,057	101,730	6,744,067	135,548,116				10,910,168	131,382,015

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Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (14)

Canada

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Cambridge and North Dumfries Ene		88102 0127 RC0001	1					
2.	Cambridge and North Dumfries Ene		88102 0325 RC0001	3					
3.	The Corporation of the City of Camt		12358 3528 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") . . . . . **200** A

Add: Cost of eligible capital property acquired during the taxation year **222**

Other adjustments **226**

Subtotal (line 222 plus line 226) x 3 / 4 = B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . . . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") ▶ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . **224** 2,252,832 E

Subtotal (add amounts A, D, and E) **230** 2,252,832 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 2,252,832 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 2,252,832

less amount from line 249

Current year deduction . . . . . 2,252,832 x 7.00 % = **250** 157,698 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 157,698 ▶ 157,698 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 2,095,134 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

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Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")			▶	O
Line N minus line O (if negative, enter "0")				P
Line 5 _____ x 1 / 2 =				Q
Line P minus line Q (if negative, enter "0")				R
Amount R _____ x 2 / 3 =				S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

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Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Employee Future Benefits Liabil		2,928,510	3,140,004	2,928,510	3,140,004
2						
	Reserves from Part 2 of Schedule 13					
	Totals		2,928,510	3,140,004	2,928,510	3,140,004

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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Attached Schedule with Total

Part 1 – Financial statement reserves – Federal – Transfer on an amalgamation or the wind-up of a subsidiary

Title Part 1 – Financial statement reserves – Federal – Transfer on an amalgama

Description	Operator (Note)	Amount
CNDHI opening balance		2,189,796 00
BCP opening balance	+	738,714 00
	+	
	Total	2,928,510 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	1,245,000	0345983			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . . 1,245,000 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 1,245,000 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

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T2 SCH 15 (13)

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

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Allocating the business limit

Date filed (do not use this area) . . . . . 025 — Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 — Year: 2016

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 — 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year before the allocation $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	ENERGY + INC.	86569 7585 RC0002	1	500,000		
2	Cambridge and North Dumfries Energy Plus In	88102 0127 RC0001	1	500,000	100.0000	500,000
3	Cambridge and North Dumfries Energy Solutio	88102 0325 RC0001	1	500,000	100.0000	500,000
4	The Corporation of the City of Cambridge	12358 3528 RC0001	1	500,000		
				Total	200.0000	1,000,000 A

Energy+ Inc.
EB-2018-0028
Exhibit 4
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Filed: April 30, 2018

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (D - $10,000,000). Details of this formula and variable D are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year, whichever is less.

Canada

T2 SCH 23 E (15)

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SCHEDULE 24

FIRST-TIME FILER AFTER INCORPORATION, AMALGAMATION, OR WINDING-UP OF A SUBSIDIARY INTO A PARENT

Name of corporation	Business Number	Tax year end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

This schedule must be filed by corporations for the first year of filing after incorporation, amalgamation, or by parent corporations filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act* during the current taxation year.

Part 1 – Type of operation

100 For those corporations filing for the first time after incorporation or amalgamation, please identify the type of operation that applies to your corporation:

99 Other

Part 2 – First year of filing after amalgamation

For the first year of filing after an amalgamation, please provide the following information:

	Name of predecessor corporation(s) **200**	Business Number (If a corporation is not registered, enter "NR") **300**
1	Brant County Power Inc	89113 2011 RC0001
2	Cambridge & North Dumfries Hydro Inc.	86569 7585 RC0001

Part 3 – First year of filing after wind-up of subsidiary corporation(s)

For the parent corporation filing for the first time after winding-up a subsidiary corporation(s) under section 88 of the *Income Tax Act*, please provide the following information:

Name of subsidiary corporation(s) **400**	Business Number (If a corporation is not registered, enter "NR") **500**	Commencement date of wind-up (YYYY/MM/DD) **600**	Date of wind-up (YYYY/MM/DD) **700**

Canada

T2 SCH 24 (04)

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1);
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the scientific research and experimental development (SR&ED) qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Expenditures for pre-production mining, apprenticeship, or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

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Detailed information (continued)

- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures***:	
– after March 28, 2012, and before 2014	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** A transitional relief rate may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraphs (k)(ii) and (iii) of the definition of **specified percentage** in subsection 127(9) for more information.

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Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . **102** 1 Yes ☐ 2 No ☒

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . . **103** _____
(Enter this amount on line 350 of Part 8)

* Enter only contributions not already included on Form T661.
Include 80% of the contributions made **after** 2012. For contributions made **before** 2013, include all of the contributions.

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Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**

Total of investments for qualified property and qualified resource property _____ A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year B1

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal (line 210 **plus** line 215) ▶ C1

ITC at the beginning of the tax year (amount B1 **minus** amount C1) 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) . . . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) . . . . . x 5 % = 242

Credit allocated from a partnership 250

Subtotal (total of lines 230 to 250) ▶ D1

Total credit available (line 220 **plus** amount D1) E1

Deduct:

Credit deducted from Part I tax (enter this amount at line D8 in Part 30) 260

Credit carried back to the previous year(s) (from amount H1 in Part 6) . . . . . a

Credit transferred to offset Part VII tax liability 280

Subtotal (total of line 260, amount a, and line 280) ▶ F1

Credit balance before refund (amount E1 **minus** amount F1) G1

Deduct:

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) 310

ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310) 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied 901

Credit to be applied 902

Credit to be applied 903

Total of lines 901 to 903 (enter amount H1 on line a in Part 5) H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5) I1

Credit balance before refund (from amount G1 in Part 5) J1

Refund (40 % of amount I1 or J1, whichever is less) K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if you don't claim an SR&ED ITC refund).

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Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 557 on Form T661) . . . . . .

Contributions to agricultural organizations for SR&ED . . . . . .

Deduct:

Government assistance, non-government assistance, or contract payment . . . . . .

Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* . . . . . + ▶

Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)* . . . . . ▶ **350**

Capital expenditures incurred **before** 2014 (from line 558 on Form T661)** **360**

Repayments made in the year (from line 560 on Form T661) **370**

Qualified SR&ED expenditures (total of lines 350 to 370) **380**

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures. Capital cost allowance can be claimed for depreciable property acquired for use in SR&ED after 2013.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . . **385** 1 Yes ☐ 2 No ☒

If you answered **no** to the question on line 385 above or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, the amounts for associated corporations will be determined on Schedule 49.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied) **390** 1,263,631

Enter your taxable capital employed in Canada for the previous tax year 147,318,679
minus $10 million. If this amount is nil or negative, enter "0".
If this amount is over $40 million, enter $40 million **398** 40,000,000

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation: $ 8,000,000

Deduct:

Taxable income for the previous tax year (from line 390 in Part 9) or $500,000, whichever is more 1,263,631 x 10 = 12,636,310 A2

Excess ($8,000,000 **minus** amount A2; if negative, enter "0") B2

$ 40,000,000 **minus** line 398 in Part 9 . . . . . a

Amount a **divided** by $ 40,000,000 . . . . . C2

Expenditure limit for the stand-alone corporation (amount B2 **multiplied** by amount C2)* D2

For an associated corporation:

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49* **400** E2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D2 or E2 _____ x Number of days in the tax year / 365 366 = ... F2

Your SR&ED expenditure limit for the year (enter the amount from amount D2, E2, or F2, whichever applies) **410**

* Amount D2 or E2 cannot be more than $3,000,000.

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Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less* . . . . . **420** _____ x 35 % = _____ G2

Line 350 **minus** line 410 (if negative, enter "0") . . . . . **430** _____

Amount from line 430 _____ x (Number of days in the tax year before 2014 / Number of days in the tax year) _____ x 20% = _____ b

Amount from line 430** _____ x (Number of days in the tax year after 2013 / Number of days in the tax year) 366 / 366 x 15 % = _____ c

Subtotal (amount b **plus** amount c) . . . . . _____ ▶ _____ H2

Line 410 **minus** line 350 (if negative, enter "0") . . . . . _____ d

Capital expenditures (from line 360 in Part 8) or amount d above, whichever is less* . . . . . **440** _____ x 35 % = _____ I2

Line 360 **minus** amount d above (if negative, enter "0") . . . . . **450** _____

Amount from line 450 _____ x (Number of days in the tax year before 2014 / Number of days in the tax year) _____ x 20% = _____ e

Amount from line 450** _____ x (Number of days in the tax year after 2013 / Number of days in the tax year) 366 / 366 x 15 % = _____ f

Subtotal (amount e **plus** amount f) . . . . . _____ ▶ _____ J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) . . . . . _____

The ITC on the repayment (the credit) is calculated using the ITC rate that you used to determine your ITC when your qualified expenditures for ITC purposes were reduced because of the government or non-government assistance, or contract payments. Enter the amount of the repayment on the line that corresponds to the appropriate rate. ***

460 _____ x 35 % = _____ g

480 _____ x 20 % = _____ h

490 _____ x 15 % = _____ i

Subtotal (**add** amounts g to i) _____ ▶ _____ K2

Current-year SR&ED ITC (total of amounts G2 to K2; enter on line 540 in Part 12) . . . . . _____ L2

* For corporations that are not CCPCs, enter "0" for amounts G2 and I2.

** For tax years that end after 2013, the general SR&ED ITC rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013. For tax years that have a start date **after** 2013, multiply the amount by 15%.

*** If you are reporting a repayment for a tax year which included two calendar years with different rates (such as a 2014 tax year that started in 2013), the amount of repayment is allocated between the two ITC rates as follows:

- For the first part of the tax year, enter on the line next to the applicable ITC rate, the result of the following calculation: The full repayment amount **multiplied** by the number of days in the tax year which were in the first calendar year, **divided** by the total number of days in the tax year.
- For the last part of the tax year which is in the second calendar year, enter on the line next to the applicable ITC rate, the difference between the first part calculated above and the full repayment amount.

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Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year M2

Deduct:

Credit deemed as a remittance of co-op corporations 510

Credit expired 515

Subtotal (line 510 **plus** line 515) ▶ N2

ITC at the beginning of the tax year (amount M2 **minus** amount N2) 520

Add:

Credit transferred on amalgamation or wind-up of subsidiary 530

Total current-year credit (from amount L2 in Part 11) 540

Credit allocated from a partnership 550

Subtotal (total of lines 530 to 550) ▶ O2

Total credit available (line 520 **plus** amount O2) P2

Deduct:

Credit deducted from Part I tax (enter this amount at line E8 in Part 30) 560

Credit carried back to the previous year(s) (from amount S2 in Part 13) . . . . . j

Credit transferred to offset Part VII tax liability 580

Subtotal (total of line 560, amount j, and line 580) ▶ Q2

Credit balance before refund (amount P2 **minus** amount Q2) R2

Deduct:

Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) 610

ITC closing balance on SR&ED (amount R2 **minus** line 610) 620

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied 911

Credit to be applied 912

Credit to be applied 913

Total of lines 911 to 913 (enter amount S2 at line j in Part 12) S2

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Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . **650** 1 Yes ☐ 2 No ☒

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) . . . . . _____ k

Refundable credits (amount k or amount R2 in Part 12, whichever is less)* . . . . . _____ T2

Deduct:

Amount T2 or amount G2 in Part 11, whichever is less . . . . . _____ U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") . . . . . _____ V2

Amount V2 **multiplied** by 40 % . . . . . _____ W2

Add:

Amount U2 . . . . . _____ X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) . . . . . _____ Y2

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (from amount R2 in Part 12) . . . . . _____ Z2

Deduct:

Amount Z2 or amount G2 in Part 11, whichever is less . . . . . _____ AA2

Net amount (amount Z2 **minus** amount AA2; if negative, enter "0") . . . . . _____ BB2

Amount BB2 or amount I2 in Part 11, whichever is less . . . . . _____ CC2

Amount CC2 **multiplied** by 40 % . . . . . _____ DD2

Add:

Amount AA2 . . . . . _____ EE2

Refund of ITC (amount DD2 **plus** amount EE2) . . . . . _____ FF2

Enter FF2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

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Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal (enter amount A3 on line C3 in Part 17) A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (total of column F) (enter amount B3 on line D3 in Part 17) B3

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Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line E3 in Part 17) **760** _____

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16	_____	C3
Recaptured ITC from calculation 2, amount B3 in Part 16	_____	D3
Recaptured ITC from calculation 3, line 760 in Part 16	_____	E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3)	_____	F3

Enter amount F3 on line A8 in Part 29.

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Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that you incurred in the tax year (**before** January 1, 2014) for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting 810

Geological, geophysical, or geochemical surveys 811

Drilling by rotary, diamond, percussion, or other methods 812

Trenching, digging test pits, and preliminary sampling 813

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping 820

Sinking a mine shaft, constructing an adit, or other underground entry 821

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826
Total of column 826	▶ A4

Total pre-production mining expenditures (total of lines 810 to 821 and amount A4) 830

Deduct:

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to on line 830 above 832

Excess (line 830 **minus** line 832) (if negative, enter "0") B4

Add:

Repayments of government and non-government assistance 835

Pre-production mining expenditures (amount B4 **plus** line 835) C4

* A pre-production mining expenditure is defined under subsection 127(9).

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Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year D4

Deduct:

Credit deemed as a remittance of co-op corporations **841**

Credit expired **845**

Subtotal (line 841 **plus** line 845) ▶ E4

ITC at the beginning of the tax year (amount D4 **minus** amount E4) **850**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **860**

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part from amount C4 in Part 18)	**870**	x	10 %	=	a
Pre-production mining exploration expenditures** incurred in 2013 (applicable part from amount C4 in Part 18)	**872**	x	5 %	=	b
Pre-production mining development expenditures incurred in 2014 (applicable part from amount C4 in Part 18)	**874**	x	7 %	=	c
Pre-production mining development expenditures incurred in 2015 (applicable part from amount C4 in Part 18)	**876**	x	4 %	=	d

Current year credit (total of amounts a to d) **880** ▶ F4

Total credit available (total of lines 850, 860, and amount F4) G4

Deduct:

Credit deducted from Part I tax (enter this amount at line F8 in Part 30) **885**

Credit carried back to the previous year(s) (from amount I4 in Part 20) . . . . . e

Subtotal (line 885 **plus** amount e) ▶ H4

ITC closing balance from pre-production mining expenditures (amount G4 **minus** amount H4) **890**

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

** Also include pre-production mining development expenditures incurred in 2015 if the expense is described in subparagraph (a)(ii) of the definition **pre-production mining expenditure** in subsection 127(9) of the Act because of paragraph (g.4) of the definition **Canadian exploration expense** in subsection 66.1(6) of the Act.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	**921**
2nd previous tax year				Credit to be applied	**922**
3rd previous tax year				Credit to be applied	**923**

Total of lines 921 to 923 (enter amount I4 on line e in Part 19) I4

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Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . . **611** 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**
1.					
2.					
3.					

Total current-year credit (total of column E) (enter amount A5 on line 640 in Part 22) A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year B5

Deduct:

Credit deemed as a remittance of co-op corporations **612**

Credit expired after 20 tax years **615**

Subtotal (line 612 **plus** line 615) ▶ C5

ITC at the beginning of the tax year (amount B5 **minus** amount C5) **625**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **630**

ITC from repayment of assistance **635**

Total current-year credit (from amount A5 in Part 21) **640** 6,000

Credit allocated from a partnership **655**

Subtotal (total of lines 630 to 655) 6,000 ▶ 6,000 D5

Total credit available (line 625 **plus** amount D5) 6,000 E5

Deduct:

Credit deducted from Part I tax (enter this amount at line G8 in Part 30) **660** 6,000

Credit carried back to the previous year(s) (from amount G5 in Part 23) . . . . . a

Subtotal (line 660 **plus** amount a) 6,000 ▶ 6,000 F5

ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5) **690**

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

. . . . . Credit to be applied **931**

. . . . . Credit to be applied **932**

. . . . . Credit to be applied **933**

Total of lines 931 to 933 (enter amount G5 on line a in Part 22) G5

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Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures.

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695) **715** _____

Add:

Specified child care start-up expenditures from the current tax year . . . . . **705** _____

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . _____ A6

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . . **725** _____

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . . _____ B6

Add:

Repayments by the corporation of government and non-government assistance . . . . . **735** _____

Total eligible expenditures for child care spaces (amount B6 **plus** line 735) . . . . . **745** _____

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 24) . . . . . _____ x 25 % = _____ C6

Number of child care spaces . . . . . **755** _____ x $ 10,000 = _____ D6

ITC from child care spaces expenditures (amount C6 or D6, whichever is less) . . . . . _____ E6

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Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year F6

Deduct:

Credit deemed as a remittance of co-op corporations 765

Credit expired after 20 tax years 770

Subtotal (line 765 **plus** line 770) ▶ G6

ITC at the beginning of the tax year (amount F6 **minus** amount G6) 775

Add:

Credit transferred on amalgamation or wind-up of subsidiary 777

Total current-year credit (from amount E6 in Part 25) 780

Credit allocated from a partnership 782

Subtotal (total of lines 777 to 782) ▶ H6

Total credit available (line 775 **plus** amount H6) I6

Deduct:

Credit deducted from Part I tax (enter this amount at line H8 in Part 30) 785

Credit carried back to the previous year(s) (from amount K6 in Part 27) . . . . . a

Subtotal (line 785 **plus** amount a) ▶ J6

ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6) 790

Part 27 – Request for carryback of credit from child care space expenditures

	Year	Month	Day
1st previous tax year	2015	12	31
2nd previous tax year	2014	12	31
3rd previous tax year	2013	12	31

1st previous tax year . . . . . Credit to be applied 941

2nd previous tax year . . . . . Credit to be applied 942

3rd previous tax year . . . . . Credit to be applied 943

Total of lines 941 to 943 (enter amount K6 on line a in Part 26) K6

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Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) **792**

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC **795**

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property **797**

Amount from line 795 or line 797, whichever is less A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799**

Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) B7

Enter amount B7 on line B8 in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F3 in Part 17) A8

Recaptured child care spaces ITC (from amount B7 in Part 28) B8

Total recapture of investment tax credit (amount A8 **plus** amount B8) C8

Enter amount C8 on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) D8

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) E8

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) F8

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) 6,000 G8

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) H8

Total ITC deducted from Part I tax (total of amounts D8 to H8) 6,000 I8

Enter amount I8 on line 652 of the T2 return.

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Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
6,000	6,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)	
2015-12-31					
2014-12-31					
2013-12-31					
2012-12-31					
2011-12-31					
2010-12-31					
2009-12-31					
2008-12-31					
2007-12-31					
2006-12-31					*
2005-12-31					
2004-12-31					
2003-12-31					
2002-12-31					
2001-12-31					
2000-12-31					
					*
Total					

B+C+D+G **Total ITC utilized** 6,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	6,895,000
Capital stock (or members' contributions if incorporated without share capital)	103	38,224,000
Retained earnings	104	44,064,000
Contributed surplus	105	
Any other surpluses	106	
Deferred unrealized foreign exchange gains	107	
All loans and advances to the corporation	108	103,587,000
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	
Any dividends declared but not paid by the corporation before the end of the year	110	
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111	
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112	
Subtotal (**add** lines 101 to 112)		192,770,000 ▶ 192,770,000 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

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Part 1 – Capital (continued)

Subtotal A (from page 1)			192,770,000 A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121	3,737,000	
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)		3,737,000 ▶	3,737,000 B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		189,033,000

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	529,000
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	529,000

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		189,033,000 C
Deduct: Investment allowance for the year (line 490)		529,000 D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	188,504,000

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Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 188,504,000 x (Taxable income earned in Canada / Taxable income) **610** 2,757,783 / 2,757,783 = **Taxable capital employed in Canada** **690** 188,504,000

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **701**

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada **711**

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada **712**

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) **713**

Total deductions (**add** lines 711, 712, and 713) ▶ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") **790**

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . . F

Deduct: . . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") H

Calculation for purposes of the small business deduction (amount H x 0.225%) I

Enter this amount at line 415 of the T2 return.

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Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount	
Customer Deposit		10,112,000	00
Interco Debt	+	6,685,000	00
Long term debt	+	84,468,000	00
Customer Deposit	+	2,322,000	00
	+		
	Total	103,587,000	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

Description	Operator (Note)	Amount
Post Employment Benefits		3,140,000 00
Deferred tax liability in regulatory assets/liabilities	+	995,000 00
Deferred tax liability	+	2,760,000 00
	+	
	+	
	+	
	Total	6,895,000 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

Part 1 – Deferred tax debit balance at the end of the year

Title Part 1 – Deferred tax debit balance at the end of the year

Description	Operator (Note)	Amount
Deferred tax asset in regulatory accounts		3,737,000 00
	+	
	Total	3,737,000 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Part 2 – A loan or advance to another corporation (other than a financial in

Description	Operator (Note)	Amount
Prepaids per BS		529,000 00
	+	
	+	
	Total	529,000 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Cambridge & North Dumfries Energy Plus Inc.	88102 0127 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 53

General Rate Income Pool (GRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

On: 2016-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☐ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☒ Yes ☐ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Has the corporation wound-up a subsidiary in the preceding taxation year? . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

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Part 1 – General rate income pool (GRIP)

GRIP at the end of the previous tax year	100	28,907,596	A
Taxable income for the year (DICs enter "0") *	110	2,757,783	B
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120		
Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less *	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140		
Subtotal (**add** lines 120, 130, and 140)			C
Income taxable at the general corporate rate (amount B **minus** amount C) (if negative enter "0")	150	2,757,783	
After-tax income (line 150 **multiplied** by 0.72 (the general rate factor for the tax year))	190	1,985,604	D
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (line 200 **plus** line 210)			E
Becoming a CCPC (amount W5 in Part 4)	220		
Post-amalgamation (total of amounts E4 in Part 3 and amounts W5 in Part 4)	230		
Post-wind-up (total of amounts E4 in Part 3 and amounts W5 in Part 4)	240		
Subtotal (**add** lines 220, 230, and 240)	290		F
Subtotal (**add** amounts A, D, E, and F)		30,893,200	G
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year	310		
(If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.)			
Subtotal (line 300 **minus** line 310)			H
GRIP before adjustment for specified future tax consequences (amount G **minus** amount H) (amount can be negative)	490	30,893,200	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount N3 in Part 2)	560		
GRIP at the end of the tax year (line 490 **minus** line 560)	590	30,893,200	

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2015-12-31

Taxable income before specified future tax consequences from the current tax year	1,263,631	A1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)		B1	
Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less		C1	
Aggregate investment income (line 440 of the T2 return)		D1	
Subtotal (**add** amounts B1, C1, and D1)			E1
Subtotal (amount A1 **minus** amount E1) (if negative, enter "0")	1,263,631		1,263,631 F1

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Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences G1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . H1

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less I1

Aggregate investment income (line 440 of the T2 return) J1

Subtotal (**add** amounts H1, I1, and J1) ▶ K1

Subtotal (amount G1 **minus** amount K1) (if negative, enter "0") ▶ L1

Subtotal (amount F1 **minus** amount L1) (if negative, enter "0") M1

GRIP adjustment for specified future tax consequences to the first previous tax year

(amount M1 **multiplied** by 0.72) **500**

Second previous tax year 2014-12-31

Taxable income before specified future tax consequences from the current tax year 2,234,488 A2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . B2

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less C2

Aggregate investment income (line 440 of the T2 return) D2

Subtotal (**add** amounts B2, C2, and D2) ▶ E2

Subtotal (amount A2 **minus** amount E2) (if negative, enter "0") 2,234,488 ▶ 2,234,488 F2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences G2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . H2

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less I2

Aggregate investment income (line 440 of the T2 return) J2

Subtotal (**add** amounts H2, I2, and J2) ▶ K2

Subtotal (amount G2 **minus** amount K2) (if negative, enter "0") ▶ L2

Subtotal (amount F2 **minus** amount L2) (if negative, enter "0") M2

GRIP adjustment for specified future tax consequences to the second previous tax year

(amount M2 **multiplied** by 0.72) **520**

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Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2013-12-31

Taxable income before specified future tax consequences from the current tax year 550,898 A3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ B3

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . _____ C3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ D3

Subtotal (**add** amounts B3, C3, and D3) _____ ▶ _____ E3

Subtotal (amount A3 **minus** amount E3) (if negative, enter "0") 550,898 ▶ 550,898 F3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . . _____ G3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ H3

Amount on line 400, 405, 410, or 427 of the T2 return, whichever is less . . . . _____ I3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ J3

Subtotal (**add** amounts H3, I3, and J3) _____ ▶ _____ K3

Subtotal (amount G3 **minus** amount K3) (if negative, enter "0") _____ ▶ _____ L3

Subtotal (amount F3 **minus** amount L3) (if negative, enter "0") _____ M3

GRIP adjustment for specified future tax consequences to the third previous tax year

(amount M3 **multiplied by** 0.72) . . . . . **540** _____

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . _____ N3

Enter amount N3 on line 560 in part 1.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . _____ A4

Eligible dividends paid by the corporation in its last tax year . . . . . _____ B4

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . _____ C4

Subtotal (amount B4 **minus** amount C4) _____ ▶ _____ D4

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

(amount A4 **minus** amount D4) . . . . . _____ E4

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the E4 amounts. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

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Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . ☐ Post amalgamation . . . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year A5

The corporation's money on hand immediately before the end of its previous/last tax year B5

Total of subsection 111(1) losses that would have been deductible in calculating the corporation's taxable income for the previous/last tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous/last tax year:

Non-capital losses	C5	
Net capital losses	D5	
Farm losses	E5	
Restricted farm losses	F5	
Limited partnership losses	G5	
Subtotal (**add** amounts C5 to G5)	▶	H5

Total of all amounts deducted under subsection 111(1) in calculating the corporation's taxable income for the previous/last tax year:

Non-capital losses	I5	
Net capital losses	J5	
Farm losses	K5	
Restricted farm losses	L5	
Limited partnership losses	M5	
Subtotal (**add** amounts I5 to M5)	▶	N5
Unused and unexpired losses at the end of the corporation's previous/last tax year (amount H5 **minus** amount N5)	▶	O5
Subtotal (**add** amounts A5, B5, and O5)		P5

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year Q5

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year R5

All the corporation's reserves deducted in its previous/last tax year S5

The corporation's capital dividend account immediately before the end of its previous/last tax year T5

The corporation's low rate income pool immediately before the end of its previous/last tax year U5

Subtotal (**add** amounts Q5 to U5) ▶ V5

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (amount P5 **minus** amount V5) (if negative, enter "0") W5

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the W5 amounts. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

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Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		2,780,237	
Total taxable dividends paid in the tax year	100	2,780,237	
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160	30,893,200	B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Ontario basic rate of tax for the year

Ontario basic rate of tax for the year . . . . . 11.5 % A

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 2,757,783 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A from Part 1) . . . . . 317,145 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

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Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)	2,767,920	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)		2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)		3

Ontario business limit reduction:

Amount from line 3 _____ a

Deduct:

Amount from line E of the T2 return _____ x (Number of days in the tax year after May 1, 2014 / Number of days in the tax year) 366 / 366 = _____ b

Reduced Ontario business limit (amount a **minus** amount b) (if negative, enter "0") _____ c

Business limit the CCPC assigns under subsection 125(3.2) ITA _____ d

Amount c **minus** amount d _____ ▶ _____ 4

Enter the least of amounts 1, 2, 3, and 4 _____ D

Ontario domestic factor (ODF): Ontario taxable income * 2,757,783.00 / Taxable income earned in all provinces and territories ** 2,757,783 = 1.00000 E

Amount D × ODF (line E) _____ e

Ontario taxable income (amount B from Part 2) 2,757,783 f

Reduced Ontario business limit (lesser of amount e and amount f) (if negative, enter "0") _____ F

OSBD rate for the year 7 % G

Ontario small business deduction: amount F **multiplied** by rate G _____ H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

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Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount f from Part 3) _____ I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

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Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		J
Deduct:		
Ontario adjusted small business income (amount I from Part 4)		K
Subtotal (amount J **minus** amount K) (if negative, enter "0")		L
Amount L **multiplied** by rate G from Part 3		M
Ontario domestic factor (line E from Part 3)	1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by ODF from line N)		O

Enter amount O on line 410 of Schedule 5.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	238,336,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	92,481,000
Total assets (total of lines 112 to 116)		330,817,000
Total revenue of the corporation for the tax year **	142	254,437,000
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	103,193,000
Total revenue (total of lines 142 to 146)		357,630,000

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

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Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *	210		6,422,000
Add (to the extent reflected in income/loss):			
Provision for current income taxes/cost of current income taxes	220	669,000	
Provision for deferred income taxes (debits)/cost of future income taxes	222	1,212,000	
Equity losses from corporations	224		
Financial statement loss from partnerships and joint ventures	226		
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230		
Other additions (see note below):			
Share of adjusted net income of partnerships and joint ventures **	228		
Total patronage dividends received, not already included in net income/loss	232		
281	282		
283	284		
Subtotal		1,881,000 ▶	1,881,000 A
Deduct (to the extent reflected in income/loss):			
Provision for recovery of current income taxes/benefit of current income taxes	320		
Provision for deferred income taxes (credits)/benefit of future income taxes	322		
Equity income from corporations	324		
Financial statement income from partnerships and joint ventures	326		
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330		
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332		
Gain on donation of listed security or ecological gift	340		
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342		
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344		
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346		
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348		
Other deductions (see note below):			
Share of adjusted net loss of partnerships and joint ventures **	328		
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334		
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336		
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338		
381 Tax recovery incl. in net movements in reg. balance on P	382	1,248,256	
383 Tax recovery incl. in OCI	384	51,606	
385	386		
387	388		
389	390		
Subtotal		1,299,862 ▶	1,299,862 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)	490		7,003,138

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

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Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) **515** 7,003,138

Deduct:

CMT loss available (amount R from Part 7) . . . . .

Minus: Adjustment for an acquisition of control * **518**

Adjusted CMT loss available C

Net income subject to CMT calculation (if negative, enter "0") **520** 7,003,138

Amount from line 520: 7,003,138 x (Number of days in the tax year before July 1, 2010: ___ / Number of days in the tax year: 366) x 4 % = 1

Amount from line 520: 7,003,138 x (Number of days in the tax year after June 30, 2010: 366 / Number of days in the tax year: 366) x 2.7 % = 189,085 2

Subtotal (amount 1 **plus** amount 2) 189,085 3

Gross CMT: amount on line 3 above x OAF ** **540** 189,085

Deduct:

Foreign tax credit for CMT purposes *** **550**

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . . 189,085 D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 317,145

Net CMT payable (if negative, enter "0") . . . . . E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor . . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

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Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		17,054	G	
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		17,054 ▶	620	17,054
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)	650			
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				17,054 H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				17,054 I
Subtotal (amount H **minus** amount I)				J
Add:				
Net CMT payable (amount E from Part 3)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)	670			L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				17,054 M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		317,145	1	
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)		189,085	2	
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)			3	
Gross SAT (line 460 from Part 6 of Schedule 512)			4	
The **greater** of amounts 3 and 4			5	
Deduct: line 2 or line 5, whichever applies:		189,085	6	
Subtotal (if negative, enter "0")		128,060 ▶		128,060 N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		317,145		
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		70,000		
Subtotal (if negative, enter "0")		247,145 ▶		247,145 O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				17,054 P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

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Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin		CMT credit balance *
10th previous tax year	680	
9th previous tax year	681	
8th previous tax year	682	
7th previous tax year	683	
6th previous tax year	684	
5th previous tax year	685	
4th previous tax year	686	
3rd previous tax year	687	
2nd previous tax year	688	
1st previous tax year	689	
Total **		

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

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Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Cambridge and North Dumfries Energy Plus Inc.	88102 0127 RC0001	42,188,000	2,827,000
2	Cambridge and North Dumfries Energy Solutions Inc.	88102 0325 RC0001	293,000	366,000
3	The Corporation of the City of Cambridge	12358 3528 RC0001	50,000,000	100,000,000
		Total	450 92,481,000	550 103,193,000

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 524

ONTARIO SPECIALTY TYPES

Name of corporation	Business Number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Use this schedule to identify the specialty type of a corporation carrying on business in the province of Ontario through a permanent establishment if:
  – its tax year includes January 1, 2009;
  – the tax year is the first year after incorporation or an amalgamation; or
  – there is a change to the specialty type.
- If none of the listed specialty types applies, tick box 99 "Other."
- Unless otherwise noted, references to sections, subsections, and clauses are from the *Taxation Act, 2007* (Ontario).

Specialty types

100 Identify the specialty type that applies to your corporation:

- ☐ 01 Family farm corporation – See subsection 64(3).
- ☐ 02 Family fishing corporation – See subsection 64(3).
- ☐ 03 Mortgage investment corporation – See subsection 130.1(6) of the federal *Income Tax Act*.
- ☐ 04 Credit union – See subsection 137(6) of the federal Act.
- ☐ 06 Bank – See subsection 248(1) of the federal Act.
- ☐ 08 Financial institution prescribed by regulation only – See clause 66(2)(f).
- ☐ 09 Registered securities dealer – See subsection 248(1) of the federal Act.
- ☐ 10 Farm feeder finance co-operative corporation
- ☐ 11 Insurance corporation – See subsection 248(1) of the federal Act.
- ☐ 12 Mutual insurance – See subsection 27(2) of the *Taxation Act, 2007* (Ontario) and paragraph 149(1)(m) of the federal Act.
- ☐ 13 Specialty mutual insurance
- ☐ 14 Mutual fund corporation – See subsection 131(8) of the federal Act.
- ☐ 15 Bare trustee corporation
- ☐ 16 Professional corporation (incorporated professional only) – See subsection 248(1) of the federal Act.
- ☐ 17 Limited liability corporation
- ☐ 18 Generator of electrical energy for sale, or producer of steam for use in the generation of electrical energy for sale – See subsection 33(7).
- ☒ 19 Hydro successor, municipal electrical utility, or subsidiary of either – See subsection 91.1(1) and section 88 of the *Electricity Act, 1998* (Ontario).
- ☐ 20 Producer and seller of steam for uses other than for the generation of electricity – See subsection 33(7).
- ☐ 21 Mining corporation
- ☐ 22 Non-resident corporation
- ☐ 99 Other (if none of the previous descriptions apply)

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

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Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
ENERGY + INC.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2016-01-01	1392322

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
1500	BISHOP ST N	

240 Additional address information if applicable (line 220 must be completed first)
PO BOX 1060

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
CAMBRIDGE	ON	CA	N1R 5X6

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 2 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 HUGHES (Last name) **451** SARAH (First name)

454 _____ (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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Part 7 – Director/Officer information

- **Director:** If the individual named in this part is a director (or must be reported ceased as a director), complete lines 700 to 797.
- **Officer:** If the individual named in this part is one of the corporation's five most senior officers (or must be reported ceased in an officer position), complete lines 700 to 790 and the applicable lines from 801 to 912.
- **Director and officer:** If the individual named in this part is a director and one of the corporation's five most senior officers (or must be reported ceased in these position(s)), complete lines 700 to 797 and the applicable lines from 801 to 912.
- The corporation is required to show information on the MGS public record for all its directors and a maximum of five of its most senior officers. If the MGS public record shows more than five officer positions, report cease dates for all except the corporation's five most senior officer positions.
- To report changes to the name of a director/officer, or changes to both the address and the date elected/appointed of a director/officer, enter the director/officer information exactly as shown incorrectly on the public record, with a cease date, and then photocopy and complete only Part 7 with the correct director/officer information.

Please photocopy this page and complete Part 7 only for each additional individual for whom director/officer information changes are being reported.

Full name and address for service (P.O. box not acceptable as stand-alone address). The name entered in lines 700 to 710 must be exactly as shown on the MGS public record.

700 Last name	705 First name	710 Middle name(s)
Vos	Sandra	

720 Street number	730 Street name/Rural route/Lot and Concession number	740 Suite number
97	Queensway Drive	

750 Additional address information if applicable (line 730 must be completed first)

760 Municipality (e.g., city, town)	770 Province/state	780 Country	790 Postal/zip code
Brantford	ON	CA	N3R 4X1

Director

Is this director a resident Canadian? . . . 795 **1** Yes [X] **2** No [ ]

(applies to directors of corporations with share capital only)

	Date elected/appointed Year Month Day		Date ceased, if applicable Year Month Day
796	2016-05-10	797	

Officer information

		Date appointed Year Month Day		Date ceased, if applicable Year Month Day
President	801		802	
Secretary	806		807	
Treasurer	811		812	
General Manager	816		817	
Chair	821		822	
Chairperson	826		827	
Chairman	831		832	
Chairwoman	836		837	
Vice-Chair	841		842	
Vice-President	846		847	
Assistant Secretary	851		852	
Assistant Treasurer	856		857	
Chief Manager	861		862	
Executive Director	866		867	
Managing Director	871		872	
Chief Executive Officer	876		877	
Chief Financial Officer	881		882	
Chief Information Officer	886		887	
Chief Operating Officer	891		892	
Chief Administrative Officer	896		897	
Comptroller	901		902	
Authorized Signing Officer	906		907	
Other (untitled)	911		912	

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Once you have completed this page, complete the certification in Part 4 of this schedule.

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Schedule 552

Ontario Apprenticeship Training Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
ENERGY + INC.	86569 7585 RC0002	2016-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009, or* the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

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Part 1 – Corporate information

110 Name of person to contact for more information: SARAH HUGHES

120 Telephone number: (519) 621-3530

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? **160** _____

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * 300 7,687,394

For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \frac{\text{amount on line 300 minus } 400{,}000}{200{,}000} \right]$$

Specified percentage . . . . . **312** 35.000 %

For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \frac{\text{amount on line 300 minus } 400{,}000}{200{,}000} \right]$$

Specified percentage . . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
1.	434a	[redacted]	[redacted]
2.	434a	[redacted]	[redacted]
3.	434a	[redacted]	[redacted]
4.	434a	[redacted]	[redacted]
5.	434a	[redacted]	[redacted]
6.	434a	[redacted]	[redacted]
7.	434a	[redacted]	[redacted]
8.			

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
1.	[redacted]	[redacted]	2016-01-01	2016-12-31
2.	[redacted]	[redacted]	2016-01-01	2016-12-31
3.	[redacted]	[redacted]	2016-01-01	2016-12-31
4.	[redacted]	[redacted]	2016-01-01	2016-12-31
5.	[redacted]	[redacted]	2016-01-01	2016-12-31
6.	[redacted]	[redacted]	2016-01-01	2016-12-31
7.	[redacted]	[redacted]	2016-01-01	2016-12-31

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	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
8.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

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Part 4 – Ontario apprenticeship training tax credit (continued)

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	Maximum credit amount for the tax year (see note 2) 445
1.	366		10,000
2.	366		10,000
3.	366		10,000
4.	366		10,000
5.	366		10,000
6.	366		10,000
7.	366		10,000
8.			

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*) or ($5,000 × H2/365*), whichever applies.
* 366 days, if the tax year includes February 29

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
1.	[redacted]		[redacted]
2.	[redacted]		[redacted]
3.	[redacted]		[redacted]
4.	[redacted]		[redacted]
5.	[redacted]		[redacted]
6.	[redacted]		[redacted]
7.	[redacted]		[redacted]
8.			

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.

For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
1.	10,000		10,000
2.	10,000		10,000
3.	10,000		10,000
4.	10,000		10,000
5.	10,000		10,000
6.	10,000		10,000
7.	10,000		10,000

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	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for the year (column L or M, whichever applies) 490
8.			

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 70,000 **O**

Or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O _____ x percentage on line 170 in Part 1 _____ % = ... _____ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

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Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . . ENERGY + INC.

Taxation Year . . . . . 2016-01-01 to 2016-12-31

Jurisdiction . . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . . Y

Corporation is related . . . . . Y

Number of associated corporations . . . 3

Type of corporation . . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . . -30,872

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		2,767,920
Taxable income		2,757,783
Donations		10,137
Calculation of income from an active business carried on in Canada		2,767,920
Dividends paid		2,780,237
Dividends paid – Regular	2,780,237	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		28,907,596
Balance of the general rate income pool at the end of the year		30,893,200
Part I tax (base amount)		1,047,958

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	407,668	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	668,631
Investment tax credits	6,000	Other*		Other*	
Abatement/Other*	634,290	Provincial or territorial tax	230,091		

Balance due/refund (–) -30,872

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Capital losses/L.P.P.	138,126
Cumulative eligible capital	2,095,134
Financial statement reserve	3,140,004

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Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-770)	Alberta (AT1)
Net income	2,767,920		
Taxable income	2,757,783		
% Allocation	100.00		
Attributed taxable income	2,757,783		
Tax payable before deduction*	317,145		
Deductions and credits	17,054		
Net tax payable	300,091		
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	300,091		
Instalments and refundable credits	70,000		
Balance due/Refund (-)	230,091		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

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Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
ENERGY + INC.	147,318,679	147,318,679	188,504,000	188,504,000
Cambridge and North Dumfries Energy Plus Inc.	98,000	98,000	129,000	129,000
Cambridge and North Dumfries Energy Solutions Inc.	228,000	228,000	130,605	130,605
The Corporation of the City of Cambridge				
Total	147,644,679	147,644,679	188,763,605	188,763,605

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Energy+ Inc.
EB-2018-0028
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Filed: April 30, 2018

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

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Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Net income	2,767,920	1,318,825	2,239,888	555,798	1,820,206
Taxable income	2,757,783	1,263,631	2,234,488	550,898	1,809,506
Active business income	2,767,920	1,277,942	2,239,888	555,798	1,820,206
Dividends paid	2,780,237	2,650,536	2,530,000	2,621,000	2,948,000
Dividends paid – Regular	2,780,237	2,650,536	2,530,000	2,621,000	2,948,000
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	28,907,596	27,997,782	26,388,951	25,992,304	24,689,460
GRIP – end of the year	30,893,200	28,907,596	27,997,782	26,388,951	25,992,304
Donations	10,137	14,311	5,400	4,900	10,700
Balance due/refund (-)	-30,872	-159,869	-47,801	-290,135	-1,611,590
Line 996 – Amended tax return	☐	☐	☐	☐	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Taxable income before loss carrybacks	N/A	N/A	2,234,488	550,898	1,809,506
Non-capital losses	N/A	N/A			
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted taxable income after loss carrybacks	N/A	N/A	2,234,488	550,898	1,809,506

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Adjusted taxable income before current year loss carrybacks*	N/A	1,263,631	2,234,488	550,898	N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A	1,263,631	2,234,488	550,898	N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

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Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Part I	407,668	177,545	263,012	78,991	208,498
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Investment tax credit	6,000	12,000	72,161	3,643	62,927
Abatement/other*	634,290	290,635	513,932	126,707	416,187

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
ITC refund					
Dividend refund					
Instalments	668,631	416,000	416,071	480,000	1,940,000
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

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Ontario

Taxation year end	2016-12-31	2015-12-31	2014-12-31	2013-12-31	2012-12-31
Net income	2,767,920	1,318,825	2,239,888	555,798	1,820,206
Taxable income	2,757,783	1,263,631	2,234,488	550,898	1,809,506
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income	2,757,783	1,263,631	2,234,488	550,898	1,809,506
Surtax					
Income tax payable before deduction	317,145	145,318	256,966	63,353	208,093
Income tax deductions /credits	17,054	9,938	101,311	35,801	49,684
Net income tax payable	300,091	135,380	155,655	27,552	158,409
Taxable capital					
Capital tax payable					
Total tax payable*	300,091	135,380	155,655	136,188	158,409
Instalments and refundable credits	70,000	56,794	50,397	25,314	38,497
Balance due/refund**	230,091	78,586	105,258	110,874	119,912

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

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ENERGY + INC.
1500 BISHOP ST N
PO BOX 1060
CAMBRIDGE, ON
N1R 5X6

CRA Taxation Centre
275 Pope Road
Summerside, PE
C1N 6A2

June 26, 2017

Dear CRA:

SUBJECT: Attachments to 2016 Corporate Income Tax Return for ENERGY + INC. (Business Number: 86569 7585 RC0002)

The corporate income tax return for ENERGY + INC. for the period ended December 31, 2016 has been efiled. We have enclosed those attachments that are required to be filed in paper.

If you have any questions concerning the attached, please do not hesitate to contact us.

Yours truly,

SARAH HUGHES
CFO

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Energy + Inc.
86569 7585 RC0001
Period ended December 31, 2016
Regulation 1101(5b.1) Election

The taxpayer hereby elects pursuant to subsection 1101(5b.1) of the Income Tax Regulations of Canada, to include each eligible non-residential building acquired during the year in a separate prescribed class.

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APPENDIX 4-6: INDECO REPORT

IndEco
Strategic Solutions for a Changing World™

Energy+ Inc. 2017 LRAMVA

Energy+ Inc. lost revenue related to Conservation and Demand Management

2011-2017

This document was prepared for Energy+ Inc. by IndEco Strategic Consulting Inc.

For additional information about this document, please contact:

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IndEco Strategic Consulting Inc. 2018
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IndEco report B8148

2 April 2018

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Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove a disincentive electricity local distribution companies (LDCs) may have to promote conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of LDCs, which directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that resulted from CDM programs the LDC offered to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts an LDC included in the LDC's load forecast.[1]

Effective January 1, 2016, Cambridge and North Dumfries Hydro Inc. ("CND") and Brant County Power Inc. ("BCP") legally amalgamated to become Energy+ Inc. The legal amalgamation was approved by the Ontario Energy Board on February 4, 2016. OEB License No. ED-2002-0574 was subsequently amended by the Ontario Energy Board to reflect the name change, as well as to incorporate the licensed service territories of the former CND and BCP under one license. In this document, "Energy+ (CND)" is used to describe the former Cambridge and North Dumfries Hydro Inc. and "Energy+ (Brant County)" is used to describe the former Brant County Power, or the part of Energy+'s service territory that was formerly Brant County Power.

The former Brant County Power submitted a cost of service application in 2010 for rate year 2011(EB-2010-0125) that included in the load forecast estimated losses association with CDM programs offered in 2011. This same forecast applied through 2018. The former Cambridge and North Dumfries Hydro submitted a cost of service application in 2013 for rate year 2014 (EB-2013-0116) that accounted for CDM programs offered in 2014, and that forecast applied through 2018. Prior to 2014, forecasts for CND did not account for CDM.

Both Energy+ (CND) and Energy+ (Brant County) contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of conservation and demand management (CDM) programs to customers in a variety of rate classes for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period. Energy+ is required to use "the most recent and appropriate final CDM evaluation report from the IESO

[1] *Guidelines for Electricity Distributor Conservation and Demand Management.* Ontario Energy Board. April 26, 2012 (EB-2012-0003).

in support of its lost revenue calculation."[2] The final 2016 annual verified results report is the most recent final CDM evaluation report available from the IESO. The 2017 final results are anticipated before the 2018 Cost of Service application is finalized, and the LRAMVA claim will be updated with the final results when available. Thus, Energy+ will claim lost revenue from CDM programs up to and including 2017 in Energy+' 2019 rate case (EB-2018-0028).

Energy+ submitted a claim for lost revenues in the Energy+ (CND) service territory as part of its 2015 rate application (EB-2014-0060) for CDM programs offered in 2011 through 2013 (including persistence of 2011 and 2012 results). In 2016 (EB-2016-0060), Energy+ submitted a claim for lost revenue variances in the Energy+ (Brant County) service territory between CDM results in 2011-2015 including persistence through 2015 and what was included in the 2011 rate year forecast.

This report determines the variance account balance for the following revenue losses:

For Energy+ (CND) service area:

- Lost revenues in 2014 related to programs offered in 2011,
- Lost revenues in 2014 related to programs offered in 2012,
- Lost revenues in 2014 related to programs offered in 2013,
- Lost revenues in 2014 related to programs offered in 2014.
- Lost revenues in 2015 related to programs offered in 2011,
- Lost revenues in 2015 related to programs offered in 2012,
- Lost revenues in 2015 related to programs offered in 2013,
- Lost revenues in 2015 related to programs offered in 2014,
- Lost revenues in 2015 related to programs offered in 2015,
- Lost revenues in 2016 related to programs offered in 2011,
- Lost revenues in 2016 related to programs offered in 2012,
- Lost revenues in 2016 related to programs offered in 2013,
- Lost revenues in 2016 related to programs offered in 2014,
- Lost revenues in 2016 related to programs offered in 2015,
- Lost revenues in 2016 related to programs offered in 2016,
- Lost revenues in 2017 related to programs offered in 2016, and
- Lost revenues in 2017 related to programs offered in 2017.

For Energy+ (Brant County) service area:

- Lost revenues in 2016 related to programs offered in 2011,
- Lost revenues in 2016 related to programs offered in 2012,
- Lost revenues in 2016 related to programs offered in 2013,
- Lost revenues in 2016 related to programs offered in 2014,

[2] *Filing Requirements For Electricity Distribution Rate Applications - 2016 Edition for 2017 Rate Applications - Chapter 2 - Cost of Service*, Ontario Energy Board. July 14, 2016.

- Lost revenues in 2016 related to programs offered in 2015,
- Lost revenues in 2016 related to programs offered in 2016,
- Lost revenues in 2017 related to programs offered in 2011,
- Lost revenues in 2017 related to programs offered in 2012,
- Lost revenues in 2017 related to programs offered in 2013,
- Lost revenues in 2017 related to programs offered in 2014,
- Lost revenues in 2017 related to programs offered in 2015,
- Lost revenues in 2017 related to programs offered in 2016, and
- Lost revenues in 2017 related to programs offered in 2017.

The carrying charges on the above variances through December 2018 are also reported.

Energy+ plans to submit a claim for these lost revenue variances as a part of its 2019 Cost of Service application. The Ontario Energy Board requires LDCs to clear their LRAMVA accounts at the time of cost of service applications. However, because Energy+ expects to submit its application before final verified results are available for 2017 CDM programs and 2016 adjustments, the LRAMVA value has been based on unverified results from the IESO as of January 2018. These values will be updated once the IESO final results are available.[3]

[3] This approach was reviewed with Board staff.

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the different time periods of results data and the rate year, and the need to determine carrying charges on the lost revenues.

The most recent input assumptions available have been used to calculate the lost revenue values.

CDM results

From 2011 through 2017, Energy+ offered provincial programs in partnership with the Independent Electricity System Operator (IESO). Energy+ did not offer custom programs beyond the IESO programs.

IESO evaluation results

The IESO performs evaluations of all of its programs, which examine gross energy savings from the programs, and the net-to-gross ratio (NTGR), and then from those calculates net energy savings by initiative within each program group (residential, business, industrial and low-income). Peak load reductions are also calculated, and reported in the same way.

Provincial results are allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO reports energy savings and peak demand reductions, by initiative in the current year, adjustments to the previous year, based on updated validation, and contribution to total savings or reductions to the end of the 2011 to 2014 period and the 2015 to 2020 period. The savings and demand reductions for a particular year for a number of programs persist in the following years. The savings and demand reductions for demand response programs do not persist beyond the year in which those particular savings and demand reductions occur. The IESO was requested to provide the persistence into future years of savings and reductions for each program in each year for 2011-2014. The IESO included persistence estimates in its 2016 reports, which include results for 2015 and 2015 adjustments.

At the time this document was prepared, final verified results for 2017 had not yet been released, so 2017 values are based on IESO unverified results provided by the IESO in January 2018. These values will be updated when the final 2017 results (and final verified 2016 adjustments) are released by the IESO.

These are the best, most definitive and defensible estimates of results associated with these programs, and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Allocating results to rate classes and service territories

The IESO reports results by 'program', within four main programs: residential, business (commercial and institutional), industrial and low-income. These only partially map onto rate classes. For initiatives that apply to more than one rate class, Energy+ staff estimated the split by rate class, drawing on project-specific information where available.

Beginning in 2016, IESO reported consolidated results for Energy+ (CND) and Energy+ (Brant County). Energy+ staff estimated the split by service territory, drawing on project-specific information where available. For some of the residential programs, project-specific data were not available. In this cases, savings were allocated based on the relative loads of the two service territories.

Application of reported results

In its verified results, the IESO reports both energy savings and reductions in demand. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For rate classes where the customer is charged for distribution by energy use (kWh), the IESO reported energy savings are used to calculate lost revenues related to CDM results. For customer classes where the LDC charges for distribution based on the customer's peak monthly demand (kW), the IESO reported demand reductions are used to calculate lost revenues related to CDM results. The demand reductions in the IESO reports should be multiplied by a multiplier based on the number of months a specific program impacts a customer's peak demand. "The IESO indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year…In the case of the Building Commissioning initiative, the demand savings provided in the Final CDM Results should only be multiplied by three (3) as these savings are related to space cooling and do not occur throughout the full year, but only during the summer months, typically."[4]

The OEB has decided that lost revenue cannot be claimed from the kW values reported by the IESO for the Demand Response 3 (DR3) program. "The monthly peak demand of a demand-billed customer used for billing purposes may not correspond with the demand

[4] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2016-0182, May 19, 2016, p. 4.

response event; even if it did, the lost revenues would only be related to a difference between the customer's peak demand absent the demand response event and the next highest peak demand for the customer in that month… Since the IESO's evaluations cannot confirm the nature of the demand savings relative to the billing period for demand-billed customers, it is not appropriate that distributors be credited with lost revenues from demand response programs, except for those situations where the distributor can explicitly demonstrate revenue impacts."[5]

Estimating 2016 adjustments and 2017 results

Since the final results were released for 2016 programs in June 2017, the IESO has identified additional unverified results (adjustments) to the 2016 program results, and Energy+ has delivered additional CDM projects throughout 2017. Unverified net energy savings associated with 2016 adjustments and 2017 results were provided by the IESO in January 2018, and these were used to estimate demand savings as well.

The lack of demand estimates does not affect residential programs, since the residential rate class is billed by energy (kWh) not demand (kW). For all non-residential programs, Energy+ has a database of projects, with estimated gross energy and demand savings. Ratios of demand to energy (kW/kWh) were calculated for projects in each program, then these ratios were applied to the unverified energy results to estimate demand savings associated with each program.

The project database was also used to allocate savings to rate classes in the two service territories, where project specific information was available.

Load reductions accounted for in the load forecast

In recent years, LDCs have tried to account for load losses due to CDM programs in their load forecasts, submitted as part of their Cost of Service applications. These forecasted reductions need to be deducted from load losses attributable to CDM programs, to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. Finally the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

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[5] Ibid. p. 7.

Distribution rates

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues. An exception is for certain rate riders related to taxes, and these are added to the distribution volumetric rates for lost revenue calculations, where applicable.

For most electricity distribution utilities in Ontario, including Energy+, distribution rates are set for the period from 1 May to 30 April of the next year. CDM results are reported for the calendar year, so average rates for the calendar year need to be calculated. For simplicity, the average rate is estimated based on the rate being four twelfths of the previous year's rate (for January through April), and eight twelfths of the current year's rate (for May through December). Energy+ has proposed to change its rate year to begin on January 1 starting in 2019, but that change does not affect the calculations underlying this document, except that carrying charges are calculated only to December 31. 2018.

Lost revenues variance

Lost revenues in a particular rate class are the product of the savings or demand reductions in that class, less what was accounted for in the load forecast, multiplied by the average rate for that class in the calendar year for which the energy savings or demand reductions were reported.[6] The variance is the difference between these lost revenues and the quantity of CDM in the load forecast, or what is called 'the LRAMVA threshold'.

Because these revenues are lost throughout the year, and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB, and published on the Board's website. The carrying charges are simple interest, not compounded and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. So 1/12 of the annual results are allocated to each month of the year.

Carrying charges accrue from the time of the results, until disposition.

The LDC reports these lost revenues on its financial statements in Account 1568, and the associated rate class-specific sub-accounts.

[6] Where distribution rates are monthly rates for the peak kW in that month, the annual loss of revenue is the monthly rate times the number of months it applies to – usually twelve.

Results

Following the methodology described above, lost revenues were calculated for Energy+. The results reference tables provided in the completed LRAMVA work forms that use the OEB's template. Because until 2016 IESO reported results separately for the two service territories, and because through 2016 the two service territories had different distribution rates, separate work forms are provided for the Energy+ (CND) and Energy+ (Brant County) service territories.

CDM results

IESO evaluation result

The most recent and appropriate final CDM evaluation reports from the IESO were used in support of the lost revenue calculations through 2016. IESO unverified results for 2016 adjustments and 2017 results were used for the 2016 adjustments and 2017 results. A working Microsoft Excel file copy of each IESO evaluation report has been filed separately by Energy+. The net verified final 2011-2014 results can be found in Table 1 of the *2011-2014 Final Results Report_HCCambridge and North Dumfries Hydro Inc..xlsx* and the *2011-2014 Final results Report_HCBrant County Power Inc..xlsx*. files released by the IESO on September 1, 2015. The net adjustments to verified final 2011, 2012, and 2013 results can be found in Table 2 of those files. These data are reproduced in Table 4-a, b, c and d of the OEB workforms for 2011, 2012, 2013 and 2014 respectively.

The net verified final 2015 results, can be found in the "Net Incremental First Year Energy Savings" and "Net Incremental First Year Peak Demand Savings" sections of the "LDC Progress" tab in the *Final 2015 Annual Verified Results Report_Cambridge and North Dumfries Hydro Inc._20160630.xlsx* and *Final 2015 Annual Verified Results Report_Brant County Power Inc._20160630.xlsx* Excel files released by the IESO on June 30, 2016. These data are reproduced in Table 5-a for each of the service territories.

The net verified final 2016 results, including adjustments in 2016 to 2015 results, can be found in the "Net Incremental First Year Energy Savings" and "Net Incremental First Year Peak Demand Savings" sections of the "LDC Progress" tab in the *Final Verified 2016 Annual LDC CDM Program Results Report Energy Inc 20170630.xlsx* Excel file released by the IESO on June 30, 2016. These data are reproduced in Table 5-a and 5-b for 2015 and 2016, respectively.

The unverified 2017 net results for residential programs, including adjustments to 2016 results made in 2017 are on Table 1.

Table 1 – Unverified 2017 results for residential programs

	2016 Unverified net energy savings (kWh)	2016 Unverified persistent energy savings in 2017[1] (kWh)	2017 Unverified net energy savings[4] (kWh)
Coupon program	354,501	354,501	3,518,877
HVAC	1,333,522	1,333,522	804,439
Home assistance			906
TOTAL	1,688,023	1,688,023	7,632,362

Source IESO. "2018. 01_2018 Participation and Cost Report - Energy+ Inc. (DEC) - 2018 01.xlsx"

Notes: 1 Calculated using the same persistence rate reported for verified 2016 results

The unverified 2017 net results for business programs, including adjustments in 2017 to 2016 results, are on Table 2. The estimated demand associated with programs offered to customers billed by demand and its derivation is also presented on Table 2. These data are reproduced in Tables 5-b and 5-c for 2016 and 2017, respectively.

Table 2 – Unverified 2016 adjustments and 2017 results for non-residential programs

2016 Unverified Adjustments

	2016 Net energy savings1 (kWh)	Demand factor[2] (kW/kWh)	2016 Demand reductions[3] (kW)	2017 Persistent energy savings[4] (kWh)	2017 Persistent demand reductions[4] (kW)
Retrofit	2,368,366	0.000106	252	2,303,877	243
High Performance New Construction	123,618	0.000418	52	123,618	52
TOTAL	2,491,984		304	2,427,495	295

2017 Unverified Results

	2017 Net energy savings1 (kWh)	Demand factor[2] (kW/kWh)	2017 Demand reductions[3] (kW)
Retrofit	7,202,274	0.000204	1,471
High Performance New Construction	338,710	0.000360	122
Small Business Lighting	91,378	0.000576	53
TOTAL	7,632,362		7,632,362

Notes:
1 From IESO. "2018. 01_2018 Participation and Cost Report - Energy+ Inc. (DEC) - 2018 01.xlsx"
2 Calculated from gross energy/gross demand for projects in that program in the projects database
3 The product of net energy savings and the demand factor
4 Calculated using the same persistent rate reported for verified 2016 results

The IESO provided Energy+ with persistence data for 2011-2014 results and 2011-2013 adjustments at the initiative level. The data provided are presented in Table 7 on Tab 7 of the OEB LRAMVA work forms that are filed with this document. These data are also presented in Table 4a-d.

The IESO provided persistence data for 2015 and 2016 as part of the standard results report. These are reproduced in Tables 5a and 5b.

Allocating results to rate classes

Energy+ provided information on the allocation of results to rate classes. In most cases, the allocation is straightforward. Initiatives that can span multiple rate classes include Retrofit, Building Commissioning, New Construction, Energy Audit,, Energy Manager, Electricity Retrofit Incentive Program, the Loblaw P4P Conservation Fund Pilot and High Performance New Construction. No allocation was provided for programs for which Energy+ has no program results.

Energy+ bills customers in different rate classes using different volumetric units, either kilowatt-hours (kWh), or customer peak monthly kilowatts (kW). The rate classes (and billing units) for Energy+ are:

- Residential (kWh)
- GS <50 kW (kWh)
- GS 50 to 999 kW (kW) – Energy+ (CND) only
- GS 1,000 to 4,999 kW (kW) – Energy+ (CND) only
- GS 50 to 4,999 kW (kW) – Energy+ (Brant County) only
- Large Use (kW) – Energy+ (CND) only
- Street Lighting (kW)
- Sentinel Lighting (kW)
- Unmetered Scattered Load (kWh)

Table 4a (beginning at column Y) of the OEB LRAMVA work forms show the percentage allocation by rate class for 2011 results and adjustments. Table 4b of the OEB LRAMVA work forms show the percentage allocation by rate class for 2012 results and adjustments. Table 4c of the OEB LRAMVA work forms show the percentage allocation by rate class for 2013 results and adjustments. Table 4d of the OEB LRAMVA work forms show the percentage allocation by rate class for 2014 results. Tables 5-a, b and c of the OEB LRAMVA work forms show the percentage allocation by rate class for 2015, 2016 and 2017 results, respectively. In each year the rate class allocation percentage totals for each program may not add up to 100% in cases because kWh savings are allocated to rate classes billed by kWh and kW demand reductions are allocated to rate classes billed by kW.

For 2016 and 2017 results, and 2015 and 2016 adjustments, it was necessary to also allocate aggregated Energy+ results to the two service territories. For the 2016 and 2017 results, the results for Energy+ as a whole are shown on Tables 5-b and 5-c and the allocation across service territories is accounted for in the allocation percentages (beginning in Column Y), which is why the totals in column AM for the table for the two service territories are less than 100% for some programs. For the 2015 adjustments, the allocation is shown in the new Table on Tab 3-a, and the results from that Table are carried over to Table 5-a.

Load reductions accounted for in the load forecast

The former Brant County Power submitted a cost of service application for the Brant County service territory in 2010 for the 2011 rate year (EB-2010-0125). The load forecast associated with that application accounted for load losses from 2011 – 2014 CDM programs. Table 2-b of the OEB LRAMVA work form for Energy+ (Brant County) shows the estimates of load reductions, by rate class that were included at the time of the load forecast.

The former Cambridge and North Dumfries Hydro submitted a cost of service application for the Cambridge and North Dumfries service territory in 2013 for the 2014 rate year (EB-2013-0116). The load forecast associated with that application accounted for load losses from 2011 – 2014 CDM programs. Table 2-b of the OEB LRAMVA work form for Energy+ (CND) shows the estimates of load reductions, by rate class that were included at the time of the load forecast. Previous load forecasts did not account for the impact of 2011 – 2014 CDM programs. Although 2011 results were not part of the manual adjustment for the 2014 forecast, they were included in the LRAMVA threshold that was part of the settlement agreement.

Overall impact of CDM on load, by rate class

Multiplying the adjusted energy savings or demand reduction reported for Energy+ for each program by the allocation by rate class provides the impact on load of that CDM program within the appropriate rate class. The sum of the energy savings and demand reductions for all of the programs for each rate class provides the overall impact of CDM on load by rate class. The overall load impact for each calendar year includes the results for the CDM programs and any adjustments to the results in that year.

The bottom of Table 4a of the OEB LRAMVA work forms shows the overall impact of CDM on load by rate class for 2011. The bottom of Table 4b of the OEB LRAMVA work forms shows the overall impact of CDM on load by rate class for 2012. The bottom of Table 4c of the OEB LRAMVA work forms shows the overall impact of CDM on load by rate class for 2013. The bottom of Table 4d of the OEB LRAMVA work forms shows the overall impact of CDM on load by rate class for 2014. The bottom of Tables 5-a, 5-b and 5-c of the OEB LRAMVA work forms

show the overall impact of CDM on load by rate class for 2015, 2016 and 2017, respectively.

Distribution rates

The distribution rates that are used to calculate the CDM impact on distributor revenue for each rate class for Energy+ are shown in Table 3 of the OEB LRAMVA work form for each service territory. The distribution rates are pro-rated from the rate year to the calendar year, as needed, using the number of months of each rate year in each calendar year in the 2011 to 2017 time period. Table 3-a of the OEB LRAMVA work form shows the pro-rated rates used for each calendar year.

Lost revenues

The lost revenues for each year by rate class for Energy+ calculated from final CDM program results are shown in Table 1 of the OEB LRAMVA work forms. The lost revenue for each year is based on the load impact for each rate class in that year multiplied by the rate for that rate class in that year. The load impact in a given year will include the impact of CDM programs in that year and the persistence of the CDM program impact from previous years in that year.

Table 1 of the OEB LRAMVA work forms also shows the lost revenue in each year due to CDM that has already been incorporated into the Energy+ load forecast. The impact on Energy+ revenue is the variance between what is calculated from final CDM program results and what has already been accounted for in the load forecast.

Carrying charges

The monthly carrying charges by rate class on Energy+ lost revenue variance are shown in Table 6 of the OEB LRAMVA work forms. The carrying charges are reported monthly, from the time the lost revenues resulted, through to December 31, 2018.

Conclusions

The LRAMVA balance at the end of December 2017 for Energy+ that includes results from 2011 – 2017 CDM programs and adjustments to 2011 to 2013 and 2015 and 2016 results is $1,168,925.16. The total carrying charges on this LRAMVA balance accumulated to December 31, 2018 are $31,526.03.

These balances are attributable to individual rate classes and service territories according to the following table:

	Energy+ (CND)			Energy+ (BCP)			Energy+		
	LRAMVA	Carrying charges	Total	LRAMVA	Carrying charges	Total	LRAMVA	Carrying charges	Total
Residential	-$42,016.66	-$4,950.90	**-$46,547.39**	$73,873.77	$1,979.28	**$75,853.04**	$31,857.11	-$2,971.62	**$28,885.49**
GS<50	-$53,105.32	-$3,056.60	**-$55,630.86**	$94,145.85	$2,506.96	**$96,652.81**	$41,040.53	-$549.63	**$40,490.89**
GS 50-999	$630,470.84	$24,167.13	**$648,333.26**	#N/A	#N/A		$630,470.84	$24,167.13	**$654,637.97**
GS 1000-4999	$41,943.28	$1,184.22	**$42,708.07**	#N/A	#N/A		$41,943.28	$1,184.22	**$43,127.50**
GS 50-4999	#N/A	#N/A		$60,777.66	$1,581.74	**$62,359.40**	$60,777.66	$1,581.74	**$62,359.40**
Large users	$308,108.47	$7,578.63	**$312,606.02**			**$0.00**	$308,108.47	$7,578.63	**$315,687.10**
Scattered load	-$2,373.67	-$91.02	**-$2,440.96**			**$0.00**	-$2,373.67	-$91.02	**-$2,464.69**
Sentinel lighting			**$0.00**			**$0.00**	$0.00	$0.00	**$0.00**
Street lighting	-$44,003.68	-$1,659.36	**-$45,223.00**	$101,104.63	$2,285.94	**$103,390.57**	$57,100.95	$626.58	**$57,727.53**
Total	**$839,023.26**	**$23,172.11**	**$862,195.37**	**$329,901.90**	**$8,353.92**	**$338,255.82**	**$1,168,925.16**	**$31,526.03**	**$1,200,451.19**

Negative values indicate that the actual reduction in load from CDM programs was less than the amount included in the load forecast.

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APPENDIX 4-7: FINAL VERIFIED 2016 ANNUAL LDC CDM

Final Verified 2016 Annual LDC CDM Program Results Report

Letter from the Vice-President, Conservation & Corporate Relations

June 30, 2017

I am pleased to provide LDCs with their Final Verified 2016 Annual Results Report. Collectively in 2016, LDCs achieved 1.2 TWh of energy savings persisting to 2020. When combined with the 2015 results, LDCs have achieved 2.6 TWh of energy savings, representing 38 % of the 7 TWh target. The results show positive progress towards the achievement of the Conservation First Framework (CFF) target and demonstrate the continued collaboration between LDCs and the IESO in promoting a culture of conservation across the province.

Key highlights from the 2016 final results include the following:

- The Coupons program produced a record achievement, delivering 428 GWh of energy savings in 2016, more than doubling the results from 2015. LED light bulbs remained the most common measure accounting for 75 % of coupons redeemed and 96 % of savings.

- The Retrofit program continues to be the highest performing program achieving 567 GWh of energy savings in 2016, despite experiencing a 29 % reduction in savings over the 2015 results (including adjustments). Lighting measures continue to produce the majority of savings, 74 % in 2016, with non-lighting measures accounting for the remainder.

- The success of the Coupons program supported residential sector programs in achieving a larger share of the portfolio savings in 2016 than in previous years, accounting for 44 % of target achievement, with business sector programs and local and pilot programs accounting for 54 % and 1 %, respectively.

  o It is important to note that there remains a considerable data lag, representing completed, but unreported projects for the Retrofit and Process and Systems Upgrades Programs. Together, these programs have roughly 250 GWh in unverified savings waiting to be reported by LDCs. It is anticipated that these savings will be reported in future year's 2016 adjustments.

- As with 2015, the IESO evaluation methodology enabled further granulation of net verified results in 2016, resulting in increased LDC-specific and regional level net-to-gross adjustment factors, where data permitted.

- Four LDCs have achieved at least 90 % of their CFF target, and nine others are above 50 %. These early successes are prompting increased dialogue between LDCs with respect to potential target exchange, which is both permitted and encouraged under the CFF.

There were minor revisions to the final results relative to the preliminary results including: 1) revisions/corrections to program savings assumptions / adjustments as required (primarily to participation levels for Coupons Program and Heating & Cooling Program); 2) the inclusion of an additional five LDC Innovation Fund and Conservation Fund Pilot Programs; and 3) amendments based on comments received by LDCs as part of their review of the preliminary results. Further details on the revisions between the preliminary and the final 2016 verified results can be found in the 2016 Frequently Asked Questions (FAQs) and Evaluation Findings Report which will be posted along with the results on the LDC extranet.

Please note that all results contained within this report are considered to be final verified results. Projects included in this report are reflected in the accompanying LDC Project List Report. Any program activity not captured in this report will be included as part of a future adjustment process.

In terms of next steps, as with the 2015 CFF results, Final Verified 2016 Annual Results Reports will be posted on the IESO website in early July. In addition, LDC-Program level and portfolio-level cost effectiveness test results will be available on September 15, 2017, as outlined in the Energy Conservation Agreement version 3.0 update. Finally, 2016 EM&V reports will be available later this summer along with key program recommendations to be shared with the LDC Working Groups and the IESO.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process. As we look ahead, the IESO will be focusing on enhancing its communication and support services to further support LDCs in the delivery of programs and to increase customer participation in these programs. I look forward to continuing to work together in achieving success in the Conservation First Framework.

Sincerely,

Terry Young
Vice-President, Conservation & Corporate Relations
Independent Electricity System Operator

Final Verified 2016 Annual LDC CDM Program Results Report

Table of Contents

#	Worksheet Name	Worksheet Description
1	How to Use This Report	Describes the contents and structure of this report
2	Report Summary	A high level summary of the Final 2016 Annual Verified Results Report, including: 1) progress toward the LDC's a) Allocated 2020 Energy Savings Target; b) Allocated 2015-2020 LDC CDM Plan Budget; c) CDM Plan 2015-2020 Forecasts; 3) annual savings and spending; 4) Annual FCR Progress; 5) annual LDC CDM Plan spending progress; 6) graphs describing: a) contribution to 2020 Target Achievement by program; b) 2015 LDC CDM Plan Budget Spending by Sector; c) annual energy savings persistence to 2020 by year; d) your Allocated Target achievement progress relative to your peers; and e) your LDC CDM Plan Budget Spending progress relative to your peers;
3	LDC Rankings	A comprehensive report of each LDC's performance rankings against all other LDCs in major performance categories.
4	LDC Progress	A comprehensive report of 2016 conservation results including: 1) activity; 2) savings including; a) energy and peak demand; b) net and gross; c) CDM Plan forecasts, verified actuals and relative progress; d) Allocated Target and Target acheivement; and 3) spending, including participant incentives and administrative expenses and IESO Value Added Services Costs. Data is grouped by category and summarized at the LDC level.
5	Province-Wide Progress	A comprehensive report of 2016 conservation results including: 1) activity; 2) savings including; a) energy and peak demand; b) net and gross; c) CDM Plan forecasts, verified actuals and relative progress; d) Allocated Target and Target acheivement; and 3) spending, including participant incentives and administrative expenses and IESO Value Added Services Costs. Data is grouped by category and summarized at the province wide level.
6	LDC Savings Persistence	A report detailing the gross and net energy and peak demand savings persistence by program and implementation year (2015, 2015 Adjustment and 2016) at the LDC Level.
7	Province-Wide Persistence	A report detailing the gross and net energy and peak demand savings persistence by program and implementation year (2015, 2015 Adjustment and 2016) at the province wide Level.
8	Methodology	A description of the methods used to calculate energy savings, financial results and cost-effectiveness.
9	Reference Table	Provides detailing how Province wide Consumer Program results were allocated to specific LDCs.
10	Glossary	Definitions for the terms used throughout this report.

Final Verified 2016 Annual LDC CDM Program Results Report

How to Use this Report

The IESO is pleased to provide you with the 2016 Annual Verified Results Report.

This report provides:
1) electricity savings;
2) annual Full Cost Recovery funding model program progress; and
3) peak demand savings;
4) IESO Value Added Services Costs
in accordance with Section 9.2(b)(i) of the Energy Conservation Agreement.

In addition to the above, this report also provides in greater detail:
1) program participation results including:
a) forecasts; b) actuals; and c) progress (forecast versus (vs) actuals);

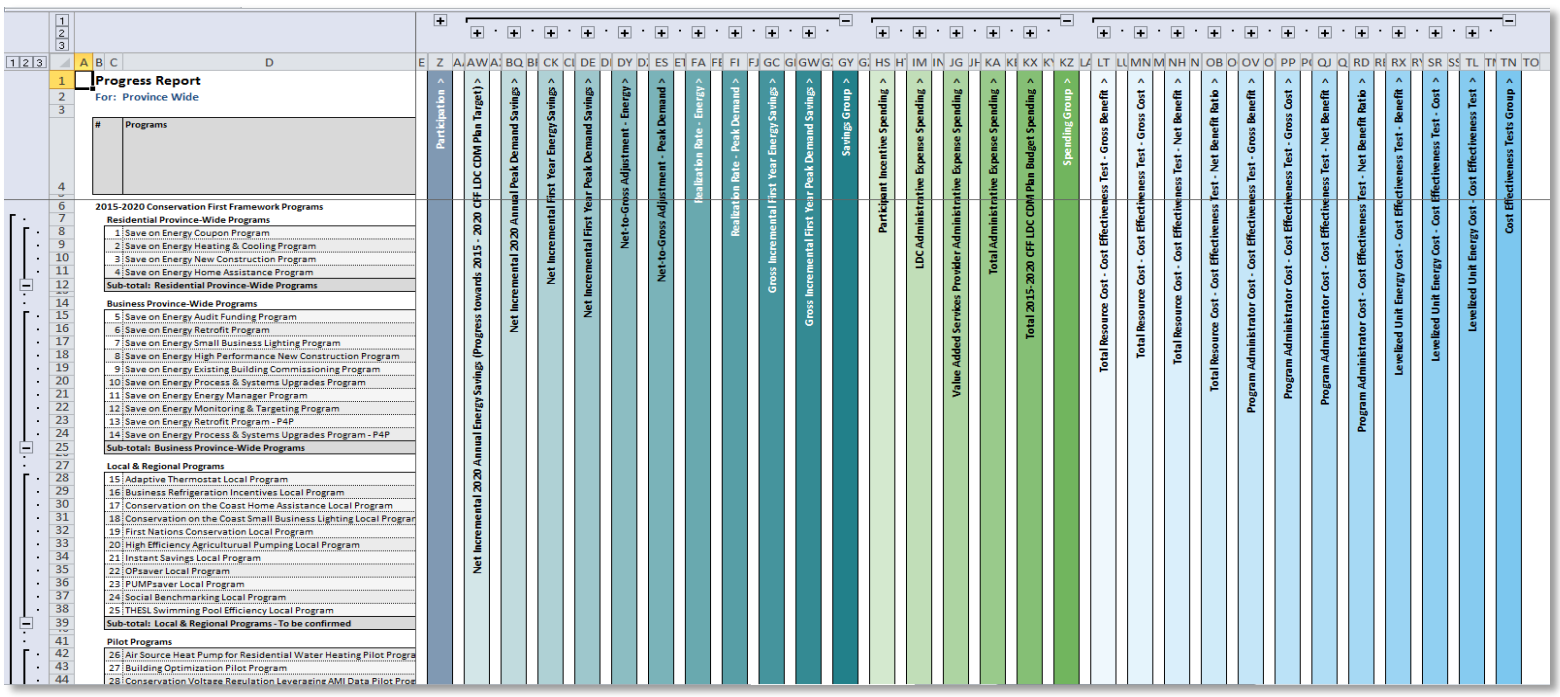
2) program savings results including:
a) net 2020 annual energy and peak demand savings;
b) allocated target, target achievement and progress towards target;
c) incremental net first year energy and peak demand savings;
d) annual net-to-gross and realization rate adjustments; and
e) incremental gross first year energy and peak demand savings;
and where available reported by: i) forecasts; ii) verified actuals; and iii) progress (forecast vs actuals);

3) program spending including:
a) participation incentive spending;
b) administrative expense spending (including IESO value-added services costs);
c) aggregated total spending; and
d) allocated budget, LDC CDM Plan budget spending and progress towards budget;
and for each cost: i) forecasts; ii) verified actuals; and iii) progress (forecast vs actuals);

4) program savings results persistence for:
a) gross energy savings;
b) gross peak demand savings;
c) net energy savings; and
d) net peak demand savings;

by both the LDC specific level and the province-wide aggregated level for 2016 and 2015 including 2015 Adjustments.

This report's format is consistent with the IESO issued Monthly Participation and Cost Report in that it is a dynamic sheet that can be expanded or collapsed by clicking the + button or "Show Detail" feature under the Data tab. Each of the four results categories listed above have been grouped together for easy accessibility.



Please note:
1) Cost Effectiveness Test (CET) results including:
a) total resource cost test;
b) program administration cost test;
c) levelized unit energy cost test;
and for each test: i) benefits; ii) cost; iii) net benefit; iv) benefit ratio; at the LDC and province wide level will not be available in this report but will be provided to LDCs by September 15 2017, as per the Energy Conservation Agreement, version 3.0.

2) forecasts of: a) activity; b) savings; and c) spending; included in this report are based on approved LDC CDM Plan - Cost Effectiveness Tools as of April 1, 2017 (from the i) Program Design; ii) Budget Inputs; iii) Savings Results; and iv) CE Results; worksheets);
Please note that this does not contain data for Legacy Framework program spending or CFF pilot program activity, savings, spending or cost effectiveness.

3) Annual FCR Progress only includes Full Cost Recovery funding model program savings results and excludes Pay-for-Performance funding model program savings results.

4) The complete list of approved programs and pilots as of April 1, 2017 approved LDC CDM Plans have been included, however only programs and pilots in market for a sufficient period of time to enable a valid EM&V process will have verified results.

5) 2015 Adjustments consists of projects completed in 2015 but were not reported to the IESO by the 2015 Verified Results Reporting deadline of March 31, 2016.

6) Pilot program savings are attributed to the LDC where the pilot program project is located in; and

7) This Annual Verified Results Report provides results for the LDC and province only. No aggregated reporting is provided for LDCs that are part of a joint CDM plan;

Final Verified 2016 Annual LDC CDM Program Results Report

Summary

For: Energy+ Inc.

Results

#	Metric	2015 Verified Results	2016 Verified Results	2015-2016 Verified Results	Allocated Target / Budget	2015-2016 Progress versus Allocated Target / Budget	2015-2020 LDC CDM Plan Forecast	2015-2016 Progress versus 2015-2020 LDC CDM Plan Forecast	2016 LDC CDM Plan Forecast	2016 Progress versus 2016 LDC CDM Plan Forecast	2015-2016 LDC CDM Plan Forecast	2015-2016 Progress versus 2015-2016 LDC CDM Plan Forecast
1	Net Verified Annual Energy Savings Persisting to 2020	77,271 MWh	14,253 MWh	91,524 MWh	100,950 MWh	91 %	106,219 MWh	86 %	10,055 MWh	142 %	67,209 MWh	136 %
2	LDC Ranking - Net Verified Annual Energy Savings Persisting to 2020	5	12	7	12	4	11	4	17	22	8	30
3	Total Spending ($)	$ 0	$ 2,916,887	$ 2,916,887	$ 25,873,071	11 %	$ 23,678,815	12 %	$ 4,939,934	59 %	$ 4,939,934	59 %
4	LDC Ranking - Total Spending ($)	43	11	11	12	32	14	28	10	38	11	39

Annual Results

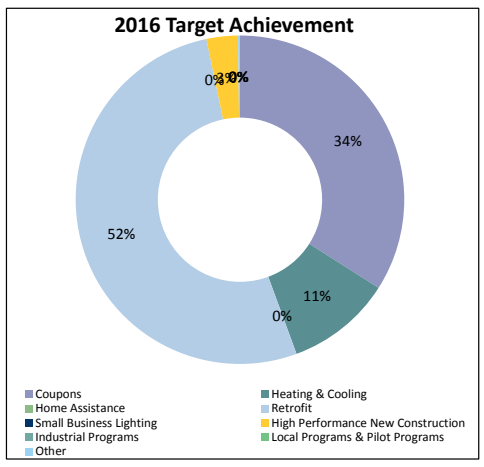
#	Metric	2015	2016	Total
1	Net Verified Annual Energy Savings Persisting to 2020 (MWh)	77,271 MWh	14,253 MWh	**91,524 MWh**
2	Net Verified Incremental First Year Energy Savings (MWh)	78,105 MWh	14,427 MWh	**92,531 MWh**
3	Total Spending ($)	$ 0	$ 2,916,887	**$ 2,916,887**

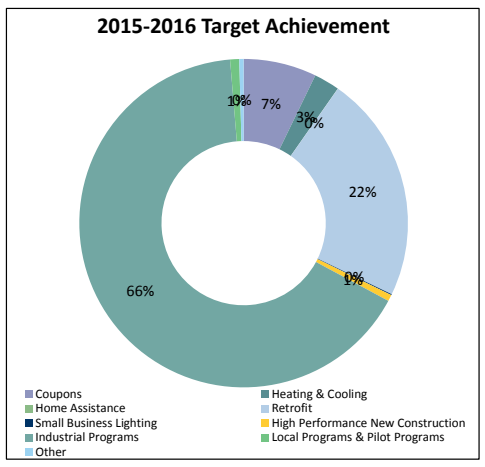
Cost Effectiveness

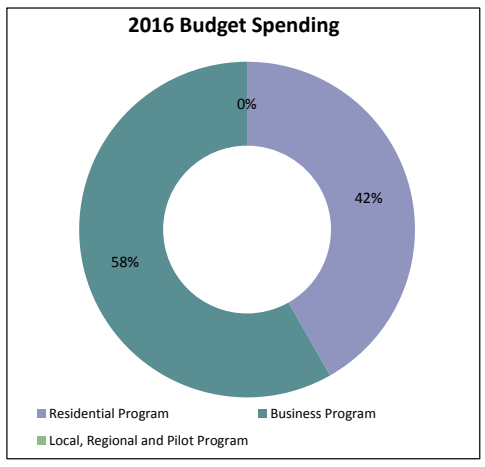
#	Test	2015	2016	Total
1	Total Resource Cost Test (Ratio)	n/a	tbd	**tbd**
2	Program Administrator Cost Test (Ratio)	n/a	tbd	**tbd**
3	Levelized Unit Energy Cost Result (¢/kWh)	n/a	tbd	**tbd**

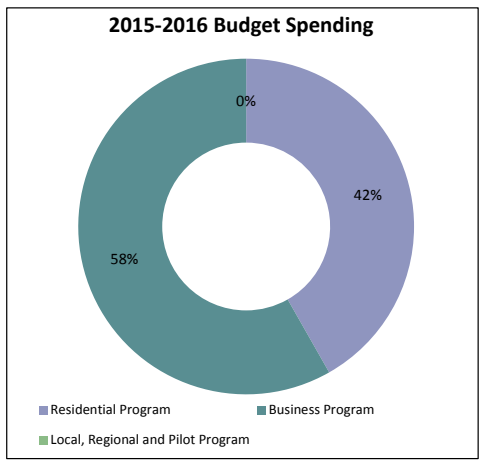
Annual FCR Progress

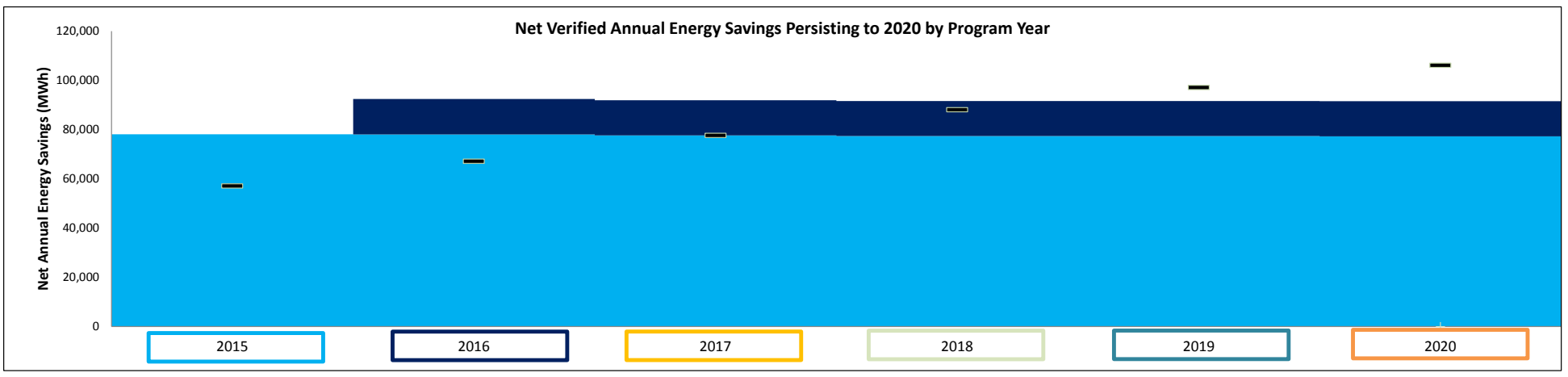
#	Metric	Result
1	2015-2016 Incremental Net Verified 2020 Annual Energy Savings from Full Cost Recovery Programs	**91,524 MWh**
2	2015-2016 Incremental Net 2020 Annual Energy Savingsfrom Full Cost Recovery Program per CDM Plan Forecast	**67,209 MWh**
3	FCR Progress (%)	**136 %**

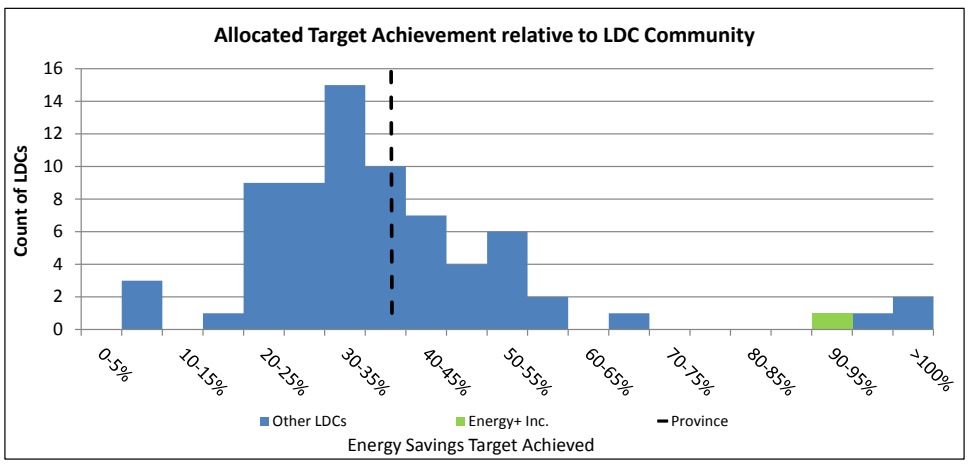


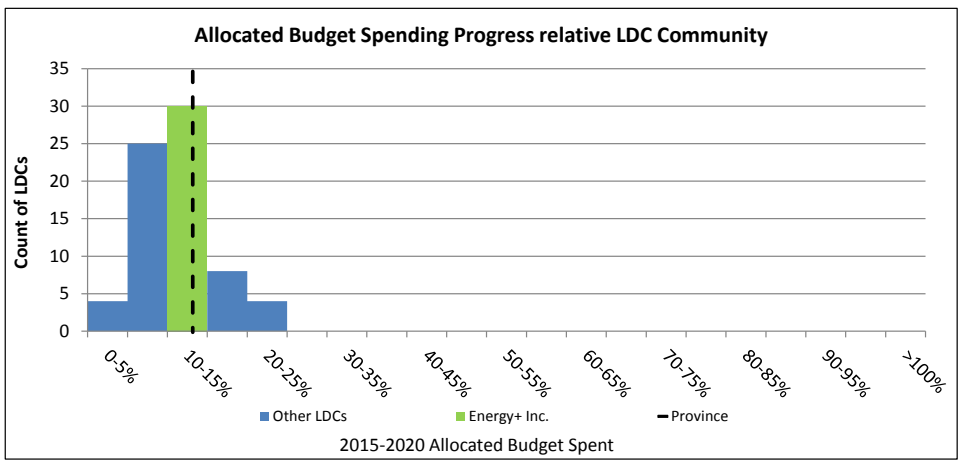












Final Verified 2016 Annual LDC CDM Program Results Report

LDC Rankings

#	LDC	Net Verified Annual Energy Savings Persisting to 2020																Total Spending																	
		2015 Verified Results		Verified 2015 Adjustment Results		Verified Adjusted 2015 Results		2016 Verified Results		2015-2016 Verified Results		Allocated Target		2015-2016 Progress versus Allocated Target		2015-2020 LDC CDM Plan Forecast		2015-2016 Progress versus 2015-2020 LDC CDM Plan Forecast		2016 LDC CDM Plan Forecast		2016 Progress versus 2016 LDC CDM Plan Forecast		2015-2016 LDC CDM Plan Forecast		2015-2016 Progress versus 2015-2016 LDC CDM Plan Forecast		2015 Verified Spending		Verified 2015 Adjustment Spending		Verified Adjusted 2015 Spending		2016 Verified Spending		2015-2016 Verified Spending		Allocated Budget		2015-2016 Progress versus Allocated Budget		2015-2020 LDC CDM Plan Forecast		2015-2016 Progress versus 2015-2020 LDC CDM Plan Forecast		2016 LDC CDM Plan Forecast		2016 Progress versus 2016 LDC CDM Plan Forecast		2015-2016 LDC CDM Plan Forecast		2015-2016 Progress versus 2015-2016 LDC CDM Plan Forecast	
		Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value (kWh)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)	Value ($)	LDC Ranking (#)	Value (%)	LDC Ranking (#)
1	Algoma Power Inc.	1,031,011	57	25,818	1,056,828	58	1,285,402	52	2,342,230	56	7,510,000	54	31	45	11,100,760	47	21	66	816,284	54	157	16	1,777,226	53	132	34	39,320	22	59,951	99,271	20	344,836	47	444,108	42	2,107,963	53	21	3	3,449,717	45	13	24	683,154	43	50	51	737,814	43	60	37
2	Atikokan Hydro Inc.	109,769	67	2,444	112,213	67	189,357	68	301,570	68	1,140,000	67	26	54	1,139,590	67	26	52	127,788	71	148	18	170,828	71	177	17	0	30	0	0	43	50,265	66	50,265	66	311,330	67	16	9	374,405	70	13	19	56,766	71	89	8	56,772	71	89	10
3	Attawapiskat Power Corporation	35,822	70	2,343	38,165	70	0	69	38,165	70	510,000	70	7	71	556,816	69	7	71	209,344	66	0	69	209,344	68	18	70	0	30	0	0	43	0	69	0	69	148,832	70	69	69	1,846,142	54	0	69	386,748	52	0	69	386,748	52	0	69
4	Bluewater Power Distribution Corporation	7,755,327	21	268,687	8,024,013	26	5,570,598	28	13,594,611	30	62,370,000	19	22	65	62,370,000	19	22	64	7,092,037	25	79	56	14,839,910	25	92	57	5,119	29	0	5,119	41	1,340,938	26	1,346,056	27	15,838,687	20	8	56	15,838,687	20	8	54	2,579,261	19	52	48	2,584,380	21	52	50
5	Brantford Power Inc.	7,457,011	22	1,458,523	8,915,534	25	10,499,455	19	19,414,989	21	54,320,000	22	36	33	54,880,608	23	35	36	9,918,198	18	106	39	17,760,851	22	109	46	0	30	29,000	29,000	30	1,564,432	22	1,593,432	24	14,048,458	22	11	30	11,591,730	23	14	16	2,207,285	23	71	29	2,236,285	23	71	28
6	Burlington Hydro Inc.	12,632,309	18	1,975,945	14,608,254	18	11,531,861	15	26,140,115	16	99,040,000	13	26	55	99,040,000	14	26	53	11,672,695	15	99	47	18,090,682	21	144	24	118,667	17	193,116	311,783	12	2,472,234	12	2,784,017	13	25,825,521	13	11	37	25,890,159	12	11	38	3,893,532	15	63	35	4,877,008	12	57	43
7	Canadian Niagara Power Inc.	3,502,396	37	5,579,808	9,082,204	23	5,553,280	29	14,635,484	27	28,480,000	32	51	12	28,104,418	31	52	15	4,745,580	30	117	29	11,046,585	27	132	33	162,334	14	58,069	220,403	13	1,200,961	27	1,421,364	26	7,355,555	33	19	5	6,338,440	35	22	4	1,589,930	29	76	22	1,643,473	29	86	23
8	Centre Wellington Hydro Ltd.	1,581,029	53	109,971	1,690,999	53	1,548,975	50	3,239,975	52	8,730,000	50	37	30	8,729,845	50	37	33	2,771,886	40	56	62	4,123,814	39	79	60	0	30	0	0	43	276,194	49	276,194	50	2,252,724	51	12	26	2,252,724	51	12	29	651,826	44	42	59	651,826	44	42	59
9	Chapleau Public Utilities Corporation	275,333	64	3,485	278,818	64	191,711	67	470,529	66	1,050,000	68	45	18	1,057,696	68	44	21	134,983	70	142	21	508,197	62	93	56	0	30	3,354	3,354	42	19,890	68	23,244	68	298,764	68	8	60	298,764	71	8	59	57,618	69	35	64	57,618	69	40	62
10	COLLUS PowerStream Corp.	1,637,947	51	385,929	2,023,876	49	2,194,349	44	4,218,225	47	16,860,000	39	25	58	16,860,000	38	25	57	2,047,097	42	107	38	3,784,720	41	111	43	157,689	15	0	157,689	16	636,318	33	794,008	31	4,446,841	39	18	7	4,446,841	39	18	8	842,348	39	76	21	1,118,451	35	71	30
11	Cooperative Hydro Embrun Inc.	120,443	66	19,234	139,677	66	730,806	57	870,483	62	1,790,000	65	49	15	1,790,697	65	49	18	241,547	65	303	2	320,602	66	272	9	0	30	0	0	43	61,223	64	61,223	65	525,743	65	12	31	78,227	68	78	18	78,227	68	78	17
12	E.L.K. Energy Inc	1,662,553	49	583,829	2,246,382	47	1,963,393	48	4,209,775	48	16,200,000	41	26	56	16,203,264	40	26	54	1,785,578	45	110	36	3,064,492	45	137	39	0	30	0	0	43	435,083	52	435,083	53	4,273,057	41	10	42	504,219	48	86	10	504,219	48	86	13
13	Energyr Inc.	17,245,241	13	60,025,983	77,271,224	5	14,252,795	12	91,524,019	7	100,950,000	12	91	4	106,219,451	11	86	4	10,054,813	17	142	22	67,208,866	8	136	30	0	30	0	0	43	2,916,887	11	2,916,887	11	25,873,071	12	11	32	23,678,815	14	12	28	4,939,935	10	59	38	4,939,935	11	59	39
14	Enersource Hydro Mississauga Inc.	59,582,917	5	15,701,481	75,284,398	6	80,992,918	4	156,277,316	4	483,270,000	4	32	42	483,273,204	4	32	42	79,419,033	3	102	42	149,356,740	4	105	50	0	30	0	0	43	5,508,332	8	5,508,332	8	122,499,403	4	4	68	123,761,401	4	4	68	23,154,175	4	24	66
15	Entegrus Powerlines Inc.	38,558,192	8	3,536,019	42,094,211	9	14,186,934	13	56,281,145	11	56,830,000	21	99	3	62,079,147	20	91	3	5,611,768	27	253	4	34,007,927	14	165	21	374,365	8	60,099	434,464	8	2,370,550	14	2,805,014	12	14,695,867	21	19	6	13,843,474	21	20	6	2,447,799	20	97	5	3,048,339	19	92	6
16	EnWin Utilities Ltd.	14,809,440	14	2,675,379	17,484,819	16	29,365,888	9	46,850,707	12	151,300,000	10	31	47	152,801,848	10	31	45	44,722,046	5	66	61	64,562,249	9	73	62	0	30	111,618	111,618	19	2,430,728	13	2,542,346	15	38,421,929	10	7	64	38,421,929	10	7	64	11,447,244	8	21	67	11,447,244	8	22	67
17	Erie Thames Powerlines Corporation	5,180,177	27	922,335	6,102,511	30	2,555,215	40	8,657,726	34	27,630,000	33	31	44	39,589,797	26	22	63	3,215,423	37	79	55	21,956,460	19	39	68	23,149	25	19,384	42,533	26	561,528	39	604,060	37	7,104,954	34	9	55	7,020,999	33	9	52	1,352,450	30	42	60	1,524,690	30	40	63
18	Espanola Regional Hydro Distribution Corporation	502,006	61	14,537	516,543	62	339,978	65	856,521	63	2,410,000	64	36	34	1,998,806	64	43	23	328,608	64	103	40	328,608	65	261	10	5,306	28	0	5,306	40	57,969	65	63,275	63	685,489	64	9	48	759,788	67	8	57	141,751	63	41	61	141,751	64	45	58
19	Essex Powerlines Corporation	3,819,710	36	1,720,380	5,540,090	33	7,059,017	26	12,599,107	31	31,430,000	30	40	24	31,430,000	28	40	24	9,728,188	29	99	46	9,728,188	29	130	35	176,840	12	6,737	183,577	14	1,818,727	18	2,002,304	17	8,532,573	30	23	1	8,421,412	30	24	3	1,871,165	25	97	4	2,199,199	25	91	5
20	Festival Hydro Inc.	4,822,853	30	2,088,958	6,911,811	27	9,417,074	21	16,328,885	26	34,650,000	28	47	17	29,884,429	30	55	10	4,336,821	31	217	7	4,336,821	36	177	5	0	30	8,075	8,075	37	1,003,864	29	1,011,939	29	8,768,149	28	12	32	8,768,149	28	12	29	1,323,777	33	76	28	1,323,777	33	76	18
21	Fort Albany Power Corporation	29,906	71	1,956	31,862	71	0	69	31,862	71	340,000	71	9	69	373,387	71	9	70	197,235	68	0	69	197,235	70	16	71	0	30	0	0	43	0	69	0	69	98,990	71	0	69	345,251	55	0	69	345,251	55	0	69	345,251	55	0	69
22	Fort Frances Power Corporation	254,688	65	11,215	265,903	65	553,935	60	819,838	64	4,000,000	61	20	67	3,687,415	61	22	62	348,835	63	159	15	486,914	64	168	19	0	30	0	0	43	92,580	60	92,580	60	1,109,758	60	8	59	1,119,638	63	8	58	124,580	66	74	23	124,601	66	74	23
23	Greater Sudbury Hydro Inc.	6,959,582	23	3,141,790	10,101,372	22	9,312,088	22	19,413,460	22	34,740,000	27	56	7	23,985,670	34	81	5	3,943,302	34	236	5	3,943,302	40	492	2	112,497	18	0	112,497	18	1,425,683	24	1,538,180	25	9,672,498	26	16	10	9,117,459	27	17	10	1,701,015	28	84	12	1,701,015	28	90	9
24	Grimsby Power Incorporated	2,804,724	40	319,119	3,123,843	40	2,159,053	45	5,282,896	43	10,850,000	48	49	14	10,863,961	48	49	17	1,870,647	44	115	33	3,670,614	42	144	25	0	30	34,500	34,500	29	292,926	48	327,426	48	2,894,613	47	11	33	2,894,612	47	11	33	633,209	45	46	57	633,209	45	52	52
25	Guelph Hydro Electric Systems Inc.	58,594,547	4	2,215,864	60,810,411	8	8,394,053	24	69,204,463	9	99,040,000	13	70	5	99,040,000	13	70	7	7,470,386	32	112	35	59,741,607	11	116	41	278,441	10	103,065	381,506	11	1,377,942	25	1,759,447	20	24,920,625	14	7	62	23,290,402	15	8	60	3,782,778	16	36	62	4,255,743	16	41	61
26	Halton Hills Hydro Inc.	5,500,566	25	212,955	5,713,521	31	4,755,591	32	10,469,112	33	30,940,000	31	34	38	30,962,677	29	34	39	3,268,861	36	145	20	6,234,990	34	168	20	0	30	0	0	43	604,017	35	604,017	38	8,387,497	31	7	61	8,387,497	31	7	62	1,310,004	33	46	58	1,458,606	31	41	60
27	Hearst Power Distribution Company Limited	1,510,384	54	985,005	2,495,390	44	2,417,972	42	4,913,361	44	3,180,000	63	155	1	3,183,595	62	154	1	369,657	62	654	1	1,033,780	59	475	3	0	30	10,063	10,063	36	71,209	62	81,272	62	843,903	63	10	45	122,762	67	58	39	122,762	67	66	36
28	Horizon Utilities Corporation	70,835,688	4	6,703,611	77,539,298	4	44,884,274	6	122,423,572	6	330,680,000	6	37	31	366,197,247	6	33	41	41,674,275	7	108	37	116,705,818	5	105	49	2,679,921	3	194,944	2,874,865	3	10,061,393	5	12,936,258	5	84,830,304	6	15	13	84,830,304	6	15	13	14,826,453	6	68	32	17,664,321	5	73	25
29	Hydro 2000 Inc.	80,683	68	3,633	84,316	68	257,750	66	342,066	67	1,360,000	66	25	57	1,360,453	66	25	56	165,677	69	156	17	215,261	67	159	23	0	30	0	0	43	41,957	67	41,957	67	394,750	66	11	38	394,750	69	11	39	56,806	70	74	24	56,806	70	74	24
30	Hydro Hawkesbury Inc.	1,162,443	52	26,255	1,188,698	57	1,339,759	51	2,528,454	54	7,920,000	53	32	43	7,920,346	53	32	43	1,335,307	50	100	44	2,406,871	49	105	48	0	30	0	0	43	435,083	52	435,083	53	3,189,356	52	5	53	3,139,160	52	9	50	1,042,400	50	51	47	1,042,400	51	47	57
31	Hydro One Brampton Networks Inc.	29,578,103	9	6,302,266	35,880,369	10	41,650,660	7	77,531,030	8	255,160,000	7	30	49	255,160,000	7	30	46	40,763,367	8	102	41	70,364,866	7	110	45	363,847	9	139,709	503,556	7	7,314,450	7	7,818,006	7	66,798,531	7	7	12	66,798,530	7	7	12	14,929,827	7	52	49	14,994,829	7	52	49
32	Hydro One Networks Inc.	220,487,100	1	89,902,682	310,389,782	1	208,374,078	2	518,763,860	2	1,220,690,000	2	42	19	1,263,550,435	2	41	26	257,427,028	2	81	54	477,719,756	1	109	47	1,742,284	4	32,818	1,775,101	5	44,738,829	1	46,513,930	2	338,355,409	2	2	74	341,857,197	1	1	14	17	62,293,684	2	72	27	63,838,190	2	73	26
33	Hydro Ottawa Limited	57,247,836	7	15,553,929	72,801,765	7	59,247,505	5	132,049,269	5	394,540,000	5	33	40	394,559,846	5	33	40	42,147,373	6	141	23	99,489,881	6	133	42	389,296	7	0	389,296	10	13,469,631	4	13,858,927	4	105,242,155	5	1	19	105,242,156	5	1	13	21	17,214,251	5	78	17	17,591,400	6	79	16
34	ImpPower Corporation	1,850,172	47	132,220	1,982,392	50	2,561,285	39	4,543,677	46	13,010,000	44	35	35	13,009,980	43	35	35	1,158,377	38	81	53	4,728,558	35	96	54	0	30	0	0	43	467,510	41	467,510	41	3,680,241	44	13	23	3,680,241	44	13	25	851,157	37	55	48	851,157	38	55	48
35	Kashechewan Power Corporation	40,200	69	2,629	42,829	69	0	69	42,829	69	520,000	69	8	70	438,286	70	10	69	209,344	66	0	69	209,344	68	20	69	0	30	0	0	43	0	69	0	69	155,966	69	0	69	1,741,263	56	0	69	358,436	54	0	69	358,436	54	0	69
36	Kenora Hydro Electric Corporation Ltd.	1,606,080	52	65,793	1,671,873	54	552,901	61	2,224,774	57	5,270,000	57	42	21	5,269,561	56	42	24	1,403,058	48	39	65	1,596,071	56	139	28	0	30	0	0	43	124,005	59	124,005	59	1,407,448	57	9	52	1,688,937	57	7	61	220,129	59	56	43	220,150	59	56	46
37	Kingston Hydro Corporation	4,445,966	32	1,046,947	5,492,913	35	2,580,410	38	8,073,324	36	34,500,000	29	23	63	37,182,911	27	22	65	11,465,768	16	23	68	14,206,168	26	57	65	0	30	17,728	17,728	34	566,812	38	584,540	39	8,674,286	29	7	63	8,631,873	29	7	63	1,716,251	27	33	65	1,716,251	27	34	65
38	Kitchener-Wilmot Hydro Inc.	21,865,242	12	2,654,908	24,520,150	12	14,184,542	14	38,704,692	14	105,710,000	11	37	32	105,712,088	12	37	34	17,127,724	12	83	52	27,136,429	16	143	25	0	30	0	0	43	1,754,249	21	2,754,249	21	27,710,719	11	6	65	27,710,719	11	6	65	4,634,072	15	38	64	4,634,072	15	38	64
39	Lakefront Utilities Inc.	2,239,136	44	280,605	2,519,741	43	1,185,986	53	3,705,727	50	12,170,000	45	30	48	12,201,915	44	30	47	1,739,771	46	68	60	3,639,829	43	102	51	0	30	0	0	43	265,025	50	265,025	51	3,077,834	45	9	53	3,077,834	46	9	54	511,743	46	52	52	511,743	46	52	51
40	Lakeland Power Distribution Ltd.	4,432,710	33	708,780	5,141,489	37	2,495,021	41	7,636,510	37	15,770,000	42	48	16	15,832,919	41	48	20	1,345,374	49	185	9	4,319,290	37	177	16	0	30	0	0	43	433,380	43	433,380	44	4,142,392	42	10	40	4,142,392	42	10	41	511,363	47	85	14	511,364	47	85	14
41	London Hydro Inc.	28,534,591	10	3,454,236	31,988,827	11	31,824,871	8	63,813,698	10	196,660,000	8	32	41	219,747,453	8	29	50	34,869,274	9	91	49	63,862,340	10	100	53	1,611,279	5	506,532	2,117,811	4	8,721,449	6	10,839,260	6	51,192,690	8	1	21	5	51,389,905	8	1	21	5	9,187,376	9	95	7	10,660,376	9	102	3
42	Midland Power Utility Corporation	2,860,953	39	301,878	3,162,831	39	2,402,265	43	5,565,096	41	10,830,000	49	51	13	10,830,000	49	51	16	1,433,109	47	168	14	3,063,543	46	182	14	0	30	0	0	43	345,045	46	345,045	47	2,739,690	49	13	24	2,739,690	48	13	26	432,693	49	80	16	432,694	49	80	15
43	Milton Hydro Distribution Inc.	9,889,501	19	476,099	10,365,601	21	6,501,088	27	16,866,689	25	45,360,000	24	37	29	45,363,753	24	37	29	5,584,323	28	116	30	9,970,719	28	169	18	0	30	41,699	41,699	27	1,562,223	23	1,604,921	23	11,911,947	24	13	17	11,908,123	22	13	18	2,051,810	24	76	18	2,205,823	24	76	19
44	Newmarket-Tay Power Distribution Ltd.	8,218,024	20	840,996	9,059,020	24	4,962,518	31	14,021,538	28	36,240,000	26	39	25	26,923,645	32	52	14	4,271,910	32	116	32	4,271,910	38	328	7	51,311	20	0	51,311	23	1,009,481	28	1,060,792	28	9,649,555	27	11	35	9,993,198	25	11	40	1,842,766	26	55	46	1,842,766	26	58	41
45	Niagara Peninsula Energy Inc.	12,742,252	17	1,752,111	14,494,363	19	10,838,434	17	25,332,796	18	74,440,000	17	34	37	74,440,000	17	34	38	7,449,258	23	145	19	20,191,139	20	125	36	0	30	40,000	40,000	28	2,317,811	15	2,357,811	16	19,056,865	18	12	25	19,056,865	18	12	27	2,378,879	22	97	3	2,378,879	22	99	2
46	Niagara-on-the-Lake Hydro Inc.	2,598,018	42	369,192	2,967,210	41	3,401,852	36	6,369,062	39	11,680,000	46	55	8	11,877,636	46	54	13	3,546,990	35	96	48	6,289,627	33	101	52	0	30	0	0	43	424,921	44	424,921	45	2,993,633	46	14	24	2,321,538	49	18	7	828,092	40	51	50	828,092	41	51	53
47	North Bay Hydro Distribution Limited	4,245,690	31	12,427,153	16,672,842	17	4,001,370	34	20,674,212	23	20,200,000	37	102	2	17,933,643	37	115	9	2,300,259	41	174	12	2,300,259	50	899	1	27,296	23	0	27,296	31	713,129	32	740,425	33	5,545,424	37	13	23	5,738,692	37	13	23	992,259	37	75	22	992,259	37	75	22
48	Northern Ontario Wires Inc.	509,731	60	38,057	547,788	60	907,761	56	1,455,549	59	4,310,000	59	34	39	2,998,209	63	49	19	492,913	61	184	10	492,913	63	295	8	6,212	27	0	6,212	39	156,126	56	162,339	56	1,174,934	59	14	15	1,139,682	62	14	15	212,627	61	73	25	212,627	61	76	19
49	Oakville Hydro Electricity Distribution Inc.	21,252,248	12	2,499,447	23,751,695	13	15,431,935	11	39,183,630	13	92,390,000	15	42	20	93,974,490	15	42	25	13,265,566	14	116	31	34,517,814	13	114	42	0	30	77,518	77,518	21	3,120,547	10	3,198,065	10	24,575,982	15	13	21	24,574,176	13	13	22	4,665,101	13	67	33	4,742,101	13	67	34
50	Orangeville Hydro Limited	3,398,117	38	314,840	3,712,958	38	2,056,808	46	5,769,766	40	14,150,000	43	41	22	14,301,698	42	40	27	1,194,829	51	172	13	2,889,637	47	200	11	0	30	0	0	43	229,432	51	229,432	52	3,705,603	43	6	66	3,705,604	43	6	66	412,100	50	56	47	412,100	50	56	47
51	Orillia Power Distribution Corporation	1,662,040	50	246,213	1,908,253	52	2,008,907	47	3,917,160	49	16,580,000	40	24	62	16,653,694	39	24	60	5,922,408	26	34	66	7,529,238	32	52	66	0	30	17,378	17,378	35	605,352	34	622,730	35	4,318,856	40	14	13	4,289,364	40	15	14	765,330	42	79	15	831,580	40	75	21
52	Oshawa PUC Networks Inc.	5,046,074	28	1,182,326	6,228,399	29	11,449,535	16	17,677,934	23	73,010,000	18	24	61	73,010,000	18	24	59	8,484,484	20	135	24	24,199,815	18	73	61	0	30	24,000	24,000	33	1,975,382	17	1,999,382	18	19,963,922	17	10	42	19,918,698	17	10	43	3,504,522	17	56	42	3,504,522	17	57	44
53	Ottawa River Power Corporation	2,779,858	41	156,362	2,936,220	42	1,812,492	49	4,748,712	45	8,720,000	51	54	9	8,724,947	51	54	11	985,681	52	184	11	2,614,339	48	182	15	0	30	0	0	43	353,106	45	353,106	46	2,282,373	50	15	11	2,282,373	50	15	12	366,122	53	96	6	366,122	53	96	5
54	Peterborough Distribution Incorporated	4,979,980	29	554,811	5,534,790	34	5,186,524	30	10,721,314	32	37,880,000	25	28	52	42,122,834	25	25	55	20,077,835	10	26	67	25,666,491	17	42	67	0	30	43,197	43,197	25	847,015	30	890,212	30	9,781,455	25	9	49	9,581,681	26	9	48	4,697,210	12	18	68	4,697,210	14	19	68
55	PowerStream Inc.	76,511,169	3	20,976,

Progress Report

For: Energy+ Inc.

#	Programs	Participation >	Net Incremental 2020 Annual Energy Savings (Progress towards 2015 - 2020 CFF LDC CDM Plan Target) >	Net Incremental 2020 Annual Peak Demand Savings >	Net Incremental First Year Energy Savings >	Net Incremental First Year Peak Demand Savings >	Net-to-Gross Adjustment - Energy >	Net-to-Gross Adjustment - Peak Demand >	Realization Rate - Energy >	Realization Rate - Peak Demand >	Gross Incremental First Year Energy Savings >	Gross Incremental First Year Peak Demand Savings >	Savings Group >	Participant Incentive Spending >	LDC Administrative Expense Spending >	Value Added Services Provider Administrative Expense Spending >	Total Administrative Expense Spending >	Total 2015-2020 CFF LDC CDM Plan Budget Spending >	Spending Group >	Total Resource Cost - Cost Effectiveness Test - Gross Benefit >	Total Resource Cost - Cost Effectiveness Test - Gross Cost >	Total Resource Cost - Cost Effectiveness Test - Net Benefit >	Total Resource Cost - Cost Effectiveness Test - Net Benefit Ratio >	Program Administrator Cost - Cost Effectiveness Test - Gross Benefit >	Program Administrator Cost - Cost Effectiveness Test - Gross Cost >	Program Administrator Cost - Cost Effectiveness Test - Net Benefit >	Program Administrator Cost - Cost Effectiveness Test - Net Benefit Ratio >	Levelized Unit Energy Cost - Cost Effectiveness Test - Benefit >	Levelized Unit Energy Cost - Cost Effectiveness Test - Cost >	Levelized Unit Energy Cost - Cost Effectiveness Test >	Cost Effectiveness Tests Group >
2015-2020 Conservation First Framework Programs																														
Residential Province-Wide Programs																														
1	Save on Energy Coupon Program																													
2	Save on Energy Heating & Cooling Program																													
3	Save on Energy New Construction Program																													
4	Save on Energy Home Assistance Program																													
Sub-total: Residential Province-Wide Programs																														
Business Province-Wide Programs																														
5	Save on Energy Audit Funding Program																													
6	Save on Energy Retrofit Program																													
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10	Save on Energy Process & Systems Upgrades Program																													
11	Save on Energy Energy Manager Program																													
12	Save on Energy Monitoring & Targeting Program																													
13	Save on Energy Retrofit Program - P4P																													
14	Save on Energy Process & Systems Upgrades Program - P4P																													
Sub-total: Business Province-Wide Programs																														
Local & Regional Programs																														
15	Adaptive Thermostat Local Program																													
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25	THESL Swimming Pool Efficiency Local Program																													
Sub-total: Local & Regional Programs																														
LDC Innovation Fund Pilot Programs																														
26	Air Source Heat Pump for Residential Water Heating Pilot Program																													
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Sub-total: LDC Innovation Fund Pilot Programs																														
Program Enabled Savings																														
46	Save on Energy Retrofit Program Enabled Savings																													
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48	Save on Energy Process & Systems Upgrades Program Enabled Savings																													
Sub-total: Program Enabled Savings																														
Other																														
49	Proposed Program or Pilot																													
50	Unassigned Target																													
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Sub-total: 2015-2020 Conservation First Framework																														
Conservation Fund																														
51	EnerNOC Conservation Fund Pilot Program																													
52	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Progra																													
53	Loblaw P4P Conservation Fund Pilot Program																													
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55	Social Benchmarking Conservation Fund Pilot Program																													
56	Strategic Energy Group Conservation Fund Pilot Program																													
Sub-total: Conservation Fund																														
2011-2014+2015 Extension Legacy Framework Programs																														
Residential Program																														
57	Appliance Retirement Initiative																													
58	Coupon Initiative																													
59	Bi-Annual Retailer Event Initiative																													
60	HVAC Incentives Initiative																													
61	Residential New Construction and Major Renovation Initiative																													
Sub-total: Residential Program																														
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62	Energy Audit Initiative																													
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Sub-total: Commercial & Institutional Program																														
Industrial Program																														
67	Process and Systems Upgrades Initiatives - Project Incentive Initiative																													
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Sub-total: Industrial Program																														
Low Income Program																														
70	Low Income Initiative																													
Sub-total: Low-Income Program																														
Other																														
71	Aboriginal Conservation Program																													
72	Program Enabled Savings																													
Sub-total: Other																														
Sub-total: 2011-2014+2015 Extension Legacy Framework																														
Total																														

Progress Report
For: Province Wide

#	Programs	Participation >	Net Incremental 2020 Annual Energy Savings (Progress towards 2015 - 2020 CFF LDC CDM Plan Target) >	Net Incremental 2020 Annual Peak Demand Savings >	Net Incremental First Year Energy Savings >	Net Incremental First Year Peak Demand Savings >	Net-to-Gross Adjustment - Energy >	Net-to-Gross Adjustment - Peak Demand >	Realization Rate - Energy >	Realization Rate - Peak Demand >	Gross Incremental First Year Energy Savings >	Gross Incremental First Year Peak Demand Savings >	Savings Group >	Participant Incentive Spending >	LDC Administrative Expense Spending >	Value Added Services Provider Administrative Expense Spending >	Total Administrative Expense Spending >	Total 2015-2020 CFF LDC CDM Plan Budget Spending >	Spending Group >	Total Resource Cost - Cost Effectiveness Test - Gross Benefit >	Total Resource Cost - Cost Effectiveness Test - Gross Cost >	Total Resource Cost - Cost Effectiveness Test - Net Benefit >	Total Resource Cost - Cost Effectiveness Test - Net Benefit Ratio >	Program Administrator Cost - Cost Effectiveness Test - Gross Benefit >	Program Administrator Cost - Cost Effectiveness Test - Gross Cost >	Program Administrator Cost - Cost Effectiveness Test - Net Benefit >	Program Administrator Cost - Cost Effectiveness Test - Net Benefit Ratio >	Levelized Unit Energy Cost - Cost Effectiveness Test - Benefit >	Levelized Unit Energy Cost - Cost Effectiveness Test - Cost >	Levelized Unit Energy Cost - Cost Effectiveness Test >	Cost Effectiveness Tests Group >
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72	Program Enabled Savings																													
Sub-total: Other																														
Sub-total: 2011-2014+2015 Extension Legacy Framework																														
Total																														

Savings Persistence Report
For: Energy+ Inc.

#	Program / Initiative Name	Implementation Year	Gross Verified Energy Savings >	Gross Verified Demand Savings >	Net Verified Energy >	Net Verified Peak Demand Savings >	Net Verified Energy >
2015							
1	Save on Energy Coupon Program	2015					
2	Save on Energy Heating & Cooling Program	2015					
3	Save on Energy New Construction Program	2015					
4	Save on Energy Home Assistance Program	2015					
5	Save on Energy Audit Funding Program	2015					
6	Save on Energy Retrofit Program	2015					
7	Save on Energy Small Business Lighting Program	2015					
8	Save on Energy High Performance New Construction Program	2015					
9	Save on Energy Existing Building Commissioning Program	2015					
10	Save on Energy Process & Systems Upgrades Program	2015					
11	Save on Energy Energy Manager Program	2015					
12	Save on Energy Monitoring & Targeting Program	2015					
13	Save on Energy Retrofit Program - PHP	2015					
14	Save on Energy Process & Systems Upgrades Program - PHP	2015					
15	Adaptive Thermostat Local Program	2015					
16	Business Refrigeration Incentives Local Program	2015					
17	Conservation on the Coast Home Assistance Local Program	2015					
18	Conservation on the Coast Small Business Lighting Local Program	2015					
19	First Nations Conservation Local Program	2015					
20	High Efficiency Agricultural Pumping Local Program	2015					
21	Instant Savings Local Program	2015					
22	Manager Local Program	2015					
23	PUMPower Local Program	2015					
24	Social Benchmarking Local Program	2015					
25	THESL Swimming Pool Efficiency Local Program	2015					
26	Air Source Heat Pump for Residential Water Heating Pilot Program	2015					
27	Building Optimization Pilot Program	2015					
28	Conservation Voltage Regulation Leveraging AMI Data Pilot Program	2015					
29	Demand Control Kitchen Ventilation Pilot Program	2015					
30	Direct Install - Hydronic Pilot Program	2015					
31	Direct Install - RTU Controls Pilot Program	2015					
32	Electronically Commutated Furnace Motor Pilot Program	2015					
33	Electronics Takeback Pilot Program	2015					
34	Home Energy Assessment and Retrofit Pilot Program	2015					
35	HONI HP Pilot Program	2015					
36	HP for Class B Office Pilot Program	2015					
37	Performance Based Conservation Pilot Program	2015					
38	Re-Invest Pilot Program	2015					
39	Residential Direct Install Pilot Program	2015					
40	Residential Direct Mail Pilot Program	2015					
41	Residential Ductless Heat Pump Pilot Program	2015					
42	Residential Install Pilot Program	2015					
43	Social Benchmarking Pilot Program	2015					
44	Solar Powered Attic Ventilation Pilot Program	2015					
45	Troubleat Event Pilot Program	2015					
46	Save on Energy Retrofit Program Enabled Savings	2015					
47	Save on Energy High Performance New Construction Program Enabled Sa	2015					
48	Save on Energy Process & Systems Upgrades Program Enabled Savings	2015					
49	Proposed Program or Pilot	2015					
50	Unassigned Target	2015					
51	CrewNOC Conservation Fund Pilot Program	2015					
52	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Pro	2015					
53	Lublaw PHP Conservation Fund Pilot Program	2015					
54	Ontario Clean Water Agency PHP Conservation Fund Pilot Program	2015					
55	Social Benchmarking Conservation Fund Pilot Program	2015					
56	Strategic Energy Group Conservation Fund Pilot Program	2015					
57	Assistance Retirement Initiative	2015					
58	Coupons Initiative	2015					
59	Bi-Annual Retailer Event Initiative	2015					
60	HVAC Incentives Initiative	2015					
61	New Construction and Major Renovation Initiative	2015					
62	Energy Audit Initiative	2015					
63	Efficiency: Equipment Replacement Incentive Initiative	2015					
64	Direct Install Lighting and Water Heating Initiative	2015					
65	New Construction and Major Renovation Initiative	2015					
66	Existing Building Commissioning Incentive Initiative	2015					
67	Process and Systems Upgrades Initiatives - Project Incentive Initiative	2015					
68	Process and Systems Upgrades Initiatives - Energy Manager Initiative	2015					
69	Process and Systems Upgrades Initiatives - Monitoring and Targeting Ini	2015					
70	Low Income Initiative	2015					
71	Aboriginal Conservation Program	2015					
72	Program Enabled Savings	2015					
2015 Total							
2015 Adjustment							
73	Save on Energy Coupon Program	2015 Adjustment					
74	Save on Energy Heating & Cooling Program	2015 Adjustment					
75	Save on Energy New Construction Program	2015 Adjustment					
76	Save on Energy Home Assistance Program	2015 Adjustment					
77	Save on Energy Audit Funding Program	2015 Adjustment					
78	Save on Energy Retrofit Program	2015 Adjustment					
79	Save on Energy Small Business Lighting Program	2015 Adjustment					
80	Save on Energy High Performance New Construction Program	2015 Adjustment					
81	Save on Energy Existing Building Commissioning Program	2015 Adjustment					
82	Save on Energy Process & Systems Upgrades Program	2015 Adjustment					
83	Save on Energy Energy Manager Program	2015 Adjustment					
84	Save on Energy Monitoring & Targeting Program	2015 Adjustment					
85	Save on Energy Retrofit Program - PHP	2015 Adjustment					
86	Save on Energy Process & Systems Upgrades Program - PHP	2015 Adjustment					
87	Adaptive Thermostat Local Program	2015 Adjustment					
88	Business Refrigeration Incentives Local Program	2015 Adjustment					
89	Conservation on the Coast Home Assistance Local Program	2015 Adjustment					
90	Conservation on the Coast Small Business Lighting Local Program	2015 Adjustment					
91	First Nations Conservation Local Program	2015 Adjustment					
92	High Efficiency Agricultural Pumping Local Program	2015 Adjustment					
93	Instant Savings Local Program	2015 Adjustment					
94	Manager Local Program	2015 Adjustment					
95	PUMPower Local Program	2015 Adjustment					
96	Social Benchmarking Local Program	2015 Adjustment					
97	THESL Swimming Pool Efficiency Local Program	2015 Adjustment					
98	Air Source Heat Pump for Residential Water Heating Pilot Program	2015 Adjustment					
99	Building Optimization Pilot Program	2015 Adjustment					
100	Conservation Voltage Regulation Leveraging AMI Data Pilot Program	2015 Adjustment					
101	Demand Control Kitchen Ventilation Pilot Program	2015 Adjustment					
102	Direct Install - Hydronic Pilot Program	2015 Adjustment					
103	Direct Install - RTU Controls Pilot Program	2015 Adjustment					
104	Electronically Commutated Furnace Motor Pilot Program	2015 Adjustment					
105	Electronics Takeback Pilot Program	2015 Adjustment					
106	Home Energy Assessment and Retrofit Pilot Program	2015 Adjustment					
107	HONI HP Pilot Program	2015 Adjustment					
108	HP for Class B Office Pilot Program	2015 Adjustment					
109	Performance Based Conservation Pilot Program	2015 Adjustment					
110	Re-Invest Pilot Program	2015 Adjustment					
111	Residential Direct Install Pilot Program	2015 Adjustment					
112	Residential Direct Mail Pilot Program	2015 Adjustment					
113	Residential Ductless Heat Pump Pilot Program	2015 Adjustment					
114	Residential Install Pilot Program	2015 Adjustment					
115	Social Benchmarking Pilot Program	2015 Adjustment					
116	Solar Powered Attic Ventilation Pilot Program	2015 Adjustment					
117	Troubleat Event Pilot Program	2015 Adjustment					
118	Save on Energy Retrofit Program Enabled Savings	2015 Adjustment					
119	Save on Energy High Performance New Construction Program Enabled Sa	2015 Adjustment					
120	Save on Energy Process & Systems Upgrades Program Enabled Savings	2015 Adjustment					
121	Proposed Program or Pilot	2015 Adjustment					
122	Unassigned Target	2015 Adjustment					
123	CrewNOC Conservation Fund Pilot Program	2015 Adjustment					
124	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Pro	2015 Adjustment					
125	Lublaw PHP Conservation Fund Pilot Program	2015 Adjustment					
126	Ontario Clean Water Agency PHP Conservation Fund Pilot Program	2015 Adjustment					
127	Strategic Energy Group Conservation Fund Pilot Program	2015 Adjustment					
128	Social Benchmarking Conservation Fund Pilot Program	2015 Adjustment					
129	Assistance Retirement Initiative	2015 Adjustment					
130	Coupons Initiative	2015 Adjustment					
131	Bi-Annual Retailer Event Initiative	2015 Adjustment					
132	HVAC Incentives Initiative	2015 Adjustment					
133	Residential New Construction and Major Renovation Initiative	2015 Adjustment					
134	Energy Audit Initiative	2015 Adjustment					
135	Efficiency: Equipment Replacement Incentive Initiative	2015 Adjustment					
136	Direct Install Lighting and Water Heating Initiative	2015 Adjustment					
137	New Construction and Major Renovation Initiative	2015 Adjustment					
138	Existing Building Commissioning Incentive Initiative	2015 Adjustment					
139	Process and Systems Upgrades Initiatives - Project Incentive Initiative	2015 Adjustment					
140	Process and Systems Upgrades Initiatives - Energy Manager Initiative	2015 Adjustment					
141	Process and Systems Upgrades Initiatives - Monitoring and Targeting Ini	2015 Adjustment					
142	Low Income Initiative	2015 Adjustment					
143	Aboriginal Conservation Program	2015 Adjustment					
144	Program Enabled Savings	2015 Adjustment					
2015 Adjustment Total							
2016							
145	Save on Energy Coupon Program	2016					
146	Save on Energy Heating & Cooling Program	2016					
147	Save on Energy New Construction Program	2016					
148	Save on Energy Home Assistance Program	2016					
149	Save on Energy Audit Funding Program	2016					
150	Save on Energy Retrofit Program	2016					
151	Save on Energy Small Business Lighting Program	2016					
152	Save on Energy High Performance New Construction Program	2016					
153	Save on Energy Existing Building Commissioning Program	2016					
154	Save on Energy Process & Systems Upgrades Program	2016					
155	Save on Energy Energy Manager Program	2016					
156	Save on Energy Monitoring & Targeting Program	2016					
157	Save on Energy Retrofit Program - PHP	2016					
158	Save on Energy Process & Systems Upgrades Program - PHP	2016					
159	Adaptive Thermostat Local Program	2016					
160	Business Refrigeration Incentives Local Program	2016					
161	Conservation on the Coast Home Assistance Local Program	2016					
162	Conservation on the Coast Small Business Lighting Local Program	2016					
163	First Nations Conservation Local Program	2016					
164	High Efficiency Agricultural Pumping Local Program	2016					
165	Instant Savings Local Program	2016					
166	Manager Local Program	2016					
167	PUMPower Local Program	2016					
168	Social Benchmarking Local Program	2016					
169	THESL Swimming Pool Efficiency Local Program	2016					
170	Air Source Heat Pump for Residential Water Heating Pilot Program	2016					
171	Building Optimization Pilot Program	2016					
172	Conservation Voltage Regulation Leveraging AMI Data Pilot Program	2016					
173	Demand Control Kitchen Ventilation Pilot Program	2016					
174	Direct Install - Hydronic Pilot Program	2016					
175	Direct Install - RTU Controls Pilot Program	2016					
176	Electronically Commutated Furnace Motor Pilot Program	2016					
177	Electronics Takeback Pilot Program	2016					
178	Home Energy Assessment and Retrofit Pilot Program	2016					
179	HONI HP Pilot Program	2016					
180	HP for Class B Office Pilot Program	2016					
181	Performance Based Conservation Pilot Program	2016					
182	Re-Invest Pilot Program	2016					
183	Residential Direct Install Pilot Program	2016					
184	Residential Direct Mail Pilot Program	2016					
185	Residential Ductless Heat Pump Pilot Program	2016					
186	Residential Install Pilot Program	2016					
187	Social Benchmarking Pilot Program	2016					
188	Solar Powered Attic Ventilation Pilot Program	2016					
189	Troubleat Event Pilot Program	2016					
190	Save on Energy Retrofit Program Enabled Savings	2016					
191	Save on Energy High Performance New Construction Program Enabled Sa	2016					
192	Save on Energy Process & Systems Upgrades Program Enabled Savings	2016					
193	Proposed Program or Pilot	2016					
194	Unassigned Target	2016					
195	CrewNOC Conservation Fund Pilot Program	2016					
196	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Pro	2016					
197	Lublaw PHP Conservation Fund Pilot Program	2016					
198	Ontario Clean Water Agency PHP Conservation Fund Pilot Program	2016					
199	Strategic Energy Group Conservation Fund Pilot Program	2016					
200	Social Benchmarking Conservation Fund Pilot Program	2016					
201	Assistance Retirement Initiative	2016					
202	Coupons Initiative	2016					
203	Bi-Annual Retailer Event Initiative	2016					
204	HVAC Incentives Initiative	2016					
205	Residential New Construction and Major Renovation Initiative	2016					
206	Energy Audit Initiative	2016					
207	Efficiency: Equipment Replacement Incentive Initiative	2016					
208	Direct Install Lighting and Water Heating Initiative	2016					
209	New Construction and Major Renovation Initiative	2016					
210	Existing Building Commissioning Incentive Initiative	2016					
211	Process and Systems Upgrades Initiatives - Project Incentive Initiative	2016					
212	Process and Systems Upgrades Initiatives - Energy Manager Initiative	2016					
213	Process and Systems Upgrades Initiatives - Monitoring and Targeting Ini	2016					
214	Low Income Initiative	2016					
215	Aboriginal Conservation Program	2016					
216	Program Enabled Savings	2016					
2016 Total							
Total							

Savings Persistence Report
For: Province Wide

#	Program / Initiative Name	Implementation Year	Gross Verified Energy Savings >	Gross Verified Demand Savings >	Net Verified Energy Savings >	Net Verified Peak Demand Savings >	Net Verified Energy >
2015							
1	Save on Energy Coupon Program	2015					
2	Save on Energy Heating & Cooling Program	2015					
3	Save on Energy New Construction Program	2015					
4	Save on Energy Home Assistance Program	2015					
5	Save on Energy Audit Funding Program	2015					
6	Save on Energy Retrofit Program	2015					
7	Save on Energy Small Business Lighting Program	2015					
8	Save on Energy High Performance New Construction Program	2015					
9	Save on Energy Existing Building Commissioning Program	2015					
10	Save on Energy Process & Systems Upgrades Program	2015					
11	Save on Energy Energy Manager Program	2015					
12	Save on Energy Monitoring & Targeting Program	2015					
13	Save on Energy Retrofit Program - PHP	2015					
14	Save on Energy Process & Systems Upgrades Program - PHP	2015					
15	Adaptive Thermostat Local Program	2015					
16	Business Refrigeration Incentives Local Program	2015					
17	Conservation on the Coast Home Assistance Local Program	2015					
18	Conservation on the Coast Small Business Lighting Local Program	2015					
19	First Nations Conservation Local Program	2015					
20	High Efficiency Agricultural Pumping Local Program	2015					
21	Instant Savings Local Program	2015					
22	Manager Local Program	2015					
23	PUMPsaver Local Program	2015					
24	Social Benchmarking Local Program	2015					
25	THESL Swimming Pool Efficiency Local Program	2015					
26	Air Source Heat Pump for Residential Water Heating Pilot Program	2015					
27	Building Optimization Pilot Program	2015					
28	Conservation Voltage Regulation Leveraging AMI Data Pilot Program	2015					
29	Demand Control Kitchen Ventilation Pilot Program	2015					
30	Direct Install - Hydronic Pilot Program	2015					
31	Direct Install - RTU Controls Pilot Program	2015					
32	Electronically Commutated Furnace Motor Pilot Program	2015					
33	Electronics Takeback Pilot Program	2015					
34	Home Energy Assessment and Retrofit Pilot Program	2015					
35	HONI HP Pilot Program	2015					
36	PHP for Class B Office Pilot Program	2015					
37	Performance Based Conservation Pilot Program	2015					
38	Re-Invest Pilot Program	2015					
39	Residential Direct Install Pilot Program	2015					
40	Residential Direct Mail Pilot Program	2015					
41	Residential Ductless Heat Pump Pilot Program	2015					
42	Residential Install Pilot Program	2015					
43	Social Benchmarking Pilot Program	2015					
44	Solar Powered Attic Ventilation Pilot Program	2015					
45	Troubleat Event Pilot Program	2015					
46	Save on Energy Retrofit Program Enabled Savings	2015					
47	Save on Energy High Performance New Construction Program Enabled Sa	2015					
48	Save on Energy Process & Systems Upgrades Program Enabled Savings	2015					
49	Proposed Program or Pilot	2015					
50	Unassigned Target	2015					
51	EnerNOC Conservation Fund Pilot Program	2015					
52	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Pro	2015					
53	Lublow PHP Conservation Fund Pilot Program	2015					
54	Ontario Clean Water Agency PHP Conservation Fund Pilot Program	2015					
55	Strategic Energy Group Conservation Fund Pilot Program	2015					
56	Social Benchmarking Conservation Fund Pilot Program	2015					
57	Assistance Retirement Initiative	2015					
58	Coupons Initiative	2015					
59	Bi-Annual Retailer Event Initiative	2015					
60	HVAC Incentives Initiative	2015					
61	New Construction and Major Renovation Initiative	2015					
62	Energy Audit Initiative	2015					
63	Efficiency: Equipment Replacement Incentive Initiative	2015					
64	Direct Install Lighting and Water Heating Initiative	2015					
65	New Construction and Major Renovation Initiative	2015					
66	Existing Building Commissioning Incentive Initiative	2015					
67	Process and Systems Upgrades Initiatives - Project Incentive Initiative	2015					
68	Process and Systems Upgrades Initiatives - Energy Manager Initiative	2015					
69	Process and Systems Upgrades Initiatives - Monitoring and Targeting Ini	2015					
70	Low Income Initiative	2015					
71	Aboriginal Conservation Program	2015					
72	Program Enabled Savings	2015					
2015 Total							
2015 Adjustment							
73	Save on Energy Coupon Program	2015 Adjustment					
74	Save on Energy Heating & Cooling Program	2015 Adjustment					
75	Save on Energy New Construction Program	2015 Adjustment					
76	Save on Energy Home Assistance Program	2015 Adjustment					
77	Save on Energy Audit Funding Program	2015 Adjustment					
78	Save on Energy Retrofit Program	2015 Adjustment					
79	Save on Energy Small Business Lighting Program	2015 Adjustment					
80	Save on Energy High Performance New Construction Program	2015 Adjustment					
81	Save on Energy Existing Building Commissioning Program	2015 Adjustment					
82	Save on Energy Process & Systems Upgrades Program	2015 Adjustment					
83	Save on Energy Energy Manager Program	2015 Adjustment					
84	Save on Energy Monitoring & Targeting Program	2015 Adjustment					
85	Save on Energy Retrofit Program - PHP	2015 Adjustment					
86	Save on Energy Process & Systems Upgrades Program - PHP	2015 Adjustment					
87	Adaptive Thermostat Local Program	2015 Adjustment					
88	Business Refrigeration Incentives Local Program	2015 Adjustment					
89	Conservation on the Coast Home Assistance Local Program	2015 Adjustment					
90	Conservation on the Coast Small Business Lighting Local Program	2015 Adjustment					
91	First Nations Conservation Local Program	2015 Adjustment					
92	High Efficiency Agricultural Pumping Local Program	2015 Adjustment					
93	Instant Savings Local Program	2015 Adjustment					
94	Manager Local Program	2015 Adjustment					
95	PUMPsaver Local Program	2015 Adjustment					
96	Social Benchmarking Local Program	2015 Adjustment					
97	THESL Swimming Pool Efficiency Local Program	2015 Adjustment					
98	Air Source Heat Pump for Residential Water Heating Pilot Program	2015 Adjustment					
99	Building Optimization Pilot Program	2015 Adjustment					
100	Conservation Voltage Regulation Leveraging AMI Data Pilot Program	2015 Adjustment					
101	Demand Control Kitchen Ventilation Pilot Program	2015 Adjustment					
102	Direct Install - Hydronic Pilot Program	2015 Adjustment					
103	Direct Install - RTU Controls Pilot Program	2015 Adjustment					
104	Electronically Commutated Furnace Motor Pilot Program	2015 Adjustment					
105	Electronics Takeback Pilot Program	2015 Adjustment					
106	Home Energy Assessment and Retrofit Pilot Program	2015 Adjustment					
107	HONI HP Pilot Program	2015 Adjustment					
108	PHP for Class B Office Pilot Program	2015 Adjustment					
109	Performance Based Conservation Pilot Program	2015 Adjustment					
110	Re-Invest Pilot Program	2015 Adjustment					
111	Residential Direct Install Pilot Program	2015 Adjustment					
112	Residential Direct Mail Pilot Program	2015 Adjustment					
113	Residential Ductless Heat Pump Pilot Program	2015 Adjustment					
114	Residential Install Pilot Program	2015 Adjustment					
115	Social Benchmarking Pilot Program	2015 Adjustment					
116	Solar Powered Attic Ventilation Pilot Program	2015 Adjustment					
117	Troubleat Event Pilot Program	2015 Adjustment					
118	Save on Energy Retrofit Program Enabled Savings	2015 Adjustment					
119	Save on Energy High Performance New Construction Program Enabled Sa	2015 Adjustment					
120	Save on Energy Process & Systems Upgrades Program Enabled Savings	2015 Adjustment					
121	Proposed Program or Pilot	2015 Adjustment					
122	Unassigned Target	2015 Adjustment					
123	EnerNOC Conservation Fund Pilot Program	2015 Adjustment					
124	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Pro	2015 Adjustment					
125	Lublow PHP Conservation Fund Pilot Program	2015 Adjustment					
126	Ontario Clean Water Agency PHP Conservation Fund Pilot Program	2015 Adjustment					
127	Strategic Energy Group Conservation Fund Pilot Program	2015 Adjustment					
128	Social Benchmarking Conservation Fund Pilot Program	2015 Adjustment					
129	Assistance Retirement Initiative	2015 Adjustment					
130	Coupons Initiative	2015 Adjustment					
131	Bi-Annual Retailer Event Initiative	2015 Adjustment					
132	HVAC Incentives Initiative	2015 Adjustment					
133	Residential New Construction and Major Renovation Initiative	2015 Adjustment					
134	Energy Audit Initiative	2015 Adjustment					
135	Efficiency: Equipment Replacement Incentive Initiative	2015 Adjustment					
136	Direct Install Lighting and Water Heating Initiative	2015 Adjustment					
137	New Construction and Major Renovation Initiative	2015 Adjustment					
138	Existing Building Commissioning Incentive Initiative	2015 Adjustment					
139	Process and Systems Upgrades Initiatives - Project Incentive Initiative	2015 Adjustment					
140	Process and Systems Upgrades Initiatives - Energy Manager Initiative	2015 Adjustment					
141	Process and Systems Upgrades Initiatives - Monitoring and Targeting Ini	2015 Adjustment					
142	Low Income Initiative	2015 Adjustment					
143	Aboriginal Conservation Program	2015 Adjustment					
144	Program Enabled Savings	2015 Adjustment					
2015 Adjustment Total							
2016							
145	Save on Energy Coupon Program	2016					
146	Save on Energy Heating & Cooling Program	2016					
147	Save on Energy New Construction Program	2016					
148	Save on Energy Home Assistance Program	2016					
149	Save on Energy Audit Funding Program	2016					
150	Save on Energy Retrofit Program	2016					
151	Save on Energy Small Business Lighting Program	2016					
152	Save on Energy High Performance New Construction Program	2016					
153	Save on Energy Existing Building Commissioning Program	2016					
154	Save on Energy Process & Systems Upgrades Program	2016					
155	Save on Energy Energy Manager Program	2016					
156	Save on Energy Monitoring & Targeting Program	2016					
157	Save on Energy Retrofit Program - PHP	2016					
158	Save on Energy Process & Systems Upgrades Program - PHP	2016					
159	Adaptive Thermostat Local Program	2016					
160	Business Refrigeration Incentives Local Program	2016					
161	Conservation on the Coast Home Assistance Local Program	2016					
162	Conservation on the Coast Small Business Lighting Local Program	2016					
163	First Nations Conservation Local Program	2016					
164	High Efficiency Agricultural Pumping Local Program	2016					
165	Instant Savings Local Program	2016					
166	Manager Local Program	2016					
167	PUMPsaver Local Program	2016					
168	Social Benchmarking Local Program	2016					
169	THESL Swimming Pool Efficiency Local Program	2016					
170	Air Source Heat Pump for Residential Water Heating Pilot Program	2016					
171	Building Optimization Pilot Program	2016					
172	Conservation Voltage Regulation Leveraging AMI Data Pilot Program	2016					
173	Demand Control Kitchen Ventilation Pilot Program	2016					
174	Direct Install - Hydronic Pilot Program	2016					
175	Direct Install - RTU Controls Pilot Program	2016					
176	Electronically Commutated Furnace Motor Pilot Program	2016					
177	Electronics Takeback Pilot Program	2016					
178	Home Energy Assessment and Retrofit Pilot Program	2016					
179	HONI HP Pilot Program	2016					
180	PHP for Class B Office Pilot Program	2016					
181	Performance Based Conservation Pilot Program	2016					
182	Re-Invest Pilot Program	2016					
183	Residential Direct Install Pilot Program	2016					
184	Residential Direct Mail Pilot Program	2016					
185	Residential Ductless Heat Pump Pilot Program	2016					
186	Residential Install Pilot Program	2016					
187	Social Benchmarking Pilot Program	2016					
188	Solar Powered Attic Ventilation Pilot Program	2016					
189	Troubleat Event Pilot Program	2016					
190	Save on Energy Retrofit Program Enabled Savings	2016					
191	Save on Energy High Performance New Construction Program Enabled Sa	2016					
192	Save on Energy Process & Systems Upgrades Program Enabled Savings	2016					
193	Proposed Program or Pilot	2016					
194	Unassigned Target	2016					
195	EnerNOC Conservation Fund Pilot Program	2016					
196	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Pro	2016					
197	Lublow PHP Conservation Fund Pilot Program	2016					
198	Ontario Clean Water Agency PHP Conservation Fund Pilot Program	2016					
199	Strategic Energy Group Conservation Fund Pilot Program	2016					
200	Social Benchmarking Conservation Fund Pilot Program	2016					
201	Assistance Retirement Initiative	2016					
202	Coupons Initiative	2016					
203	Bi-Annual Retailer Event Initiative	2016					
204	HVAC Incentives Initiative	2016					
205	Residential New Construction and Major Renovation Initiative	2016					
206	Energy Audit Initiative	2016					
207	Efficiency: Equipment Replacement Incentive Initiative	2016					
208	Direct Install Lighting and Water Heating Initiative	2016					
209	New Construction and Major Renovation Initiative	2016					
210	Existing Building Commissioning Incentive Initiative	2016					
211	Process and Systems Upgrades Initiatives - Project Incentive Initiative	2016					
212	Process and Systems Upgrades Initiatives - Energy Manager Initiative	2016					
213	Process and Systems Upgrades Initiatives - Monitoring and Targeting Ini	2016					
214	Low Income Initiative	2016					
215	Aboriginal Conservation Program	2016					
216	Program Enabled Savings	2016					
2016 Total							
Total							

Final Verified 2016 Annual LDC CDM Program Results Report
Methodology

General

All results are at the end-user level (not including transmission and distribution losses) and reported to IESO by April 15, 2017. 2015 results are based on projects completed between January 1, 2015 and December 31, 2015 and reported to the IESO by March 31, 2016. 2015 Adjustment results are based on projects completed between January 1, 2015 and December 31, 2015 and reported to the IESO between April 1, 2016 and April 15 2017. 2016 results are based on projects compelted between January 1, 2016 and December 31, 2016 and reported to the IESO by April 15, 2017.

Legacy Framework results are based on projects begun prior to an LDC's transition to the Conservation First Framework program and completed by December 31, 2015. Conservation First Framework results are based on projects begun after an LDC's transition to the Conservation First Framework program and projects transitioned to the Conservation First Framework through a valid Extension Agreement or eligible Programs.

Savings Calculations

#	Project Type	Attributing Savings to LDCs
1	Prescriptive Measures and Projects Programs	**Gross Reported Savings** = Activity * Per Unit Assumption Savings **Gross Verified Savings** = Gross Reported Savings * Realization Rate **Net Verified Savings** = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
2	Engineered and Custom Projects / Programs	**Gross Reported Savings** = Reported Savings **Gross Verified Savings** = Gross Reported Savings * Realization Rate **Net Verified Savings** = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
3	Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the annual effect of energy savings.

Cost Determination

Costs are determined and allocated to the period based on the date the cost has been reported to the IESO regardless of when the cost was incurred.

E.g. if an LDC reports by the December 2016 IESO Reporting Period: 1) program savings; 2) Participant Incentives; and 3) Administrative Expenses associated with a 2016 completed project, then: a) the savings; b) expenditures; and c) corresponding cost effectiveness; are attributed to the 2016 program year.

However if the same is reported in or after the January 2017 IESO Reporting Period: i) the savings will be attributed to the 2016 program year; ii) the expenditures will be attributed to the 2017 program year and will not appear in the 2016 Verified Results Report; but iii) the project's Participant Incentives will be used to calculate 2016 Cost Effectiveness;

2015-2020 Conservation First Framework

#	Program	Attributing Savings to LDCs	Project List Date	Savings 'start' Date	Calculating Resource Savings
1	Save on Energy Coupon Program	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on Consumer Program Allocation Reference Table.	April 15, 2017	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Save on Energy Heating & Cooling Program	Results directly attributed to LDC based on customer applications and postal code.	April 15, 2017	Savings are considered to begin in the year that the installation occurred.	
3	Save on Energy New Construction Program	Results are directly attributed to LDC based on LDC identified in LDC Report	April 15, 2017	Savings are considered to begin in the year of the project completion date.	
4	Save on Energy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year in which the measures were installed.	
5	Save on Energy Audit Funding Program	Projects are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
6	Save on Energy Retrofit Program	Projects are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year of the actual project completion date as reported in the LDC Report	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
7	Save on Energy Small Business Lighting Program	Results are directly attributed to LDC based on the LDC specified on the work order.	April 15, 2017	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
8	Save on Energy High Performance New Construction Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined by the total savings for a given project as reported in the CDM LDC Report Template. Preliminary unverified net savings are calculated by multiplying reported savings by 2014 Net-to-gross ratios and realization rates.
9	Save on Energy Existing Building Commissioning Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year of the actual project completion date.	
10	Save on Energy Process and Systems Upgrades Program	Results are directly attributed to LDC based on LDC identified in application.	April 15, 2017	Savings are considered to begin in the year in which the project was in-service.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
11	Save on Energy Energy Manager Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year in which the project was completed by the energy manager.	
12	Save on Energy Monitoring and Targeting Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year in which the incentive project was completed.	

2011-2014+2015 Extension Legacy Framework

#	Initiative	Attributing Savings to LDCs	Project List Date	Savings 'start' Date	Calculating Resource Savings
1	saveONenergy Appliance Retirement Initiative	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	April 15, 2017	Savings are considered to begin in the year the appliance is picked up.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	saveONenergy Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	April 15, 2017	Savings are considered to begin in the year in which the coupon was redeemed.	
3	saveONenergy Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	April 15, 2017	Savings are considered to begin in the year in which the event occurs.	
4	saveONenergy HVAC Incentives	Results directly attributed to LDC based on customer applications and postal code.	April 15, 2017	Savings are considered to begin in the year that the installation occurred.	
5	saveONenergy Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system.	April 15, 2017	Savings are considered to begin in the year of the project completion date.	
6	saveONenergy Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
7	saveONenergy Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	April 15, 2017	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track). Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)
8	saveONenergy Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	April 15, 2017	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
9	saveONenergy New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017		Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
10	saveONenergy Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017		
11	saveONenergy Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	April 15, 2017	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	saveONenergy Energy Manager	Results are directly attributed to LDC based on LDC identified in application.	April 15, 2017	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	
13	saveONenergy Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in application.	April 15, 2017	Savings are considered to begin in the year in which the incentive project was completed.	
14	saveONenergy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
15	Aboriginal Conservation Program	Results are directly attributed to LDC based on LDC identified in the application.	April 15, 2017		
16	Program Enabled Savings		April 15, 2017		

Final Verified 2016 Annual LDC CDM Program Results Report

Consumer Program Allocation Reference Table

#	Local Distribution Company	Allocation (%)
1	Algoma Power Inc.	0.18
2	Atikokan Hydro Inc.	0.02
3	Attawapiskat Power Corporation	0.01
4	Bluewater Power Distribution Corporation	0.62
5	Brantford Power Inc.	0.67
6	Burlington Hydro Inc.	1.34
7	Canadian Niagara Power Inc.	0.35
8	Centre Wellington Hydro Ltd.	0.11
9	Chapleau Public Utilities Corporation	0.03
10	COLLUS PowerStream Corp.	0.25
11	Cooperative Hydro Embrun Inc.	0.06
12	E.L.K. Energy Inc.	0.25
13	Energy+ Inc.	1.12
14	Enersource Hydro Mississauga Inc.	4.64
15	Entegrus Powerlines Inc.	0.70
16	EnWin Utilities Ltd.	1.49
17	Erie Thames Powerlines Corporation	0.32
18	Espanola Regional Hydro Distribution Corporation	0.06
19	Essex Powerlines Corporation	0.61
20	Festival Hydro Inc.	0.32
21	Fort Albany Power Corporation	0.01
22	Fort Frances Power Corporation	0.09
23	Greater Sudbury Hydro Inc.	0.80
24	Grimsby Power Incorporated	0.18
25	Guelph Hydro Electric Systems Inc.	0.85
26	Halton Hills Hydro Inc.	0.59
27	Hearst Power Distribution Company Limited	0.05
28	Horizon Utilities Corporation	3.72
29	Hydro 2000 Inc.	0.04
30	Hydro Hawkesbury Inc.	0.15
31	Hydro One Brampton Networks Inc.	3.59
32	Hydro One Networks Inc.	27.29
33	Hydro Ottawa Limited	6.61
34	InnPower Corporation	0.33
35	Kashechewan Power Corporation	0.02
36	Kenora Hydro Electric Corporation Ltd.	0.09
37	Kingston Hydro Corporation	0.29
38	Kitchener-Wilmot Hydro Inc.	1.51
39	Lakefront Utilities Inc.	0.11
40	Lakeland Power Distribution Ltd.	0.23
41	London Hydro Inc.	2.61
42	Midland Power Utility Corporation	0.10
43	Milton Hydro Distribution Inc.	0.66
44	Newmarket-Tay Power Distribution Ltd.	0.60
45	Niagara Peninsula Energy Inc.	0.82
46	Niagara-on-the-Lake Hydro Inc.	0.13
47	North Bay Hydro Distribution Limited	0.42
48	Northern Ontario Wires Inc.	0.09
49	Oakville Hydro Electricity Distribution Inc.	1.51
50	Orangeville Hydro Limited	0.20
51	Orillia Power Distribution Corporation	0.22
52	Oshawa PUC Networks Inc.	1.48
53	Ottawa River Power Corporation	0.12
54	Peterborough Distribution Incorporated	0.46
55	PowerStream Inc.	7.82
56	PUC Distribution Inc.	0.65
57	Renfrew Hydro Inc.	0.05
58	Rideau St. Lawrence Distribution Inc.	0.07
59	Sioux Lookout Hydro Inc.	0.08
60	St. Thomas Energy Inc.	0.28
61	Thunder Bay Hydro Electricity Distribution Inc.	0.82
62	Tillsonburg Hydro Inc.	0.12
63	Toronto Hydro-Electric System Limited	15.57
64	Veridian Connections Inc.	2.39
65	Wasaga Distribution Inc.	0.18
66	Waterloo North Hydro Inc.	0.96
67	Welland Hydro-Electric System Corp.	0.31
68	Wellington North Power Inc.	0.06
69	West Coast Huron Energy Inc.	0.06
70	Westario Power Inc.	0.37
71	Whitby Hydro Electric Corporation	1.12
Total		**100.00**

Final Verified 2016 Annual LDC CDM Program Results Report
Glossary

#	Term	Definition
	Reporting Terms	
1	Forecast	An LDCs' forecast of program activity, savings, net-to-gross adjustments, expenditures and cost effectiveness as indicated in each LDC's submitted CDM Plan Cost Effectiveness Tools. Forecasts at the province wide level are the sum of all LDCs' forecasts.
2	Reported	Program activity savings and expenditures as determined by the LDC. For savings: 1) for prescriptive projects/programs: calculating quantity x prescriptive savings assumptions; and 2) for engineered or custom program projects/programs: calculated using prescribed methodologies.
3	Verified	The IESO's annually EM&V assessed program activity, savings, net-to-gross, expenditures and cost effectiveness. Preliminary Verified results are provided by June 1st of each year and Final Verfied results are provided by July 1st of each year.
4	Adjustment	Verified results that were achieved in previous years but were not provided in a previous years' Annual Verified Results Report.
5	Progress or Comparison	An assessment of Actual results versus Verified results.
	Framework Terms	
6	2011-2014+2015 Extension Legacy Framework	Programs in market from 2011-2015 resulting from the April 23, 2010 GEA CDM Ministerial Directive and funded separately from 2015-2020 Conservation First Framework Programs but whose savings in 2015 are attributed towards the 2015-2020 Conservation First Framework target.
7	2015-2020 Conservation First Framework	Programs in market from 2015-2020 resulting from the March 31, 2014 CFF Ministerial Directive and funded separately from 2011-2014+2015 Extension Legacy Framework Programs.
8	LDC Innovation Fund	A source of funding under the 2015-2020 Conservation First Framework separate from LDC CDM Plan Budgets that the IESO maintains to support LDC led program design and market testing of new initiatives. Savings from LDC Innovation Fund pilot programs contribute to the LDCs savings targets based on the LDC service territory the pilot program is delivered in.
9	Conservation Fund	A source of funding external to the 2015-2020 Conservation First Framework that provides financial support for innovative electricity conservation technologies, practices, research, and pilot programs. Savings from Conservation Fund pilot programs contribute to the LDCs savings targets based on the LDC service territory the pilot program is delivered in.
	Programs Terms	
10	Program	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (e.g. Coupon; or Retrofit;) from the 2015-2020 Conservation First Framework.
11	Province-Wide Program	Programs available to all LDCs to deliver and that are consistent across the province.
12	Regional Program	Programs designed by LDCs to serve their region and approved by the IESO.
13	Local Program	Programs designed by LDCs to serve their communities and approved by the IESO.
14	Pilot Program	A program pilot that may achieve energy or demand savings and is funded separately from an LDC's CDM Plan Budget.
15	Initiative	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (e.g. Fridge & Freezer Pickup) from the 2011-2014+2015 Extension Legacy Framework.
	Activity Terms	
16	Participation	A measure of the level of program participation, such as number of projects, homes, equipment, etc..
17	Unit of Measure	For a specific initiative the relevant type of participation acquired in the market place (e.g. appliances picked up; coupon products installed; HVAC equipment installed; audits performed; or projects completed;).
	Savings Terms	
18	Energy Savings	Energy savings attributable to conservation and demand management activities.
19	Peak Demand Savings	Peak Demand savings attributable to conservation and demand management activities, as determined by the IESO's EM&V Protocols.
20	Incremental Savings	The energy or peak demand savings newly attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'. Savings attributed to activity performed or completed in 2016 are presented as 2016 savings.
21	First Year Savings	The energy or peak demand savings that occur in the year it was achieved (includes resource savings from only new program activity).
22	Annual Savings	The energy or peak demand savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).
23	Gross Savings	The energy or peak demand savings that have been reported based on a conservation and demand management program's participation tracking.
24	Net Savings	The energy or peak demand savings attributable to conservation and demand management activities, net of free-riders, spill over, etc.
25	Realization Rate	A comparison of originally reported savings and observed or measured savings that adjusts reported savings to arrive at verified savings. Accounts for discrepancies such as audited measure counts; adjustment for connected demand savings to peak demand savings; etc.
26	Net-to-Gross Adjustment	The ratio of net savings to gross savings, which takes into account factors such as free-ridership, spillover, etc.
27	Free-ridership	The percentage of participants who would have implemented the program measure or practice in the absence of the program.
28	Spillover	Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.
29	Allocated Target	Each LDC's assigned portion of the Province's 7 TWh Net 2020 Annual Energy Savings Target of the 2015-2020 Conservation First Framework.
	Costs Terms	
30	Participant Incentive	Costs incurred in the delivery of a program related to incenting participants to perform peak demand or energy savings.
31	LDC Administrative Expense	Costs reported by the LDC in the delivery of a program related to labour, marketing, third-party expenses, etc.
32	IESO Value Added Services Cost	Costs incurred by the IESO's Value Added Service Provider related to associated programs (Coupons and Heating & Cooling), and charged to the LDC in which the programs's activity took place.
33	Total Administrative Expense	The sum of LDC Adminsitrative Expense and IESO Value Added Services Cost.
34	Delivery Cost	The sum of Total Administrative Expenses and Participant Incentives. **All costs are presented based on the period reported by LDCs to the IESO, not necessarily associated with reported activity.** **E.g. if an LDC reports by the December 2016 IESO Reporting Period: 1) program savings; 2) Participant Incentives; and 3) Administrative Expenses associated with a 2016 completed project, then: a) the savings; b) expenditures; and c) corresponding cost effectiveness; are attributed to the 2016 program year.** **However if the same is reported in or after the January 2017 IESO Reporting Period: i) the savings will be attributed to the 2016 program year; ii) the expenditures will be attributed to the 2017 program year and will not appear in the 2016 Verified Results Report; but iii) the project's Participant Incentives will be used to calculate 2016 Cost Effectiveness;**
35	Allocated Budget	Each LDC's assigned portion of the Province's $ 1.835 billion CDM Plan Budget of the 2015-2020 Conservation First Framework.
	Cost Effectiveness Terms	
36	Total Resource Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on the total costs of the program including both participants' and utility's costs.
37	Program Administrator Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on costs incurred by the program administrator, including incentive costs and excluding net costs incurred by the participant.
38	Levelized Unit Energy Cost Cost Effectiveness Test	A cost effectiveness test that normalizes the costs incurred by the program administrator per unit of energy or demand reduced.

APPENDIX 4-8: KINECTRICS – USEFUL LIFE OF ASSETS

Cambridge and North Dumfries Hydro, Kitchener-Wilmot Hydro & Guelph Hydro

Useful Life of Assets

Kinectrics Inc. Report No: K-418029-RA-001-R001

March 24, 2010

Confidential & Proprietary Information
Contents of this report shall not be disclosed
without authority of client.
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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Cambridge and North Dumfries Hydro, Kitchener-Wilmot Hydro & Guelph Hydro.

@Kinectrics Inc., 2009.

Cambridge and North Dumfries Hydro, Kitchener-Wilmot Hydro & Guelph Hydro – Useful Life of Assets

Kinectrics Inc. Report No: K-418029-RA-001-R001

March 24, 2010

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EXECUTIVE SUMMARY

Ontario's Local Distribution Companies (LDCs) are switching to International Financial Reporting Standards (IFRS) methodology. One of the "tenants" of IFRS is the time period assets are amortized over should align with their actual useful life.

LDCs typically own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Furthermore, some assets are comprised of several components that may have differing useful lives than the assets themselves. To facilitate conversion to IFRS, LDCs need to ensure that a) they track all relevant asset categories and their components and b) that the amortization period for these are adequately aligned with actual LDC-specific useful lives.

This report reviews the useful lives of the assets, and their respective asset components that are applicable to Cambridge and North Dumfries Hydro, Kitchener-Wilmot Hydro & Guelph Hydro (the Consortium). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all of which listed in Section 3 of this Report. Useful lives of assets are dependent on a number of utilization factors, specifically time-base maintenance, operating practices and utilization (electrical loading). These factors are described in *Section 1.3.6* of this report and are used to decide where the LDC-specific typical asset/components lives should be relative to the typical lives based on the industry data. It is also worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

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1 INTRODUCTION

Ontario's Local Distribution Companies (LDCs) are switching to International Financial Reporting Standards (IFRS) methodology. One of the "tenants" of IFRS is the time period assets are amortized over should align with their actual useful life.

LDCs typically own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Furthermore, some assets are comprised of several components that may have differing useful lives than the assets themselves. To facilitate conversion to IFRS, LDCs need to ensure that a) they track all relevant asset categories and their components and b) that the amortization period for these are adequately aligned with actual LDC-specific useful lives.

This report reviews the useful lives of the assets, and their respective asset components that are applicable to Cambridge and North Dumfries Hydro, Kitchener-Wilmot Hydro & Guelph Hydro (the Consortium). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all of which listed in Section 3 of this Report.

This report is intended to be used to determine the useful life of assets as follows: Useful lives of assets are dependent on a number of utilization factors, specifically maintenance practices, operating practices and utilization (electrical loading). These factors are described in detail in *Section 1.3.6* of this report and are used to decide where the LDC-specific asset/components lives should be relative to the typical lives based on the industry data. It is also worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

1.1 Project Scope

This report provides an in-depth evaluation of the useful lives of the assets that are owned and operated by the Consortium. The typical parent system(s) to which the asset belongs is provided and these "parent" systems are: *Overhead Lines* (OH), *Distribution Transformers* (DT), *Transformer Stations (TS), Municipal Stations* (MS), *Underground Systems* (UG) and *Monitoring and Control System* (S). The long term degradation mechanism is described for each asset category and when applicable assets are sub-categorized into components. Components are included when their cost is material enough and, at the same time, could be replaced without a need to replace the whole asset. For each asset or component, the following information is presented:

- End of life criteria
- Useful Life Range
- Typical Life
- Typical time-based maintenance intervals, if applicable
- Utilization Factors

Section 1.3 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

1.2 Project Execution Process

The project execution process entailed a number of steps to ensure that the industry-based information compiled by Kinectrics not only includes all the relevant assets and components used by Consortium, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

- The initial list of assets and components was produced by the Consortium to Kinectrics for review.

- Upon review of the initial list, Kinectrics generated an intermediate asset list that had a somewhat different background, granularity, and componentization, based on industry practices and Kinectrics experience.

- The intermediate list was reviewed jointly by Consortium and Kinectrics to derive a "final" list.

- For each asset and component in the "final" list, Kinectrics then gathered the information described in *Section 1.1* of this report. A Draft Report that summarized the findings and provided detail descriptions, including degradation mechanisms and applicable assumptions for each asset, was then produced.

- This Draft Report was reviewed by Consortium and their feedback was incorporated in the Final Report.

1.3 Definition of Terms

1.3.1 *Typical Distribution System Asset*

Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

1.3.2 *Component*

For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

- Its replacement value is significant enough, relative to the asset value.

- A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

1.3.3 *Useful Life*

Useful Life refers to an estimated range of years during which an electric utility asset or its component is expected to operate as designed, without experiencing major functional degradation that requires major refurbishment or replacement.

In this report, the useful life range, in years, is presented in terms of a minimum, maximum, and typical value. An overwhelming number of units within a population will perform their intended design functions for a period of time greater than or equal to the *minimum* life. Conversely, an overwhelming number of units will cease to perform as designed at or beyond the *maximum* life. A majority of the population will have useful lives of around the *typical* life. For example, consider an asset class with a useful life range of 20 to 40 years, and a typical life of 30 years. The majority of the units within this class will perform as required for at least 20 years and likewise the majority of the units will not operate beyond 40 years. Finally, a majority of the units within the population will operate for approximately 30 years. Note that an asset category can have a

typical life that is equal to either the maximum or minimum life. This is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum years; i.e. the statistical data is skewed towards either the maximum or minimum values. The range in useful lives reflects differences in various utilization factors including mechanical stress, electrical loading, and environmental conditions and operating practices.

1.3.4 *Typical Life*

Refers to the typical age at which the asset or component fails or is normally removed from service for other reasons such as obsolescence or collateral replacement. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses.

1.3.5 *Typical Time-based Maintenance Intervals*

For the purposes of this report, time-based maintenance refers to either *Routine Inspections* (RI) or *Routine Testing/Maintenance* (RTM) applicable generally to North American electric utilities, but particularly to Ontario electric utilities.

Routine Inspections (RI) include patrol or simple visual inspections consists of walking, driving by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism.

Routine Testing/Maintenance (RTM) activities are left to the discretion of the distributor, and include literally hundreds of maintenance activities that range from insulator washing, cable replacement, CO2 cleaning of switchgear, to gas-in-oil testing of station transformers, etc.

Other maintenance techniques such as Condition Based Maintenance, Reliability Centered Maintenance, and more intrusive periodic overhauls are very much dependent on individual utility's maintenance strategy and practices and, as such, could not be included in compiling industry-wide typical values.

Typical time-based maintenance intervals will be given only for assets that are proactively maintained, i.e. assets for which useful life is affected by regular planned maintenance. This excludes assets that are not routinely maintained. Typical values have been determined from worldwide electric utility sources.

1.3.6 *Utilization Factors*

Useful lives of assets are dependent on a number of utilization factors, specifically maintenance practices, operating practices and utilization (electrical or mechanical loading).

Maintenance practices are further subdivided into the categories of "Routine Inspection" and "Routine Testing and Maintenance".

"Operating practices" refers to the frequency with which an asset is subject to operating procedures (automatic or manual) that impact its useful life, e.g. recloser operations. For the purposes of this report typical operating practice refers to operating assets at the rated load. The typical number of operations for an asset is based on the specific manufacturers' recommendations for that specific asset or component type.

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2 RESULTS AND FINDINGS

Table 1-1 summarizes useful and typical lives, time based maintenance schedules, and impact of stress for Consortium assets.

Table 2-1 Summary of Componentized Assets

PARENT*	#	ASSET		USEFUL LIFE (years)			FACTORS¤		MAINTENANCE§	
		Category - Component - Type		Min	Typ	Max	OP	MP	Type	Schedule (years)
OH	1	Fully Dressed Poles	Wood	40	45	50	-	✓	RI	3-6
			Composite	45	70	100				
			Concrete	35	60	80				
			Steel	60	60	80				
	2	Insulators	Porcelain	40	40	50	-	✓	RI	3-6
			Glass	40	40	50				
			Composite	25	45	50				
	3	Fuse Cutouts		30	40	60	-	-	RI	3-6
	4	Manual Overhead Switches		30	50	60	✓	✓	RTM	2
	5	Local Motorized Overhead Switches	Switch	30	50	60	✓	✓	RTM	2
			Motor	15	20	20				
	6	Remote Automated Overhead Switches	Switch	30	50	60	✓	✓	RTM	2
			Motor	15	20	20				
			RTU	15	20	30				
	7	Integral Switch		30	45	50	✓	✓	RTM	2

* OH = Overhead Lines √=Applicable
¤ OP = Operating Practices MP = Maintenance Practices § RI = Routine Inspection RTM = Routine Testing and Maintenance

PARENT*	#	ASSET			USEFUL LIFE			FACTORS¤		MAINTENANCE§	
		Category	Component	Type	Min	Typ	Max	OP	MP	Type	Schedule
OH	8	Conductors	Primary & Secondary	ACSR	50	60	77	-	-	RI	3-6
				AAC	50	60	77				
				Copper	50	60	77				
				Weather Protected	50	60	77				
				Insulated Wire	50	60	77				
	9	Capacitor Banks			25	30	40	-	-	RI	3-6
	10	Voltage Regulators			15	20	40	✓	-	RI	3-6
	11	Reclosers			30	40	60	✓	✓	RTM	3-6
DT	12	Pole Top Transformer			30	40	60	-	✓	RI	3-6
	13	Pole-Tran			25	30	35	✓	✓	RTM	2
	14	Pad Mounted Transformer	Transformer		30	40	60	✓	-	RI	3-6
			Foundation		30	60	80				
	15	Network Transformer	Transformer		20	35	50	✓	✓	RI	2
			Vault		40	60	80				
			Roof		20	25	40				
			High Voltage Switch		30	45	50				
			Secondary Network Protector		20	35	40				
	16	Submersible Transformer	Transformer		25	35	40	✓	✓	RI	2
			Vault		40	60	80				
			Roof		20	25	40				
	17	Indoor Vault Transformer	Transformer		25	35	40	✓	✓	RI	2
			Vault		40	60	80				
			Roof		20	25	40				

* OH = Overhead Lines DT = Distribution Transformers √=Applicable
¤ OP = Operating Practices MP = Maintenance Practices § RI = Routine Inspection RTM = Routine Testing and Maintenance

PARENT*	#	ASSET		USEFUL LIFE			FACTORS¤		MAINTENANCE§	
		Category - Component - Type		Min	Typ	Max	OP	MP	Type	Schedule
UG	18	UG Switchgear	Air Insulated	20	25	40	✓	✓	RI	3
			Gas Insulated	30	30	50				
			Solid Dielectric	30	30	50				
	19	Primary Cables	PILC	70	75	80	-	-	RI	3-6
			Solid Dielectric In Duct	40	40	60				
			Solid Dielectric Direct Buried	20	25	25				
	20	Secondary Cables	Solid Dielectric In Duct	40	40	60	-	-	RI	3-6
			Solid Dielectric Direct Buried	20	30	35				
	21	Ducts	Concrete Encased	30	50	80	-	-	-	-
			PVC (Direct Buried)	30	50	75				
			HDPE (Direct Buried)	50	50	100				
			FRE (Direct Buried)	30	50	100				
	22	Cable Chambers		50	60	80	-	✓	RTM	3
	23	Junction Cubicle/Service Box	Pads/bases	30	60	80	-	✓	RTM	3
			Junction/switching cabinets	25	40	50				
TS & MS	24	Station Grounding Transformer		30	40	40	-	✓	RTM	3
	25	Station Service Transformer		32	45	55	-	✓	RTM	3
	26	TS Power Transformer	Overall	32	45	55	✓	✓	RTM	2
			Bushing	20	30	40				
			Tap Changer	20	30	60				

* UG = Underground Systems TS&MS = Transformer and Municipal Stations √=Applicable

¤ OP = Operating Practices MP = Maintenance Practices § RI = Routine Inspection RTM = Routine Testing and Maintenance

PARENT*	#	ASSET			USEFUL LIFE			FACTORS¤		MAINTENANCE§	
		Category	Component	Type	Min	Typ	Max	OP	MP	Type	Schedule
TS & MS	27	MS Power Transformer	Overall		30	45	55	✓	✓	RTM	2
			Bushing		20	30	40				
			Tap Changer		20	30	60				
	28	MV Switchgear	Assembly	Air Insulated	40	50	60	✓	✓	RTM	6
				Gas (SF6) Insulated	40	50	60				
			Removable Breaker	Air Magnetic	25	40	60				
				Vacuum	30	40	60				
				SF6	30	45	60				
	29	Independent Breakers		Oil	30	45	60	✓	✓	RTM	3
				Gas (SF6)	30	45	60				
				Air Magnetic	25	30	60				
				Air Blast	30	40	50				
				Vacuum	30	40	60				
	30	Protection & Control Devices	Panels		40	40	60	✓	-	RI	3-6
			Control Cable		25	40	50				
			Relays	Electromechanical	20	30	50				
				Solid State	10	30	50				
				Digital	10	15	20				
	31	Station Disconnect Switch			30	45	50	✓	✓	RTM	6
	32	DC System	Batteries		10	20	30	✓	✓	RTM	1
			Chargers		20	20	30				
			DC Distribution Equipment		10	20	30				

* TS&MS = Transformer and Municipal Stations √=Applicable
¤ OP = Operating Practices MP = Maintenance Practices § RI = Routine Inspection RTM = Routine Testing and Maintenance

PARENT*	#	ASSET			USEFUL LIFE			FACTORS¤		MAINTENANCE§	
		Category - Component - Type			Min	Typ	Max	OP	MP	Type	Schedule
TS & MS	33	Station Grounding System		Ground Grid	25	40	50	-	-	-	-
				Neutral Reactors	25	45	60				
				Arresters	10	20	30				
				Sky Wire	30	45	50				
	34	Bus Work & Steel Structures			35	50	100	-	-	-	-
	35	Station Building	Structure		30	50	80	-	✓	RI	1
			Roof		15	20	30				
			Fence		30	35	60				
S	36	Metering	Meter	Smart	15	15	20	-	-	-	-
				Industrial/Commercial	20	30	60				
				Wholesale	20	30	60				
			Transformers (CTs, PTs)		30	45	50				
	37	SCADA	RTU		10	20	30	✓	-	-	-
			Battery		10	15	15				
	38	Smart Fault Indicators			10	15	15	✓	-	-	-
	39	Communication Towers			35	65	100	-	-	RI	3-6

* TS&MS = Transformer and Municipal Stations S = Monitoring and Control Systems √=Applicable
¤ OP = Operating Practices MP = Maintenance Practices § RI = Routine Inspection RTM = Routine Testing and Maintenance

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1 Fully Dressed Poles

The asset referred to in this category is the fully dressed pole ranging in size from 30 to 75 feet. This includes the pole, cross arm, bracket, insulator, and anchor & guys. The most important component with respect to useful life is the pole itself. For the purposes of this report we are discussing the degradation and useful life of four types: wood, composite, concrete and steel.

1.1 Degradation Mechanism

The most significant component of this asset is the wood pole itself. The degradation of poles is based on the pole type. This report covers wood poles, composite poles, concrete poles and steel poles.

1.1.1 *Wood Poles*

Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon. As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

1.1.2 *Composite Poles*

The major degradation of composite poles is ultra violet (UV) degradation. It represents an attack from ultra-violet radiation, which might result in crack or disintegration in composite poles. It is a common problem in products exposed to sunlight. Continuous exposure is a more serious problem than intermittent exposure, since attack is dependent on the extent and degree of exposure. In fiber products like composite poles, useful life will be shortened because the outer fibers will be attacked first, and will easily be damaged by abrasion. This will end up with fiber blooming and fading.

1.1.3 *Concrete Pole*

Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in); however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice, resulting in cracking and separation of the concrete. The spun concrete process used in manufacturing poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

1.1.4 *Steel Poles*

The degradation of directly buried steel poles is mainly due to steel corrosion in-ground. In-ground situations are vastly different because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground. There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is

the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations. Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

1.2 System Hierarchy

Fully Dressed Poles are considered to be a part of the Overhead Lines asset grouping.

1.3 Useful Life and Typical Life

The overall useful life of Fully Dressed Poles is dependent on the pole type:

- Wood
- Composite
- Concrete
- Steel

1.3.1 *Wood*

The useful life of a wood pole is in the range of 40 to 50 years; the typical life is 44 years.

1.3.2 *Composite*

The useful life of a composite pole is in the range of 45 to 100 years; the typical life is 70 years.

1.3.3 *Concrete*

The useful life of a concrete pole is in the range of 35 to 80 years; the typical life is 60 years.

1.3.4 *Steel*

The useful life of a steel pole is in the range of 60 to 80 years; the typical life is 60 years.

1.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 3-6 years.

1.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Maintenance practices
- Utilization (mechanical loading).

2 Insulators

The asset referred to in this category is the overhead line insulator. Insulators must support the conductors and withstand both the normal operating voltage and surges due to switching and lightning. Insulators are typically porcelain or glass, with increasing use of polymer insulators. For the purposes of this report we will be discussing three insulator types: porcelain, glass and composite.

2.1 Degradation Mechanism

The end of life of insulators is primarily due to environmental factors. Insulators are exposed to lightning withstand requirements, altitude, and environmental factors such as fog, pollution, or salt spray. Longer insulators, with longer creepage distance for leakage current, are required in these cases. Strain insulators must be strong enough mechanically to support the full weight of the span of conductor, as well as loads due to ice accumulation, and wind.

Porcelain insulators may have a semi-conductive glaze finish, so that a small current passes through the insulator. This warms the surface slightly and reduces the effect of fog and dirt accumulation. The semiconducting glaze also insures a more even distribution of voltage along the length of the chain of insulator units. Insulator grading rings, installed at their terminals, improves the electric field distribution around the insulator and makes it more resistant to flash-over during voltage surges.

2.2 System Hierarchy

Insulators are considered to be a part of the Overhead Lines asset grouping.

2.3 Useful Life and Typical Life

The overall useful life of Insulators is dependent on the insulator type:

- Porcelain
- Glass
- Composite

2.3.1 *Porcelain*

The useful life of a porcelain insulator is in the range of 40 to 50 years; the typical life is 40 years.

2.3.2 *Glass*

The useful life of a glass insulator is in the range of 40 to 50 years; the typical life is 40 years.

2.3.3 *Composite*

The useful life of a composite insulator is in the range of 25 to 50 years; the typical life is 45 years.

2.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 3-6 years.

2.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices
- Utilization (mechanical loading).

3 Fuse Cutouts

The asset referred to in this category is the Fuse Cutouts. They are applied on overhead transformers, capacitors, cables or lines. Fuse Cutouts will interrupt all faults including low current that will melt the fuse link and high rated interrupting current so long as the system is under realistic transient-recovery-voltage conditions.

3.1 Degradation Mechanism

The major degradation of fuse cutouts is on fuse body and insulator. There are several degradation modes in practice:

In the case of fuse link, the following is the major degradation modes:

- Production of carbon from organic materials in the fuse body. This carbon is not produced until a particular body temperature is reached, and the time for this to occur depends on the fuse design.
- For some fuses that generate water vapor to assist current interruption, the water is deposited on the inside surface of the body. Tracking is observed on the surface, ultimately leading to a steady increase in leakage current until failure.

In the case of insulator part, the following is the major degradation modes:

- Cracking on porcelain insulator due to combined impact from improper processing at manufacturing stage and operational mechanical stress.
- Contamination driven leakage current and flashover

3.2 System Hierarchy

Fuse Cutouts are considered to be a part of the Overhead Lines asset grouping.

3.3 Useful Life and Typical Life

The overall useful life of Fuse Cutouts is in the range of 30 to 60 years; the typical life is 40 years.

3.4 Time Based Maintenance Intervals

Fuse Cutouts are not subject to routine maintenance practices. These assets are subject to routine inspection every 3 to 6 years.

3.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices
- Operating practices
- Utilization (electrical loading).

4 Manual Overhead Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

4.1 Degradation Mechanism

The main degradation processes associated with manually operated line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Insulators damage
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

4.2 System Hierarchy

Overhead Switches asset category belongs to the Overhead Lines assets grouping.

4.3 Useful Life and Typical Life

The useful life of manually operated switches is in the range of 30 to 60 years; the typical life is 50 years.

4.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for manually operated overhead switches is two years.

4.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

5 Local Motorized Overhead Switches

This asset class consists of overhead line three-phase, gang operated switches and a motor. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism is controlled by a motor.

5.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with local motorized overhead switches include the following:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Insulators damage
- Missing ground connections

The rate and severity of degradation are a function on operating duties and environment.

5.2 System Hierarchy

Local Motorized Overhead Switches category belongs to the Overhead Lines assets grouping.

5.3 Useful Life and Typical Life

The local motorized overhead switch can be componentized into two components:

- Switch
- Motor

5.3.1 *Switch*

The useful life of local motorized switches is in the range of 30 to 60 years; the typical life is 50 years.

5.3.2 *Motor*

The useful life of the motor of local motorized switches is in the range of 15 to 20 years; the typical life is about 20 years.

5.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for local motorized switches is every two years.

5.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

6 Remote Automated Overhead Switches

This asset class consists of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions and operate only when the current through the switch is zero. Most distribution line switches are rated 600 to 900 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in open position. This component also consists of a remote terminal unit (RTU) component.

6.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Insulators damage
- Missing ground connections

The rate and severity of degradation are a function on operating duties and environment.

6.2 System Hierarchy

Remote Automated Overhead switches asset category belongs to the Overhead Lines assets grouping.

6.3 Useful Life and Typical Life

The remote automated overhead switch can be componentized into three components:

- Switch
- Motor
- Remote Terminal Unit (RTU)

6.3.1 *Switch*

The useful life of remote automated switches is in the range of 30 to 60 years; the typical life is 50 years.

6.3.2 *Motor*

The useful life of a motor is in the range of 15 to 20 years; the typical life is 20 years.

6.3.3 *Remote Terminal Unit (RTU)*

The useful life of an RTU is in the range of 15 to 30 years; the typical life is 20 years.

6.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for remote automated overhead switches is every two years.

6.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

7 Integral Switch

Integral switches are a type of overhead line switches that are can receive signals from and be monitored by the SCADA system. These units include the switch, communications, and RTU. As with other line switches, this asset allows for the isolation of overhead line sections or equipment for maintenance, safety, or other operating requirements.

7.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Insulators damage
- Missing ground connections

7.2 System Hierarchy

Integral switches asset category belongs to the Overhead Lines assets grouping.

7.3 Useful Life and Typical Life

The useful life of integral switches is in the range of 30 to 50 years; the typical life is 45 years.

7.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for integral switches is every two years.

7.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

8 Conductors

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the Consortium are primary and secondary conductors. The types include aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), copper, weather protected wire and insulated wire.

8.1 Degradation Mechanism

To function properly, conductors must retain both their conductive properties and mechanical (i.e. tensile) strength. Aluminum conductors have three primary modes of degradation: corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, as well as environmental and operating conditions. Most utilities find that corrosion and fatigue present the most critical forms of degradation.

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

Fatigue degradation presents greater detection and assessment challenges than corrosion degradation. In extreme circumstances, under high tensions or inappropriate vibration or galloping control, fatigue can occur in very short timeframes. However, under normal operating conditions, with proper design and application of vibration control, fatigue degradation rates are relatively slow. Under normal circumstances, widespread fatigue degradation is not commonly seen in conductors less than 70 years of age. Also, in many cases detectable indications of fatigue may only exist during the last 10% of a conductor's life.

In designing distribution lines, engineers ensure that conductors receive no more than a certain percentage of their rated tensile strength (RTS) during heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions beyond 50% of their RTS, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor's RTS, significant sag occurs, requiring either resagging or replacement of the conductor.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminum strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to the chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low Cl contents could enter, causing a dislocation of the passivity. This may also be the result of a deficit of oxygen which would make the area anodic.

Please note that the weather protection and insulation on the Cables is for improving reliability of the distribution system as opposed to improving the useful life of this asset. The conductive properties of the wire are what degradation impacts, although Utilities may choose to replace weather protected cables for their own system reliability practices.

8.2 System Hierarchy

The Wire asset category belongs to the Overhead Lines assets grouping.

8.3 Useful Life and Typical Life

The useful life of conductors is dependent on the conductor type:

- Aluminum Conductor Steel Reinforced (ACSR)
- All Aluminum Conductor (AAC)
- Copper
- Weather Protected Wire
- Insulated Wire

8.3.1 *Aluminum Conductor Steel Reinforced (ACSR)*

The useful life of ACSR conductors in the range of 50 to 77 years; the typical life is 60 years.

8.3.2 *All Aluminum Conductor (AAC)*

The useful life of AAC conductors in the range of 50 to 77 years; the typical life is 60 years.

8.3.3 *Copper*

The useful life of copper conductors in the range of 50 to 77 years; the typical life is 60 years.

8.3.4 *Weather Protected Wire*

The useful life of weather protected conductors in the range of 50 to 77 years; the typical life is 60 years.

8.3.5 *Insulated Wire*

The useful life of insulated conductors in the range of 50 to 77 years; the typical life is 60 years.

8.4 Time Based Maintenance Intervals

Conductors are not generally subject to planned maintenance according to industry surveys. These assets are subject to routine inspection every 3 to 6 years.

8.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Utilization (electrical and mechanical loading).

9 Capacitor Banks

This asset category refers to a group of capacitors arranged in rows, equipped with inter-rack insulators, interconnecting bus work, or support frame installed on pole top. The capacitor bank also includes capacitor unit fuses, break switch, instrumental transformers, protection and control devices, and in some cases, current-limiting fuse cutout or surge arrester. They regulate voltage in distribution systems, provide reactive compensation and voltage support.

9.1 Degradation Mechanism

The major degradation of overhead capacitor banks is related to the capacitors themselves. They are exposed to detrimental environmental factors including: extreme temperatures, contamination, birds etc. They also experience steady state, transient and dynamic over voltage conditions. The switching devices add an additional stress to the capacitors. These environmental conditions, electrical loading and operating practices cause non-reversible degradation of the insulation in capacitor units and external insulation.

Fuse and bushing degradation result primarily from the failure of seals (hence moisture seeps in). Based on the surrounding environmental conditions this may cause corrosion of the capacitor units and support frame. Internal degradation can also occur in insulators.

9.2 System Hierarchy

Capacitor Bank asset category belongs to the Overhead Lines assets grouping.

9.3 Useful Life and Typical Life

The useful life of capacitor bank is in the range of 25 to 40 years; the typical life is 30 years.

9.4 Time Based Maintenance Intervals

Capacitor Banks are not subject to planned maintenance. These assets are subject to routine inspection every 3 to 6 years.

9.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Utilization (electrical loading).

10 Voltage Regulators

Voltage regulators are devices that perform step-up and step-down voltage change operations. Distribution line transformers change the medium or low distribution voltage to 120/240 V or other common voltages for use in residential and commercial applications.

10.1 Degradation Mechanism

It has been demonstrated that the life of the voltage regulator's internal insulation is related to temperature-rise and duration. Therefore, voltage regulator life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of voltage regulators.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of voltage regulator that should be selected for a given number and type of customers to obtain optimal life. There is also the operating practices affect on voltage regulators. If the distribution system is robust, the voltage regulator may not need to step-up or step-down the voltage, in which case there would be less stress on the device itself.

10.2 System Hierarchy

Voltage Regulators asset category belongs to the Overhead Lines assets grouping.

10.3 Useful Life and Typical Life

The useful life of voltage regulators is in the range of 15 to 40 years; the typical life is 20 years.

10.4 Time Based Maintenance Intervals

Voltage Regulators are subject to routine inspection every 3 to 6 years.

10.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Operating practices;
- Utilization (electrical loading).

11 Reclosers

This asset class consists of light duty circuit breakers equipped with interrupters that use controllers. This is where the breaking and making of fault current takes place. The interrupters use oil as the arc extinguishing medium. It is designed for single phase or three phase use, depending on the model.

11.1 Degradation Mechanism

The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect suppression devices as well as the contacts, the oil, and the arc control. The degradation of these devices depends on the prevailing fault, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism mal-function. For deterioration, exposure to weather is a potentially significant degradation process – primarily corrosion of the tank and other metallic components and deterioration of bushings.

11.2 System Hierarchy

Recloser asset category belongs to the Overhead Lines assets grouping.

11.3 Useful Life and Typical Life

The useful life of reclosers is in the range of 30 to 60 years; the typical life is 40 years.

11.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for the breaker component of reclosers is every 3-6 years.

11.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

12 Pole Top Transformers

Distribution pole top transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

12.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

12.2 System Hierarchy

The Pole Top Transformer asset category belongs to the Distribution Transformers assets grouping.

12.3 Useful Life and Typical Life

The useful life of the pole top transformer is in the range of 30 to 60 years, with an average value close to 40 years.

12.4 Time Based Maintenance Intervals

The typical routine inspection schedule for pole top transformers is every 3-6 years.

12.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Utilization (electrical loading).

13 Pole-Trans

The asset referred to in this category is the Pole-Trans. They are typically employed in areas where high and uniform levels of illumination, easy maintenance, and minimum ground level obstruction are required. They are, for example, used in roadways and highways. Pole-trans are constructed from welded tubular sections that taper towards the top. The masts are finished through a hot-dip galvanizing process and are therefore designed to withstand extreme weather conditions. The towers have welded base plates that are bolted to concrete foundations. A ring at the top of the towers holds multiple luminaries.

13.1 Degradation Mechanism

Degradation of the overall pole-trans is heavily weighted to the degradation of the high voltage circuitry, especially with switching section, and less weighted to the remaining components of the pole-trans.

13.2 System Hierarchy

The Pole-Trans asset category belongs to the Distribution Transformers asset grouping.

13.3 Useful Life and Typical Life

Pole-Trans have a useful life range of 25 to 35 years; the typical life is 30 years.

13.4 Time Based Maintenance Intervals

The time based routine testing/maintenance interval for pole-trans is every two years.

13.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

14 Pad-Mounted Transformers

Pad-Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. For the purposes of this report, the pad-mounted transformer has been componentized into the transformer itself and the enclosure.

14.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

14.2 System Hierarchy

Pad-Mounted Transformers asset category belongs to the Distribution Transformers asset grouping.

14.3 Useful Life and Typical Life

The useful life of pad-mounted transformers is dependent on the components useful life. Pad-mounted transformers can be componentized into the following:

- Transformer
- Foundation

14.3.1 *Transformer*

The overall useful life range of pad mounted distribution transformers are 30 to 60 years; the typical life is 40 years.

14.3.2 *Foundation*

The overall useful life range of pad mounted distribution transformers' foundations are 30 to 80 years; the typical life is 60 years.

14.4 Time Based Maintenance Intervals

Pad-Mounted Transformers are not subject to planned maintenance. These assets are subject to routine inspection every 3 to 6 years.

14.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Operating practices;
- Utilization (electrical loading).

15 Network Transformers

Network transformers are special purpose distribution transformers, designed and constructed for successful operation in a parallel mode with a large number of transformers with similar characteristic. The primary winding of the transformers is connected in Delta configuration while the secondary is in grounded star configuration. The network transformers are provided with a primary disconnect, which has no current interrupting rating and is used merely as in isolating device after the transformer has been de-energized both from primary and secondary source. The secondary bushings are mounted on the side wall of the transformer in a throat, suitable for mounting of the network protector.

Network protectors are special purpose low voltage air circuit breakers, designed for successful parallel operation of network transformers. Network protectors are fully self contained units, equipped with protective relays and instrument transformers to allow automatic closing and opening of the protector. The relays conduct a line test before initiating close command and allow closing of the breaker only if the associated transformer has the correct voltage condition in relation to the grid to permit flow of power from the transformer to the grid. If the conditions are not right, protector closing is blocked. The protector is also equipped with a reverse current relay that trips if the power flow reverses from its normal direction, i.e. if the power flows from grid into the transformer.

15.1 Degradation Mechanism

Since in a majority of the applications transformers are installed in below grade vaults, the transformer is designed for partially submersible operation with additional protection against corrosion. While network transformers are available in dry-type (cast coil and epoxy impregnation) designs, a vast majority of the network transformers employ mineral oil for insulation and cooling. The network transformer has a similar degradation mechanism to other distribution transformers.

The life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

The breaker design in network protectors employs mechanical linkages, rollers, springs and cams for operation which require periodic maintenance. All network protectors are equipped with special load-side fuses, mounted either internally or external to the network protector housing. The fuses are intended to allow normal load current and overloads while providing backup protection in the event that the protector fails to open on reverse fault current (due to faults internal to the protector or near transformer low voltage terminals). Every time arcing occurs in open air within the network protector housing, whether due to operation of the air breaker or because of fuse blowing (except silver sand), a certain amount of metal vapour is liberated and dispersed over insulating parts. Fuses evidently liberate more vapour than breaker operation. Over time, this buildup reduces the dielectric strength of insulating barriers. Eventually this may result in a breakdown, unless care is taken to clean the network protector internally, particularly after fuse operations.

Various parameters that impact the health and condition and eventually lead to end of life of a network include condition of mechanical moving parts, condition of inter phase barriers, number of protector operations (counter reading), accumulation of dirt or debris in protector housing, corrosion of protector housing, condition of fuses, condition of arc chutes and time period elapsed since last major overhaul of the protector.

The health of network protector is established by taking into account the following:

- Number of operations since last overhaul
- Operating age of protector

- Condition of operating mechanism
- Condition of fuses
- Condition of arc chutes
- Condition of protector relays
- Condition of gaskets and seals for submersible units

15.2 System Hierarchy

Network Transformers asset category belongs to the Distribution Transformers asset grouping.

15.3 Useful Life and Typical Life

This asset class can be componentized into the following:

- Transformer
- Vault
- Roof
- High Voltage (HV) Switch
- Secondary Network Protector

15.3.1 *Transformer*

The useful life range of the transformer is 20 to 50 years; typical life is 35 years.

15.3.2 *Vault*

The useful life range of the vault is 40 to 80 years; typical life is 60 years.

15.3.3 *Roof*

The useful life range of the roof is 20 to 40 years; typical life is 25 years.

15.3.4 *High Voltage Switch*

The useful life range of the HV switch is 30 to 50 years; typical life is 45 years.

15.3.5 *Secondary Network Protector*

The useful life range of the protector, assuming it is not waterproof enclosed is 20 to 40 years; typical life is 35 years. If the protector is waterproof, maximum useful life could be 50 years.

15.4 Time Based Maintenance Intervals

The typical routine inspection schedule for both the transformer and protector components is every two years.

15.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

16 Submersible Transformers

Submersible transformers typically employ sealed tank construction with corrosion resistance hardware and are liquid filled with mineral insulating oil.

16.1 Degradation Mechanism

The submersible transformer has a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

16.2 System Hierarchy

Submersible Transformers asset category belongs to the Distribution Transformers asset grouping.

16.3 Useful Life and Typical Life

This asset class can be componentized into the following:

- Transformer
- Vault
- Roof

16.3.1 *Transformer*

The useful life range of the submersible distribution transformers is 25 to 40 years; the typical life is 35 years.

16.3.2 *Vault*

The useful life range of the vault is 40 to 80 years; typical life is 60 years.

16.3.3 *Roof*

The useful life range of the roof is 20 to 40 years; typical life is 25 years.

16.4 Time Based Maintenance Intervals

The typical routine inspection schedule for the transformer component is every two years.

16.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

17 Indoor Vault Transformers

Similar to submersible transformers, indoor vault transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

17.1 Degradation Mechanism

The transformer has a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

17.2 System Hierarchy

Indoor Vault Transformers asset category belongs to the Distribution Transformers asset grouping.

17.3 Useful Life and Typical Life

This asset class can be componentized into the following:

- Transformer
- Vault
- Roof

17.3.1 *Transformer*

The useful life range of the indoor vault transformers is 25 to 40 years; the typical life is 35 years.

17.3.2 *Vault*

The useful life range of the vault is 40 to 80 years; typical life is 60 years.

17.3.3 *Roof*

The useful life range of the roof is 20 to 40 years; typical life is 25 years.

17.4 Time Based Maintenance Intervals

The typical routine inspection schedule for the transformer component is every two years.

17.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices;
- Utilization (electrical loading).

18 Underground Switchgear

Underground Switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, solid dielectric and gas insulated.

18.1 Degradation Mechanism

The Underground Switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

18.2 System Hierarchy

Underground Switchgear asset category belongs to the Underground Systems assets grouping.

18.3 Useful Life and Typical Life

The overall useful life range of the switchgear itself is dependent on the pad mount switchgear type:

- Air Insulated
- Gas Insulated
- Solid Dielectric

18.3.1 *Air Insulated*

The useful life range of this air insulated switchgear is 20 to 40 years; the typical life is 25 years.

18.3.2 *Gas Insulated*

The useful life range of this gas insulated switchgear is 30 to 50 years; the typical life is 30 years.

18.3.3 *Solid Dielectric*

The useful life range of this solid dielectric switchgear is 30 to 50 years; the typical life is 30 years.

18.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is three years.

18.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices
- Utilization (electrical loading).

19 Primary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The Consortium uses two cable types: paper insulated lead covered (PILC), and solid dielectric both in duct and direct buried. For the purposes of this report, solid dielectric cable refers to cross linked polyethylene (XLPE) cable and ethylene-propylene rubber (EPR).

19.1 Degradation Mechanism

For PILC cables, the two significant long-term degradation processes are corrosion of the lead sheath and dielectric degradation of the oil impregnated paper insulation. Isolated sites of corrosion resulting in moisture penetration or isolated sites of dielectric deterioration resulting in insulation breakdown can result in localized failures. However, if either of these conditions becomes widespread there will be frequent cable failures and the cable can be deemed to be at effective end-of-life.

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

19.2 System Hierarchy

Underground Primary Cables asset category belongs to the Underground Systems assets grouping.

19.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable type:

- Paper Insulated Lead Covered (PILC)
- Solid Dielectric - In Duct
- Solid Dielectric - Direct Buried

19.3.1 *Paper Insulated Lead Covered (PILC)*

The useful life range of PILC cable is 70 to 80 years; the typical life is 75 years.

19.3.2 *Solid Dielectric - In Duct*

The useful life range of direct buried solid dielectric cable is 40 to 60 years; the typical life is 40 years.

19.3.3 *Solid Dielectric - Direct Buried*

The useful life range of in duct solid dielectric cable is 20 to 25 years; the typical life is 25 years.

19.4 Time Based Maintenance Intervals

Underground Primary Cables are not subject to planned maintenance. These assets are typically subject to routine inspection every 3 to 6 years.

19.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Utilization (electrical loading).

20 Secondary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. Secondary underground cables are used to supply customer premises. The Consortium uses solid dielectric both in duct and direct buried. For the purposes of this report, solid dielectric cable refers to cross linked polyethylene (XLPE) cable and ethylene-propylene rubber (EPR).

20.1 Degradation Mechanism

For XLPE cables, the polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

20.2 System Hierarchy

Underground Secondary Cables asset category belongs to the Underground Systems assets grouping.

20.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable:

- In Duct
- Direct Buried

20.3.1 *In Duct*

The useful life range of direct buried solid dielectric cable is 40 to 60 years; the typical life is 40 years.

20.3.2 *Direct Buried*

The useful life range of in duct solid dielectric cable is 20 to 35 years; the typical life is 30 years.

20.4 Time Based Maintenance Intervals

Underground Secondary Cables are not subject to planned maintenance. These assets are typically subject to routine inspection where possible every 3 to 6 years.

20.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Utilization (electrical loading).

21 Ducts

In areas such as road crossings, ducts provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete. Ducts are sized as required and are usually two to six inches in diameter. This report discusses both concrete encased duct banks and directly buried pipes. The Consortium has three direct buried pipe types: Polyvinyl Chloride (PVC), High Density Polyethylene (HDPE) and Fiber Reinforced Epoxy (FRE).

21.1 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

21.2 System Hierarchy

The useful life range of the duct itself is dependent on whether they are concrete encased and the duct type:

- Concrete Encased Duct Banks
- Direct Buried Pipe
    - Polyvinyl Chloride (PVC)
    - High Density Polyethylene (HDPE)
    - Fiber Reinforced Epoxy (FRE)

21.2.1 *Concrete Encased Duct Banks*

The useful life range of concrete encased duct banks is 30 to 80 years; the typical life is 50 years.

21.2.2 *Direct Buried Pipe*

The useful life range of PVC duct is 30 to 75 years; the typical life is 50 years.

The useful life range of HDPE duct is 50 to 100 years; the typical life is 50 years.

The useful life range of FRE duct is 30 to 100 years; the typical life is 50 years.

21.3 Time Based Maintenance Intervals

Ducts are not subject to planned maintenance.

21.4 Utilization Factors

The useful life of this asset is not dependent on utilization factors.

22 Cable Chamber

Cable Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

22.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, cable chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, cable chamber chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Cable chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Cable chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a cable chamber system. Similarly, cable chamber systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with cable chambers also requires evaluation in assessing the overall condition of a cable chamber system.

22.2 System Hierarchy

Cable Chambers asset category belongs to the Underground Systems assets grouping.

22.3 Useful Life and Typical Life

Cable chambers have a useful life range of 50 to 80 years; the typical life range is 60 years.

22.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

22.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Maintenance practices.

23 Junction Cubicle & Service Box

This asset class consists of a wiring box similar to pad mount switchgear. For the purposes of this study there is reference to the junction cubicle and service boxes pads and bases, and junction/switching cabinets. However as a distinction from pad mount switchgear, some of the units are directly buried.

23.1 Degradation Mechanism

The main degradation associated with the junction cubicle casing is caused by outside sources. These include corrosion, vehicle damage, case rusting, and dirt or contamination.

23.2 System Hierarchy

Junction cubicle is used in the Underground Systems assets grouping.

23.3 Useful Life and Typical Life

The junction cubicle and service box can be componentized into two categories:

- Pads/Bases
- Junction/Switching Cabinet

23.3.1 *Pads/Bases*

The useful life of the pads/bases component is 30 to 80 years; the typical life is 60 years.

23.3.2 *Junction/Switching Cabinets*

The useful life of the junction/switching cabinet component is 25 to 50 years; the typical life is 40 years.

23.4 Time Based Maintenance Intervals

The typical routine maintenance and testing for the pads and bases of this asset category is every three years.

23.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Maintenance practices.

24 Station Grounding Transformer

Electrical distribution systems can be configured as a grounded or ungrounded system. A grounded system has an electrical connection between source and the earth, whereas an ungrounded system has no intentional connection. Sometimes it is necessary to create a ground on an ungrounded system for safety or to aid in protective relaying applications. Grounding transformers, smaller transformers similar in construction to power transformers, are used in this application.

24.1 Degradation Mechanism

Like a majority of transformers, the end of life for this asset is a result of insulation degradation, more specifically, the failure of pressboard and paper insulation. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

24.2 System Hierarchy

Station grounding transformers belong to the Transformer and Municipal Station asset grouping.

24.3 Useful Life and Typical Life

Station grounding transformers have a typical life range of 30 to 40 years; the typical life of this asset is 40 years.

24.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset class is three years.

24.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Utilization (electrical loading).

25 Station Service Transformer

The station service transformer is the supply system that provides power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. The most reliable source of such power is directly from the transmission or distribution lines. Small power transformers are configured to provide this requirement.

25.1 Degradation Mechanism

As with most transformers, end of life is typically a result of insulation failure, particularly paper insulation. The oil and paper insulation degrade as oxidation takes place in the presence of oxygen, high temperature, and moisture. Acids, particles, and static electricity also have degrading effects to the insulation.

25.2 System Hierarchy

The Station service transformer belongs to the Transformer and Municipal Station asset grouping.

25.3 Useful Life and Typical Life

The station service transformer has a useful life range of 32 to 55 years; the typical life is 45 years.

25.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is three years.

25.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Utilization (electrical loading).

26 TS Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA.

26.1 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

26.2 System Hierarchy

TS Power Transformer asset category belongs to the Transformer and Municipal Station asset grouping.

26.3 Useful Life and Typical Life

The power transformer also has major components that have different useful lives. Componentization is as follows:

- Overall
- Bushing
- Tap Changer

26.3.1 *Overall*

The useful life of the overall transformer is 32 to 55 years; the typical life is 45 years.

26.3.2 *Bushing*

The useful life range of the bushing is 20 to 40 years; the typical life is 30 years.

26.3.3 *Tap Changer*

The useful life range of tap changers is 20 to 60 years; the typical life is 30 years.

26.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is two years.

26.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices
- Utilization (electrical loading).

27 MS Power Transformers

Substation power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA.

27.1 Degradation Mechanism

The degradation of the power transformers at municipal stations or at customer sites is similar to that of the transformers at transmission stations. These transformers are subject to electrical, thermal, and mechanical aging. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

27.2 System Hierarchy

MS Power Transformer asset category belongs to the Transformer and Municipal Station asset grouping.

27.3 Useful Life and Typical Life

The power transformer also has major components that have different useful lives. Componentization is as follows:

- Overall
- Bushing
- Tap Changer

27.3.1 *Overall*

The useful life of the overall transformer is 32 to 55 years; the typical life is 45 years.

27.3.2 *Bushing*

The useful life range of the bushing is 20 to 40 years; the typical life is 30 years.

27.3.3 *Tap Changer*

The useful life range of tap changers is 20 to 60 years; the typical life is 30 years.

27.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is two years.

27.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices
- Utilization (electrical loading).

28 Medium Voltage Switchgear

The medium voltage (MV) switchgear asset category can be classified in two types: gas insulated and air insulated switchgear. The gear also is compartmentalized with separate compartments for removable breakers which have three types of interrupting mediums: air magnetic, vacuum and gas (SF6).

28.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor.

28.2 System Hierarchy

Switchgear asset category belongs to the Transformer and Municipal Station asset grouping.

28.3 Useful Life and Typical Life

The overall useful life range of the switchgear itself is dependent on the component, each of which has its own useful and typical life:

- Switchgear Assembly
  - Air Insulated
  - Gas (SF6) Insulated
- Removable Breaker
  - Air Magnetic
  - Vacuum
  - Gas (SF6)

28.3.1 *Switchgear Assembly*

The useful life range of air insulated switchgear assembly is 40 to 60 years; typical life is 50 years.

The useful life range of gas (SF6) insulated switchgear assembly is 40 to 60 years; typical life is 50 years.

28.3.2 *Breaker*

The useful life range of air magnetic type breaker in MV switchgear is 25 to 60 years; typical life is 40 years.

The useful life range of vacuum type breaker in MV switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of gas (SF6) type breaker in MV switchgear is 30 to 60 years; typical life is 42 years.

28.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

28.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices
- Utilization (electrical loading).

29 Independent Breakers

Circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. This report refers to five types of independent circuit breakers: oil, gas (SF6), air magnetic, air blast and vacuum.

The oil circuit breaker is the oldest type of breaker design and has been in use for over 70 years. Two types of designs exist among OCBs: bulk oil breakers (in which oil serves as the insulating and arc quenching medium) and minimum oil breakers (in which oil provides the arc quenching function only).

Gas, sulfur hexafluoride (SF6) insulated equipment is a relatively young technology. The first SF6 equipment was developed in the late 1960s. After some initial design and manufacturing problems equipment was increasingly used to replace oil filled equipment with widespread adoption and utilization since the mid 1980s. One of the more remarkable features of SF6 is its performance when subjected to an arc, or during a fault operation. SF6 is extremely stable and even at the high temperatures associated with an arc, limited breakdown occurs. Furthermore, most of the products of the breakdown recombine to form SF6. Consequently, SF6 circuit breakers can operate under fault conditions many more times than oil breakers before requiring maintenance.

In air magnetic circuit breakers, magnetic blowout coils are used to create a strong magnetic field that draws the arc into specially designed arc chutes. The breaker current flows through the blowout coils and produces a magnetic flux. This magnetic field drives the arc against barriers built perpendicular to the length of the arc. The cross sectional area of the arc is thereby reduced, and its resistance is considerably increased. The surface of the barriers cool and de-ionize the arc, thus collaborating to extinguish the arc.

Air-blast breakers use compressed air as the quenching, insulating and actuating medium. In normal operation, a blast of compressed air carries the arc into an arc chute where it is quickly extinguished. A combination cooler-muffler is often provided to cool ionized exhaust gases before they pass out into the atmosphere and to reduce noise during operation.

Vacuum Breakers consist of fixed and moving butt type contacts in small evacuated chambers (i.e. bottles). A bellows attached to the moving contact permits the required short stroke to occur with no vacuum losses. Arc interruption occurs at current zero after withdrawal of the moving contact. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully rated short circuits up to 100 times, and operate reliably over 30,000 or more switching operations. Vacuum breakers also are safe and protective of the environment.

29.1 Degradation Mechanism

Circuit breakers have many moving parts that are subject to wear and stress. They frequently “make” and “break” high currents and experience the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker’s specific duties. The following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs

- Changes in operating conditions, rendering the existing asset obsolete
- Maintenance overhaul requirements
- Circuit breaker age

Many of the earlier breakers relied on hydraulic or pneumatic assisted mechanisms. These have proved problematic in some cases and contributed significantly to the higher failure rates associated with this generation of equipment. More recent equipment usually utilize spring assisted mechanisms that have proved more reliable and require less maintenance.

29.1.1 *Oil Breakers*

For oil type circuit breakers the key degradation processes associated is as follows:

- Corrosion
- Effects of moisture
- Mechanical
- Bushing deterioration

The rate and severity of these degradation processes is dependent on a number of inter-related factors, in particular the operating duties and environment in which the equipment is installed. Often the critical degradation process is either corrosion or moisture ingress or a combination of the two, resulting in degradation to internal insulation, deterioration of the mechanism affecting the critical performance of the breaker, damage to major components such as bushings or widespread degradation to oil seals and structurally components.

Recent international experience indicates that a significant area of concern is barrier-bushing deterioration resulting from moisture ingress. The Synthetic Resin Bonded Paper (SRBP) insulation absorbs the moisture, which can result in discharge tracking across its surface leading to eventual failure of the bushing. Oil impregnated paper bushings are particularly sensitive to moisture. Once moisture finds its way into the oil and then into the paper insulation, it is very difficult to remove and can eventually lead to failure. Significant levels of moisture in the main tank can lead to general degradation of internal components and in acute cases free water can collect at the bottom of the tank. This creates a condition where a catastrophic failure could occur during operation.

Corrosion of the main tank and other structural components is also a concern. One area that is particularly susceptible to corrosion is underneath the main tank on the “bell end”, this problem is common to both single and three tank circuit breakers.

Corrosion of the mechanical linkages associated with the oil circuit breaker operating mechanism is also a widespread problem that can lead to the eventual seizure of the links.

A lesser mode of degradation, although still serious in certain circumstances, is pollution of bushings, particularly where the equipment is located by the sea or in a heavy industrial area.

Other areas of degradation include:

- Deterioration of contacts
- Wear of mechanical components such as bearings
- Loose primary connections
- Deterioration of concrete plinth affecting stability of the circuit breaker

29.1.2 *Gas (SF6) Breakers*

Failures relating to internal degradation and ultimate breakdown of insulation are limited to early life failures where design or manufacture led to specific problems. There is virtually no experience of failures

resulting from long term degradation within the SF6 chambers. Failures and incorrect operations are primarily related to gas leaks and problems with the mechanism and other ancillary systems. Gas seals and valves are a potential weak point. Clearly, loss of SF6 or ingress of moisture and air compromise the performance of the breaker. As would be expected the earlier SF6 equipment was more prone to these problems. Seals and valves have progressively been improved in more modern equipment.

29.1.3 *Air Blast Breakers*

The air blast circuit breaker has a similar degradation to other types of circuit breakers. The key degradation processes associated with air blast circuit breakers are:

- Corrosion
- Effects of moisture
- Bushing/insulator deterioration
- Mechanical

Severity and rate are dependent on factors such as operating duty and environment. Corrosion is a problem for most types of breakers. It can degrade internal insulators, performance mechanisms, major components (e.g. bushings), structural components, and oil seals. Moisture causes degradation of the insulating system. Mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections
- Oil contamination and/or leakage
- Deterioration of concrete foundation affecting stability of breakers

29.1.4 *Air Magnetic Breakers*

Air magnetic breakers have a similar degradation mechanism to other breakers in that corrosion; moisture, bushing/insulator deterioration, and mechanical degradation are factors.

29.1.5 *Vacuum Breakers*

The vacuum breakers in this asset class have a similar degradation mechanism to other breakers, where corrosion, moisture, bushing/insulator deterioration, and mechanical degradation are factors.

29.2 System Hierarchy

Independent breakers are belongs to the Transformer and Municipal Station asset grouping.

29.3 Useful Life and Typical Life

The useful life and typical life of independent breakers are based on breaker type:

- Oil
- Gas (SF6)
- Air Magnetic
- Air Blast
- Vacuum

29.3.1 *Oil*

The typical life range of the oil breaker is 30 to 60 years; the typical life is 42 years.

29.3.2 *Gas (SF6)*

The typical life range of the SF6 breaker is 30 to 60 years; typical life is 42 years.

29.3.3 *Air Magnetic*

The typical useful life range of the air magnetic breaker is 25 to 60 years; the typical life is 30 years.

29.3.4 *Air Blast*

The typical useful life range of the air blast breaker is 30 to 50 years; the typical life is 40 years.

29.3.5 *Vacuum*

The typical useful life range of the vacuum breaker is 30 to 60 years; the typical life is 40 years.

29.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for oil breakers is three years.

29.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices
- Utilization (electrical loading).

30 Protective and Control Devices

This asset of protective and control devices are classified into panels, control cables and relays.

Relays are classified into of three types, electromechanical, solid state and digital. The function of these relays is to increase long term reliability. The protection relays work to detect and isolate faults on the system by opening and closing the circuit breakers.

30.1 Degradation Mechanism

The degradation of protective and control devices is primarily based on the degradation of relays. Degradation of relay contacts is due to the following factors:

- Contact oxidation
- Contact welding or pitting due to excessive current
- Chemical corrosion

In the case of degradation of relay moving parts, such as wear of moving parts like spring/armature, the major contributing factor is the wear after numerous switching cycles.

Degradation on relay coils is mainly a thermal aging issue due to continuous energization or elevated cabinet temperatures. Excessive heat generated by coil or associated components may cause the coil to burn out or adversely affect other nearby components or components within the relay or nearby (e.g. chemical breakdown of varnishes causing contact contamination, or change in component dimensions).

30.1.1 *Electromechanical Relays*

As a consequence, the failure mode of an electromechanical relay can be:

- Failure to actuate when commanded
- Actuates without command
- Does not make or break current
- Failure to carry current
- High contact resistance
- Set-point shift
- Time delay shift

To assess the health status of an electromechanical relay, the following condition parameters are studied:

- Operating mechanism, including contact, coil, spring, insulation, connection and component replacement
- Recalibration, including recalibration record and relay functionality (e.g., over current, distance etc.)
- Reliability, including mal-operation count, loading and age

30.1.2 *Solid State Relays*

Physical degradation of a solid state relay is similar to the overall degradation of relays. Solid state relays are particularly sensitive to ambient environmental conditions.

30.1.3 *Digital Relays*

Physical degradation of digital relays happen on hardware part of digital relays. Compared to solid state relays, digital relays are not sensitive to ambient environment. The major contributing factor of

degradation is the electrical environment, i.e. inrush transient. Since digital relays have built-in self-supervision system, the settings with perfect long time stability is guaranteed.

The failure mode of a digital relay can be:

- Fail to trip because communication port is held by defective external equipment
- Mal-function due to hardware/firmware/software version mismatch
- Mal-function due to software design flaw causing software latched by external EMI interference
- On strike due to power supply failure

To assess the health status of a digital relay, the following condition parameters are studied:

- Operating mechanism, including power supply, insulation, connection
- Recalibration, including recalibration record and relay functionality (e.g., over current, distance etc.)
- Reliability, including mal-operation count, loading and age

30.2 System Hierarchy

Protection and control devices belong to the Transformer and Municipal Station asset grouping.

30.3 Useful Life and Typical Life

This asset is classified into two components each of which has a different useful life:

- Panels
- Control Cables
- Relays
    - Electromechanical
    - Solid State
    - Digital

30.3.1 *Panels*

The useful life range of the panel is 40 to 60 years; the typical life is 40 years.

30.3.2 *Control Cables*

The useful life range of the control cable is 25 to 50 years; the typical life is 40 years.

30.3.3 *Relays*

The useful life range of the electromechanical type is 20 to 50 years; the typical life is 30 years.

The useful life range of the solid state type is 10 to 50 years; the typical life is 30 years.

The useful life range of the digital type is 10 to 20 years; the typical life is 15 years.

30.4 Time Based Maintenance Intervals

Protection and control relays are not subject to planned maintenance.

30.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Operating practices

31 Station Disconnect Switch

This asset class consists of the disconnect switches used to physically and electrically isolate sections of the power system for the purposes of maintenance, safety, and other operational requirements. Switches typically consist of manual or motor operated isolating devices mounted on support insulators and metal support structures. Many high voltage disconnect switches (e.g. line and transformer isolating switches) have motor-operators and the capability of remote-controlled operation. These switches are normally operated when there is no current through the switch, unless specifically designed to be capable of operating under load.

31.1 Degradation Mechanism

Disconnect switches have many moving parts that are subject to wear and operational stress. Except for parts contained in motor-operator cabinets, switch components are exposed to the ambient environment. Thus, environmental factors, along with operating conditions, vintage, design, and configuration all contribute to switch degradation. Critical degradation processes include corrosion, moisture ingress, and ice formation. A combination of these factors that may result in permanent damage to major components such as contacts, blades, bearings, drives and support insulators.

Generally, the following represent key end-of-life factors for disconnect switches:

- Decreasing reliability, availability, and maintainability
- High maintenance and operating costs
- Maintenance overhaul requirements
- Obsolete design, lack of parts and service support
- Switch age

Application criticality and manufacturer also play key roles in determining the end-of-life for disconnect switches. Generally, absent a major burnout, widespread deterioration of live components, support insulators, motor-operators, and drive linkages define the end-of-life for these switches. However, routine maintenance programs usually provide ample opportunity to assess switch condition and viability.

Disconnect switches have components fabricated from dissimilar materials, and use of these different materials influences degradation. For example, blade, hinge and jaw contacts may consist of combinations of copper, aluminum, silver and stainless steel, several of which have tin, silver and chrome plating. Further switch bases may consist of galvanized steel or aluminum.

Most disconnect switches have porcelain support and rotating insulators. The porcelain offers rigidity, strength and dielectric characteristics needed for reliability. However, excessive deflection or deformation of support or rotating stack insulators can cause blade misalignment and other problems, resulting in operational failures.

Disconnect switches must have the ability to open and close properly even with heavy ice build-up on their blades and contacts. However, these switches may sit idle for several months or more. This infrequent operation may lead to corrosion and water ingress damage, increasing the potential for component seizures. Bearings commonly seize from poor lubrication and sealing, despite manufacturers' claims that such components are sealed, greaseless and maintenance-free for life.

Normally, when blades enter or leave jaw contacts, they rotate to clean accumulated ice from contact surfaces. To accomplish this, hinge ends have rotating or other current transfer contacts. These contacts are often simple, long-life copper braids. However, some switches have more complex rotating contacts in grease-filled chambers. Without proper maintenance these more complex switches may degrade, causing blade failures.

31.2 System Hierarchy

The station disconnect switch is a part of the Transformer and Municipal Station asset grouping.

31.3 Useful Life and Typical Life

This asset has a useful life range of 30 to 50 years; the typical life is 45 years.

31.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is every 6 years. Utilities will typically increase diagnostic testing to justify the increase of maintenance intervals.

31.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices
- Utilization (electrical loading).

32 Direct Current System

Direct current (DC) systems are critical to the safe and efficient operation of transformer cooling, switchgear and protection & control. This asset category has been componentized into batteries, chargers and other DC distribution equipment. Maintaining batteries in a condition capable of delivering the necessary energy as required is essential.

Batteries consist of multiple individual cells. For the purposes of this report, these are lead-acid battery banks. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the battery banks.

32.1 Degradation Mechanism

The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery. The ability to detect significant deterioration and pre-empt battery failure is especially critical if monitoring and alarm systems are not installed.

Historically, battery end-of-life was determined mainly by a number of factors including age, appearance (indication of physical deterioration) and the history of specific gravity and cell voltage measurements. Presently, the battery load test is now considered the “best” indicator of battery condition. This test is now used to identify and confirm the condition of suspect batteries identified from the previous tests.

Battery chargers are also critical to the satisfactory performance of the whole battery system. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

For battery chargers, diagnostic testing programs are coordinated with the battery maintenance program. This involves a number of functional tests and each test has a defined TP/TF criteria. Failure of any functional test may lead to further investigations or consideration of replacement.

Due to the critical functionality of batteries, most utilities take a conservative approach towards battery replacement: any significant evidence of battery deterioration usually leads to decisions to replace the battery.

32.2 System Hierarchy

DC System asset category belongs to the Transformer and Municipal Station assets grouping.

32.3 Useful Life and Typical Life

This asset is classified into three major components, each of which has a different useful life:

- Battery
- Charger
- DC Distribution Equipment

32.3.1 *Battery*

The useful life range of the battery component is 10 to 30 years; the typical life is 20 years.

32.3.2 *Charger*

The useful life range of the charger component is 20 to 30 years; the typical life is 20 years.

32.3.3 *DC Distribution Equipment*

The useful life range of the charger component is 10 to 30 years; the typical life is 20 years.

32.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is every year.

32.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Maintenance practices;
- Operating practices

33 Station Grounding System

Grounding systems in stations dissipate maximum ground fault currents without interfering with power system operation or causing voltages dangerous to people or equipment. Safety hazards from inadequate grounding include excessive ground potential rises and excessive step and touch potentials. Generally, grounding system assets provide suitable paths for ground currents to follow from power equipment and conductors into the earth. Consequently, complete grounding systems include buried conductors, ground rods and connections, plus soil and vegetation in the area. Soil and vegetative conditions affect water retention and drainage, which impact overall performance of the grounding system. For the purposes of this report, the station grounding system has been componentized into four categories: the ground grid, neutral reactors, arresters and sky wire.

33.1 Degradation Mechanism

Station grounding systems keep ground potential rise, step and touch potentials below specified limits when maximum (i.e. worst case) ground faults occur. Under fault conditions, the following factors determine step and touch potentials:

- Magnitude of the fault current
- Resistance of ground combined with the ground grid consisting of station electrodes, transmission line sky wires and distribution neutrals
- Ground resistivity of upper and lower layers of earth.
- Prolonged exposure to severe environment

Increases in system capacity and fault currents at a station may lead to unacceptable performance of the ground grid. Corrosion of buried conductors and connectors, mechanical damage to buried electrodes, plus burning-off of grounding conductors and connectors during heavy fault currents also may lead to unsatisfactory performance. Further, changes in resistivity of upper or lower layers of earth may adversely affect ground grid characteristics.

33.2 System Hierarchy

Grounding systems used in both the Transformer and Municipal Station asset grouping.

33.3 Useful Life and Typical Life

The station grounding system consists of four components each with its own useful life values:

- Ground Grid
- Neutral Reactors
- Arresters
- Sky Wire

33.3.1 *Ground Grid*

The ground grid component has a useful life range of 25 to 50 years; the typical life is 40 years.

33.3.2 *Neutral Reactors*

The neutral reactor component has a useful life range of 25 to 60 years; the typical life is 45 years.

33.3.3 *Arresters*

The arrester component has a useful life range of 10 to 30 years; the typical life is 20 years.

RESULTS AND FINDINGS

0 The useful life of this asset is not dependent on utilization factors.

33.3.4 *Sky Wire*

The sky wire component has a useful life range of 30 to 50 years; the typical life is 45 years.

33.4 Time Based Maintenance Intervals

Station grounding systems are not subject to planned maintenance.

33.5 Utilization Factors

The useful life of this asset is not dependent on utilization factors.

34 Bus Work and Steel Structures

There are a number of different types of structures at distribution stations for supporting buses and equipment. The predominant types are galvanized steel, either lattice or hollow sections.

34.1 Degradation Mechanism

Degradation or reduction in strength of steel structures can result from corrosion, structural fatigue, or gradual deterioration of foundation components.

Corrosion of lattice steel members and hardware reduces their cross-sectional area causing a reduction in strength. Similarly, corrosion of tubular steel poles reduces the effectiveness of the tubular walls. Rates of corrosion may vary, depending upon environmental and climatic conditions (e.g., the presence of salt spray in coastal areas or heavy industrial pollution).

Structural fatigue results from repeated structural loading and unloading of support members. Temperature variations, plus wind and ice loadings lead to changes in conductor tension. Tension changes result in structural load variations on angle and dead end towers. Other changes such as foundation displacements and breaks in wires, guys and anchors may result in abnormal tower loading.

Typically, steel pole foundations are cylindrical steel reinforced concrete structures with anchor bolts connecting the pole to its base. Common degradation processes include corrosion of foundation rebar, concrete spalling and storm damage.

34.2 System Hierarchy

Bus Work and Steel Structures belongs to the Transformer and Municipal Station asset grouping.

34.3 Useful Life and Typical Life

The useful life of bus work and steel structures is in the range of 35 to100 years and the typical life is 50 years.

34.4 Time Based Maintenance Intervals

Bus work and steel structures are not subject to planned maintenance.

34.5 Utilization Factors

The useful life of this asset is not dependent on utilization factors.

35 Station Buildings

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the building structure itself, the roof and fence.

35.1 Degradation Mechanism

The following contribute to the degradation of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements
- Environmental concerns
- Functional requirements

Buildings are a very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life. Rather impacts such as environmental rain, wind and snow storms contribute highly to the degradation of buildings.

Also, since the foundation materials typically consist of reinforced concrete designed to consider environmental elements including soil conditions and climate. Landscaping is used to control soil erosion, maintain site cleanliness and facilitate an efficient and safe work environment.

Preventative maintenance helps ensure long-term integrity of buildings. This type of maintenance should be done on a regular basis. As well the occasional refurbishment of doors, windows and roofs helps with the viability of the building.

The building roof is the most susceptible to degradation due to environmental factors. The roof is typically level and composed of tar and an aggregate that is designed to keep the wind from wearing at the tar. Nevertheless, the roof is still susceptible to environmental degradation and if not sealed properly can become a source of flooding. The maintenance of the roof is generally the largest undertaking for buildings.

35.2 System Hierarchy

Distribution building asset category belongs to the Transformer and Municipal Station asset grouping.

35.3 Useful Life and Typical Life

This asset has three major components, each of which has a different useful life. From a maintenance practice perspective, the building can be componentized into the following:

- Structure
- Roof
- Fence

35.3.1 *Structure*

The useful life of the structure component of the building can be in the range of 30 to 80 years, with a typical life of 50 years.

35.3.2 *Roof*

The useful life of the roof can be in the range of 15 to 30 years, with a typical life of 20 years.

35.3.3 *Fence*

The useful life range of the fence is 30 to 60 years, with a typical life of 35 years.

35.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is every year.

35.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factor:

- Maintenance practices.

36 Metering

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on smart meters, industrial/commercial meters and wholesale meters. This asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT). A smart meter is an advanced meter is an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via some network back to the local utility for monitoring and billing purposes.

36.1 Degradation Mechanism

The major degradation mechanism of traditional meters is listed as follows:

- Electronic component aging due to long-term power quality impact, for solid-state meters
- Meter creep due to high temperature for induction type meters. This occurs when the meter disc rotates continuously with potential applied and the load terminals open circuited
- Magnetization alteration due to overload or short-circuited conditions
- Mechanical damage due to vibration of meter mounting
- Other adverse operating environment that might expedite the aging of components, such as humidity or dirt

The major degradation mechanism of smart metering system is listed as follows:

- Wiring insulation deterioration due to corrosion, moisture or overheating
- Poor electrical connections due to corrosion, vibration or other physical problems
- Cabinetry or rack damage or wear
- Faulty electronic components

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur. When water enters equipment rooms through roof or other leaks, it can affect performance and aggravate corrosion.

36.2 System Hierarchy

Metering belongs to the Monitoring and Control Systems assets grouping.

36.3 Useful Life and Typical Life

The overall useful life range of the meter itself is dependent on the meter type and component, which can be broken down into the following:

- Smart
- Industrial/Commercial
- Wholesale
- Transformer (CT,PT)

RESULTS AND FINDINGS *0 The useful life of this asset is not dependent on utilization factors.*

36.3.1 *Smart Meter*

The useful life range of the smart meter is 15 to 20 years; typical life is 15 years.

36.3.2 *Industrial/Commercial*

The useful life range of industrial/commercial type meter is 20 to 60 years; typical life is 30 years.

36.3.3 *Wholesale*

The useful life range of wholesale type meter is 20 to 60 years; typical life is 30 years.

36.3.4 *Transformer*

The useful life range of the current transformer components is 30 to 50 years; typical life is 45 years.

The useful life range of the potential transformer components is 30 to 50 years; typical life is 45 years.

36.4 Time Based Maintenance Intervals

Meters are not subject to planned maintenance.

36.5 Utilization Factors

The useful life of this asset is not dependent on utilization factors.

37 SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

37.1 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution, and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

37.2 System Hierarchy

SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

37.3 Useful Life and Typical Life

SCADA has been broken down into two components, each with its own useful life values:

- Remote Terminal Unit (RTU)
- Battery

37.3.1 *Remote Terminal Unit (RTU)*

The useful life of the SCADA RTU is in the range of 10 to 30 years; the typical life is 20 years.

37.3.2 *Battery*

The useful life of the SCADA battery is in the range of 10 to 15 years; the typical life is 15 years.

37.4 Time Based Maintenance Intervals

SCADA are not subject to planned maintenance.

37.5 Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Operating practices

38 Smart Fault Indicators

Fault indicators are used for loaded underground distribution circuits where secondary voltage is available. A sensor monitors the line current. When the trip rating is exceeded, the indicator trips to the fault position. To reset the display the fault indicator uses a secondary voltage source, such as the low-voltage terminals of distribution transformers. For the purposes of this report, only smart fault indicators will be discussed.

38.1 Degradation Mechanism

T he major contributing factor of the degradation of smart fault indicators is the electrical environment, i.e. inrush transient.

The failure mode of smart fault indicators can be:

- Fail to trip because communication port is held by defective external equipment
- Mal-function due to hardware/firmware/software version mismatch
- Will not operate due to power supply failure

To assess the health status of a smart fault indicator, the following condition parameters are studied:

- Operating mechanism, including power supply, insulation, connection
- Recalibration, including recalibration record and relay functionality (e.g., overcurrent, distance etc.)
- Reliability, including mal-operation count, loading and age

38.2 System Hierarchy

Smart fault indicators asset category belongs to the Monitoring and Control Systems assets grouping.

38.3 Useful Life and Typical Life

The useful life of the smart fault indicators is in the range of 10 to 15 years; the typical life is 15 years.

38.4 Time Based Maintenance Intervals

Smart fault indicators are not subject to planned maintenance.

38.5 Impact of Utilization Factors

The useful life of this asset is dependent on the following utilization factors:

- Operating practices

39 Communication Towers

A communication tower is used to communicate via some network back to the local utility for monitoring and billing purposes.

39.1 Degradation Mechanism

The major degradation mechanism of smart metering system is listed as follows:

- Cabinetry or rack damage or wear
- Faulty electronic components

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur.

39.2 System Hierarchy

Communication Towers belong to the Monitoring and Control Systems assets grouping.

39.3 Useful Life and Typical Life

The useful life range of the communication tower is 35 to 100 years; typical life is 63 years.

39.4 Time Based Maintenance Intervals

Communication towers are not subject to planned maintenance.

39.5 Utilization Factors

The useful life of this asset is not dependent on utilization factors.

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APPENDIX 4-9: 2011-2014 FINAL RESULTS REPORT

CAMBRIDGE & NORTH DUMFRIES HYDRO

Message from the Vice President:

The IESO is pleased to provide the enclosed 2011-2014 Final Results Report. This report is designed to help populate LDC Annual Reports that will be submitted to the Ontario Energy Board (OEB) in September 2015.

2011-2014 Conservation Framework Highlights:

- LDCs have made significant achievements against dual energy and peak demand savings targets. Collectively, the LDCs have achieved 109% of the energy target and 70% of the peak demand target.
- Momentum has built as we transition to the Conservation First Framework. 2014 demonstrated an achievement of over 1 TWh of net incremental energy savings, positioning us well for average net incremental energy savings of 1.2 TWh required in the new framework to meet our 2020 CDM targets.
- Throughout the past framework, program results have become more predictable year over year as noted in the increasingly smaller variance between quarterly preliminary results and verified final results.
- Customer engagement continued to increase in both the Consumer and Business Programs. Between 2011 - 2014 consumers have purchased over 10 million energy efficient products through the saveONenergy COUPONS program. Customers in RETROFIT continue to declare a positive experience participating in the program with 86% likely to recommend.
- saveONenergy has seen a steady and significant increase in unaided brand awareness by 33% from 2011-2014
- Conservation is becoming even more cost-effective as programs become more efficient and effective. 2014 proved early investments in long lead time projects will pay off with the high savings now being realized in programs like PROCESS & SYSTEMS and RETROFIT. Within 4 cents per kWh, Conservation programs continue to be a valuable and cost effective resource for customers across the province.

The 2011-2014 Final Results within this report vary from the Draft 2011-2014 Final Results Report for the following reasons:

- Savings from Time of Use pricing are included in the Final Results Report. Overall the province saved 55 MWs from Time-of-Use pricing in 2014, or 0.73% of residential summer peak demand.
- Between August 4th and August 28th, the IESO and LDCs have worked collaboratively to reconcile projects from 2011-2014 Final Results Report to ensure every eligible project was captured and accurately reported.
- Verified savings from Innovation Fund pilots are also included for participating LDCs.

All results will be considered final for the 2011-2014 Conservation Framework. Any additional program activity not captured in the 2011-2014 Final Results Report will not be included as part of a future adjustment process.

Please continue to monitor saveONenergy E-blasts for future updates and should you have any other questions or comments please contact LDC.Support@ieso.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process and we look forward to the success ahead in the Conservation First Framework.

Sincerely,

Terry Young

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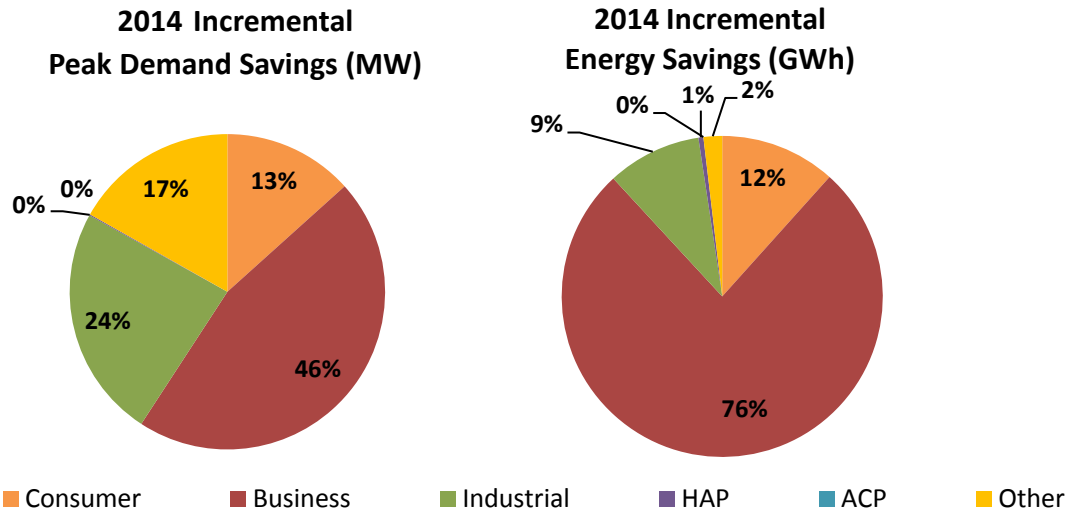
IESO-Contracted Province-Wide CDM Programs: 2011-2014 Final Results Report

LDC: Cambridge and North Dumfries Hydro Inc.

Final 2014 Achievement Against Targets	2014 Incremental	2011-2014 Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	5.6	11.9	**67.4%**
Net Energy Savings (GWh)	20.2	120.5	**163.6%**

Unless otherwise noted, results are presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Achievement by Sector



Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)

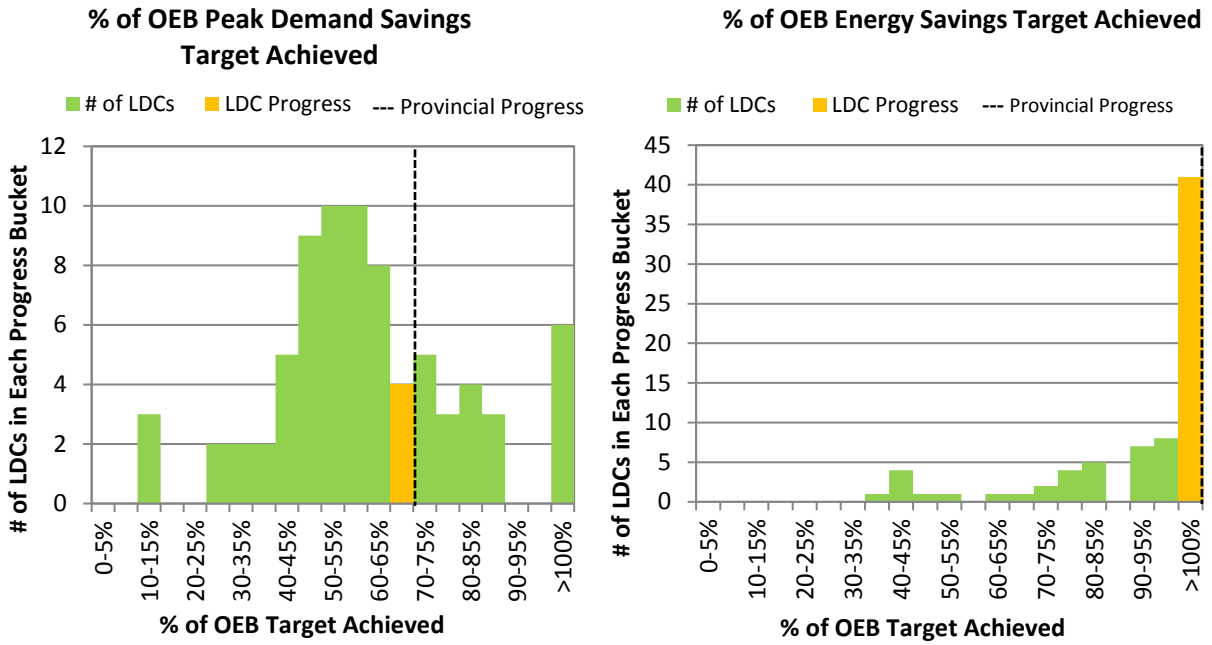


Table 1: Cambridge and North Dumfries Hydro Inc. Initiative and Program Level Net Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
														2014	2014
Consumer Program															
Appliance Retirement	Appliances	440	175	98	83	24	9	6	5	175,906	67,918	42,616	36,516	45	1,028,921
Appliance Exchange	Appliances	23	25	51	53	2	4	11	11	2,690	6,491	18,841	19,580	26	86,144
HVAC Incentives	Equipment	978	1,115	1,427	1,697	359	248	285	328	670,601	428,617	489,074	603,250	1,220	5,549,652
Conservation Instant Coupon Booklet	Items	4,891	296	3,332	10,539	11	2	5	21	179,901	13,391	73,819	286,647	39	1,194,066
Bi-Annual Retailer Event	Items	9,119	10,161	9,049	46,209	16	14	11	77	281,459	256,502	164,540	1,177,103	119	3,401,526
Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	82	0	131	473	46	0	50	167	0	0	129	0	167	129
Residential Demand Response (IHD)	Devices	0	0	0	334	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	18	0	0	0	4	0	0	0	22,425	4	22,425
Consumer Program Total						**458**	**277**	**369**	**614**	**1,310,556**	**772,919**	**789,021**	**2,145,522**	**1,620**	**11,282,863**
Business Program															
Retrofit	Projects	23	121	161	148	256	1,203	1,377	1,818	1,336,743	6,206,217	7,268,169	13,491,681	4,625	51,859,650
Direct Install Lighting	Projects	123	108	39	84	158	95	54	111	398,982	356,510	188,436	383,422	388	3,341,957
Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Construction	Buildings	0	1	2	2	0	0	60	5	0	0	337,062	18,778	66	692,903
Energy Audit	Audits	0	1	4	3	0	5	26	40	0	25,176	145,352	195,821	72	562,054
Small Commercial Demand Response	Devices	1	0	1	0	1	0	1	0	0	0	1	0	0	1
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	3	3	4	3	180	180	346	136	7,018	2,621	5,215	0	136	14,854
Business Program Total						**595**	**1,483**	**1,864**	**2,110**	**1,742,744**	**6,590,523**	**7,944,236**	**14,089,702**	**5,286**	**56,471,419**
Industrial Program															
Process & System Upgrades	Projects	0	0	0	1	0	0	80	151	0	0	691,097	1,318,000	230	2,700,194
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	2	10	22	0	0	33	78	0	0	175,934	430,152	89	638,332
Retrofit	Projects	22	0	0	0	466	0	0	0	3,083,118	0	0	0	466	12,332,473
Demand Response 3	Facilities	6	7	4	6	544	705	525	870	31,908	16,979	11,952	0	870	60,838
Industrial Program Total						**1,009**	**705**	**637**	**1,098**	**3,115,026**	**16,979**	**878,983**	**1,748,152**	**1,655**	**15,731,836**
Home Assistance Program															
Home Assistance Program	Homes	0	33	1,057	252	0	1	31	5	0	11,421	458,390	91,897	37	1,040,249
Home Assistance Program Total						**0**	**1**	**31**	**5**	**0**	**11,421**	**458,390**	**91,897**	**37**	**1,040,249**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	64	0	0	0	1,191	0	0	0	6,710,956	0	0	0	1,191	26,843,823
High Performance New Construction	Projects	2	0	2	0	11	1	0	0	57,223	1,049	0	0	12	232,038
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total						**1,202**	**1**	**0**	**0**	**6,768,179**	**1,049**	**0**	**0**	**1,203**	**27,075,862**
Other															
Program Enabled Savings	Projects	0	4	5	10	0	0	8	46	0	0	51,500	345,824	54	448,824
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	728	0	0	0	0	728	0
LDC Pilots	Projects	0	0	0	1,157	0	0	0	624	0	0	0	461,513	624	461,513
Other Total						**0**	**0**	**8**	**775**	**0**	**0**	**51,500**	**345,824**	**1,406**	**910,337**
Adjustments to 2011 Verified Results							**63**	**0**	**24**		**517,468**	**0**	**89,603**	**87**	**2,428,282**
Adjustments to 2012 Verified Results								**302**	**81**			**830,319**	**511,136**	**383**	**4,055,300**
Adjustments to 2013 Verified Results									**236**				**753,448**	**236**	**1,486,290**
Energy Efficiency Total						**2,494**	**1,582**	**1,988**	**4,053**	**12,897,579**	**7,373,292**	**10,104,833**	**18,882,610**	**10,034**	**112,436,744**
Demand Response Total (Scenario 1)						**770**	**885**	**921**	**1,173**	**38,926**	**19,599**	**17,297**	**0**	**1,173**	**75,822**
Adjustments to Previous Years' Verified Results Total						**0**	**63**	**302**	**340**	**0**	**517,468**	**830,319**	**1,354,186**	**705**	**7,969,873**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**3,264**	**2,530**	**3,211**	**5,566**	**12,936,504**	**7,910,359**	**10,952,449**	**20,236,797**	**11,912**	**120,482,439**
													Full OEB Target:	**17,680**	**73,660,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**67.4%**	**163.6%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a

Table 2: Adjustments to Cambridge and North Dumfries Hydro Inc. Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-242	43	80		-70	9	17		-130,311	18,628	29,564		-44	-406,233
Conservation Instant Coupon Booklet	Items	79	0	10		0	0	0		2,640	0	226		0	11,012
Bi-Annual Retailer Event	Items	784	0	0		1	0	0		20,911	0	0		1	83,646
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	0		0	0	0		0	0	0		0	0
Consumer Program Total						**-69**	**9**	**17**		**-106,759**	**18,628**	**29,790**		**-42**	**-311,574**
Business Program															
Retrofit	Projects	1	17	15		53	169	225		282,442	935,719	1,052,676		440	6,017,778
Direct Install Lighting	Projects	5	0	0		4	0	0		8,048	0	0		4	32,191
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	1	0		0	2	0		0	9,363	0		2	28,089
Energy Audit	Audits	0	0	1		0	0	9		0	854	48,579		9	99,721
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**57**	**171**	**234**		**290,490**	**945,936**	**1,101,256**		**454**	**6,177,778**
Industrial Program															
Process & System Upgrades	Projects	0	0	-1		0	0	-80		0	0	-691,097		-80	-1,382,194
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	2	1		0	26	1		0	231,203	15,440		30	754,453
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**0**	**26**	**-79**		**0**	**231,203**	**-675,657**		**-49**	**-627,741**
Home Assistance Program															
Home Assistance Program	Homes	0	19	16		0	1	1		0	14,057	9,851		2	61,545
Home Assistance Program Total						**0**	**1**	**1**		**0**	**14,057**	**9,851**		**2**	**61,545**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0		0	0	0		0	0
High Performance New Construction	Projects	1	0	2		75	0	39		333,737	0	201,151		114	1,737,253
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**75**	**0**	**39**		**333,737**	**0**	**201,151**		**114**	**1,737,253**
Other															
Program Enabled Savings	Projects	3	4	4		24	180	23		89,603	147,100	66,452		227	932,612
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
LDC Pilots	Projects	0	0	0		0	0	0		0	0	0		0	0
Other Total						**24**	**180**	**23**		**89,603**	**147,100**	**66,452**		**227**	**932,612**
Adjustments to 2011 Verified Results						**87**				**607,070**				**87**	**2,428,282**
Adjustments to 2012 Verified Results							**388**				**1,356,923**			**383**	**4,055,300**
Adjustments to 2013 Verified Results								**235**				**732,842**		**236**	**1,486,290**
Total Adjustments to Previous Years' Verified Results						**87**	**388**	**235**		**607,070**	**1,356,923**	**732,842**		**705**	**7,969,873**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 3: Cambridge and North Dumfries Hydro Inc. Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a	n/a	0.50	0.46	0.42	0.42	1.00	1.00	n/a	n/a	0.51	0.46	0.44	0.44
Appliance Exchange	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	n/a	1.00	0.60	0.50	0.48	0.51	1.00	1.00	n/a	1.00	0.60	0.49	0.48	0.51
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.68	1.00	1.00	1.00	1.00	1.11	1.05	1.13	1.70
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.13	0.91	1.04	1.74	1.00	1.00	1.00	1.00	1.10	0.92	1.04	1.75
Retailer Co-op	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	n/a	n/a	n/a	0.92	n/a	n/a	n/a	0.63	n/a	n/a	n/a	0.53	n/a	n/a	n/a	0.63
Business Program																
Retrofit	0.93	0.96	0.97	0.88	0.74	0.74	0.72	0.73	1.28	1.04	1.03	0.99	0.76	0.74	0.74	0.73
Direct Install Lighting	1.08	0.68	0.81	0.78	0.93	0.94	0.94	0.94	0.90	0.85	0.84	0.83	0.93	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
New Construction	n/a	n/a	0.58	0.44	n/a	n/a	0.54	0.54	n/a	n/a	0.92	0.82	n/a	n/a	0.54	0.54
Energy Audit	n/a	n/a	1.02	0.96	n/a	n/a	0.66	0.68	n/a	n/a	0.97	1.00	n/a	n/a	0.66	0.67
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	1.04	0.96	n/a	n/a	0.94	1.00	n/a	n/a	1.04	0.96	n/a	n/a	0.93	1.00
Monitoring & Targeting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Energy Manager	n/a	n/a	0.90	0.91	n/a	n/a	0.90	0.90	n/a	n/a	0.90	0.96	n/a	n/a	0.90	0.90
Retrofit																
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	n/a	1.49	0.89	0.89	n/a	1.00	1.00	1.00	n/a	1.00	0.84	0.70	n/a	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.77	n/a	n/a	n/a	0.52	n/a	n/a	n/a	0.77	n/a	n/a	n/a	0.52	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50
Toronto Comprehensive	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	n/a	1.00	0.94	n/a	n/a	1.00	1.00	n/a	n/a	1.00	0.98	n/a	n/a	1.00	1.00
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Pilots	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Achievement Against CDM Targets

Results are recognized using current IESO reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenario 1). Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	3.3	2.5	2.5	2.5
2012 - Verified†	0.1	2.5	1.6	1.6
2013 - Verified†	0.0	0.3	3.2	2.3
2014 - Verified†	0.0	0.1	0.3	5.6
Verified Net Annual Peak Demand Savings Persisting in 2014:				**11.9**
Cambridge and North Dumfries Hydro Inc. 2014 Annual CDM Capacity Target:				**17.7**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**67.4%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	12.9	12.9	12.9	12.8	51.5
2012 - Verified†	0.5	7.9	7.9	7.8	24.1
2013 - Verified†	0.0	0.8	11.0	10.8	22.5
2014 - Verified†	0.1	0.6	1.35	20.2	22.3
Verified Net Cumulative Energy Savings 2011-2014:					**120.5**
Cambridge and North Dumfries Hydro Inc. 2011-2014 Annual CDM Energy Target:					**73.7**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**163.6%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes CDM)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146	20,952	22,563	3,299	2,011	1,433	1,617	23,005,812	13,424,518	8,713,107	9,497,343	8,221	159,100,415
Appliance Exchange	Appliances	3,688	3,836	5,337	5,685	371	556	1,106	1,178	450,187	974,621	1,971,701	2,100,266	2,973	10,556,192
HVAC Incentives	Equipment	92,748	87,540	96,286	113,002	32,037	19,060	19,552	23,106	59,437,670	32,841,283	33,923,592	42,888,217	93,755	447,009,930
Conservation Instant Coupon Booklet	Items	567,678	30,891	347,946	1,208,108	1,344	230	517	2,440	21,211,537	1,398,202	7,707,573	32,802,537	4,531	137,258,436
Bi-Annual Retailer Event	Items	952,149	1,060,901	944,772	4,824,751	1,681	1,480	1,184	8,043	29,387,468	26,781,674	17,179,841	122,902,769	12,389	355,157,348
Retailer Co-op	Items	152	0	0	0	0	0	0	0	2,652	0	0	0	0	10,607
Residential Demand Response	Devices	19,550	98,388	171,733	241,381	10,947	49,038	93,076	117,513	24,870	359,408	390,303	8,379	117,513	782,960
Residential Demand Response (IHD)	Devices	0	49,689	133,657	188,577	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	27	21	279	2,367	0	2	18	369	743	17,152	163,690	2,330,865	390	2,712,676
Consumer Program Total						**49,681**	**72,377**	**116,886**	**154,267**	**133,520,941**	**75,796,859**	**70,049,807**	**212,530,376**	**239,772**	**1,112,588,565**
Business Program															
Retrofit	Projects	2,828	6,481	9,746	10,925	24,467	61,147	59,678	70,662	136,002,258	314,922,468	345,346,008	462,903,521	213,493	2,631,401,223
Direct Install Lighting	Projects	20,741	18,691	17,833	23,784	23,724	15,284	18,708	23,419	61,076,701	57,345,798	64,315,558	84,503,302	73,304	604,196,658
Building Commissioning	Buildings	0	0	0	5	0	0	0	988	0	0	0	1,513,377	988	1,513,377
New Construction	Buildings	25	98	158	226	123	764	1,584	6,432	411,717	1,814,721	4,959,266	20,381,204	8,904	37,390,767
Energy Audit	Audits	222	357	589	473	0	1,450	2,811	6,323	0	7,049,351	15,455,795	30,874,399	10,583	82,934,042
Small Commercial Demand Response	Devices	132	294	1,211	3,652	84	187	773	2,116	157	1,068	373	319	2,116	1,916
Small Commercial Demand Response (IHD)	Devices	0	0	378	820	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	145	151	175	180	16,218	19,389	23,706	23,380	633,421	281,823	346,659	0	23,380	1,261,903
Business Program Total						**64,617**	**98,221**	**107,261**	**133,319**	**198,124,253**	**381,415,230**	**430,423,659**	**600,176,121**	**332,769**	**3,358,699,887**
Industrial Program															
Process & System Upgrades	Projects	0	0	5	10	0	0	294	9,692	0	0	2,603,764	72,053,255	9,986	77,260,782
Monitoring & Targeting	Projects	0	1	3	5	0	0	0	102	0	0	0	502,517	102	502,517
Energy Manager	Projects	1	132	306	379	0	1,086	3,558	5,191	0	7,372,108	21,994,263	40,436,427	8,384	95,324,998
Retrofit	Projects	433	0	0	0	4,615	0	0	0	28,866,840	0	0	0	4,613	115,462,282
Demand Response 3	Facilities	124	185	281	336	52,484	74,056	162,543	166,082	3,080,737	1,784,712	4,309,160	0	166,082	9,174,609
Industrial Program Total						**57,098**	**75,141**	**166,395**	**181,066**	**31,947,577**	**9,156,820**	**28,907,187**	**112,992,199**	**189,168**	**297,725,188**
Home Assistance Program															
Home Assistance Program	Homes	46	5,920	29,654	25,424	2	566	2,361	2,466	39,283	5,442,232	20,987,275	19,582,658	5,370	77,532,571
Home Assistance Program Total						**2**	**566**	**2,361**	**2,466**	**39,283**	**5,442,232**	**20,987,275**	**19,582,658**	**5,370**	**77,532,571**
Aboriginal Program															
Home Assistance Program	Homes	0	0	717	1,125	0	0	267	549	0	0	1,609,393	3,101,207	816	6,319,993
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**	**816**	**6,319,993**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,028	0	0	0	21,662	0	0	0	121,138,219	0	0	0	21,662	484,552,876
High Performance New Construction	Projects	182	73	19	3	5,098	3,251	772	134	26,185,591	11,901,944	3,522,240	688,738	9,255	148,181,415
Toronto Comprehensive	Projects	577	15	4	5	15,805	0	0	281	86,964,886	0	0	2,479,840	16,086	350,339,385
Multifamily Energy Efficiency Rebates	Projects	110	0	0	0	1,981	0	0	0	7,595,683	0	0	0	1,981	30,382,733
LDC Custom Programs	Projects	8	0	0	0	399	0	0	0	1,367,170	0	0	0	399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**	**772**	**415**	**243,251,550**	**11,901,944**	**3,522,240**	**3,168,578**	**49,382**	**1,018,925,088**
Other															
Program Enabled Savings	Projects	33	71	46	43	0	2,304	3,692	5,500	0	1,188,362	4,075,382	19,035,337	11,496	30,751,187
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	54,795	0	0	0	0	54,795	0
LDC Pilots	Projects	0	0	0	1,174	0	0	0	1,170	0	0	0	5,061,522	1,170	5,061,522
Other Total						**0**	**2,304**	**3,692**	**61,466**	**0**	**1,188,362**	**4,075,382**	**24,096,859**	**67,462**	**35,812,709**
Adjustments to 2011 Verified Results							**1,406**	**641**	**1,418**		**18,689,081**	**1,736,381**	**7,319,857**	**3,215**	**110,143,550**
Adjustments to 2012 Verified Results								**6,260**	**9,221**			**41,947,840**	**37,080,215**	**15,401**	**238,780,637**
Adjustments to 2013 Verified Results									**24,391**				**150,785,808**	**24,391**	**296,465,211**
Energy Efficiency Total						**136,610**	**109,191**	**117,536**	**224,457**	**603,144,419**	**482,474,435**	**554,528,447**	**975,639,300**	**575,647**	**5,896,382,612**
Demand Response Total (Scenario 1)						**79,733**	**142,670**	**280,099**	**309,091**	**3,739,185**	**2,427,011**	**5,046,495**	**8,698**	**309,091**	**11,221,389**
Adjustments to Previous Years' Verified Results Total						**0**	**1,406**	**6,901**	**35,030**	**0**	**18,689,081**	**43,684,221**	**195,185,880**	**43,006**	**645,389,397**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**	**404,536**	**568,578**	**606,883,604**	**503,590,526**	**603,259,163**	**1,170,833,878**	**927,745**	**6,552,993,397**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**70%**	**109%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 7: Adjustments to Province-Wide Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-18,839	2,319	4,705		-5,270	479	1,037		-9,707,002	955,512	1,838,408		-3,754	-32,284,656
Conservation Instant Coupon Booklet	Items	8,216	0	1,050		16	0	2		275,655	0	23,571		18	1,149,763
Bi-Annual Retailer Event	Items	81,817	0	0		108	0	0		2,183,391	0	0		108	8,733,563
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	20	2	193		1	1	72		14,667	985	441,938		74	945,497
Consumer Program Total						**-5,145**	**480**	**1,111**		**-7,233,290**	**956,497**	**2,303,917**		**-3,555**	**-21,664,975**
Business Program															
Retrofit	Projects	312	876	961		3,208	7,233	11,961		16,266,129	42,498,052	78,146,280		22,056	347,545,386
Direct Install Lighting	Projects	444	197	51		501	204	46		1,250,388	736,541	164,667		620	7,158,143
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	15	29	72		850	1,304	2,241		3,604,553	4,825,774	8,636,179		4,401	46,187,216
Energy Audit	Audits	119	77	270		604	439	2,383		2,945,189	2,145,367	13,100,635		3,426	44,418,129
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**5,162**	**9,181**	**16,631**		**24,066,259**	**50,205,734**	**100,047,761**		**30,503**	**385,148,444**
Industrial Program															
Process & System Upgrades	Projects	0	0	2		0	0	324		0	0	968,659		324	1,937,318
Monitoring & Targeting	Projects	0	1	3		0	0	54		0	528,000	639,348		54	2,862,696
Energy Manager	Projects	1	93	101		27	1,067	2,395		241,515	8,266,841	25,814,853		4,345	81,853,489
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**27**	**1,067**	**2,774**		**241,515**	**8,794,841**	**27,422,860**		**4,723**	**61,215,516**
Home Assistance Program															
Home Assistance Program	Homes	0	887	2,898		0	222	791		0	1,316,749	4,321,794		1,009	12,515,300
Home Assistance Program Total						**0**	**222**	**791**		**0**	**1,316,749**	**4,321,794**		**1,009**	**8,581,177**
Aboriginal Program															
Home Assistance Program	Homes	0	0	133		0	0	134		0	0	563,715		134	1,127,430
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**134**		**0**	**0**	**563,715**		**134**	**1,127,430**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12	0	0		138	0	0		545,536	0	0		138	2,182,145
High Performance New Construction	Projects	37	4	15		1,507	363	-184		2,398,941	2,832,533	-993,596		1,686	16,106,171
Toronto Comprehensive	Projects	0	15	4		0	672	185		0	4,523,517	1,324,388		857	16,219,327
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**1,645**	**1,035**	**2**		**2,944,477**	**7,356,050**	**330,792**		**2,682**	**11,104,528**
Other															
Program Enabled Savings	Projects	33	55	33		1,776	3,712	2,020		7,727,573	11,481,687	10,688,564		7,509	86,732,481
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
LDC Pilots	Projects	0	0	0		0	0	0		0	0	0		0	0
Other Total						**1,776**	**3,712**	**2,020**		**7,727,573**	**11,481,687**	**10,688,564**		**7,509**	**86,732,481**
Adjustments to 2011 Verified Results						**3,465**				**27,746,535**				**3,215**	**110,143,550**
Adjustments to 2012 Verified Results							**15,697**				**80,111,558**			**15,401**	**238,780,637**
Adjustments to 2013 Verified Results								**23,463**				**145,679,403**		**24,391**	**296,465,211**
Adjustments to Previous Years' Verified Results Total						**3,465**	**15,697**	**23,463**		**27,746,535**	**80,111,558**	**145,679,403**		**43,006**	**645,389,397**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	1.00	1.00	0.51	0.46	0.42	0.45	1.00	1.00	1.00	1.00	0.46	0.47	0.44	0.47
Appliance Exchange	1.00	1.00	1.00	1.00	0.51	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	1.00	1.00	0.60	0.50	0.48	0.48	1.00	1.00	1.00	1.00	0.50	0.49	0.48	0.48
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.00	1.05	1.13	1.73
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.12	0.91	1.04	1.74	1.00	1.00	1.00	1.00	0.91	0.92	1.04	1.75
Retailer Co-op	1.00	n/a	n/a	n/a	0.68	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	1.00	3.65	0.78	1.03	0.41	0.49	0.63	0.63	3.65	7.17	3.09	0.62	0.49	0.49	0.63	0.63
Business Program																
Retrofit	1.06	0.93	0.92	0.84	0.72	0.75	0.73	0.71	0.93	1.05	1.01	0.98	0.75	0.76	0.73	0.72
Direct Install Lighting	1.08	0.69	0.82	0.78	1.08	0.94	0.94	0.94	0.69	0.85	0.84	0.83	0.94	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	1.97	n/a	n/a	n/a	1.00	n/a	n/a	n/a	1.16	n/a	n/a	n/a	1.00
New Construction	0.50	0.98	0.68	0.71	0.50	0.49	0.54	0.54	0.98	0.99	0.76	0.79	0.49	0.49	0.54	0.54
Energy Audit	n/a	n/a	1.02	0.96	n/a	n/a	0.66	0.68	n/a	n/a	0.97	1.00	n/a	n/a	0.66	0.67
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	0.85	0.96	n/a	n/a	0.94	0.79	n/a	n/a	0.87	0.96	n/a	n/a	0.93	0.80
Monitoring & Targeting	n/a	n/a	n/a	0.59	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.36	n/a	n/a	n/a	1.00
Energy Manager	n/a	1.16	0.90	0.91	n/a	0.90	0.90	0.90	1.16	1.16	0.90	0.96	0.90	0.90	0.90	0.85
Retrofit	1.11	n/a	n/a	n/a	0.72	n/a	n/a	n/a	0.91	n/a	n/a	n/a	0.75	n/a	n/a	n/a
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	1.00	0.32	0.26	0.49	0.70	1.00	1.00	1.00	0.32	0.99	0.88	0.78	1.00	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	0.05	0.15	n/a	n/a	1.00	1.00	n/a	n/a	0.95	0.97	n/a	n/a	1.00	1.00
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a	n/a	0.54	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	n/a	0.49	0.50	0.50	0.50	1.00	1.00	1.00	n/a	0.50	0.50	0.50	0.50
Toronto Comprehensive	1.13	n/a	n/a	n/a	0.50	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	0.93	n/a	n/a	n/a	0.78	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	1.00	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	1.06	1.00	0.86	n/a	1.00	1.00	1.00	n/a	2.26	1.00	0.98	n/a	1.00	1.00	1.00
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Pilots	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Provincial Progress Towards CDM Targets

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012†	1.4	253.3	109.8	108.2
2013†	0.6	7.0	404.5	122.0
2014†	1.4	10.8	34.2	568.6
Verified Net Annual Peak Demand Savings in 2014:				**927.7**
2014 Annual CDM Capacity Target:				**1,330**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**69.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393.1
2012†	18.7	503.6	498.4	492.6	1,513.3
2013†	1.7	44.4	603.3	583.4	1,232.8
2014†	7.3	44.8	191.0	1,170.8	1,413.9
Verified Net Cumulative Energy Savings 2011-2014:					**6,553.0**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**109.2%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings = Activity * Per Unit Assumption** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Engineered and Custom Projects	**Gross Savings = Reported Savings * Realization Rate** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Demand Response	**Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio** **Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW** **All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)**
Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year that the exchange event occurred.	
HVAC Incentives	Results directly attributed to LDC based on customer postal code.	Savings are considered to begin in the year that the installation occurred.	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to IESO through project completion reports and continuing participant lists.	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system. Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to IESO through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program			

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Aboriginal Program			
Aboriginal Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014 assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported. A realization rate is applied to the reported savings to

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.		
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation.		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation.		

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%
Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%

Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (e.g. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Table 11: Cambridge and North Dumfries Hydro Inc. Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	50	9	14	11	364,466	67,918	90,231	77,228
Appliance Exchange**	Appliances	4	4	20	21	5,219	6,491	35,798	37,201
HVAC Incentives	Equipment	596	497	587	688	1,121,468	872,613	1,024,559	1,269,224
Conservation Instant Coupon Booklet	Items	10	2	4	13	163,353	12,699	65,532	165,887
Bi-Annual Retailer Event	Items	14	16	11	44	257,628	279,875	157,467	672,863
Retailer Co-op	Items	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	46	0	50	167	0	0	129	0
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	6	0	0	0	35,595
Consumer Program Total		**720**	**528**	**686**	**950**	**1,912,135**	**1,239,595**	**1,373,715**	**2,257,999**
Business Program									
Retrofit	Projects	347	1,569	1,927	2,524	1,750,908	7,838,649	9,917,602	18,420,008
Direct Install Lighting	Projects	148	127	57	118	429,688	428,469	199,642	406,223
Building Commissioning	Buildings	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	112	10	0	0	624,190	34,774
Energy Audit	Audits	0	5	40	59	0	25,176	219,932	291,834
Small Commercial Demand Response	Devices	1	0	1	0	0	0	1	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	180	180	346	136	7,018	2,621	5,215	0
Business Program Total		**676**	**1,882**	**2,482**	**2,846**	**2,187,614**	**8,294,914**	**10,966,582**	**19,152,839**
Industrial Program									
Process & System Upgrades	Projects	0	0	85	151	0	0	743,115	1,318,000
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	0	37	86	0	0	195,483	477,947
Retrofit	Projects	634	0	0	0	4,045,237	0	0	0
Demand Response 3	Facilities	544	705	525	870	31,908	16,979	11,952	0
Industrial Program Total		**1,177**	**705**	**646**	**1,107**	**4,077,144**	**16,979**	**950,549**	**1,795,947**
Home Assistance Program									
Home Assistance Program	Homes	0	0	31	5	0	11,367	458,390	91,897
Home Assistance Program Total		**0**	**0**	**31**	**5**	**0**	**11,367**	**458,390**	**91,897**
Aboriginal Program									
Home Assistance Program	Homes	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	2,288	0	0	0	12,898,238	0	0	0
High Performance New Construction	Projects	22	2	0	0	114,446	2,097	0	0
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total		**2,310**	**2**	**0**	**0**	**13,012,685**	**2,097**	**0**	**0**
Other									
Program Enabled Savings	Projects	0	0	8	46	0	0	51,500	345,824
Time-of-Use Savings	Homes	0	0	0	728	0	0	0	0
LDC Pilots	Projects	0	0	0	624	0	0	0	461,513
Other Total		**0**	**0**	**8**	**775**	**0**	**0**	**51,500**	**345,824**
Adjustments to 2011 Verified Results			**143**	**0**	**24**		**927,060**	**0**	**89,603**
Adjustments to 2012 Verified Results				**388**	**94**			**1,209,703**	**581,930**
Adjustments to 2013 Verified Results					**388**				**1,369,823**
Energy Efficiency Total		**4,113**	**2,232**	**2,932**	**5,134**	**21,150,652**	**9,545,353**	**13,783,439**	**24,106,019**
Demand Response Total		**770**	**885**	**921**	**1,173**	**38,926**	**19,599**	**17,297**	**0**
Adjustments to Previous Years' Verified Results Total		**0**	**143**	**388**	**506**	**0**	**927,060**	**1,209,703**	**2,041,355**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**4,883**	**3,260**	**4,241**	**6,813**	**21,189,578**	**10,492,012**	**15,010,440**	**26,147,374**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to Cambridge and North Dumfries Hydro Inc. Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-116	21	35		-218,104	37,978	62,073	
Conservation Instant Coupon Booklet	Items	0	0	0		2,452	0	198	
Bi-Annual Retailer Event	Items	1	0	0		22,733	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	0		0	0	0	
Consumer Program Total		**-115**	**21**	**35**		**-192,919**	**37,978**	**62,271**	
Business Program									
Retrofit	Projects	82	216	322		434,577	1,335,529	1,461,076	
Direct Install Lighting	Projects	4	0	0		8,667	0	0	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	0	0		0	19,108	0	
Energy Audit	Audits	0	0	13		0	1,259	73,505	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**86**	**216**	**336**		**443,244**	**1,355,896**	**1,534,581**	
Industrial Program									
Process & System Upgrades	Projects	0	0	-85		0	0	-743,115	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	0	1		0	256,892	17,155	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**0**	**0**	**-84**		**0**	**256,892**	**-725,960**	
Home Assistance Program									
Home Assistance Program	Homes	0	0	1		0	14,057	9,851	
Home Assistance Program Total		**0**	**0**	**1**		**0**	**14,057**	**9,851**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0	
High Performance New Construction	Projects	172	0	78		676,736	0	402,303	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**172**	**0**	**78**		**676,736**	**0**	**402,303**	
Other									
Program Enabled Savings	Projects	0	151	23		0	147,100	66,452	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		**0**	**151**	**23**		**0**	**147,100**	**66,452**	
Adjustments to 2011 Verified Results		**143**				**927,060**			
Adjustments to 2012 Verified Results			**388**				**1,811,922**		
Adjustments to 2013 Verified Results				**389**				**1,349,498**	
Total Adjustments to Previous Years' Verified Results		**143**	**388**	**389**		**927,060**	**1,811,922**	**1,349,498**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	6,750	2,011	3,151	3,579	45,971,627	13,424,518	18,616,239	20,315,770
Appliance Exchange**	Appliances	719	556	2,101	2,238	873,531	974,621	3,746,106	3,990,372
HVAC Incentives	Equipment	53,209	38,346	40,418	48,467	99,413,430	66,929,213	71,225,037	90,274,814
Conservation Instant Coupon Booklet	Items	1,184	231	464	1,442	19,192,453	1,325,898	6,842,244	19,000,254
Bi-Annual Retailer Event	Items	1,504	1,622	1,142	4,626	26,899,265	29,222,072	16,441,329	70,254,471
Retailer Co-op	Items	0	0	0	0	3,917	0	0	0
Residential Demand Response	Devices	10,390	49,038	93,076	117,513	23,597	359,408	390,303	8,379
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	1	29	587	1,813	4,884	259,826	3,699,786
Consumer Program Total		**73,757**	**91,805**	**140,380**	**178,452**	**192,379,633**	**112,240,615**	**117,521,084**	**207,543,846**
Business Program									
Retrofit	Projects	34,201	78,965	82,896	98,849	184,070,265	387,817,248	478,410,896	642,515,421
Direct Install Lighting	Projects	22,155	20,469	19,807	24,794	65,777,197	68,896,046	68,140,249	89,528,509
Building Commissioning	Buildings	0	0	0	988	0	0	0	1,513,377
New Construction	Buildings	247	1,596	2,934	11,911	823,434	3,755,869	9,183,826	37,742,970
Energy Audit	Audits	0	1,450	4,283	9,367	0	7,049,351	23,386,108	46,012,517
Small Commercial Demand Response	Devices	55	187	773	2,116	131	1,068	373	319
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	21,390	19,389	23,706	23,380	633,421	281,823	346,659	0
Business Program Total		**78,048**	**122,056**	**134,399**	**171,405**	**251,304,448**	**467,801,406**	**579,468,111**	**817,313,113**
Industrial Program									
Process & System Upgrades	Projects	0	0	313	12,287	0	0	2,799,746	90,463,617
Monitoring & Targeting	Projects	0	0	0	102	0	0	0	502,517
Energy Manager	Projects	0	1,034	3,953	5,767	0	7,067,535	24,438,070	44,929,364
Retrofit	Projects	6,372	0	0	0	38,412,408	0	0	0
Demand Response 3	Facilities	176,180	74,056	162,543	166,082	4,243,958	1,784,712	4,309,160	0
Industrial Program Total		**182,552**	**75,090**	**166,809**	**184,238**	**42,656,366**	**8,852,247**	**31,546,976**	**135,895,498**
Home Assistance Program									
Home Assistance Program	Homes	4	1,777	2,361	2,466	56,119	5,524,230	20,987,275	19,582,658
Home Assistance Program Total		**4**	**1,777**	**2,361**	**2,466**	**56,119**	**5,524,230**	**20,987,275**	**19,582,658**
Aboriginal Program									
Home Assistance Program	Homes	0	0	267	549	0	0	1,609,393	3,101,207
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	40,418	0	0	0	223,956,390	0	0	0
High Performance New Construction	Projects	10,197	6,501	772	268	52,371,183	23,803,888	3,522,240	1,377,475
Toronto Comprehensive	Projects	33,467	0	0	802	174,070,574	0	0	7,085,257
Multifamily Energy Efficiency Rebates	Projects	2,553	0	0	0	9,774,792	0	0	0
LDC Custom Programs	Projects	534	0	0	0	649,140	0	0	0
Pre-2011 Programs completed in 2011 Total		**87,169**	**6,501**	**772**	**1,070**	**460,822,079**	**23,803,888**	**3,522,240**	**8,462,733**
Other									
Program Enabled Savings	Projects	0	2,177	3,692	5,500	0	525,011	4,075,382	19,035,337
Time-of-Use Savings	Homes	0	0	0	54,795	0	0	0	0
LDC Pilots	Projects	0	0	0	1,170	0	0	0	5,061,522
Other Total		**0**	**2,177**	**3,692**	**60,296**	**0**	**525,011**	**4,075,382**	**19,035,337**
Adjustments to 2011 Verified Results			**13,266**	**645**	**1,601**		**48,705,294**	**20,581**	**6,028**
Adjustments to 2012 Verified Results				**8,632**	**13,449**			**54,301,893**	**59,098,939**
Adjustments to 2013 Verified Results					**34,727**				**206,413,158**
Energy Efficiency Total		**213,515**	**156,735**	**168,583**	**289,384**	**942,317,539**	**616,320,385**	**753,683,966**	**1,210,925,694**
Demand Response Total		**208,015**	**142,670**	**280,099**	**309,091**	**4,901,107**	**2,427,011**	**5,046,495**	**8,698**
Adjustments to Previous Years' Verified Results Total		**0**	**13,266**	**9,277**	**49,777**	**0**	**48,705,294**	**54,322,474**	**265,518,125**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**421,530**	**312,671**	**457,958**	**648,252**	**947,218,646**	**667,452,690**	**813,052,934**	**1,476,452,516**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results
**Net results substituted for gross results due to unavailability of data

Table 14: Adjustments to Province-Wide Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-8,759	1,091	2,157		-16,241,086	1,952,473	3,873,449	
Conservation Instant Coupon Booklet	Items	15	0	1		255,975	0	20,668	
Bi-Annual Retailer Event	Items	117	0	0		2,373,616	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	1	1	115		330,093	2,009	701,488	
Consumer Program Total		**-8,628**	**1,092**	**2,273**		**-13,281,402**	**1,954,483**	**4,595,605**	
Business Program									
Retrofit	Projects	4,511	10,114	16,584		22,046,931	58,528,789	108,677,566	
Direct Install Lighting	Projects	541	217	49		1,346,618	781,858	174,460	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	3,287	2,673	4,151		11,323,593	9,884,305	15,992,924	
Energy Audit	Audits	656	488	3,631		2,391,744	2,386,374	19,822,524	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**8,996**	**13,491**	**24,414**		**37,108,886**	**71,581,326**	**144,667,473**	
Industrial Program									
Process & System Upgrades	Projects	0	0	426		0	0	1,232,785	
Monitoring & Targeting	Projects	0	0	54		0	528,000	639,348	
Energy Manager	Projects	29	1,071	2,687		0	8,968,007	28,893,596	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**29**	**1,071**	**3,168**		**0**	**9,496,007**	**30,765,729**	
Home Assistance Program									
Home Assistance Program	Homes	0	222	791		0	1,316,749	4,321,794	
Home Assistance Program Total		**0**	**222**	**791**		**0**	**1,316,749**	**4,321,794**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	134		0	0	563,715	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**134**		**0**	**0**	**563,715**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	266	0	0		1,049,108	0	0	
High Performance New Construction	Projects	13,072	727	405		23,905,663	5,665,066	1,535,048	
Toronto Comprehensive	Projects	0	1,920	529		0	12,924,335	3,783,965	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**13,337**	**2,647**	**934**		**24,954,771**	**18,589,400**	**5,319,013**	
Other									
Program Enabled Savings	Projects	1,776	3,712	2,020		1,673,712	11,481,687	10,688,564	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		**1,776**	**3,712**	**2,020**		**1,673,712**	**11,481,687**	**10,688,564**	
Adjustments to 2011 Verified Results		**15,511**				**50,455,967**			
Adjustments to 2012 Verified Results			**22,235**				**114,419,652**		
Adjustments to 2013 Verified Results				**33,734**				**200,921,892**	
Adjustments to Previous Years' Verified Results Total		**15,511**	**22,235**	**33,734**		**50,455,967**	**114,419,652**	**200,921,892**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

APPENDIX 4-10: FINAL 2015 ANNUAL VERIFIED RESULS REPORT
BRANT COUNTY POWER

Final 2015 Annual Verified Results - Annual Persistence Report

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Connecting Today.
Powering Tomorrow.

#	Worksheet Name	Worksheet Description
1	How to Use This Report	Describes the contents and structure of this report
2	Energy Savings	Provides a description of the 2015 - 2040 annual persistence of Net Verified Energy Savings at the end-user level resulting from the 2015 CDM Program Year
3	Demand Savings	Provides a description of the 2015 - 2040 annual persistence of Net Verified Demand Savings at the end-user level resulting from the 2015 CDM Program Year

Final 2015 Annual Verified Results - Annual Persistence Report

The IESO is pleased to provide the Final 2015 Annual Verified Results - Annual Persistence Report.

This report is based on the same data used to provide the Final 2015 Annual Verified Results Report to LDCs on June 30, 2016. The data included in this report is provided on a more granular level, providing annual savings amounts for the 2015 - 2040 period resulting from the 2015 CDM Program Year to aid LDCs in analysis such as supporting Lost Revenue Adjustment Mechanism (LRAM) calculations.

The data provided is the same final 2015 net verified, end-user level savings amounts for both energy savings and demand savings for the specific LDC service areas only, no province-wide data is included in this report. The program list has been condensed to show only those programs that had achieved savings in the province, not necessarily in every LDC's service area. Initiatives, programs, pilots that were in market in 2015 and adjustments to specific years that may be populated in future years are not displayed for ease of use.

The list of initiatives, programs and pilots is shown on the left and each year's remaining savings is shown across the columns. Savings may deteriorate by year as a result of the mix of measures actually installed may have some measures with shorter expected useful lives (EULs) than others and some measures may have a baseline shift occur during their EULs.

This type of data will be incorporated on an annual basis in each future year's Annual Verified Results Reports rather than provided separately for 2015. We hope you will find this report useful.

Final 2015 Annual Verified Results - Annual Persistence Report

For: Brant County Power Inc.

#	Program	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Legacy Framework																											
1	Cavanu Initiative	101 586	101 586	101 586	101 586	101 586	101 586	101 586	101 586	101 586	101 586	91 172	90 844	90 844	90 457	90 457	90 457	90 281	54 365	54 365	54 365	54 365	54 365	0	0	0	0	0	0
2	Hi-Level Retailer Push Initiative	167 474	179 179	179 179	179 179	179 179	179 179	179 179	179 179	179 179	179 179	179 179	165 381	158 771	158 771	155 369	155 369	155 041	52 894	52 894	52 894	52 894	52 894	0	0	0	0	0	0
3	Appliance Retirement Initiative	17 924	17 924	17 924	17 924	8 962	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	HVAC Incentives Initiative	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	100 249	98 058	0	0	0	0	0	0	0
5	Residential New Construction and Major Renovation Initiative	21 209	21 209	21 209	21 209	21 209	21 209	21 209	21 209	21 209	21 209	21 209	20 848	20 848	20 848	20 848	20 848	20 848	20 848	20 848	20 848	20 848	20 848	11 126	11 126	11 126	0	0	0
6	Energy Audit Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Efficiency: Equipment Replacement Incentive Initiative	1 258 097	1 258 097	1 247 897	1 247 897	1 247 897	1 247 897	1 181 875	1 181 875	1 177 926	961 487	429 169	418 629	137 489	137 489	137 489	104 825	33 503	33 503	33 503	33 503	0	0	0	0	0	0	0	0
8	Direct Install Lighting and Water Heating Initiative	41 295	35 503	22 603	19 170	19 170	19 170	19 170	19 170	19 170	19 170	19 170	13 266	5 586	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	New Construction and Major Renovation Initiative	153 964	153 964	153 964	153 964	153 964	153 964	153 964	153 964	153 964	153 964	153 964	153 964	125 684	125 684	125 684	125 684	0	0	0	0	0	0	0	0	0	0	0	0
10	Process Building Commissioning Incentive Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Process and Systems Upgrades Initiative – Project Incentive Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Process and Systems Upgrades Initiative – Project Manager Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Process and Systems Upgrades Initiative – Monitoring and Targeting Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Low Income Initiative	9 764	7 460	7 082	6 772	6 772	6 772	6 445	6 265	5 754	5 754	5 535	5 535	5 336	5 336	5 336	5 336	5 337	5 337	5 337	5 337	5 337	5 337	456	0	0	0	0	0
15	Lighting Pilot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Retail Benchmarking Pilot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Conservation Fund Pilot - SBS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Conservation Fund Pilot - Fleet/K*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Demand Conservation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Process Fueled Tactics	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation First Framework																											
21	Save on Energy Cooling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Save on Energy Heating and Cooling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Save on Energy Home Assistance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Save on Energy Audit Funding Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Save on Energy Retrofit Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		**1 867 486**	**1 852 781**	**1 851 577**	**1 838 051**	**1 818 967**	**1 818 186**	**1 745 868**	**1 745 815**	**1 737 116**	**1 520 698**	**965 741**	**937 188**	**636 357**	**631 937**	**595 266**	**471 981**	**348 186**	**348 186**	**348 186**	**345 995**	**147 657**	**12 582**	**11 126**	**11 126**	**0**	**0**	**0**

Final 2015 Annual Verified Results - Annual Persistence Report

For: Brant County Power Inc.

#	Program	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Legacy Framework																											
1	Coupon Initiative	7	7	7	7	7	7	7	7	7	7	6	6	6	6	6	6	2	2	2	2	0	0	0	0	0	0
2	Bi-Annual Retailer Event Initiative	12	12	12	12	12	12	12	12	12	12	10	10	10	10	10	10	4	4	4	4	0	0	0	0	0	0
3	Appliance Retirement Initiative	3	3	3	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	HVAC Incentives Initiative	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	48	0	0	0	0	0	0	0
5	Residential New Construction and Major Renovation Initiative	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	0	0	0
6	Energy Audit Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Efficiency: Equipment Replacement Incentive Initiative	302	302	299	299	299	299	281	281	280	221	77	76	37	37	37	28	11	11	11	11	0	0	0	0	0	0
8	Direct Install Lighting and Water Heating Initiative	11	9	6	5	5	5	5	5	5	5	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	New Construction and Major Renovation Initiative	25	25	25	25	25	25	25	25	25	25	24	24	24	24	0	0	0	0	0	0	0	0	0	0	0	0
10	Existing Building Commissioning Incentive Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Process and Systems Upgrades Initiatives - Energy Manager Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Low Income Initiative	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0
15	Loblaws Pilot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Social Benchmarking Pilot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Conservation Fund Pilot - SEG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Conservation Fund Pilot - EnerNOC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Aboriginal Conservation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Program Enabled Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation First Framework																											
21	Save on Energy Coupon Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Save on Energy Heating and Cooling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Save on Energy Home Assistance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Save on Energy Audit Funding Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Save on Energy Retrofit Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		418	416	410	409	407	406	388	388	387	328	180	175	135	135	111	102	75	75	71	23	5	5	5	0	0	0

APPENDIX 4-11: FINAL 2015 ANNUAL VERIFIED RESULS REPORT CAMBRIDGE AND NORTH DUMFRIES HYDRO

Final 2015 Annual Verified Results - Annual Persistence Report

ieso
Connecting Today.
Powering Tomorrow.

#	Worksheet Name	Worksheet Description
1	How to Use This Report	Describes the contents and structure of this report
2	Energy Savings	Provides a description of the 2015 - 2040 annual persistence of Net Verified Energy Savings at the end-user level resulting from the 2015 CDM Program Year
3	Demand Savings	Provides a description of the 2015 - 2040 annual persistence of Net Verified Demand Savings at the end-user level resulting from the 2015 CDM Program Year

Final 2015 Annual Verified Results - Annual Persistence Report

The IESO is pleased to provide the Final 2015 Annual Verified Results - Annual Persistence Report.

This report is based on the same data used to provide the Final 2015 Annual Verified Results Report to LDCs on June 30, 2016. The data included in this report is provided on a more granular level, providing annual savings amounts for the 2015 - 2040 period resulting from the 2015 CDM Program Year to aid LDCs in analysis such as supporting Lost Revenue Adjustment Mechanism (LRAM) calculations.

The data provided is the same final 2015 net verified, end-user level savings amounts for both energy savings and demand savings for the specific LDC service areas only, no province-wide data is included in this report. The program list has been condensed to show only those programs that had achieved savings in the province, not necessarily in every LDC's service area. Initiatives, programs, pilots that were in market in 2015 and adjustments to specific years that may be populated in future years are not displayed for ease of use.

The list of initiatives, programs and pilots is shown on the left and each year's remaining savings is shown across the columns. Savings may deteriorate by year as a result of the mix of measures actually installed may have some measures with shorter expected useful lives (EULs) than others and some measures may have a baseline shift occur during their EULs.

This type of data will be incorporated on an annual basis in each future year's Annual Verified Results Reports rather than provided separately for 2015. We hope you will find this report useful.

Final 2015 Annual Verified Results - Annual Persistence Report

For: Cambridge and North Dumfries Hydro Inc.

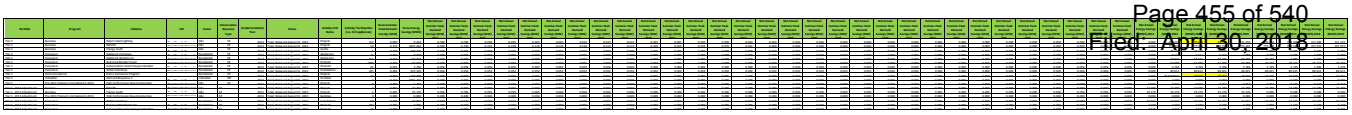
#	Program	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Legacy Framework																											
1	Cooling Initiative	479 715	474 695	474 695	474 695	474 695	474 695	474 695	474 767	474 767	474 767	474 767	417 875	416 397	416 397	416 779	414 779	414 491	163 305	163 305	163 305	163 305	0	0	0	0	0
2	Bi-Level Rebate Pilot Initiative	867 756	866 189	866 189	866 189	866 189	866 189	866 189	867 512	867 512	867 512	867 512	800 587	798 887	798 887	797 562	797 562	797 855	774 241	774 241	774 241	774 241	0	0	0	0	0
3	Appliance Retirement Initiative	6 298	6 298	6 298	6 298	3 667																					
4	HVAC Incentives Initiative	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	705 823	674 994	0	0	0	0	0
5	Residential New Construction and Major Renovation Initiative	177 361	177 361	177 361	177 361	177 361	177 361	177 361	177 361	177 361	177 361	177 361	177 131	177 131	177 131	177 131	177 131	177 131	177 131	177 131	177 131	177 131	177 131	97 103	97 103	97 103	0
6	Energy Audit Initiative	142 541	142 541	142 541	142 541	142 541	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Efficiency: Equipment Replacement Incentive Initiative	11 365 498	11 365 498	11 297 696	10 974 116	10 974 116	10 979 116	10 892 961	10 892 961	10 896 951	10 896 951	10 918 919	8 341 909	8 108 990	4 958 046	4 958 046	4 958 046	3 448 463	230 138	230 138	230 138	230 138	0	0	0	0	0	0
8	Direct Install Lighting and Water Heating Initiative	122 193	122 193	64 046	64 046	64 046	64 046	64 046	64 046	64 046	64 046	64 046	62 543	40 011	0	0	0	0	0	0	0	0	0	0	0	0	0
9	New Construction and Major Renovation Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Process Building Commissioning Incentive Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Process and Systems Upgrades Initiative – Project Incentive Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Process and Systems Upgrades Initiative – Project Manager Initiative	1 693 873	1 693 173	1 366 074	1 366 074	1 366 074	1 196 918	1 196 918	1 196 918	1 196 918	1 158 643	1 154 661	1 108 547	54 676	7 535	7 535	7 535	0	0	0	0	0	0	0	0	0	0
13	Process and Systems Upgrades Initiative – Monitoring and Targeting Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Lighting Initiative	70 467	63 470	59 106	55 956	55 956	55 956	55 464	54 844	50 509	50 495	50 495	39 795	39 795	39 774	39 774	8 439	8 437	8 437	8 437	8 437	8 437	8 437	8 311	0	0	0
15	Lighting Pilot	817 576	817 576	817 576	817 576	817 576	817 576	817 576	817 576	817 576	817 576	817 576	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Retail Benchmarking Pilot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Conservation Fund Pilot - SBG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Conservation Fund Pilot - FleetSAVE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Electrical Conservation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Program Enabled Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation First Framework																											
21	Save on Energy Cooling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Save on Energy Heating and Cooling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Save on Energy Home Assistance Program	1 172	765	285	217	217	217	101	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Save on Energy Audit Funding Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Save on Energy Retrofit Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		16 574 176	16 557 254	15 941 950	15 672 581	15 539 865	15 435 157	15 352 387	15 353 186	12 585 887	12 587 836	11 665 746	10 361 546	7 077 814	7 052 368	7 052 368	6 515 276	1 958 581	1 958 581	1 527 644	857 568	105 414	97 103	97 103	0	0	0

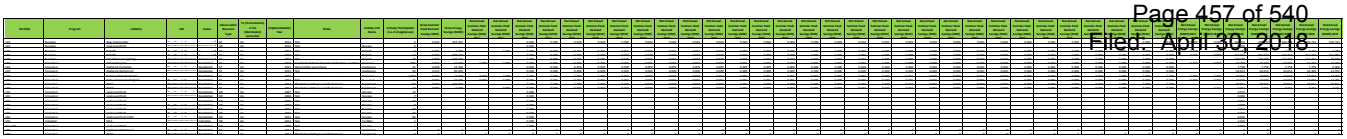
Final 2015 Annual Verified Results - Annual Persistence Report

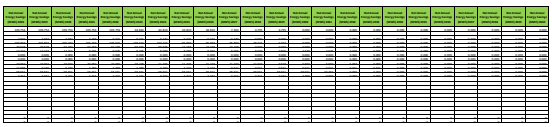
For: Cambridge and North Dumfries Hydro Inc.

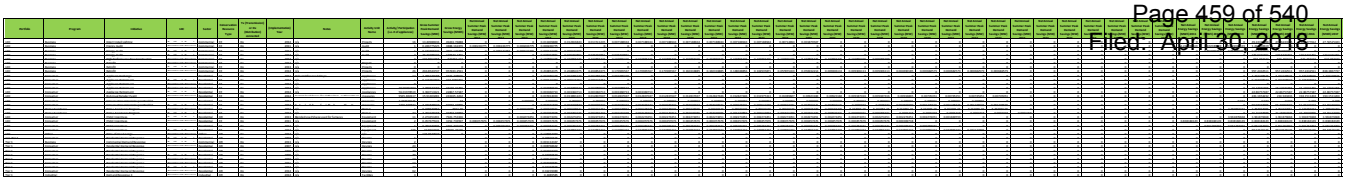
#	Program	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Legacy Framework																											
1	Coupon Initiative	31	31	31	31	31	31	31	31	31	31	27	27	27	27	27	27	10	10	10	10	0	0	0	0	0	0
2	Bi-Annual Retailer Event Initiative	60	59	59	59	59	59	59	59	59	59	49	47	47	47	47	47	17	17	17	17	0	0	0	0	0	0
3	Appliance Retirement Initiative	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	HVAC Incentives Initiative	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	336	0	0	0	0	0	0
5	Residential New Construction and Major Renovation Initiative	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	37	37	37	0	0	0
6	Energy Audit Initiative	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Efficiency: Equipment Replacement Incentive Initiative	1,752	1,752	1,743	1,670	1,670	1,670	1,639	1,639	1,601	1,500	1,241	1,231	880	880	880	618	79	79	79	79	0	0	0	0	0	0
8	Direct Install Lighting and Water Heating Initiative	32	31	16	16	16	16	16	16	16	16	16	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	New Construction and Major Renovation Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Existing Building Commissioning Incentive Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Process and Systems Upgrades Initiatives - Energy Manager Initiative	182	174	102	102	102	87	87	87	78	76	65	3	1	1	1	0	0	0	0	0	0	0	0	0	0	0
13	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Low Income Initiative	7	6	6	6	6	6	6	6	5	5	5	5	4	4	2	2	2	2	2	2	1	0	0	0	0	0
15	Loblaws Pilot	80	80	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Social Benchmarking Pilot	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Conservation Fund Pilot - SEG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Conservation Fund Pilot - EnerNOC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Aboriginal Conservation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Program Enabled Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation First Framework																											
21	Save on Energy Coupon Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Save on Energy Heating and Cooling Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Save on Energy Home Assistance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Save on Energy Audit Funding Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Save on Energy Retrofit Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		2,588	2,577	2,481	2,408	2,378	2,369	2,331	2,331	2,283	2,180	1,816	1,737	1,372	1,372	1,370	1,107	521	521	487	151	38	37	37	0	0	0

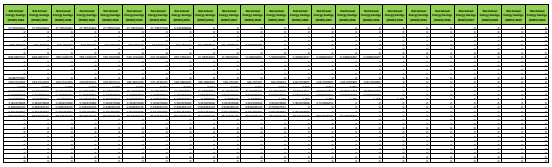
APPENDIX 4-12: 2011-2014 PERSISTENCE REPORT BRANT COUNTY POWER











APPENDIX 4-13: ENERGY+ (BRANT COUNTY) OEB LRAMVA WORK FORM

Ontario Energy Board

Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form

Version 2.0 (2017)

Generic LRAMVA Work Forms

Worksheet Name	Description
1. LRAMVA Summary	**Tables 1-a and 1-b** provide a summary of the LRAMVA balances and carrying charges associated with the LRAMVA disposition. The balances are populated from entries into other tabs throughout this work form.
1-a. Summary of Changes	**Tables A-1 and A-2** include a template for LDCs to summarize changes to the LRAMVA work form.
2. LRAMVA Threshold	**Tables 2-a, 2-b and 2-c** include the LRAMVA thresholds and allocations by rate class.
3. Distribution Rates	**Tables 3-a and 3-b** include the distribution rates that are used to calculate lost revenues.
3-a. Rate Class Allocations	A blank spreadsheet is provided to allow LDCs to populate distributor specific rate class percentages to allocate actual CDM savings to different customer classes.
4. 2011-2014 LRAM	**Tables 4-a, 4-b, 4-c and 4-d** include the template 2011-2014 LRAMVA work forms.
5. 2015-2020 LRAM	**Tables 5-a, 5-b, 5-c and 5-d** include the template 2015-2020 LRAMVA work forms.
6. Carrying Charges	**Table 6-b** includes the variance on carrying charges related to the LRAMVA disposition.
7. Persistence Data	**Tables 7-a to 7-j** should be populated with CDM savings persistence data provided to LDCs from the IESO.
8. Streetlighting	A blank spreadsheet is provided to allow LDCs to populate data on streetlighting projects whose savings were not provided by the IESO in the CDM Final Results Report.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the

results.

Ontario Energy Board

LRAMVA Work Form: Checklist and Schematic

Version 2.0 (2017)

General Note on the LRAMVA Model

The LRAMVA work form has been created in a generic manner that should allow for use by all LDCs. There are some elements that are not applicable at this time (i.e., 2017, 2018, 2019 and 2020 related components). These have been included (but hidden in the work form) in an effort to avoid major updates in the future. This LRAMVA work form consolidates information that LDCs are already required to file with the OEB. The model has been created to provide LDCs with a consistent format to display CDM impacts, the forecast savings component and, ultimately, any variance between actual CDM savings and forecast CDM savings. The majority of the information required in the LRAMVA work form will be provided to LDCs from the IESO as part of the Final CDM Results each year. Please contact the IESO for any reports that may be required to complete this LRAMVA work form.

The LRAMVA work form is unlocked to enable LDCs to tailor it to their own unique circumstances.

LRAMVA ($) = (Actual Net CDM Savings - Forecast CDM Savings) x Distribution Volumetric Rate + Carrying Charges from LRAMVA balance

Legend	Drop Down List (Blue)

Important Checklist

Yes	o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a
Yes	o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form
Yes	o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved
yes	o Include a copy of initiative-level persistence savings information that was verified by the IESO in Tab 7. Persistence information is available upon request from the IESO
Yes	o Apply the IESO verified savings adjustments to the year it relates to.
	o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable
Yes	o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a

Work Form Calculations	Source of Calculation	Inputs (Tables to Complete)	Source of Data Inputs	Outputs of Data (Auto-Populated)
Actual Incremental CDM Savings by Initiative	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D & O)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+/- IESO Verified Savings Adjustments	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D-M & Columns O-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+ Initiative Level Savings Persistence	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns E-M & Columns P-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
x Allocation % to Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AJ)	Determined by the LDC	
Actual Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			
- Forecast Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tab "2. LRAMVA Threshold" Tables 2-a, 2-b and 2-c		
x Distribution Rate by Rate Class	Tab "3. Distribution Rates"	Table 3	LDC's Approved Tariff Sheets	
LRAMVA ($) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			Tables 1-a and 1-b
+ Carrying Charges ($) by Rate Class	Tabs "1. LRAMVA Summary" and "6. Carrying Charges"	Table 6		Table 6-a
Total LRAMVA ($) by Rate Class	Tab "1. LRAMVA Summary"			

Ontario Energy Board

LRAMVA Work Form: Instructions

Version 2.0 (2017)

Tab	Instructions
LRAMVA Checklist/Schematic Tab	The LRAMVA work form was created in a generic manner for use by all LDCs. There are some elements that are not applicable at this time (i.e., 2017, 2018, 2019 and 2020 related components) but have been included in an effort to avoid major updates in the future. Distributors should follow the checklist, which is referenced in this tab of the work form and listed below: o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a. o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form. o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved. o Include a copy of initiative-level persistence savings information that was verified by the IESO. Persistence information is available upon request from the IESO. o Apply the IESO verified savings adjustments to the year it relates to. For example, savings adjustments to 2015 programs will be provided to LDCs with the 2016 Final Results Report. The 2015 savings adjustments should be included in the 2015 verified savings portion of the work form. o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable. o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a.
Tab 1. LRAMVA Summary	Distributors are required to report any past approved LRAMVA amounts along with the current LRAMVA amount requested for approval. There are separate tables indicating new lost revenues and carrying charges amounts by year and the totals for rate rider calculations.
Tab 1-a. Summary of Changes	Distributors should list all significant changes and changes in assumptions in the generic work form affecting the LRAMVA.
Tab 2. LRAMVA Threshold	Distributors should use the tables to display the LRAMVA threshold amounts as approved at a rate class level. This should be taken from the LDC's most recently approved cost of service application.
Tab 3. Distribution Rates	Distributors should complete the tables with rate class specific distribution rates and adjustments as applicable.
Tab 3-a. Rate Class Allocations	A tab is provided to allow LDCs to include documentation or analysis on how rate class allocations for actual CDM savings were determined by customer class and program each year. The rate class allocations would support the LRAMVA rate class allocation figures used in Tabs 4 and 5.
Tabs 4 and 5 (2011-2020)	Distributors should complete the lost revenue calculation for 2011-2014 program years and 2015-2020 program years, as applicable, by undertaking the following: o Input or manually link the savings, adjustments and program savings persistence data from Tab 7 (Persistence Report) to Tabs 4 and 5. As noted earlier, persistence data is available upon request from the IESO. o Ensure that the IESO verified savings adjustments apply to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. o Confirm the monthly multipliers applied to demand savings. If a different monthly multiplier is used than what was confirmed in the LRAMVA Report, provide rationale in Tab 1-a and highlight the new monthly multiplier that has been used. o Input the rate class allocations by program and year to allocate actual savings to customers. If a different allocation is proposed for adjustments, LDCs must provide the supporting rationale in Tab 1-a and highlight the change. o Provide assumptions about the year(s) in which persistence is captured in the load forecast via the "Notes" section of each table and adjust what is included in the LRAMVA totals, as appropriate.
Tab 6. Carrying Charges	Distributors are requested to calculate carrying charges based on the methodology provided in the work form. This includes updating Table 6 as new prescribed interest rates for deferral and variance accounts become available and entering any collected interest amounts into the "Amounts Cleared" row to calculate outstanding variances on carrying charges.
Tab 7. Persistence Report	Persistence savings report(s) provided by the IESO should be included for the relevant years in the LRAMVA work form. Tab 7 has been created consistently with the IESO's persistence report.
Tab 8. Streetlighting	A tab is provided to ensure LDCs include documentation or data to support projects whose program savings were not provided by the IESO (i.e., streetlighting projects).

Ontario Energy Board

LRAMVA Work Form: Summary Tab

Version 2.0 (2017)

Legend	User Inputs (Green)
	Auto Populated Cells (White)
	Instructions (Grey)
LDC Name	Energy + Inc. - (BCP)
Application Details	Claim for results for 2016 including persistence from 2011

Please fill in the requested information: a) the amounts approved in the previous LRAMVA application, b) details on the current application, and c) documentation of changes if applicable.

A. Previous LRAMVA Application

Previous LRAMVA Application (EB#)	EB-2016-0060
Application of Previous LRAMVA Claim	2017 IRM
Period of LRAMVA Claimed in Previous Application	2011-2015
Amount of LRAMVA Claimed in Previous Application	$ 146,113.00

B. Current LRAMVA Application

Current LRAMVA Application (EB#)		EB-2018-0028
Application of Current LRAMVA Claim		2019 COS
Period of New LRAMVA in this Application		2016-2017
Actual Lost Revenues ($)	A	**$ 151,139**
Forecast Lost Revenues ($)	B	**$ 19,746**
Carrying Charges ($)	C	**$ 8,354**
LRAMVA ($) for Account 1568	A-B+C	**$ 139,747**

C. Documentation of Changes

Original Amount	
Amount for Final Disposition	

Table 1-a. LRAMVA Totals by Rate Class

Please input the customer rate classes applicable to the LDC and associated billing units (kWh or kW) in Table 1-a below. This will update all tables throughout the workform.

The LRAMVA total by rate class in Table 1-a should be used to inform the determination of rate riders in the Deferral and Variance Account Work Form or IRM Rate Generator Model. Please also ensure that the principal amounts in column E of Table 1-a capture the appropriate years and amounts for the LRAMVA claim.

NOTE: If the LDC has more than 14 customer classes in which CDM savings was allocated, LDCs must contact OEB staff to make adjustments to the workform.

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$73,874	$1,979	$75,853
GS<50 kW	kWh	$94,146	$2,507	$96,653
GS 50 to 4999 kW	kW	$60,778	$1,582	$62,359
Large User (GS > 5,000 kW)	kW	$0	$0	$0
Unmetered Scattered Load	kWh	$0	$0	$0
Sentinel Lighting	kW	$0	$0	$0
Street Lighting	kW	$101,105	$2,286	$103,391
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
Total		**$329,902**	**$8,354**	**$338,256**

Table 1-b. Annual LRAMVA Breakdown by Year and Rate Class

In column C of Table 1-b below, please insert a 'check mark' to indicate the years in which LRAMVA has been claimed. If you inserted a check-mark for a particular year, please delete the amounts associated with the actual and forecast lost revenues for all rate classes for that year, up to and including the total. Any LRAMVA from a prior year that has already been claimed cannot be included in the current LRAMVA disposition, with the exception of the case noted below.

If LDCs are seeking to claim true-up amounts that were previously approved by the OEB, please note that the "Amount Cleared" rows are applicable to the LDC and should be filled out. This may relate to claiming the difference in LRAM approved before the May 19, 2016 Peak Demand Consultation, and the lost revenues that would have been incurred after that consultation, as approved by the OEB. If this is the case, reference to the decision must be noted in the rate application. If this is not the case, LDCs are requested to leave those rows blank.

Depending on the period of LRAMVA to be claimed, LDCs are expected to adjust the totals for carrying charges in row 82 of Table 1-b and the years included in the LRAMVA balance in row 83, as appropriate.

Description	LRAMVA Previously Claimed	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting								Total
		kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	0	0	0	
2011 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2012 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2013 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2014 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2015 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2015 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2016 Actuals		$46,855.08	$52,353.49	$36,224.57	$0.00	$0.00	$0.00	$15,705.85	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$151,138.99
2016 Forecast		($7,706.27)	($3,845.71)	($8,194.12)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($19,746.10)
Amount Cleared																
2017 Actuals		$40,110.59	$49,483.77	$40,939.24	$0.00	$0.00	$0.00	$85,398.78	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$215,932.39
2017 Forecast		($5,385.63)	($3,845.71)	($8,192.03)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($17,423.38)
Carrying Charges		$1,979.28	$2,506.96	$1,581.74	$0.00	$0.00	$0.00	$2,285.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8,353.92
Total LRAMVA Balance		**$75,853**	**$96,653**	**$62,359**	**$0**	**$0**	**$0**	**$103,391**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$338,255.82**

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form: Summary of Changes

Version 2.0 (2017)

Legend	
	User Inputs (Green)
	Drop Down List (Blue)
	Instructions (Grey)

Table A-1. Changes to Generic Assumptions in LRAMVA Work Form

Please document any changes in assumptions made to the generic inputs of the LRAMVA work form. This may include, but are not limited to, the use of different monthly multipliers to claim demand savings from energy efficiency programs; use of different rate allocations between current year savings and prior year savings adjustments; inclusion of additional adjustments affecting distribution rates; use of a different LRAMVA threshold; etc. All important changes should be highlighted in the work form as well.

No.	Tab	Cell Reference	Description	Rationale
1	5. 2015-2020 LRAM	D39:X39 (for example)	Adjustment results and persistence are from the new table on Tab 3-a	It was necessary to split out Energy+ (BCP) rate zone from the IESO aggregated results for Energy+
2				
3	6. Carrying Charges	C41:C44	Estimated carrying charges through April 2018 at most current rate	
4	5. 2015-2020 LRAM	D304:H304	Removed kWh for streetlighting, which is dealt with separately	IESO results don't capture kW reductions from streetlighting so needs to be handled specially
5	5. 2015-2020 LRAM	AE378	Add demand reductions for streetlighting from Tab 8	IESO results don't capture kW reductions from streetlighting so needs to be handled specially
6	5. 2015-2020 LRAM	AE392:AE395	Add persisting demand reductions for streetlighting from Tab 8	IESO results don't capture kW reductions from streetlighting so needs to be handled specially
7	1. LRAMVA Summary	D82:Q82	Changed to reference row 147 on Tab 6	Changed to reference carrying charges through Dec 2018
8	5. 2015-2020 LRAM	Red cells below row 289	Not available until ~July 2017. Will be updated when final results available	Not available until ~July 2017. Will be updated when final results available
9				
10				
etc.				

Table A-2. Updates to LRAMVA Disposition

Please document any changes related to interrogatories or questions during the application process that affect the LRAMVA amount.

No.	Tab	Cell Reference	Description	Rationale
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
etc.				

Ontario Energy Board

LRAMVA Work Form: Forecast Lost Revenues

Version 2.0 (2017)

Legend

- User Inputs (Green)
- Drop Down List (Blue)
- Auto Populated Cells (White)
- Instructions (Grey)

Table 2-a. LRAMVA Threshold — **2011**

Please provide the LRAMVA threshold approved in the cost of service (COS) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting							
		kWh	kWh	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	1,494,000	437,856	213,651	842,493	0	0	0	0	0	0	0	0			
kW	2,087	0	0	2,087	0	0	0	0	0	0	0	0			
Summary		437856.4017	213650.5919	2087.24855	0	0	0	0	0	0	0	0	0	0	0

Basis of Threshold
Source of Threshold

Table 2-b. LRAMVA Threshold — **2014**

Please provide the LRAMVA threshold approved in the last COS application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting							
		kWh	kWh	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0	0	0	0	0	0	0	0	0	0	0	0			
kW	0	0	0	0	0	0	0	0	0	0	0	0			
Summary		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Basis of Threshold: !00% of 2011-2014 estimated CDM savings
Source of Threshold: p.19 of 30 of EB-2013-0116 settlement proposal

Table 2-c. Inputs for LRAMVA Thresholds

Please complete Table 2-c below by selecting the appropriate LRAMVA threshold year in column C. The LRAMVA threshold values in Table 2-c will auto-populate from Tables 2-a and 2-b depending on the year selected. If there was no LRAMVA threshold established for a particular year, please select the "blank" option. The LRAMVA threshold values in Table 2-c will be auto-populated in Tabs 4 and 5 of this work form.

Year	LRAMVA Threshold	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting							
		kWh	kWh	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	2011	437,856	213,651	2,087	0	0	0	0	0	0	0	0	0	0	0
2012	2011	437,856	213,651	2,087	0	0	0	0	0	0	0	0	0	0	0
2013	2011	437,856	213,651	2,087	0	0	0	0	0	0	0	0	0	0	0
2014	2011	437,856	213,651	2,087	0	0	0	0	0	0	0	0	0	0	0
2015	2011	437,856	213,651	2,087	0	0	0	0	0	0	0	0	0	0	0
2016	2011	437,856	213,651	2,087	0	0	0	0	0	0	0	0	0	0	0
2017	2011	437,856	213,651	2,087	0	0	0	0	0	0	0	0	0	0	0

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form: Distribution Rates

Version 2.0 (2017)

Table 3. Inputs for Distribution Rates and Adjustments by Rate Class

Please complete Table 3 with the rate class specific distribution rates that pertain to the years of the LRAMVA disposition. Any adjustments that affect distribution rates can be incorporated in the calculation by expanding the "plus" button at the left hand bar. Table 3 will convert the distribution rates to a calendar year rate (January to December) based on the number of months entered in row 16 of each rate year starting from January to the start of the LDC's rate year. Please enter 0 in row 16, if the rate year begins on January 1. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas in Table 3-a accordingly.

	Billing Unit	EB-2009-0258	EB-2010-0125	EB-2011-0154	EB-2012-0108	EB-2013-0113	EB-2014-0058	EB-2015-0054	EB-2016-0060	EB-2017-XXXX	EB-2018-XXXX	EB-2019-XXXX	EB-2020-XXXX
Rate Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Period 1 (# months)		*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*				
Period 2 (# months)		*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*12*	*12*	*12*	*12*
Residential	kWh	$ 0.0216	$ 0.0237	$ 0.0208	$ 0.0209	$ 0.0211	$ 0.0211	$ 0.0158	$ 0.0105				
Adjusted rate		$ 0.0216	$ 0.0237	$ 0.0208	$ 0.0209	$ 0.0211	$ 0.0211	$ 0.0158	$ 0.0105	$ -	$ -	$ -	
Calendar year equivalent			**$ 0.0230**	**$ 0.0218**	**$ 0.0209**	**$ 0.0210**	**$ 0.0211**	**$ 0.0176**	**$ 0.0123**	**$ -**	**$ -**	**$ -**	
GS<50 kW	kWh	$ 0.0186	$ 0.0170	$ 0.0178	$ 0.0178	$ 0.0180	$ 0.0180	$ 0.0180	$ 0.0180				
Adjusted rate		$ 0.0186	$ 0.0170	$ 0.0178	$ 0.0178	$ 0.0180	$ 0.0180	$ 0.0180	$ 0.0180	$ -	$ -	$ -	
Calendar year equivalent			**$ 0.0175**	**$ 0.0175**	**$ 0.0178**	**$ 0.0179**	**$ 0.0180**	**$ 0.0180**	**$ 0.0180**	**$ -**	**$ -**	**$ -**	
GS 50 to 4999 kW	kW	$ 5.2549	$ 3.2855	$ 3.8760	$ 3.8869	$ 3.9297	$ 3.9297	$ 3.9239	$ 3.9253				
Adjusted rate		$ 5.2549	$ 3.2855	$ 3.8760	$ 3.8869	$ 3.9297	$ 3.9297	$ 3.9239	$ 3.9253	$ -	$ -	$ -	
Calendar year equivalent			**$ 3.9420**	**$ 3.6792**	**$ 3.8833**	**$ 3.9154**	**$ 3.9297**	**$ 3.9258**	**$ 3.9248**	**$ -**	**$ -**	**$ -**	
Large User (GS > 5,000 kW)	kW	$ 0.8131	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ 0.8131	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ 0.2710**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
Unmetered Scattered Load	kWh	$ 0.0186	$ 0.0187	$ 0.0229	$ 0.0230	$ 0.0233	$ 0.0233	$ 0.0233	$ 0.0233				
Adjusted rate		$ 0.0186	$ 0.0187	$ 0.0229	$ 0.0230	$ 0.0233	$ 0.0233	$ 0.0233	$ 0.0233	$ -	$ -	$ -	
Calendar year equivalent			**$ 0.0187**	**$ 0.0215**	**$ 0.0230**	**$ 0.0232**	**$ 0.0233**	**$ 0.0233**	**$ 0.0233**	**$ -**	**$ -**	**$ -**	
Sentinel Lighting	kW	$ 8.2496	$ 29.8835	$ 30.0867	$ 30.1709	$ 30.5028	$ 30.5028	$ 30.4211	$ 30.5028				
Adjusted rate		$ 8.2496	$ 29.8835	$ 30.0867	$ 30.1709	$ 30.5028	$ 30.5028	$ 30.4211	$ 30.5028	$ -	$ -	$ -	
Calendar year equivalent			**$ 22.6722**	**$ 30.0190**	**$ 30.1428**	**$ 30.3922**	**$ 30.5028**	**$ 30.4483**	**$ 30.4756**	**$ -**	**$ -**	**$ -**	
Street Lighting	kW	$ 4.1543	$ 43.9802	$ 44.2793	$ 44.4033	$ 44.8917	$ 44.8917	$ 44.8221	$ 44.8917				
Adjusted rate		$ 4.1543	$ 43.9802	$ 44.2793	$ 44.4033	$ 44.8917	$ 44.8917	$ 44.8221	$ 44.8917	$ -	$ -	$ -	
Calendar year equivalent			**$ 30.7049**	**$ 44.1796**	**$ 44.3620**	**$ 44.7289**	**$ 44.8917**	**$ 44.8453**	**$ 44.8685**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	

Note: LDC to make note of adjustments made to Table 3 to accommodate the LDC's specific circumstances

Table 3-a. Distribution Rates by Rate Class

Table 3-a below autopopulates the average distribution rates from Table 3. Please ensure that the distribution rates relevant to the years of the LRAMVA disposition are used. As such, please clear the rates related to the year(s) that are not part of the LRAMVA claim. The distribution rates that remain in Table 3-a will be used in Tabs 4 and 5 of the work form to calculate actual and forecast lost revenues. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas from Table 3-a, as well as the distribution rate links in Tabs 4 and 5.

Year	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting							
	kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	0	0	0
2011														
2012														
2013														
2014														
2015														
2016	$0.0176	$0.0180	$3.9258	$0.0000	$0.0233	$30.4483	$44.8453	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2017	$0.0123	$0.0180	$3.9248	$0.0000	$0.0233	$30.4756	$44.8685	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Note: Rates for 2011-2015 are removed as LRAMVA for these years was recovered in EB-2016-0060

Ontario Energy Board

LRAMVA Work Form: Determination of Rate Class Allocations

Version 2.0 (2017)

Instructions

LDCs must clearly show how it has allocated actual CDM savings to applicable rate classes, including supporting documentation and rationale for its proposal. This should be shown by customer class and program each year.

Allocations are shown on Tab 4 and 5. Allocations are based on project specific information where available.
For 2016, IESO provided aggregated results for 2016 and 2015 adjustments that covered both Energy+ (CND) and Energy+ (BCP) rate zones.
For 2016 and 2015 adjustments, the allocations take into account the relative split of program results by rate zone.
2016 aggregate results are shown on Table 5b and rate zone allocations are captured in the allocation rates
For 2015 adjustments, allocations are shown below and the products of the adjustments and the Rate Zone allocation are transferred to Table 5a

2015 ADJUSTMENTS

Initiative	Net Incremental Peak Demand Savings	Net Incremental Energy Savings (kWh)	Persistence of 2015 adjustments: Incremental Peak Demand Savings (kW)					Persistence of 2015 adjustments: Incremental Energy Savings (kWh)					Rate zone allocation		Net Incremental Peak Demand Savings (kW) Energy+ (BCP)	Net Incremental Energy Savings (kWh). Energy+ (BCP)	Persistence of 2015 adjustments. (Energy+ BCP): Incremental Peak Demand Savings (kW)					Incremental Energy Savings (kWh)				
	2015	2015	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020	to CND	to BCP	2015	2015	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
2015-2020 Conservation First Framework Programs																										
Residential Province-Wide Program																										
1 Save on Energy Coupon Program															0	0	0	0	0	0	0	0	0	0	0	0
2 Save on Energy Heating and Cooling Program															0	0	0	0	0	0	0	0	0	0	0	0
3 Save on Energy New Construction Program															0	0	0	0	0	0	0	0	0	0	0	0
4 Save on Energy Home Assistance Program		-1,122						-759	-688	-617	-617	-617	89%	11%	0	-120	0	0	0	0	0	-82	-74	-66	-66	-66
Sub-total - Residential Province-Wide Program	0	-1,122	0	0	0	0	0	-759	-688	-617	-617	-617			0	-120	0	0	0	0	0	-82	-74	-66	-66	-66
Business Province-Wide Program																										
5 Save on Energy Audit Funding Program															0	0	0	0	0	0	0	0	0	0	0	0
6 Save on Energy Retrofit Program	31	151,028	31	31	31	31	31	151,028	151,028	151,028	151,028	151,028	90%	10%	3	15,421	3	3	3	3	3	15,421	15,421	15,421	15,421	15,421
7 Save on Energy Small Business Lighting Program															0	0	0	0	0	0	0	0	0	0	0	0
8 Save on Energy High Performance New Construction Program															0	0	0	0	0	0	0	0	0	0	0	0
9 Save on Energy Existing Building Commissioning Program															0	0	0	0	0	0	0	0	0	0	0	0
10 Save on Energy Process & Systems Upgrades Program															0	0	0	0	0	0	0	0	0	0	0	0
11 Save on Energy Energy Manager Program															0	0	0	0	0	0	0	0	0	0	0	0
12 Save on Energy Monitoring & Targeting Program															0	0	0	0	0	0	0	0	0	0	0	0
13 Save on Energy Retrofit Program - P4P															0	0	0	0	0	0	0	0	0	0	0	0
14 Save on Energy Process & Systems Upgrades Program - P4P															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Business Province-Wide Program	31	151,028	31	31	31	31	31	151,028	151,028	151,028	151,028	151,028			3	15,421	3	3	3	3	3	15,421	15,421	15,421	15,421	15,421
Local & Regional Program																										
15 Adaptive Thermostat Local Program															0	0	0	0	0	0	0	0	0	0	0	0
16 Business Refrigeration Incentives Local Program															0	0	0	0	0	0	0	0	0	0	0	0
17 Conservation on the Coast Home Assistance Local Program															0	0	0	0	0	0	0	0	0	0	0	0
18 Conservation on the Coast Small Business Lighting Local Program															0	0	0	0	0	0	0	0	0	0	0	0
19 First Nations Conservation Local Program															0	0	0	0	0	0	0	0	0	0	0	0
20 High Efficiency Agricultural Pumping Local Program															0	0	0	0	0	0	0	0	0	0	0	0
21 Instant Savings Local Program															0	0	0	0	0	0	0	0	0	0	0	0
22 OPsaver Local Program															0	0	0	0	0	0	0	0	0	0	0	0
23 PUMPsaver Local Program															0	0	0	0	0	0	0	0	0	0	0	0
24 Social Benchmarking Local Program															0	0	0	0	0	0	0	0	0	0	0	0
25 THESL Swimming Pool Efficiency Local Program															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Local & Regional Program	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
Pilot Program																										
26 Air Source Heat Pump for Residential Water Heating Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
27 Building Optimization Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
28 Conservation Voltage Regulation Leveraging AMI Data Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
29 Demand Control Kitchen Ventilation Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
30 Direct Install - Hydronic Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
31 Direct Install - RTU Controls Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
32 Electronically Commutated Furnace Motor Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
33 Electronics Takeback Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
34 Home Energy Assessment and Retrofit Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
35 HONI HP Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
36 P4P for Class B Office Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
37 Performance Based Conservation Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
38 Re-Invest Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
39 Residential Direct Install Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
40 Residential Ductless Heat Pump Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
41 Residential Install Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
42 Social Benchmarking Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
43 Solar Powered Attic Ventilation Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
44 Truckload Event Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Pilot Program	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
Program Enabled Savings																										
45 Save on Energy Retrofit Program Enabled Savings															0	0	0	0	0	0	0	0	0	0	0	0
46 Save on Energy High Performance New Construction Program Enabled Savings															0	0	0	0	0	0	0	0	0	0	0	0
47 Save on Energy Process & Systems Upgrades Program Enabled Savings															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Program Enabled Savings	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
Other																										
48 Proposed Program or Pilot															0	0	0	0	0	0	0	0	0	0	0	0
49 Unassigned Target															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Other	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - 2015-2020 Conservation First Framework P	31	149,906	31	31	31	31	31	150,269	150,340	150,411	150,411	150,411			3	15,300	3	3	3	3	3	15,339	15,347	15,354	15,354	15,354
Conservation Fund																										
50 EnerNOC Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
51 Home Depot Home Appliance Market Uplift															0	0	0	0	0	0	0	0	0	0	0	0
52 Loblaw P4P Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
53 Ontario Clean Water Agency P4P Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
54 Strategic Energy Group Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
55 Social Benchmarking Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Conservation Fund	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
2011-2014+2015 Extension Legacy Framework Programs																										
Residential Program																										
56 Appliance Retirement Initiative																										
57 Coupon Initiative	6	98,171	6	6	6	6	6	96,771	96,771	96,771	96,771	96,771	83%	17%	1	16,960	1	1	1	1	1	16,718	16,718	16,718	16,718	16,718
58 Bi-Annual Retailer Event Initiative	1	11,030	1	1	1	1	1	10,901	10,901	10,901	10,901	10,901	83%	17%	0	1,888	0	0	0	0	0	1,866	1,866	1,866	1,866	1,866
59 HVAC Incentives Initiative	14	27,228	14	14	14	14	14	27,228	27,228	27,228	27,228	27,228	88%	12%	2	3,386	2	2	2	2	2	3,386	3,386	3,386	3,386	3,386
60 Residential New Construction and Major Renovation Initiative	1	11,717	1	1	1	1	1	11,717	11,717	11,717	11,717	11,717	89%	11%	0	1,251	0	0	0	0	0	1,251	1,251	1,251	1,251	1,251
Sub-total - Residential Program	22	148,146	22	22	22	22	22	146,617	146,617	146,617	146,617	146,617			3	23,486	3	3	3	3	3	23,222	23,222	23,222	23,222	23,222
Commercial & Institutional Program																										
61 Energy Audit Initiative	2	9,592	2	2	2	32	32	9,592	9,592	9,592	152,133	152,133	100%	0%	0	0	0	0	0	0	0	0	0	0	0	0
62 Efficiency: Equipment Replacement Incentive Initiative	90	673,530	90	90	90	90	90	673,530	673,530	673,530	673,530	673,530	90%	10%	9	68,770	9	9	9	9	9	68,770	68,770	68,770	68,770	68,770
63 Direct Install Lighting and Water Heating Initiative															0	0	0	0	0	0	0	0	0	0	0	0
64 New Construction and Major Renovation Initiative															0	0	0	0	0	0	0	0	0	0	0	0
65 Existing Building Commissioning Incentive Initiative															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Commercial & Institutional Program	92	683,122	92	92	92	122	122	683,122	683,122	683,122	825,663	825,663			9	68,770	9	9	9	9	9	68,770	68,770	68,770	68,770	68,770
Industrial Program																										
66 Process and Systems Upgrades Initiatives - Project Incentive Initiative		58,955,828						58,955,828	58,955,828	58,955,828	58,955,828	58,955,828	100%	0%	0	0	0	0	0	0	0	0	0	0	0	0
67 Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative															0	0	0	0	0	0	0	0	0	0	0	0
68 Process and Systems Upgrades Initiatives - Energy Manager Initiative															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Industrial Program	0	58,955,828	0	0	0	0	0	58,955,828	58,955,828	58,955,828	58,955,828	58,955,828			0	0	0	0	0	0	0	0	0	0	0	0
Low Income Program																										
69 Low Income Initiative	-7	-75,175	-6	-6	-6	-6	-6	-59,013	-55,775	-52,536	-52,536	-52,536	89%	11%	-1	-8,073	-1	-1	-1	-1	-1	-6,337	-5,990	-5,642	-5,642	-5,642
Sub-total - Low Income Program	-7	-75,175	-6	-6	-6	-6	-6	-59,013	-55,775	-52,536	-52,536	-52,536			-1	-8,073	-1	-1	-1	-1	-1	-6,337	-5,990	-5,642	-5,642	-5,642
Other																										
70 Aboriginal Conservation Program															0	0	0	0	0	0	0	0	0	0	0	0
71 Program Enabled Savings															0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - Other	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
Sub-total - 2011-2014+2015 Extension Legacy Framew	107	59,711,921	108	108	108	138	138	59,726,554	59,729,792	59,733,031	59,875,572	59,875,572			11	84,183	12	12	12	12	12	85,655	86,003	86,350	86,350	86,350
Total	138	59,861,827	139	139	139	169	169	59,876,823	59,880,132	59,883,442	60,025,983	60,025,983			15	99,483	15	15	15	15	15	100,994	101,349	101,705	101,705	101,705

Note: Total results for Energy+ from IESO 2016 final verified results. Allocation across rate zones calculated by Energy+ staff

Ontario Energy Board

LRAMVA Work Form:
2011 - 2014 Lost Revenues Work Form

Version 2.0 (2017)

Legend

- User Inputs (Green)
- Auto Populated Cells (White)
- Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 4-a. 2011 Lost Revenues
Table 4-b. 2012 Lost Revenues
Table 4-c. 2013 Lost Revenues
Table 4-d. 2014 Lost Revenues

Table 4-a. 2011 Lost Revenues Work Form

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA									
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting								Total
	Consumer Program																							kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	0	0	0	
1	Appliance Retirement	Verified	54,690	54,690	54,690	54,185	39,875	0	0	0	0	0		8	8	8	7	5	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	266	266	266	113	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	147,245	147,245	147,245	147,245	147,245	147,245	147,245	147,245	147,245	147,245		80	80	80	80	80	80	80	80	80	80	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					100%
	Adjustment to 2011 savings	True-up	-33,585	-33,585	-33,585	-33,585	-33,585	-33,585	-33,585	-33,585	-33,585	-33,585		-18	-18	-18	-18	-18	-18	-18	-18	-18	-18	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	38,137	38,137	38,137	38,137	35,116	31,815	24,996	24,840	31,163	12,187		2	2	2	2	2	2	2	2	2	1	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	545	545	545	545	545	498	306	305	305	108		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	58,144	58,144	58,144	58,144	53,139	47,672	35,941	35,810	46,282	14,852		3	3	3	3	3	3	2	2	3	1	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					100%
	Adjustment to 2011 savings	True-up	4,320	4,320	4,320	4,320	4,320	3,926	2,119	2,119	2,119	467		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	0	0	0	0	0	0	0	0	0	0		20	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																																					
10	Retrofit	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					100%
	Adjustment to 2011 savings	True-up	17,289	17,289	17,289	17,289	17,289	17,289	17,289	17,289	17,289	17,289	12	2	2	2	2	2	2	0				0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified	9,616	9,616	9,616	9,616	9,616	9,616	2,186	2,186	2,186	2,186	12	4	4	4	4	4	4	1	1	1	1	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0				0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	80.00%	20.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	80.00%	20.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	26,398	26,398	26,398	26,398							12	5	5	5	5	5	0	0				0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																					
18	Process & System Upgrades	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%					100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified	12,763	0	0	0	0	0	0	0	0	0		217	0	0	0	0	0	0	0	0	0	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																																					
23	Home Assistance Program	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																																					
24	Home Assistance Program	Verified	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%						0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

25	Direct Install Lighting	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																																
26	Electricity Retrofit Incentive Program	Verified	93,507	93,507	93,507	93,507	93,507	93,507	93,507	93,507	93,507	93,507	12	16	16	16	16	16	16	16	16	16	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0				0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified	841	841	841	841	841	841	841	841	841	841	12	0	0	0	0	0	0	0	0	0	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																																
31	Program Enabled Savings	Verified											12										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2011 savings	True-up											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified											0																				0%
	Adjustment to 2011 savings	True-up											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2011		430,176											341									269,762	65,014	178	0	0	0	0	0	0	0	
	Forecast CDM Savings in 2011																						437,856	213,651	2,087	0	0	0	0	0	0	0	
	Distribution Rate in 2011																						$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2011 from 2011 programs																						**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2011																						**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2011																																**$0.00**
	2011 Savings Persisting in 2012																						269,762	65,014	178	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2013																						269,762	65,014	178	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2014																						269,104	65,014	178	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2015																						246,655	65,014	175	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2016																						197,570	65,014	113	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2017																						177,022	57,584	99	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2018																						176,735	57,584	99	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2019																						193,529	57,584	99	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2020																						141,274	57,584	99	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

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	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA									
			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting					Total
	Consumer Program																							kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	
1	Appliance Retirement	Verified	58,541	58,541	58,541	57,722	35,266	0	0	0	0			9	9	9	8	5	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	5,111	5,111	5,111	4,955	0	0	0	0	0			3	3	3	3	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	89,611	89,611	89,611	89,611	89,611	89,611	89,611	89,611	89,611			52	52	52	52	52	52	52	52	52		100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	3,879	3,879	3,879	3,879	3,879	3,879	3,879	3,879	3,879			2	2	2	2	2	2	2	2	2		100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	2,766	2,766	2,766	2,766	2,725	2,725	1,283	1,276	1,276			0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	52,988	52,988	52,988	52,988	47,633	38,732	26,419	26,365	26,365			3	3	3	3	3	2	2	2	2		100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																																
10	Retrofit	Verified	793,415	777,516	756,746	755,495	755,495	748,149	737,073	737,073	675,741		12	130	125	118	118	118	116	114	114	105		0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	100%
	Adjustment to 2012 savings	True-up	3,184	3,184	3,184	3,184	3,184	3,184	3,042	3,042	3,042		12	1	1	1	1	1	1	1	1	1		0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified	351,227	351,227	345,747	231,534	231,534	113,300	113,300	111,157	111,157		12	96	96	95	65	65	33	33	31	31		0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0						12	0	0	0	0	0						0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified	0	0	0	0	0						3	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2012 savings	True-up	0	0	0	0	0						3	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified	25,176	25,176	25,176	25,176	0	0	0	0	0		12	5	5	5	5	0						0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	854	854	854	854	0	0	0	0	0		12	0	0	0	0	0	0	0	0	0		0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																
18	Process & System Upgrades	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2012 savings	True-up	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2012 savings	True-up	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0						12	0	0	0	0	0						0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2012 savings	True-up	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified	2,209	0	0	0	0							92	0	0	0	0						0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																																
23	Home Assistance Program	Verified	20,019	20,019	20,019	18,919	18,919	18,919	17,219	17,071	3,633			2	1	1	1	1	1	1	1	1		100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%
	Adjustment to 2012 savings	True-up	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

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Ontario Energy Board

LRAMVA Work Form:
2015 - 2020 Lost Revenues Work Form

Version 2.0 (2017)

Legend

- User Inputs (Green)
- Auto Populated Cells (White)
- Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2016 programs that were reported by the IESO in 2017 should be included in the 2016 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 5-a. 2015 Lost Revenues
Table 5-b. 2016 Lost Revenues
Table 5-c. 2017 Lost Revenues
Table 5-d. 2018 Lost Revenues
Table 5-e. 2019 Lost Revenues
Table 5-f. 2020 Lost Revenues

Table 5-a. 2015 Lost Revenues Work Form

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA										
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting								Total
	Legacy Framework																							kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	0	0	0	
	Residential Program																																					
1	Coupon Initiative	Verified	101,999	101,086	101,086	101,086	101,086	101,086						7	7	7	7	7	7					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	16,960	16,718	16,718	16,718	16,718	16,718						1	1	1	1	1	1					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified	182,574	179,329	179,329	179,329	179,329	179,329						12	12	12	12	12	12					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	1,888	1,866	1,866	1,866	1,866	1,866						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified	17,924	17,924	17,924	17,924	17,924	17,924						3	3	3	3	1	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initaitive	Verified	100,249	100,249	100,249	100,249	100,249	100,249						52	52	52	52	52	52					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	3,386	3,386	3,386	3,386	3,386	3,386						2	2	2	2	2	2					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	Verified	21,209	21,209	21,209	21,209	21,209	21,209						5	5	5	5	5	5					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	1,251	1,251	1,251	1,251	1,251	1,251						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																																					
6	Energy Audit Initiative	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	1,258,037	1,278,698	1,274,818	1,247,909	1,247,909	1,247,807					12	302	302	299	299	299	299					0.00%	13.00%	87.00%	0.00%	0.00%	0.00%	0.00%			0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	68,770	68,770	68,770	68,770	68,770	68,770					12	9	9	9	9	9	9					0.00%	13.00%	87.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified	42,235	36,299	20,465	19,733	19,733	19,733					12	11	9	6	5	5	5					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified	133,964	133,964	133,964	133,964	133,964	133,964					12	25	25	25	25	25	25					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified	0	0	0	0	0	0					3	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					3	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																					
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																																					
14	Low Income Initiative	Verified	9,294	7,529	7,130	6,732	6,732	6,732					12	1	1	1	1	1	1					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	True-up	-8,073	-6,337	-5,990	-5,642	-5,642	-5,642					12	-1	-1	-1	-1	-1	-1					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																																					
15	Aboriginal Conservation Program	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																																					
17	Conservation Fund Pilot - EnerNOC	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%

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Distribution Rate in 2015												$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Lost Revenue in 2015 from 2011 programs												$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2012 programs												$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2013 programs												$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2014 programs												$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2015 from 2015 programs												$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2015												**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2015												**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2015																												**$0.00**
2015 Savings Persisting in 2016												444,129	345,433	3,249	0	0	0	0	0	0.00	0	0	0	0	0	0	0	
2015 Savings Persisting in 2017												444,086	329,095	3,217	0	0	0	0	0	0	0	0	0	0	0	0	0	
2015 Savings Persisting in 2018												444,043	324,865	3,217	0	0	0	0	0	0	0	0	0	0	0	0	0	
2015 Savings Persisting in 2019												444,043	324,865	3,217	0	0	0	0	0	0	0	0	0	0	0	0	0	
2015 Savings Persisting in 2020												444,043	324,852	3,217	0	0	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-b. 2016 Lost Revenues Work Form Return to top

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA										
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting								Total
	Legacy Framework																							kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	0	0	0	
	Residential Program																																					
1	Coupon Initiative	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initaitive	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major Renovation Initiative	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																																					
6	Energy Audit Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified	0	0	0	0	0						3	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																					
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																																					
14	Low Income Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																																					
15	Aboriginal Conservation Program	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																																					
17	Conservation Fund Pilot - EnerNOC	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation First Framework																																					
	Residential Province-Wide Programs																																					
21	Save on Energy Coupon Program	Verified	4,849,013	4,849,013	4,849,013	4,849,013	4,849,013							318	318	318	318	318						17.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				17%
	Adjustment to 2016 savings	True-up	354,501	354,501																				17.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified	1,480,421	1,480,421	1,480,421	1,480,421	1,480,421							437	437	437	437	437						12.44%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				12%
	Adjustment to 2016 savings	True-up	1,333,523	1,333,523																				12.44%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																																					
25	Save on Energy Audit Funding Program	Verified	26,285	26,285	26,285	26,285	26,285						12	3	3	3	3	3						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	6,386,852	6,212,943	6,212,943	6,212,943	6,212,943						12	939	905	905	905	905						0.00%	5.76%	20.43%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				26%
	Adjustment to 2016 savings	True-up	2,368,366	2,303,877									12	252	243									0.00%	5.76%	20.43%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

27	Save on Energy Small Business Lighting Program	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified	441,208	441,208	441,208	441,208	441,208						12	59	59	59	59	59						0.00%	0.00%	38.22%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	38%
	Adjustment to 2016 savings	True-up	123,618	123,618									12	52	52									0.00%	0.00%	38.22%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Save on Energy Existing Building Commissioning Program	Verified	0	0	0	0	0						3	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting Program	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Local & Regional Programs																																
33	Business Refrigeration Local Program	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	First Nation Conservation Local Program	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																																
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																															0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified											0																				0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2016		**17,363,787**											**2,060**										**1,248,910**	**504,020**	**3,427**	**0**	**0**	**0**	**350**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2016																							**437,856**	**213,651**	**2,087**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2016																							$0.01760	$0.01800	$3.92580	$0.00000	$0.02330	$30.44830	$44.84530	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2016 from 2011 programs																							$3,477.24	$1,170.26	$443.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$5,091.21
	Lost Revenue in 2016 from 2012 programs																							$3,485.38	$10,995.74	$2,813.37	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$17,294.49
	Lost Revenue in 2016 from 2013 programs																							$3,084.53	$4,781.63	$1,277.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9,143.34
	Lost Revenue in 2016 from 2014 programs																							$7,010.44	$20,115.71	$5,481.35	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32,607.50
	Lost Revenue in 2016 from 2015 programs																							$7,816.67	$6,217.80	$12,754.21	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$26,788.67
	Lost Revenue in 2016 from 2016 programs																							$21,980.82	$9,072.36	$13,454.74	$0.00	$0.00	$0.00	$15,705.85	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$60,213.77
	Total Lost Revenues in 2016																							**$46,855.08**	**$52,353.49**	**$36,224.57**	**$0.00**	**$0.00**	**$0.00**	**$15,705.85**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$151,138.99**
	Forecast Lost Revenues in 2016																							**$7,706.27**	**$3,845.71**	**$8,194.12**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$19,746.10**
	LRAMVA in 2016																																					**$131,392.89**
	2016 Savings Persisting in 2017																							1,248,910	490,296	3,322	0	0		1,903	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2018																							1,021,821	357,667	2,489	0	0		1,708	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2019																							1,021,821	357,667	2,489	0	0		1,708	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2020																							1,021,821	357,667	2,489	0	0		1,708	0	0	0	0	0	0	0	

Note: Rate allocations sum to considerably less than 100% in some cases because Energy+ (BCP) results had to be separated from aggregated Energy+ results provided by IESO

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Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA										
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting								Total
Legacy Framework																							kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	0	0	0	
Residential Program																																						

1	Coupon Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
2	Bi-Annual Retailer Event Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
3	Appliance Retirement Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
4	HVAC Incentives Initaitive	Verified																													
	Adjustment to 2017 savings	True-up																													0%
5	Residential New Construction and Major Renovation Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
	Commercial & Institutional Program																														
6	Energy Audit Initiative	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
7	Efficiency: Equipment Replacement Incentive Initiative	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
8	Direct Install Lighting and Water Heating Initiative	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
9	New Construction and Major Renovation Initiative	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
10	Existing Building Commissioning Incentive Initiative	Verified									3																				
	Adjustment to 2017 savings	True-up									3																				0%
	Industrial Program																														
11	Process and Systems Upgrades Initiatives - Proiect Incentive Initiative	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
	Low Income Program																														
14	Low Income Initiative	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
	Other																														
15	Aboriginal Conservation Program	Verified									0																				
	Adjustment to 2017 savings	True-up									0																				0%
16	Program Enabled Savings	Verified									0																				
	Adjustment to 2017 savings	True-up									0																				0%
	Conservation Fund Pilots																														
17	Conservation Fund Pilot - EnerNOC	Verified									0																				
	Adjustment to 2017 savings	True-up									0																				0%
18	Loblaws Pilot	Verified									0																				
	Adjustment to 2017 savings	True-up									0																				0%
19	Conservation Fund Pilot - SEG	Verified									0																				
	Adjustment to 2017 savings	True-up									0																				0%
20	Social Benchmarking Pilot	Verified									0																				
	Adjustment to 2017 savings	True-up									0																				0%
	Conservation First Framework																														
	Residential Province-Wide Programs																														
21	Save on Energy Coupon Program	Unverified	3,518,877																												
	Adjustment to 2017 savings	True-up																													17%
22	Save on Energy Heating and Cooling Program	Unverified	804,439																												
	Adjustment to 2017 savings	True-up																													12%
23	Save on Energy New Construction Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%
24	Save on Energy Home Assistance Program	Unverified	906																												
	Adjustment to 2017 savings	True-up																													100%
	Non-Residential Province-Wide Programs																														
25	Save on Energy Audit Funding Program	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
26	Save on Energy Retrofit Program	Unverified	7,202,274								12																				
	Adjustment to 2017 savings	True-up									12																				16%
27	Save on Energy Small Business Lighting Program	Unverified	91,378								12	53																			
	Adjustment to 2017 savings	True-up									12																				22%
28	Save on Energy High Performance New Construction Program	Unverified	338,710								12	122																			
	Adjustment to 2017 savings	True-up									12																				100%
29	Save on Energy Existing Building Commissioning Program	Verified									3																				
	Adjustment to 2017 savings	True-up									3																				0%
30	Save on Energy Process & Systems Upgrades Program	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
31	Save on Energy Monitoring & Targeting Program	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
32	Save on Energy Energy Manager Program	Verified									12																				
	Adjustment to 2017 savings	True-up									12																				0%
	Local & Regional Programs																														
33	Business Refrigeration Local Program	Verified									0																				
	Adjustment to 2017 savings	True-up									0																				0%

1	Coupon Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
2	Bi-Annual Retailer Event Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
3	Appliance Retirement Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
4	HVAC Incentives Initaitive	Verified																													
	Adjustment to 2017 savings	True-up																													0%
5	Residential New Construction and Major Renovation Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
	Commercial & Institutional Program																														
6	Energy Audit Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
7	Efficiency: Equipment Replacement Incentive Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
8	Direct Install Lighting and Water Heating Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
9	New Construction and Major Renovation Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
10	Existing Building Commissioning Incentive Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
	Industrial Program																														
11	Process and Systems Upgrades Initiatives - Proiect Incentive Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
	Low Income Program																														
14	Low Income Initiative	Verified																													
	Adjustment to 2017 savings	True-up																													0%
	Other																														
15	Aboriginal Conservation Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%
16	Program Enabled Savings	Verified																													
	Adjustment to 2017 savings	True-up																													0%
	Conservation Fund Pilots																														
17	Conservation Fund Pilot - EnerNOC	Verified																													
	Adjustment to 2017 savings	True-up																													0%
18	Loblaws Pilot	Verified																													
	Adjustment to 2017 savings	True-up																													0%
19	Conservation Fund Pilot - SEG	Verified																													
	Adjustment to 2017 savings	True-up																													0%
20	Social Benchmarking Pilot	Verified																													
	Adjustment to 2017 savings	True-up																													0%
	Conservation First Framework																														
	Residential Province-Wide Programs																														
21	Save on Energy Coupon Program	Unverified																													
	Adjustment to 2017 savings	True-up																													17%
22	Save on Energy Heating and Cooling Program	Unverified																													
	Adjustment to 2017 savings	True-up																													12%
23	Save on Energy New Construction Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%
24	Save on Energy Home Assistance Program	Unverified																													
	Adjustment to 2017 savings	True-up																													100%
	Non-Residential Province-Wide Programs																														
25	Save on Energy Audit Funding Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%
26	Save on Energy Retrofit Program	Unverified																													
	Adjustment to 2017 savings	True-up																													16%
27	Save on Energy Small Business Lighting Program	Unverified																													
	Adjustment to 2017 savings	True-up																													22%
28	Save on Energy High Performance New Construction Program	Unverified																													
	Adjustment to 2017 savings	True-up																													100%
29	Save on Energy Existing Building Commissioning Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%
30	Save on Energy Process & Systems Upgrades Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%
31	Save on Energy Monitoring & Targeting Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%
32	Save on Energy Energy Manager Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%
	Local & Regional Programs																														
33	Business Refrigeration Local Program	Verified																													
	Adjustment to 2017 savings	True-up																													0%

34	First Nation Conservation Local Program	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
35	Social Benchmarking Local Program	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
	Pilot Programs																																
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																															
	Adjustment to 2017 savings	True-up																															0%
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified										0																					
	Adjustment to 2017 savings	True-up										0																					0%

	Actual CDM Savings in 2017		**11,956,585**										**175**										**693,758**	**150,917**	**1,465**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2017																						**437,856**	**213,651**	**2,087**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2017																						$0.01230	$0.01800	$3.92480	$0.00000	$0.02330	$30.47560	$44.86850	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2017 from 2011 programs																						$2,177.37	$1,036.51	$386.66	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3,600.54
	Lost Revenue in 2017 from 2012 programs																						$1,892.56	$8,801.40	$2,759.53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$13,453.49
	Lost Revenue in 2017 from 2013 programs																						$1,795.05	$3,979.85	$1,267.51	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7,042.41
	Lost Revenue in 2017 from 2014 programs																						$4,888.54	$18,200.47	$5,112.86	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$28,201.87
	Lost Revenue in 2017 from 2015 programs																						$5,462.26	$5,923.72	$12,628.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$24,014.01
	Lost Revenue in 2017 from 2016 programs																						$15,361.60	$8,825.33	$13,036.40	$0.00	$0.00	$0.00	$85,398.78	$0.00	$0.00	$0.00	$0.00	$0.00	$122,622.11
	Lost Revenue in 2017 from 2017 programs																						$8,533.22	$2,716.50	$5,748.24	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$16,997.96
	Total Lost Revenues in 2017																						**$40,110.59**	**$49,483.77**	**$40,939.24**	**$0.00**	**$0.00**	**$0.00**	**$85,398.78**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$215,932.39**
	Forecast Lost Revenues in 2017																						**$5,385.63**	**$3,845.71**	**$8,192.03**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$17,423.38**
	LRAMVA in 2017																																		**$198,509.01**
	2017 Savings Persisting in 2018																						0	0	0	0	0	0	0	0	0	0	0	0	
	2017 Savings Persisting in 2019																						0	0	0	0	0	0	0	0	0	0	0	0	
	2017 Savings Persisting in 2020																						0	0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

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Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA										
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting					Total
Legacy Framework																							kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	
Actual CDM Savings in 2018		**0**											**0**										**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2018																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Distribution Rate in 2018																							$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2018 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2013 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2014 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2015 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2016 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2017 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2018 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2018																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2018																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2018																																		**$0.00**
2018 Savings Persisting in 2019																							0	0	0	0	0	0	0	0	0	0	0	
2018 Savings Persisting in 2020																							0	0	0	0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-e. 2019 Lost Revenues Work Form Return to top

		Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)										Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA										

	Program	Results Status	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Monthly Multiplier	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting								Total
	Legacy Framework																							kWh	kWh	kW	kW	kWh	kW	kW	0	0	0	0	0	0	0	
	Residential Program																																						
1	Coupon Initiative	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initaitive	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																																					
6	Energy Audit Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified											3																									0%
	Adjustment to 2019 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																					
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																																					
14	Low Income Initiative	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																																					
15	Aboriginal Conservation Program	Verified											0																									0%
	Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified											0																									0%
	Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																																					
17	Conservation Fund Pilot - EnerNOC	Verified											0																									0%
	Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot	Verified											0																									0%
	Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified											0																									0%
	Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified											0																									0%
	Adjustment to 2019 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation First Framework																																					
	Residential Province-Wide Programs																																					
21	Save on Energy Coupon Program	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified																																				0%
	Adjustment to 2019 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																																					
25	Save on Energy Audit Funding Program	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting Program	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Save on Energy Existing Building Commissioning Program	Verified											3																									0%
	Adjustment to 2019 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting Program	Verified											12																									0%
	Adjustment to 2019 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified											12																									0%

| | | |

Ontario Energy Board

LRAMVA Work Form: Carrying Charges by Rate Class

Version 2.0 (2017)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. Please update Table 6 as new approved prescribed interest rates for deferral and variance accounts become available. Monthly interest rates are used to calculate the variance on the carrying charges for LRAMVA. Starting from column I, the principle will auto-populate as monthly variances in Table 6-a, and are multiplied by the interest rate from column H to determine the monthly variances on carrying charges for each rate class by year.

2. The annual carrying charges totals in Table 6-a below pertain to the amount that was originally collected in interest from forecasted CDM savings and what should have been collected based on actual CDM savings. As the amounts calculated in Table 6-a are cumulative, LDCs are requested to enter any collected interest amounts into the "Amounts Cleared" row in order to clear the balance and calculate outstanding variances on carrying charges.

Table 6. Prescribed Interest Rates

Quarter	Approved Deferral & Variance Accounts
2011 Q1	1.47%
2011 Q2	1.47%
2011 Q3	1.47%
2011 Q4	1.47%
2012 Q1	1.47%
2012 Q2	1.47%
2012 Q3	1.47%
2012 Q4	1.47%
2013 Q1	1.47%
2013 Q2	1.47%
2013 Q3	1.47%
2013 Q4	1.47%
2014 Q1	1.47%
2014 Q2	1.47%
2014 Q3	1.47%
2014 Q4	1.47%
2015 Q1	1.47%
2015 Q2	1.10%
2015 Q3	1.10%
2015 Q4	1.10%
2016 Q1	1.10%
2016 Q2	1.10%
2016 Q3	1.10%
2016 Q4	1.10%
2017 Q1	1.10%
2017 Q2	1.10%
2017 Q3	1.10%
2017 Q4	1.50%
2018 Q1	1.50%
2018 Q2	1.50%
2018 Q3	1.50%
2018 Q4	1.50%
2019 Q1	
2019 Q2	
2019 Q3	
2019 Q4	
2020 Q1	
2020 Q2	
2020 Q3	
2020 Q4	

Check OEB website

Table 6-a. Calculation of Carrying Costs by Rate Class

Go to Tab 1: Summary

Month	Period	Quarter	Monthly Rate	Residential	GS<50 kW	GS 50 to 4999 kW	Large User (GS > 5,000 kW)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting								Total
Jan-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2011				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2014				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2014				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2015				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Jul-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2015				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2016				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-16	2011-2016	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-16	2011-2016	Q1	0.09%	$2.99	$3.71	$2.14	$0.00	$0.00	$0.00	$1.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.04
Mar-16	2011-2016	Q1	0.09%	$5.98	$7.41	$4.28	$0.00	$0.00	$0.00	$2.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20.07
Apr-16	2011-2016	Q2	0.09%	$8.97	$11.12	$6.42	$0.00	$0.00	$0.00	$3.60	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$30.11
May-16	2011-2016	Q2	0.09%	$11.96	$14.82	$8.56	$0.00	$0.00	$0.00	$4.80	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$40.15
Jun-16	2011-2016	Q2	0.09%	$14.95	$18.53	$10.71	$0.00	$0.00	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$50.18
Jul-16	2011-2016	Q3	0.09%	$17.94	$22.23	$12.85	$0.00	$0.00	$0.00	$7.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$60.22
Aug-16	2011-2016	Q3	0.09%	$20.93	$25.94	$14.99	$0.00	$0.00	$0.00	$8.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$70.26
Sep-16	2011-2016	Q3	0.09%	$23.92	$29.64	$17.13	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$80.30
Oct-16	2011-2016	Q4	0.09%	$26.91	$33.35	$19.27	$0.00	$0.00	$0.00	$10.80	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$90.33
Nov-16	2011-2016	Q4	0.09%	$29.91	$37.05	$21.41	$0.00	$0.00	$0.00	$12.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$100.37
Dec-16	2011-2016	Q4	0.09%	$32.90	$40.76	$23.55	$0.00	$0.00	$0.00	$13.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$110.41
Total for 2016				**$197.38**	**$244.56**	**$141.32**	**$0.00**	**$0.00**	**$0.00**	**$79.18**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$662.44**
Amount Cleared																		
Opening Balance for 2017				**$197.38**	**$244.56**	**$141.32**	**$0.00**	**$0.00**	**$0.00**	**$79.18**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$662.44**
Jan-17	2011-2017	Q1	0.09%	$35.89	$44.47	$25.69	$0.00	$0.00	$0.00	$14.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$120.44
Feb-17	2011-2017	Q1	0.09%	$38.54	$47.95	$28.20	$0.00	$0.00	$0.00	$20.92	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$135.61
Mar-17	2011-2017	Q1	0.09%	$41.19	$51.44	$30.70	$0.00	$0.00	$0.00	$27.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$150.77
Apr-17	2011-2017	Q2	0.09%	$43.84	$54.92	$33.20	$0.00	$0.00	$0.00	$33.97	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$165.94
May-17	2011-2017	Q2	0.09%	$46.50	$58.41	$35.70	$0.00	$0.00	$0.00	$40.49	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$181.10
Jun-17	2011-2017	Q2	0.09%	$49.15	$61.90	$38.20	$0.00	$0.00	$0.00	$47.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$196.26
Jul-17	2011-2017	Q3	0.09%	$51.80	$65.38	$40.70	$0.00	$0.00	$0.00	$53.54	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$211.43
Aug-17	2011-2017	Q3	0.09%	$54.45	$68.87	$43.21	$0.00	$0.00	$0.00	$60.06	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$226.59
Sep-17	2011-2017	Q3	0.09%	$57.11	$72.36	$45.71	$0.00	$0.00	$0.00	$66.59	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$241.75
Oct-17	2011-2017	Q4	0.13%	$81.49	$103.42	$65.74	$0.00	$0.00	$0.00	$99.69	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$350.34
Nov-17	2011-2017	Q4	0.13%	$85.11	$108.17	$69.15	$0.00	$0.00	$0.00	$108.59	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$371.02
Dec-17	2011-2017	Q4	0.13%	$88.73	$112.93	$72.56	$0.00	$0.00	$0.00	$117.49	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$391.70
Total for 2017				**$871.17**	**$1,094.78**	**$670.08**	**$0.00**	**$0.00**	**$0.00**	**$769.37**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$3,405.39**
Amount Cleared																		
Opening Balance for 2018				**$871.17**	**$1,094.78**	**$670.08**	**$0.00**	**$0.00**	**$0.00**	**$769.37**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$3,405.39**
Jan-18	2011-2018	Q1	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Feb-18	2011-2018	Q1	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Mar-18	2011-2018	Q1	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Apr-18	2011-2018	Q2	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
May-18	2011-2018	Q2	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Jun-18	2011-2018	Q2	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Jul-18	2011-2018	Q3	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Aug-18	2011-2018	Q3	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Sep-18	2011-2018	Q3	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Oct-18	2011-2018	Q4	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Nov-18	2011-2018	Q4	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Dec-18	2011-2018	Q4	0.13%	$92.34	$117.68	$75.97	$0.00	$0.00	$0.00	$126.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$412.38
Total for 2018				**$1,979.28**	**$2,506.96**	**$1,581.74**	**$0.00**	**$0.00**	**$0.00**	**$2,285.94**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$8,353.92**
Amount Cleared																		
Opening Balance for 2019				**$1,979.28**	**$2,506.96**	**$1,581.74**	**$0.00**	**$0.00**	**$0.00**	**$2,285.94**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$8,353.92**
Jan-19	2011-2019	Q1	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-19	2011-2019	Q1	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-19	2011-2019	Q1	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-19	2011-2019	Q2	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-19	2011-2019	Q2		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-19	2011-2019	Q2		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-19	2011-2019	Q3		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-19	2011-2019	Q3		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-19	2011-2019	Q3		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-19	2011-2019	Q4		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-19	2011-2019	Q4		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-19	2011-2019	Q4		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2019				**$1,979.28**	**$2,506.96**	**$1,581.74**	**$0.00**	**$0.00**	**$0.00**	**$2,285.94**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$8,353.92**
Amount Cleared																		

Ontario Energy Board

Supporting Documentation:
LDC Persistence Savings Results from IESO

Version 3.0 (MAY)

Legend

User Inputs (Green)
Drop Down List (Blue)
Instructions (Grey)

Instructions (Steps)

1. Columns B to H of this tab have been structured in a way to match the formatting of the persistence report provided by the IESO. Please copy and paste the program information by initiative in Columns B to H and the corresponding demand and energy savings data by initiative in Columns L to BT of this work form.
2. Please identify the source of the report via the dropdown list in Column I
3. To facilitate the identification of adjustments that may be available in a prospective year's results report, it will be easier to sort all the savings by implementation year (Column H). This can be done by clicking on the filter button at cell H25 (highlighted in orange). Before you sort values, please ensure that all table columns have filters.
4. Please identify what the savings value represents (i.e., current year savings for the year or an adjustment to a prior year) via the dropdown list in Column J. Current year savings would be identified with an implementation year that matches the year of the persistence report. A savings adjustment would be identified with a prior year implementation in the future year's results report.
5. Please manually input or link the applicable savings and adjustments (Columns L to BT) for all applicable initiatives in Tabs 4 and 5 of this work form

NOTE: The Net Verified Peak Demand Savings table and Net Verified Energy Savings table below are in the reverse order to the accompanying tables in Tab 4 and Tab 5. The tables below match those provided by the IESO.

Table 7. 2011-2020 Verified Program Results and Persistence into Future Years

| Rate Portfolio | Program | Initiative | LDC | Sector | Construction Resource Type | Implementation Year | Identify Source of Report | Identify Status of Savings | Net Verified Annual Peak Demand Savings at the End User Level (kW) | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | Net Verified Annual Energy Savings at the End User Level (kWh) | | | | | | | | | | | | | | | | | | |

Ontario Energy Board

LRAMVA Work Form:
Documentation for Streetlighting Projects

Version 2.0 (2017)

Instructions

Please provide documentation and/or data to substantiate program savings that were not provided by the IESO (i.e., streetlighting projects) as applicable.

Energy savings attributed to street lighting project in IESO results				
Year	Gross	NTG	Net	Comments
2016	1,572,329	0.79	1,242,140	
2017			-	

2016

Actual lost revenue based on kW billing				
Month	Billed kW	Gross kW reduction	NTG	Net kW reduction
Jan-16	397.54		0.79	
Feb-16	397.54		0.79	
Mar-16	397.54		0.79	
Apr-16	397.54		0.79	
May-16	397.54		0.79	
Jun-16	397.54		0.79	
Jul-16	363.16	34.38	0.79	27.1602
Aug-16	363.16	34.38	0.79	27.1602
Sep-16	363.16	34.38	0.79	27.1602
Oct-16	363.16	34.38	0.79	27.1602
Nov-16	175.88	221.66	0.79	175.1114
Dec-16	175.88	221.66	0.79	175.1114
2016 total		**443.32**		**350.22**
2016 Persisting in 2017*				**1,903**
2016 Persisting in 2018				**1,708**
2016 Persisting in 2019				**1,708**
2016 Persisting in 2020				**1,708**

*** In Feb. 2017, 124 lights were transferred to the City of Brantford - load dropped from 175.09 to 157.09, persistent savings were adjusted accordingly**

APPENDIX 4-14: ENERGY+ (CND) OEB LRAMVA WORK FORM

Ontario Energy Board

Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form

Version 2.0 (2017)

Generic LRAMVA Work Forms

Worksheet Name	Description
1. LRAMVA Summary	**Tables 1-a and 1-b** provide a summary of the LRAMVA balances and carrying charges associated with the LRAMVA disposition. The balances are populated from entries into other tabs throughout this work form.
1-a. Summary of Changes	**Tables A-1 and A-2** include a template for LDCs to summarize changes to the LRAMVA work form.
2. LRAMVA Threshold	**Tables 2-a, 2-b and 2-c** include the LRAMVA thresholds and allocations by rate class.
3. Distribution Rates	**Tables 3-a and 3-b** include the distribution rates that are used to calculate lost revenues.
3-a. Rate Class Allocations	A blank spreadsheet is provided to allow LDCs to populate distributor specific rate class percentages to allocate actual CDM savings to different customer classes.
4. 2011-2014 LRAM	**Tables 4-a, 4-b, 4-c and 4-d** include the template 2011-2014 LRAMVA work forms.
5. 2015-2020 LRAM	**Tables 5-a, 5-b, 5-c and 5-d** include the template 2015-2020 LRAMVA work forms.
6. Carrying Charges	**Table 6-b** includes the variance on carrying charges related to the LRAMVA disposition.
7. Persistence Data	**Tables 7-a to 7-j** should be populated with CDM savings persistence data provided to LDCs from the IESO.
8. Streetlighting	A blank spreadsheet is provided to allow LDCs to populate data on streetlighting projects whose savings were not provided by the IESO in the CDM Final Results Report.

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of filing your application. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing the application or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the

results.

Ontario Energy Board

LRAMVA Work Form: Checklist and Schematic

Version 2.0 (2017)

General Note on the LRAMVA Model

The LRAMVA work form has been created in a generic manner that should allow for use by all LDCs. There are some elements that are not applicable at this time (i.e., 2017, 2018, 2019 and 2020 related components). These have been included (but hidden in the work form) in an effort to avoid major updates in the future. This LRAMVA work form consolidates information that LDCs are already required to file with the OEB. The model has been created to provide LDCs with a consistent format to display CDM impacts, the forecast savings component and, ultimately, any variance between actual CDM savings and forecast CDM savings. The majority of the information required in the LRAMVA work form will be provided to LDCs from the IESO as part of the Final CDM Results each year. Please contact the IESO for any reports that may be required to complete this LRAMVA work form.

The LRAMVA work form is unlocked to enable LDCs to tailor it to their own unique circumstances.

LRAMVA ($) = (Actual Net CDM Savings - Forecast CDM Savings) x Distribution Volumetric Rate + Carrying Charges from LRAMVA balance

Legend	Drop Down List (Blue)

Important Checklist

Yes	o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a
Yes	o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form
Yes	o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved
yes	o Include a copy of initiative-level persistence savings information that was verified by the IESO in Tab 7. Persistence information is available upon request from the IESO
Yes	o Apply the IESO verified savings adjustments to the year it relates to.
	o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable
Yes	o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a

Work Form Calculations	Source of Calculation	Inputs (Tables to Complete)	Source of Data Inputs	Outputs of Data (Auto-Populated)
Actual Incremental CDM Savings by Initiative	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D & O)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+/- IESO Verified Savings Adjustments	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D-M & Columns O-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+ Initiative Level Savings Persistence	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns E-M & Columns P-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
x Allocation % to Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AJ)	Determined by the LDC	
Actual Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			
- Forecast Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tab "2. LRAMVA Threshold" Tables 2-a, 2-b and 2-c		
x Distribution Rate by Rate Class	Tab "3. Distribution Rates"	Table 3	LDC's Approved Tariff Sheets	
LRAMVA ($) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			Tables 1-a and 1-b
+ Carrying Charges ($) by Rate Class	Tabs "1. LRAMVA Summary" and "6. Carrying Charges"	Table 6		Table 6-a
Total LRAMVA ($) by Rate Class	Tab "1. LRAMVA Summary"			

Ontario Energy Board

LRAMVA Work Form: Instructions

Version 2.0 (2017)

Tab	Instructions
LRAMVA Checklist/Schematic Tab	The LRAMVA work form was created in a generic manner for use by all LDCs. There are some elements that are not applicable at this time (i.e., 2017, 2018, 2019 and 2020 related components) but have been included in an effort to avoid major updates in the future. Distributors should follow the checklist, which is referenced in this tab of the work form and listed below: o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a. o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form. o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved. o Include a copy of initiative-level persistence savings information that was verified by the IESO. Persistence information is available upon request from the IESO. o Apply the IESO verified savings adjustments to the year it relates to. For example, savings adjustments to 2015 programs will be provided to LDCs with the 2016 Final Results Report. The 2015 savings adjustments should be included in the 2015 verified savings portion of the work form. o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable. o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a.
Tab 1. LRAMVA Summary	Distributors are required to report any past approved LRAMVA amounts along with the current LRAMVA amount requested for approval. There are separate tables indicating new lost revenues and carrying charges amounts by year and the totals for rate rider calculations.
Tab 1-a. Summary of Changes	Distributors should list all significant changes and changes in assumptions in the generic work form affecting the LRAMVA.
Tab 2. LRAMVA Threshold	Distributors should use the tables to display the LRAMVA threshold amounts as approved at a rate class level. This should be taken from the LDC's most recently approved cost of service application.
Tab 3. Distribution Rates	Distributors should complete the tables with rate class specific distribution rates and adjustments as applicable.
Tab 3-a. Rate Class Allocations	A tab is provided to allow LDCs to include documentation or analysis on how rate class allocations for actual CDM savings were determined by customer class and program each year. The rate class allocations would support the LRAMVA rate class allocation figures used in Tabs 4 and 5.
Tabs 4 and 5 (2011-2020)	Distributors should complete the lost revenue calculation for 2011-2014 program years and 2015-2020 program years, as applicable, by undertaking the following: o Input or manually link the savings, adjustments and program savings persistence data from Tab 7 (Persistence Report) to Tabs 4 and 5. As noted earlier, persistence data is available upon request from the IESO. o Ensure that the IESO verified savings adjustments apply to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. o Confirm the monthly multipliers applied to demand savings. If a different monthly multiplier is used than what was confirmed in the LRAMVA Report, provide rationale in Tab 1-a and highlight the new monthly multiplier that has been used. o Input the rate class allocations by program and year to allocate actual savings to customers. If a different allocation is proposed for adjustments, LDCs must provide the supporting rationale in Tab 1-a and highlight the change. o Provide assumptions about the year(s) in which persistence is captured in the load forecast via the "Notes" section of each table and adjust what is included in the LRAMVA totals, as appropriate.
Tab 6. Carrying Charges	Distributors are requested to calculate carrying charges based on the methodology provided in the work form. This includes updating Table 6 as new prescribed interest rates for deferral and variance accounts become available and entering any collected interest amounts into the "Amounts Cleared" row to calculate outstanding variances on carrying charges.
Tab 7. Persistence Report	Persistence savings report(s) provided by the IESO should be included for the relevant years in the LRAMVA work form. Tab 7 has been created consistently with the IESO's persistence report.
Tab 8. Streetlighting	A tab is provided to ensure LDCs include documentation or data to support projects whose program savings were not provided by the IESO (i.e., streetlighting projects).

Ontario Energy Board

LRAMVA Work Form: Summary Tab

Version 2.0 (2017)

Legend	User Inputs (Green)
	Auto Populated Cells (White)
	Instructions (Grey)
LDC Name	Energy + Inc. - (CND)
Application Details	Claim for results for 2014-2016 including persistence from 2011

Please fill in the requested information: a) the amounts approved in the previous LRAMVA application, b) details on the current application, and c) documentation of changes if applicable.

A. Previous LRAMVA Application

Previous LRAMVA Application (EB#)	EB-2014-0060
Application of Previous LRAMVA Claim	2015 IRM Application
Period of LRAMVA Claimed in Previous Application	2011-2013
Amount of LRAMVA Claimed in Previous Application	$ 282,030.00

B. Current LRAMVA Application

Current LRAMVA Application (EB#)		EB-2018-0028
Application of Current LRAMVA Claim		2019 COS
Period of New LRAMVA in this Application		2014-2017
Actual Lost Revenues ($)	A	**$ 1,970,310**
Forecast Lost Revenues ($)	B	**$ 1,471,615**
Carrying Charges ($)	C	**$ 23,172**
LRAMVA ($) for Account 1568	A-B+C	**$ 521,867**

C. Documentation of Changes

Original Amount	
Amount for Final Disposition	

Table 1-a. LRAMVA Totals by Rate Class

Please input the customer rate classes applicable to the LDC and associated billing units (kWh or kW) in Table 1-a below. This will update all tables throughout the workform.

The LRAMVA total by rate class in Table 1-a should be used to inform the determination of rate riders in the Deferral and Variance Account Work Form or IRM Rate Generator Model. Please also ensure that the principal amounts in column E of Table 1-a capture the appropriate years and amounts for the LRAMVA claim.

NOTE: If the LDC has more than 14 customer classes in which CDM savings was allocated, LDCs must contact OEB staff to make adjustments to the workform.

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	(42,016.66)	-$4,950.90	-$46,967.56
GS<50 kW	kWh	(53,105.32)	-$3,056.60	-$56,161.92
GS 50 to 999 kW	kW	630,470.84	$24,167.13	$654,637.97
GS 1000 - 4,999	kW	41,943.28	$1,184.22	$43,127.50
Large Use	kW	308,108.47	$7,578.63	$315,687.10
Unmetered Scattered Load	kWh	(2,373.67)	-$91.02	-$2,464.69
Street Lighting	kW	(44,003.68)	-$1,659.36	-$45,663.04
		-	$0.00	$0.00
		-	$0.00	$0.00
		-	$0.00	$0.00
		-	$0.00	$0.00
		-	$0.00	$0.00
		-	$0.00	$0.00
		-	$0.00	$0.00
Total		**$839,023**	**$23,172**	**$862,195**

Table 1-b. Annual LRAMVA Breakdown by Year and Rate Class

In column C of Table 1-b below, please insert a 'check mark' to indicate the years in which LRAMVA has been claimed. If you inserted a check-mark for a particular year, please delete the amounts associated with the actual and forecast lost revenues for all rate classes for that year, up to and including the total. Any LRAMVA from a prior year that has already been claimed cannot be included in the current LRAMVA disposition, with the exception of the case noted below.

If LDCs are seeking to claim true-up amounts that were previously approved by the OEB, please note that the "Amount Cleared" rows are applicable to the LDC and should be filled out. This may relate to claiming the difference in LRAM approved before the May 19, 2016 Peak Demand Consultation, and the lost revenues that would have been incurred after that consultation, as approved by the OEB. If this is the case, reference to the decision must be noted in the rate application. If this is not the case, LDCs are requested to leave those rows blank.

Depending on the period of LRAMVA to be claimed, LDCs are expected to adjust the totals for carrying charges in row 82 of Table 1-b and the years included in the LRAMVA balance in row 83, as appropriate.

Description	LRAMVA Previously Claimed	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting								Total
		kWh	kWh	kW	kW	kW	kWh	kW	0	0	0	0	0	0	0	
2011 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2012 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2013 Actuals	☑	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2014 Actuals	☐	$103,837.25	$16,927.39	$271,589.19	$42,369.42	$13,503.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$448,226.96
2014 Forecast		($192,179.52)	($58,245.74)	($150,268.62)	($48,776.09)	($26,955.13)	($618.59)	($10,336.76)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($487,380.46)
Amount Cleared																
2015 Actuals	☐	$136,497.13	$38,006.05	$344,408.88	$64,538.09	$16,600.74	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$600,050.89
2015 Forecast		($198,844.71)	($60,402.99)	($155,686.19)	($50,453.62)	($28,011.62)	($575.44)	($11,039.66)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($505,014.22)
Amount Cleared																
2016 Actuals		$210,241.17	$64,280.72	$379,101.02	$71,394.64	$197,014.58	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$922,032.14
2016 Forecast		($167,740.51)	($61,697.34)	($158,230.16)	($51,277.16)	($28,469.78)	($585.03)	($11,220.16)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($479,220.13)
Amount Cleared																
2017 Actuals		$185,035.01	$70,586.82	$260,423.91	$66,279.15	$193,369.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$775,694.11
2017 Forecast		($118,862.48)	($62,560.24)	($160,867.20)	($52,131.15)	($28,943.26)	($594.62)	($11,407.09)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($435,366.03)
Amount Cleared																
Carrying Charges		($4,950.90)	($3,056.60)	$24,167.13	$1,184.22	$7,578.63	($91.02)	($1,659.36)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$23,172.11
Total LRAMVA Balance		**-$46,968**	**-$56,162**	**$654,638**	**$43,128**	**$315,687**	**-$2,465**	**-$45,663**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$862,195.37**

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form: Summary of Changes

Version 2.0 (2017)

Legend	
	User Inputs (Green)
	Drop Down List (Blue)
	Instructions (Grey)

Table A-1. Changes to Generic Assumptions in LRAMVA Work Form

Please document any changes in assumptions made to the generic inputs of the LRAMVA work form. This may include, but are not limited to, the use of different monthly multipliers to claim demand savings from energy efficiency programs; use of different rate allocations between current year savings and prior year savings adjustments; inclusion of additional adjustments affecting distribution rates; use of a different LRAMVA threshold; etc. All important changes should be highlighted in the work form as well.

No.	Tab	Cell Reference	Description	Rationale
1	5. 2015-2020 LRAM	D39:X39 (for example)	Adjustment results and persistence are from the new table on Tab 3-a	It was necessary to split out Energy+ (CND) rate zone from the IESO aggregated results for Energy+
2				
3	6. Carrying Charges	C41:C44	Estimated carrying charges through December 2018 at most current rate	
4	1. LRAMVA Summary	D82:Q82	Changed reference to carrying charges to capture charges through April 2018	
5		Tab 9	New tab for CHP project in 2015 showing actual changes in billed amounts	IESO results don't capture changes in monthly demand associated with the project
6	5. 2015-2020 LRAM	A378:AM380	Added new rows for 2016 program not listed originally	
7	5. 2015-2020 LRAM	A381:AM381	Adjusted formulae to capture new rows added	
8	5. 2015-2020 LRAM	P71:T71	Persistence for PSUI comes from new Tab 9 (no data yet for 2017 and later)	IESO results don't capture changes in monthly demand associated with the project
9	9. CHP Projects		New tab for CHP project in 2015 showing actual changes in billed amounts	IESO results don't capture changes in monthly demand associated with the project
10	5. 2015-2020 LRAM	Red values below row 289	Unverified results for 2016 adjustments and 2017 results used	Not available until ~July 2017. Will be updated when final results available
etc.				

Table A-2. Updates to LRAMVA Disposition

Please document any changes related to interrogatories or questions during the application process that affect the LRAMVA amount.

No.	Tab	Cell Reference	Description	Rationale
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
etc.				

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LRAMVA Work Form: Forecast Lost Revenues

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Legend

- User Inputs (Green)
- Drop Down List (Blue)
- Auto Populated Cells (White)
- Instructions (Grey)

Table 2-a. LRAMVA Threshold — **2010**

Please provide the LRAMVA threshold approved in the cost of service (COS) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting							
		kWh	kWh	kW	kW	kW	kWh	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0	0	0	0	0	0	0	0	0	0	0	0			
kW	0	0	0	0	0	0	0	0	0	0	0	0			
Summary		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Basis of Threshold
Source of Threshold

Table 2-b. LRAMVA Threshold — **2014**

Please provide the LRAMVA threshold approved in the last COS application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting							
		kWh	kWh	kW	kW	kW	kWh	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
kWh	39,520,173	11,108,643	4,314,499	12,006,086	6,095,436	5,684,186	47,953	263,370	0	0	0	0			
kW	65,764	0	0	38,780	14,499	11,778	0	707	0	0	0	0			
Summary		11108643	4314499	38780	14499	11778	47953	707	0	0	0	0	0	0	0

Basis of Threshold: 100% of 2011-2014 estimated CDM savings
Source of Threshold: p.19 of 30 of EB-2013-0116 settlement proposal

Table 2-c. Inputs for LRAMVA Thresholds

Please complete Table 2-c below by selecting the appropriate LRAMVA threshold year in column C. The LRAMVA threshold values in Table 2-c will auto-populate from Tables 2-a and 2-b depending on the year selected. If there was no LRAMVA threshold established for a particular year, please select the "blank" option. The LRAMVA threshold values in Table 2-c will be auto-populated in Tabs 4 and 5 of this work form.

Year	LRAMVA Threshold	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting							
		kWh	kWh	kW	kW	kW	kWh	kW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	2010	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	2010	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2013	2010	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	2014	11,108,643	4,314,499	38,780	14,499	11,778	47,953	707	0	0	0	0	0	0	0
2015	2014	11,108,643	4,314,499	38,780	14,499	11,778	47,953	707	0	0	0	0	0	0	0
2016	2014	11,108,643	4,314,499	38,780	14,499	11,778	47,953	707	0	0	0	0	0	0	0
2017	2014	11,108,643	4,314,499	38,780	14,499	11,778	47,953	707	0	0	0	0	0	0	0
2018		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Note: LDC to make note of assumptions included above, if any

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Table 3. Inputs for Distribution Rates and Adjustments by Rate Class

Please complete Table 3 with the rate class specific distribution rates that pertain to the years of the LRAMVA disposition. Any adjustments that affect distribution rates can be incorporated in the calculation by expanding the "plus" button at the left hand bar. Table 3 will convert the distribution rates to a calendar year rate (January to December) based on the number of months entered in row 16 of each rate year starting from January to the start of the LDC's rate year. Please enter 0 in row 16, if the rate year begins on January 1. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas in Table 3-a accordingly.

	Billing Unit	EB-2009-0260	EB-2010-0068	EB-2011-0156	EB-2012-0111	EB-2013-0116	EB-2014-0060	EB-2015-0057	EB-2016-0060	EB-2017-XXXX	EB-2018-XXXX	EB-2019-XXXX	EB-2020-XXXX
Rate Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Period 1 (# months)		*4*	*4*	*4*	*4*	*4*	*4*	*4*	*4*				
Period 2 (# months)		*8*	*8*	*8*	*8*	*8*	*8*	*8*	*8*	*12*	*12*	*12*	*12*
Residential	kWh	$ -	$ -	$ 0.0160	$ 0.0162	$ 0.0178	$ 0.0180	$ 0.0137	$ 0.0092				
Adjusted rate		$ -	$ -	$ 0.0160	$ 0.0162	$ 0.0178	$ 0.0180	$ 0.0137	$ 0.0092	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ 0.0107**	**$ 0.0161**	**$ 0.0173**	**$ 0.0179**	**$ 0.0151**	**$ 0.0107**	**$ -**	**$ -**	**$ -**	
GS<50 kW	kWh	$ -	$ -	$ 0.0125	$ 0.0126	$ 0.0139	$ 0.0141	$ 0.0144	$ 0.0146				
Adjusted rate		$ -	$ -	$ 0.0125	$ 0.0126	$ 0.0139	$ 0.0141	$ 0.0144	$ 0.0146	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ 0.0083**	**$ 0.0126**	**$ 0.0135**	**$ 0.0140**	**$ 0.0143**	**$ 0.0145**	**$ -**	**$ -**	**$ -**	
GS 50 to 999 kW	kW	$ -	$ -	$ 3.6403	$ 3.6646	$ 3.9801	$ 4.0318	$ 4.1044	$ 4.1701				
Adjusted rate		$ -	$ -	$ 3.6403	$ 3.6646	$ 3.9801	$ 4.0318	$ 4.1044	$ 4.1701	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ 2.4269**	**$ 3.6565**	**$ 3.8749**	**$ 4.0146**	**$ 4.0802**	**$ 4.1482**	**$ -**	**$ -**	**$ -**	
GS 1000 - 4,999	kW	$ -	$ -	$ 3.1714	$ 3.1925	$ 3.4499	$ 3.4947	$ 3.5576	$ 3.6145				
Adjusted rate		$ -	$ -	$ 3.1714	$ 3.1925	$ 3.4499	$ 3.4947	$ 3.5576	$ 3.6145	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ 2.1143**	**$ 3.1855**	**$ 3.3641**	**$ 3.4798**	**$ 3.5366**	**$ 3.5955**	**$ -**	**$ -**	**$ -**	
Large Use	kW	$ -	$ -	$ 2.1356	$ 2.1501	$ 2.3578	$ 2.3885	$ 2.4315	$ 2.4704				
Adjusted rate		$ -	$ -	$ 2.1356	$ 2.1501	$ 2.3578	$ 2.3885	$ 2.4315	$ 2.4704	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ 1.4237**	**$ 2.1453**	**$ 2.2886**	**$ 2.3783**	**$ 2.4172**	**$ 2.4574**	**$ -**	**$ -**	**$ -**	
Unmetered Scattered Load	kWh	$ -	$ -	$ 0.0148	$ 0.0149	$ 0.0119	$ 0.0121	$ 0.0123	$ 0.0125				
Adjusted rate		$ -	$ -	$ 0.0148	$ 0.0149	$ 0.0119	$ 0.0121	$ 0.0123	$ 0.0125	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ 0.0099**	**$ 0.0149**	**$ 0.0129**	**$ 0.0120**	**$ 0.0122**	**$ 0.0124**	**$ -**	**$ -**	**$ -**	
Street Lighting	kW	$ -	$ -	$ 12.7988	$ 12.9005	$ 15.4807	$ 15.6819	$ 15.9642	$ 16.2196				
Adjusted rate		$ -	$ -	$ 12.7988	$ 12.9005	$ 15.4807	$ 15.6819	$ 15.9642	$ 16.2196	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ 8.5325**	**$ 12.8666**	**$ 14.6206**	**$ 15.6148**	**$ 15.8701**	**$ 16.1345**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
0	0												
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	

Note: LDC to make note of adjustments made to Table 3 to accommodate the LDC's specific circumstances

Table 3-a. Distribution Rates by Rate Class

Table 3-a below autopopulates the average distribution rates from Table 3. Please ensure that the distribution rates relevant to the years of the LRAMVA disposition are used. As such, please clear the rates related to the year(s) that are not part of the LRAMVA claim. The distribution rates that remain in Table 3-a will be used in Tabs 4 and 5 of the work form to calculate actual and forecast lost revenues. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas from Table 3-a, as well as the distribution rate links in Tabs 4 and 5.

Year	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting							
	kWh	kWh	kW	kW	kW	kWh	kW	0	0	0	0	0	0	0
2011														
2012														
2013														
2014	$0.0173	$0.0135	$3.8749	$3.3641	$2.2886	$0.0129	$14.6206	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2015	$0.0179	$0.0140	$4.0146	$3.4798	$2.3783	$0.0120	$15.6148	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2016	$0.0151	$0.0143	$4.0802	$3.5366	$2.4172	$0.0122	$15.8701	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2017	$0.0107	$0.0145	$4.1482	$3.5955	$2.4574	$0.0124	$16.1345	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Note: Rates for 2011-2013 are removed as LRAMVA for these years was recovered in EB-2014-0060

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LRAMVA Work Form: Determination of Rate Class Allocations

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Instructions

LDCs must clearly show how it has allocated actual CDM savings to applicable rate classes, including supporting documentation and rationale for its proposal. This should be shown by customer class and program each year.

Allocations are shown on Tab 4 and 5. Allocations are based on project specific information where available.
For 2016, IESO provided aggregated results for 2016 and 2015 adjustments that covered both Energy+ (CND) and Energy+ (BCP) rate zones.
For 2016 and 2015 adjustments, the allocations take into account the relative split of program results by rate zone.
2016 aggregate results are shown on Table 5b and rate zone allocations are captured in the allocation rates
For 2015 adjustments, allocations are shown below and the products of the adjustments and the Rate Zone allocation are transferred to Table 5a

2015 ADJUSTMENTS

	Initiative	Net Incremental Peak Demand Savings	Net Incremental Energy Savings (kWh)	Persistence of 2015 adjustments: Incremental Peak Demand Savings (kW)					Persistence of 2015 adjustments: Incremental Energy Savings (kWh)					Rate zone allocation		Net Incremental Peak Demand Savings (kW) Energy+ (CND)	Net Incremental Energy Savings (kWh). Energy+ (CND)	Persistence of 2015 adjustments. (Energy+ CND): Incremental Peak Demand Savings (kW)					Incremental Energy Savings (kWh)				
		2015	2015	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020	to CND	to BCP	2015	2015	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
	2015-2020 Conservation First Framework Programs																										
	Residential Province-Wide Program																										
1	Save on Energy Coupon Program															0	0	0	0	0	0	0	0	0	0	0	0
2	Save on Energy Heating and Cooling Program															0	0	0	0	0	0	0	0	0	0	0	0
3	Save on Energy New Construction Program															0	0	0	0	0	0	0	0	0	0	0	0
4	Save on Energy Home Assistance Program		-1,122						-759	-688	-617	-617	-617	89%	11%	0	-1,002	0	0	0	0	0	-677	-614	-551	-551	-551
	Sub-total - Residential Province-Wide Program	0	-1,122	0	0	0	0	0	-759	-688	-617	-617	-617			0	-1,002	0	0	0	0	0	-677	-614	-551	-551	-551
	Business Province-Wide Program																										
5	Save on Energy Audit Funding Program															0	0	0	0	0	0	0	0	0	0	0	0
6	Save on Energy Retrofit Program	31	151,028	31	31	31	31	31	151,028	151,028	151,028	151,028	151,028	90%	10%	28	135,607	28	28	28	28	28	135,607	135,607	135,607	135,607	135,607
7	Save on Energy Small Business Lighting Program															0	0	0	0	0	0	0	0	0	0	0	0
8	Save on Energy High Performance New Construction Program															0	0	0	0	0	0	0	0	0	0	0	0
9	Save on Energy Existing Building Commissioning Program															0	0	0	0	0	0	0	0	0	0	0	0
10	Save on Energy Process & Systems Upgrades Program															0	0	0	0	0	0	0	0	0	0	0	0
11	Save on Energy Energy Manager Program															0	0	0	0	0	0	0	0	0	0	0	0
12	Save on Energy Monitoring & Targeting Program															0	0	0	0	0	0	0	0	0	0	0	0
13	Save on Energy Retrofit Program - P4P															0	0	0	0	0	0	0	0	0	0	0	0
14	Save on Energy Process & Systems Upgrades Program - P4P															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Business Province-Wide Program	31	151,028	31	31	31	31	31	151,028	151,028	151,028	151,028	151,028			28	135,607	28	28	28	28	28	135,607	135,607	135,607	135,607	135,607
	Local & Regional Program																										
15	Adaptive Thermostat Local Program															0	0	0	0	0	0	0	0	0	0	0	0
16	Business Refrigeration Incentives Local Program															0	0	0	0	0	0	0	0	0	0	0	0
17	Conservation on the Coast Home Assistance Local Program															0	0	0	0	0	0	0	0	0	0	0	0
18	Conservation on the Coast Small Business Lighting Local Program															0	0	0	0	0	0	0	0	0	0	0	0
19	First Nations Conservation Local Program															0	0	0	0	0	0	0	0	0	0	0	0
20	High Efficiency Agricultural Pumping Local Program															0	0	0	0	0	0	0	0	0	0	0	0
21	Instant Savings Local Program															0	0	0	0	0	0	0	0	0	0	0	0
22	OPsaver Local Program															0	0	0	0	0	0	0	0	0	0	0	0
23	PUMPsaver Local Program															0	0	0	0	0	0	0	0	0	0	0	0
24	Social Benchmarking Local Program															0	0	0	0	0	0	0	0	0	0	0	0
25	THESL Swimming Pool Efficiency Local Program															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Local & Regional Program	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
	Pilot Program																										
26	Air Source Heat Pump for Residential Water Heating Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
27	Building Optimization Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
28	Conservation Voltage Regulation Leveraging AMI Data Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
29	Demand Control Kitchen Ventilation Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
30	Direct Install - Hydronic Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
31	Direct Install - RTU Controls Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
32	Electronically Commutated Furnace Motor Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
33	Electronics Takeback Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
34	Home Energy Assessment and Retrofit Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
35	HONI HP Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
36	P4P for Class B Office Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
37	Performance Based Conservation Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
38	Re-Invest Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
39	Residential Direct Install Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
40	Residential Ductless Heat Pump Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
41	Residential Install Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
42	Social Benchmarking Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
43	Solar Powered Attic Ventilation Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
44	Truckload Event Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Pilot Program	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
	Program Enabled Savings																										
45	Save on Energy Retrofit Program Enabled Savings															0	0	0	0	0	0	0	0	0	0	0	0
46	Save on Energy High Performance New Construction Program Enabled Savings															0	0	0	0	0	0	0	0	0	0	0	0
47	Save on Energy Process & Systems Upgrades Program Enabled Savings															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Program Enabled Savings	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
	Other																										
48	Proposed Program or Pilot															0	0	0	0	0	0	0	0	0	0	0	0
49	Unassigned Target															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Other	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - 2015-2020 Conservation First Framework P	31	149,906	31	31	31	31	31	150,269	150,340	150,411	150,411	150,411			28	134,606	28	28	28	28	28	134,930	134,993	135,057	135,057	135,057
	Conservation Fund																										
50	EnerNOC Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
51	Home Depot Home Appliance Market Uplift															0	0	0	0	0	0	0	0	0	0	0	0
52	Loblaw P4P Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
53	Ontario Clean Water Agency P4P Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
54	Strategic Energy Group Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
55	Social Benchmarking Conservation Fund Pilot Program															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Conservation Fund	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
	2011-2014+2015 Extension Legacy Framework Programs																										
	Residential Program																										
56	Appliance Retirement Initiative																										
57	Coupon Initiative	6	98,171	6	6	6	6	6	96,771	96,771	96,771	96,771	96,771	83%	17%	5	81,211	5	5	5	5	5	80,053	80,053	80,053	80,053	80,053
58	Bi-Annual Retailer Event Initiative	1	11,030	1	1	1	1	1	10,901	10,901	10,901	10,901	10,901	83%	17%	1	9,142	1	1	1	1	1	9,035	9,035	9,035	9,035	9,035
59	HVAC Incentives Initiative	14	27,228	14	14	14	14	14	27,228	27,228	27,228	27,228	27,228	88%	12%	12	23,842	12	12	12	12	12	23,842	23,842	23,842	23,842	23,842
60	Residential New Construction and Major Renovation Initiative	1	11,717	1	1	1	1	1	11,717	11,717	11,717	11,717	11,717	89%	11%	1	10,466	1	1	1	1	1	10,466	10,466	10,466	10,466	10,466
	Sub-total - Residential Program	22	148,146	22	22	22	22	22	146,617	146,617	146,617	146,617	146,617			19	124,660	19	19	19	19	19	123,395	123,395	123,395	123,395	123,395
	Commercial & Institutional Program																										
61	Energy Audit Initiative	2	9,592	2	2	2	32	32	9,592	9,592	9,592	152,133	152,133	100%	0%	2	9,592	2	2	2	32	32	9,592	9,592	9,592	152,133	152,133
62	Efficiency: Equipment Replacement Incentive Initiative	90	673,530	90	90	90	90	90	673,530	673,530	673,530	673,530	673,530	90%	10%	81	604,760	81	81	81	81	81	604,760	604,760	604,760	604,760	604,760
63	Direct Install Lighting and Water Heating Initiative															0	0	0	0	0	0	0	0	0	0	0	0
64	New Construction and Major Renovation Initiative															0	0	0	0	0	0	0	0	0	0	0	0
65	Existing Building Commissioning Incentive Initiative															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Commercial & Institutional Program	92	683,122	92	92	92	122	122	683,122	683,122	683,122	825,663	825,663			83	614,352	83	83	83	113	113	614,352	614,352	614,352	756,893	756,893
	Industrial Program																										
66	Process and Systems Upgrades Initiatives - Project Incentive In	0	58,955,828	6,248	6,198	0	0	0	58,955,828	########	########	########	########	100%	0%	0	58,955,828	6,248	6,198	0	0	0	58,955,828	58,955,828	########	########	########
67	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative															0	0	0	0	0	0	0	0	0	0	0	0
68	Process and Systems Upgrades Initiatives - Energy Manager Initiative															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Industrial Program	0	58,955,828	6,248	6,198	0	0	0	58,955,828	########	########	########	########			0	58,955,828	6,248	6,198	0	0	0	58,955,828	58,955,828	########	########	########
	Low Income Program																										
69	Low Income Initiative	-7	-75,175	-6	-6	-6	-6	-6	-59,013	-55,775	-52,536	-52,536	-52,536	89%	11%	-6	-67,102	-5	-5	-5	-5	-5	-52,676	-49,785	-46,894	-46,894	-46,894
	Sub-total - Low Income Program	-7	-75,175	-6	-6	-6	-6	-6	-59,013	-55,775	-52,536	-52,536	-52,536			-6	-67,102	-5	-5	-5	-5	-5	-52,676	-49,785	-46,894	-46,894	-46,894
	Other																										
70	Aboriginal Conservation Program															0	0	0	0	0	0	0	0	0	0	0	0
71	Program Enabled Savings															0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - Other	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
	Sub-total - 2011-2014+2015 Extension Legacy Framew	107	59,711,921	6,356	6,306	108	138	138	59,726,554	########	########	########	########			96	59,627,738	6,345	6,295	96	126	126	59,640,899	59,643,789	########	########	########
	Total	138	59,861,827	6,387	6,337	139	169	169	59,876,823	########	########	########	########			123	59,762,344	6,373	6,322	124	154	154	59,775,829	59,778,783	########	########	########

Note: Total results for Energy+ from IESO 2016 final verified results. Allocation across rate zones calculated by Energy+ staff

Ontario Energy Board

LRAMVA Work Form:
2011 - 2014 Lost Revenues Work Form

Version 2.0 (2017)

Legend

- User Inputs (Green)
- Auto Populated Cells (White)
- Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 4-a. 2011 Lost Revenues
Table 4-b. 2012 Lost Revenues
Table 4-c. 2013 Lost Revenues
Table 4-d. 2014 Lost Revenues

Table 4-a. 2011 Lost Revenues Work Form

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting								Total
	Consumer Program																							kWh	kWh	kW	kW	kW	kWh	kW	0	0	0	0	0	0	0	
1	Appliance Retirement	Verified	175,906	175,906	175,906	175,702	128,754	0						24	24	24	24	17	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified	2,690	2,690	2,690	1,340	0	0						2	2	2	1	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified	670,601	670,601	670,601	670,601	670,601	670,601	670,601	670,601	670,601	670,601		359	359	359	359	359	359					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	-130,311	-130,311	-130,311	-130,311	-130,311	-130,311	-130,311	-130,311	-130,311	-130,311		-70	-70	-70	-70	-70	-70					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified	179,901	179,901	179,901	179,901	165,487	149,740	117,113	116,362	146,523	55,997		11	11	11	11	10	10					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	2,640	2,640	2,640	2,640	2,640	2,412	1,480	1,478	1,478	523		0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified	281,459	281,459	281,459	281,459	257,233	230,767	173,983	173,349	224,041	71,893		16	16	16	16	15	14					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	20,911	20,911	20,911	20,911	20,911	19,003	10,259	10,257	10,257	2,263		1	1	1	1	1	1					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified	0	0	0	0	0	0						46	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																																					
10	Retrofit	Verified	1,336,743	1,336,743	1,336,743	1,336,743	1,336,743	1,336,743	1,336,743	1,336,743	1,193,542	1,193,542	12	256	256	256	256	256	256					0.00%	0.00%	79.99%	14.99%	5.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	282,442	282,442	282,442	282,442	282,442	282,442	282,442	282,442	282,442	282,442	12	53	53	53	53	53	53					0.00%	0.00%	79.99%	14.99%	5.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified	398,982	398,982	396,704	320,480	320,480	315,742	103,425	103,425	103,425	103,425	12	158	158	157	130	130	128					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	8,048	8,048	8,048	8,048	8,048	8,048	2,342	2,342	2,342	2,342	12	4	4	4	4	4	4					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified	0	0	0	0	0	0					3	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					3	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified	0	0	0	0	0	0						1	0	0	0	0	0					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified	7,018	0	0	0	0	0						180	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																					
18	Process & System Upgrades	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified	3,083,118	3,083,118	3,083,118	3,083,118	3,083,118	3,083,118	3,083,118	3,083,118	2,573,476	2,573,476	12	466	466	466	466	466	466					0.00%	0.00%	79.99%	14.99%	5.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	79.99%	14.99%	5.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified	31,908	0	0	0	0	0						544	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																																					
23	Home Assistance Program	Verified	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																																					
24	Home Assistance Program	Verified	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2011 savings	True-up	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

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25	Direct Install Lighting	Verified	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2013 savings	True-up	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																															
26	Electricity Retrofit Incentive Program	Verified	0	0	0	0	0	0	0	0			12	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Adjustment to 2013 savings	True-up	0	0	0	0	0	0	0	0			12	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified	0	0	0	0	0	0	0	0			12	0	0	0	0	0	0	0	0		0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2013 savings	True-up	201,151	0	0	0	0	0	0	0			12	39	39	39	39	0	0	0	0		0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2013 savings	True-up	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2013 savings	True-up	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2013 savings	True-up	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																															
31	Program Enabled Savings	Verified	51,500	51,500	51,500	51,500	51,500	51,500	51,500	51,500			12	8	8	8	8	8	8	8	8		0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2013 savings	True-up	66,452	66,452	66,452	66,452	66,452	66,452	66,452	66,452			12	23	23	23	23	23	23	23	23		0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2013 savings	True-up	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified											0																			0%
	Adjustment to 2013 savings	True-up											0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2013		**10,854,972**											**3,144**									**1,287,052**	**188,437**	**17,363**	**3,290**	**963**	**0**	**0**		**0**	**0**	
	Forecast CDM Savings in 2013																						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2013																													$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2013 from 2011 programs																						$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2013 from 2012 programs																						$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2013 from 2013 programs																						$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2013																						**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2013																						**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2013																																**$0.00**
	2013 Savings Persisting in 2014																						1,284,229	188,436	17,266	3,053	957	0	0	0	0	0	0
	2013 Savings Persisting in 2015																						1,271,119	180,628	17,201	3,041	953	0	0	0	0	0	0
	2013 Savings Persisting in 2016																						1,166,260	176,288	17,156	3,030	950	0	0	0	0	0	0
	2013 Savings Persisting in 2017																						1,096,638	101,163	15,883	2,959	926	0	0	0	0	0	0
	2013 Savings Persisting in 2018																						1,044,312	101,163	15,625	2,824	910	0	0	0	0	0	0
	2013 Savings Persisting in 2019																						1,030,522	101,163	15,625	2,824	910	0	0	0	0	0	0
	2013 Savings Persisting in 2020																						1,027,627	101,163	15,625	2,824	910	0	0	0	0	0	0

Note: LDC to make note of key assumptions included above

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Table 4-d. 2014 Lost Revenues Work Form

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA									
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting								Total
Consumer Program																							kWh	kWh	kW	kW	kW	kWh	kW	0	0	0	0	0	0	0	0	
1 Appliance Retirement	Verified	36,516	36,516	36,516	36,412	21,266	0	0					5	5	5	5	3	0	0				100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2 Appliance Exchange	Verified	19,580	19,580	19,580	19,580	0	0	0					11	11	11	11	0	0	0				100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3 HVAC Incentives	Verified	603,250	603,250	603,250	603,250	603,250	603,250	603,250					328	328	328	328	328	328	328				100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4 Conservation Instant Coupon Booklet	Verified	286,647	264,788	252,529	252,529	252,529	252,529	252,529					21	20	19	19	19	19	19				100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5 Bi-Annual Retailer Event	Verified	1,177,103	1,021,125	939,837	939,837	939,837	939,837	939,837					77	67	62	62	62	62	62				100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6 Retailer Co-op	Verified	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7 Residential Demand Response	Verified	0	0	0	0	0	0	0					167	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8 Residential Demand Response (IHD)	Verified	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9 Residential New Construction	Verified	22,425	0	0	0	0	0	0					4	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Business Program																																						
10 Retrofit	Verified	13,491,681	########	########	13,426,282	########	13,396,537	########				12	1,818	1,816	1,816	1,800	1,797	1,792	1,680				0.00%	0.00%	75.00%	15.00%	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			91%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	75.00%	15.00%	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11 Direct Install Lighting	Verified	383,422	373,416	359,695	249,502	249,502	249,502	249,502				12	111	108	105	70	70	70	70				0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12 Building Commissioning	Verified	0	0	0	0	0	0	0				3	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				3	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13 New Construction	Verified	18,778	18,778	18,778	18,778	18,778	18,778	18,778				12	5	5	5	5	5	5	5				0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14 Energy Audit	Verified	195,821	195,821	195,821	195,821	0	0	0				12	40	40	40	40	0	0	0				0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15 Small Commercial Demand Response	Verified	0	0	0	0	0	0	0					0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16 Small Commercial Demand Response (IHD)	Verified	0	0	0	0	0	0	0					0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17 Demand Response 3	Verified	0	0	0	0	0	0	0					136	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Industrial Program																																						
18 Process & System Upgrades	Verified	1,318,000	1,318,000	1,318,000	1,318,000	1,318,000	1,318,000	1,318,000				12	151	151	151	151	151	151	151				0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19 Monitoring & Targeting	Verified	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20 Energy Manager	Verified	430,152	430,152	217,790	217,790	217,790	217,790	217,790				12	78	78	33	33	33	33	33				0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21 Retrofit	Verified	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22 Demand Response 3	Verified	0	0	0	0	0	0	0					870	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Home Assistance Program																																						
23 Home Assistance Program	Verified	91,897	91,839	76,882	69,635	62,388	62,388	60,268					5	5	4	4	4	4	3				100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%			100%
Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Aboriginal Program																																						
24 Home Assistance Program	Verified	0	0	0	0	0	0	0					0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0%

	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0					0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																																
26	Electricity Retrofit Incentive Program	Verified	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																																
31	Program Enabled Savings	Verified	345,824	345,824	345,824	345,824	345,824	345,824	345,824				12	46	46	46	46	46	46	46				0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%
	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				12	0	0	0	0	0	0	0				0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified	0	0	0	0	0	0	0				0	728	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2014 savings	True-up	0	0	0	0	0	0	0				0	0	0	0	0	0	0	0				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified	461,513			0	0	0	0				0	624			0	0	0	0				100.00%																100%
	Adjustment to 2014 savings	True-up				0	0	0	0				0				0	0	0	0				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2014		**18,882,610**											**5,226**										**2,698,932**	**383,422**	**17,465**	**3,273**	**2,955**	**0**	**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**		
	Forecast CDM Savings in 2014																							**11,108,643**	**4,314,499**	**38,780**	**14,499**	**11,778**	**47,953**	**707**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		
	Distribution Rate in 2014																							$0.01730	$0.01350	$3.87490	$3.36410	$2.28860	$0.01290	$14.62060	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000		
	Lost Revenue in 2014 from 2011 programs																							$20,798.82	$4,435.12	$78,209.46	$11,897.48	$2,707.35	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$118,048.22
	Lost Revenue in 2014 from 2012 programs																							$14,129.74	$4,772.19	$58,801.90	$9,191.81	$1,843.56	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$88,739.19
	Lost Revenue in 2014 from 2013 programs																							$22,217.17	$2,543.89	$66,903.45	$10,270.17	$2,189.46	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$104,124.12
	Lost Revenue in 2014 from 2014 programs																							$46,691.53	$5,176.20	$67,674.39	$11,009.97	$6,763.34	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		$137,315.43
	Total Lost Revenues in 2014																							**$103,837.25**	**$16,927.39**	**$271,589.19**	**$42,369.42**	**$13,503.71**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**		**$448,226.96**
	Forecast Lost Revenues in 2014																							**$192,179.52**	**$58,245.74**	**$150,268.62**	**$48,776.09**	**$26,955.13**	**$618.59**	**$10,336.76**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**		**$487,380.46**
	LRAMVA in 2014																																**-$39,153.49**
	2014 Savings Persisting in 2015																							2,037,099	373,416	17,447	3,269	2,955	0	0	0	0	0	0	0	0	0	0		
	2014 Savings Persisting in 2016																							1,928,596	359,695	17,447	3,269	2,424	0	0	0	0	0	0	0	0	0	0		
	2014 Savings Persisting in 2017																							1,921,244	249,502	17,299	3,240	2,422	0	0	0	0	0	0	0	0	0	0		
	2014 Savings Persisting in 2018																							1,879,271	249,502	16,792	3,234	2,422	0	0	0	0	0	0	0	0	0	0		
	2014 Savings Persisting in 2019																							1,858,005	249,502	16,752	3,226	2,421	0	0	0	0	0	0	0	0	0	0		
	2014 Savings Persisting in 2020																							1,855,886	249,502	15,740	3,024	2,408	0	0	0	0	0	0	0	0	0	0		

Note: LDC to make note of key assumptions included above

Ontario Energy Board

LRAMVA Work Form:
2015 - 2020 Lost Revenues Work Form

Version 2.0 (2017)

Legend

- User Inputs (Green)
- Auto Populated Cells (White)
- Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2016 programs that were reported by the IESO in 2017 should be included in the 2016 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 5-a. 2015 Lost Revenues
Table 5-b. 2016 Lost Revenues
Table 5-c. 2017 Lost Revenues
Table 5-d. 2018 Lost Revenues
Table 5-e. 2019 Lost Revenues
Table 5-f. 2020 Lost Revenues

Table 5-a. 2015 Lost Revenues Work Form

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA												Total
			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting							
	Legacy Framework																							kWh	kWh	kW	kW	kW	kWh	kW	0	0	0	0	0	0	0	
	Residential Program																																				
1	Coupon Initiative	Verified	479,019	474,665	474,665	474,665	474,665	474,665						31	30	30	30	30	30					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	81,211	80,053	80,053	80,053	80,053	80,053						5	5	5	5	5	5					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified	883,796	868,089	868,089	868,089	868,089	868,089						60	59	59	59	59	59					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	9,142	9,035	9,035	9,035	9,035	9,035						1	1	1	1	1	1					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified	6,208	6,208	6,208	6,208	6,208	6,208						1	1	1	1	1	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0						0	0	0	0	0	0					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initaitive	Verified	705,823	705,823	705,823	705,823	705,823	705,823						370	370	370	370	370	370					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	23,842	23,842	23,842	23,842	23,842	23,842						12	12	12	12	12	12					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	Verified	177,361	177,361	177,361	177,361	177,361	177,361						43	43	43	43	43	43					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	10,466	10,466	10,466	10,466	10,466	10,466						1	1	1	1	1	1					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																																				
6	Energy Audit Initiative	Verified	142,541	142,541	142,541	142,541	0	0					12	30	30	30	30	0	0					0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	9,592	9,592	9,592	9,592	152,133	152,133					12	2	2	2	2	32	32					0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	11,265,428	########	########	########	10,974,014	10,973,118					12	1,752	1,752	1,743	1,680	1,680	1,679					0.00%	11.56%	71.32%	19.08%	0.10%	0.00%	0.00%	0.00%		0.00%	0.00%				102%
	Adjustment to 2015 savings	True-up	604,760	604,760	604,760	604,760	604,760	604,760					12	81	81	81	81	81	81					0.00%	11.56%	71.32%	19.08%	0.10%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified	127,193	121,417	68,454	66,006	66,006	66,006					12	32	30	16	16	16	16					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified	0	0	0	0	0	0					3	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					3	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																				
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%			0.00%				100%
	Adjustment to 2015 savings	True-up	58,955,828	########	########	########	58,955,828	58,955,828					12	0	6,248	6,198	0	0	0					0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	1,689,813	1,669,113	1,386,024	1,386,024	1,386,024	1,295,918					12	182	174	102	102	102	87					0.00%	0.00%	0.00%	50.00%	50.00%	0.00%	0.00%			0.00%				100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																																				
14	Low Income Initiative	Verified	79,492	62,576	59,267	55,956	55,956	55,956					12	7	7	6	6	6	6					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%							100%
	Adjustment to 2015 savings	True-up	-67,102	-52,676	-49,785	-46,894	-46,894	-46,894					12	-6	-5	-5	-5	-5	-5					100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																																				
15	Aboriginal Conservation Program	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																																				
17	Conservation Fund Pilot - EnerNOC	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot	Verified	817,579	817,579	817,579	817,579	817,579	817,579					12	80	80	80	80	80	80					0.00%	0.00%	20.00%	80.00%	0.00%	0.00%	0.00%			0.00%				100%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					12	0	0	0	0	0	0					0.00%	0.00%	20.00%	80.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%				0%
	Adjustment to 2015 savings	True-up	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified	0	0	0	0	0	0					0	0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			0.00%				0%

| | | |

Total Lost Revenues in 2015													**$136,497.13**	**$38,006.05**	**$344,408.88**	**$64,538.09**	**$16,600.74**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$660,050.89**
Forecast Lost Revenues in 2015													**$198,844.71**	**$60,402.99**	**$155,686.19**	**$50,453.62**	**$28,011.62**	**$575.44**	**$11,039.66**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$504,012.12**
LRAMVA in 2015																														**$950,036.67**
2015 Savings Persisting in 2016													2,365,524	1,490,674	16,262	6,009	76,048	0	0	0	0.00	0	0	0	0	0				
2015 Savings Persisting in 2017													2,365,096	1,433,769	16,182	5,556	75,012	0	0	0	0	0	0	0	0	0				
2015 Savings Persisting in 2018													2,364,669	1,403,976	15,649	5,413	633	0	0	0	0	0	0	0	0	0				
2015 Savings Persisting in 2019													2,364,669	1,403,976	15,649	5,413	633	0	0	0	0	0	0	0	0	0				
2015 Savings Persisting in 2020													2,364,669	1,403,872	15,641	5,321	543	0	0	0	0	0	0	0	0	0				

Note: LDC to make note of key assumptions included above

Table 5-b. 2016 Lost Revenues Work Form Return to top

	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting								Total
																								kWh	kWh	kW	kW	kW	kWh	kW	0	0	0	0	0	0	0	
	Legacy Framework																																				
	Residential Program																																				
1	Coupon Initiative	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initaitve	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major Renovation Initiative	Verified	0	0	0	0	0							0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program																																				
6	Energy Audit Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	New Construction and Major Renovation Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Existing Building Commissioning Incentive Initiative	Verified	0	0	0	0	0						3	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																																				
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program																																				
14	Low Income Initiative	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																																				
15	Aboriginal Conservation Program	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Program Enabled Savings	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation Fund Pilots																																				
17	Conservation Fund Pilot - EnerNOC	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
18	Loblaws Pilot	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%								100%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Conservation Fund Pilot - SEG	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Social Benchmarking Pilot	Verified	0	0	0	0	0						0	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation First Framework																																				
	Residential Province-Wide Programs																																				
21	Save on Energy Coupon Program	Verified	4,849,013	4,849,013	4,849,013	4,849,013	4,849,013							318	318	318	318	318						82.72%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								83%
	Adjustment to 2016 savings	True-up	354,501	354,501																				82.72%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified	1,480,421	1,480,421	1,480,421	1,480,421	1,480,421							437	437	437	437	437						87.56%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								88%
	Adjustment to 2016 savings	True-up	1,333,523	1,333,523																				87.56%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	Verified	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								100%
	Adjustment to 2016 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Home Assistance Program	Verified	0	0	0	0	0							0	0	0	0	0						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								100%
	Adjustment to 2016 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																																				
25	Save on Energy Audit Funding Program	Verified	26,285	26,285	26,285	26,285	26,285						12	3	3	3	3	3						0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%								100%
	Adjustment to 2016 savings	True-up											12											0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	6,386,852	6,212,943	6,212,943	6,212,943	6,212,943						12	939	905	905	905	905						0.00%	17.05%	49.44%	11.89%	0.87%	0.00%	0.00%								79%
	Adjustment to 2016 savings	True-up	2,368,366	2,303,877									12	252	243									0.00%	17.05%	49.44%	11.89%	0.87%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting Program	Verified	0	0	0	0	0						12	0	0	0	0	0						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								0%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified	441,208	441,208	441,208	441,208	441,208						12	59	59	59	59	59						0.00%	54.11%	18.24%	0.00%	0.00%	0.00%	0.00%								72%
	Adjustment to 2016 savings	True-up	123,618	123,618									12	52	52									0.00%	54.11%	18.24%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

29	Save on Energy Existing Building Commissioning Program	Verified	0	0	0	0	0					3	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up										3										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	Save on Energy Process & Systems Upgrades Program	Verified	0	0	0	0	0					12	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up										12										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
31	Save on Energy Monitoring & Targeting Program	Verified	0	0	0	0	0					12	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up										12										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified	0	0	0	0	0					12	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up										12										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Local & Regional Programs																														
33	Business Refrigeration Local Program	Verified	0	0	0	0	0					0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
34	First Nation Conservation Local Program	Verified	0	0	0	0	0					0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
35	Social Benchmarking Local Program	Verified	0	0	0	0	0					0	0	0	0	0	0					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																														
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	EnWin Utilities Ltd. - Building Optimization Pilot	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	EnWin Utilities Ltd. - Re-Invest Pilot	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
39	Horizon Utilities Corporation - ECM Furnace Motor Pilot	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
40	Horizon Utilities Corporation - Social Benchmarking Pilot	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
41	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
42	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot	Verified																													0%
	Adjustment to 2016 savings	True-up																				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
44	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agricultural Sector	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
45	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
47	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
48	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
49	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)	Verified										0																			0%
	Adjustment to 2016 savings	True-up										0										0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
50	Home Depot Home Appliance Market Uplift	Verified	785	785	785	785	785															100.00%										100%
		True-up																				100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2016		**17,364,572**									**2,060**										**6,769,332**	**1,811,399**	**7,327**	**1,699**	**125**	**0**	**0**		**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2016																					**11,108,643**	**4,314,499**	**38,780**	**14,499**	**11,778**	**47,953**	**707**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2016																					$0.01510	$0.01430	$4.08020	$3.53660	$2.41720	$0.01220	$15.87010	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2016 from 2011 programs																					$14,227.40	$4,630.20	$82,040.29	$12,507.54	$2,859.49	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$116,264.90
	Lost Revenue in 2016 from 2012 programs																					$11,345.13	$4,766.33	$59,623.69	$9,345.57	$1,874.80	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$86,955.53
	Lost Revenue in 2016 from 2013 programs																					$17,610.52	$2,520.92	$70,000.80	$10,716.43	$2,295.89	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$103,144.56
	Lost Revenue in 2016 from 2014 programs																					$29,121.79	$5,143.64	$71,188.41	$11,562.13	$5,859.97	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$122,875.94
	Lost Revenue in 2016 from 2015 programs																					$35,719.41	$21,316.64	$66,351.57	$21,252.71	$183,822.47	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$328,462.79
	Lost Revenue in 2016 from 2016 programs																					$102,216.92	$25,903.00	$29,896.26	$6,010.27	$301.96	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$164,328.41
	Total Lost Revenues in 2016																					**$210,241.17**	**$64,280.72**	**$379,101.02**	**$71,394.64**	**$197,014.58**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$922,032.14**
	Forecast Lost Revenues in 2016																					**$167,740.51**	**$61,697.34**	**$158,230.16**	**$51,277.16**	**$28,469.78**	**$585.03**	**$11,220.16**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$479,220.13**
	LRAMVA in 2016																																**$442,812.00**
	2016 Savings Persisting in 2017																					6,769,332	1,770,755	7,071	1,638	120	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2018																					5,308,398	1,311,090	5,516	1,291	95	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2019																					5,308,398	1,311,090	5,516	1,291	95	0	0	0	0	0	0	0	
	2016 Savings Persisting in 2020																					5,308,398	1,311,090	5,516	1,291	95	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-c. 2017 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA										
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting								Total
Legacy Framework																							kWh	kWh	kW	kW	kW	kWh	kW	0	0	0	0	0	0	0	
Residential Program																																						
1 Coupon Initiative	Verified																																					0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2 Bi-Annual Retailer Event Initiative	Verified																																					0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3 Appliance Retirement Initiative	Verified																																					0%
Adjustment to 2017 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

4	HVAC Incentives Initaitive	Verified																											
	Adjustment to 2017 savings	True-up																											0.00%
5	Residential New Construction and Major Renovation Initiative	Verified																											0%
	Adjustment to 2017 savings	True-up																											0.00%
	Commercial & Institutional Program																												
6	Energy Audit Initiative	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
7	Efficiency: Equipment Replacement Incentive Initiative	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
8	Direct Install Lighting and Water Heating Initiative	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
9	New Construction and Major Renovation Initiative	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
10	Existing Building Commissioning Incentive Initiative	Verified									3																		0%
	Adjustment to 2017 savings	True-up									3																		0.00%
	Industrial Program																												
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
	Low Income Program																												
14	Low Income Initiative	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
	Other																												
15	Aboriginal Conservation Program	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
16	Program Enabled Savings	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
	Conservation Fund Pilots																												
17	Conservation Fund Pilot - EnerNOC	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
18	Loblaws Pilot	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
19	Conservation Fund Pilot - SEG	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
20	Social Benchmarking Pilot	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
	Conservation First Framework																												
	Residential Province-Wide Programs																												
21	Save on Energy Coupon Program	Unverified	3,518,877																										83%
	Adjustment to 2017 savings	True-up																											83.15%
22	Save on Energy Heating and Cooling Program	Unverified	804,439																										88%
	Adjustment to 2017 savings	True-up																											87.56%
23	Save on Energy New Construction Program	Verified																											0%
	Adjustment to 2017 savings	True-up																											0.00%
24	Save on Energy Home Assistance Program	Unverified	906																										100%
	Adjustment to 2017 savings	True-up																											100.00%
	Non-Residential Province-Wide Programs																												
25	Save on Energy Audit Funding Program	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
26	Save on Energy Retrofit Program	Unverified	7,202,274								12	1,471																	78%
	Adjustment to 2017 savings	True-up									12																		0.00%
27	Save on Energy Small Business Lighting Program	Unverified	91,378								12	53																	78%
	Adjustment to 2017 savings	True-up									12																		0.00%
28	Save on Energy High Performance New Construction Program	Unverified	338,710								12	122																	0%
	Adjustment to 2017 savings	True-up									12																		0.00%
29	Save on Energy Existing Building Commissioning Program	Verified									3																		0%
	Adjustment to 2017 savings	True-up									3																		0.00%
30	Save on Energy Process & Systems Upgrades Program	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
31	Save on Energy Monitoring & Targeting Program	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
32	Save on Energy Energy Manager Program	Verified									12																		0%
	Adjustment to 2017 savings	True-up									12																		0.00%
	Local & Regional Programs																												
33	Business Refrigeration Local Program	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
34	First Nation Conservation Local Program	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
35	Social Benchmarking Local Program	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%
	Pilot Programs																												
36	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - Conservation Fund	Verified									0																		0%
	Adjustment to 2017 savings	True-up									0																		0.00%

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Ontario Energy Board

LRAMVA Work Form:
Carrying Charges by Rate Class

Version 2.0 (2017)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. Please update Table 6 as new approved prescribed interest rates for deferral and variance accounts become available. Monthly interest rates are used to calculate the variance on the carrying charges for LRAMVA. Starting from column I, the principle will auto-populate as monthly variances in Table 6-a, and are multiplied by the interest rate from column H to determine the monthly variances on carrying charges for each rate class by year.

2. The annual carrying charges totals in Table 6-a below pertain to the amount that was originally collected in interest from forecasted CDM savings and what should have been collected based on actual CDM savings. As the amounts calculated in Table 6-a are cumulative, LDCs are requested to enter any collected interest amounts into the "Amounts Cleared" row in order to clear the balance and calculate outstanding variances on carrying charges.

Table 6. Prescribed Interest Rates

Quarter	Approved Deferral & Variance Accounts
2011 Q1	1.47%
2011 Q2	1.47%
2011 Q3	1.47%
2011 Q4	1.47%
2012 Q1	1.47%
2012 Q2	1.47%
2012 Q3	1.47%
2012 Q4	1.47%
2013 Q1	1.47%
2013 Q2	1.47%
2013 Q3	1.47%
2013 Q4	1.47%
2014 Q1	1.47%
2014 Q2	1.47%
2014 Q3	1.47%
2014 Q4	1.47%
2015 Q1	1.47%
2015 Q2	1.10%
2015 Q3	1.10%
2015 Q4	1.10%
2016 Q1	1.10%
2016 Q2	1.10%
2016 Q3	1.10%
2016 Q4	1.10%
2017 Q1	1.10%
2017 Q2	1.10%
2017 Q3	1.10%
2017 Q4	1.50%
2018 Q1	1.50%
2018 Q2	1.50%
2018 Q3	1.50%
2018 Q4	1.50%
2019 Q1	
2019 Q2	
2019 Q3	
2019 Q4	
2020 Q1	
2020 Q2	
2020 Q3	
2020 Q4	

Check OEB website

Table 6-a. Calculation of Carrying Costs by Rate Class

Go to Tab 1: Summary

Month	Period	Quarter	Monthly Rate	Residential	GS<50 kW	GS 50 to 999 kW	GS 1000 - 4,999	Large Use	Unmetered Scattered Load	Street Lighting								Total
Jan-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2011				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2014				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-14	2011-2014	Q1	0.12%	-$9.02	-$4.22	$12.38	-$0.65	-$1.37	-$0.06	-$1.06	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$4.00
Mar-14	2011-2014	Q1	0.12%	-$18.04	-$8.44	$24.77	-$1.31	-$2.75	-$0.13	-$2.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$7.99
Apr-14	2011-2014	Q2	0.12%	-$27.05	-$12.65	$37.15	-$1.96	-$4.12	-$0.19	-$3.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$11.99
May-14	2011-2014	Q2	0.12%	-$36.07	-$16.87	$49.54	-$2.62	-$5.49	-$0.25	-$4.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$15.99
Jun-14	2011-2014	Q2	0.12%	-$45.09	-$21.09	$61.92	-$3.27	-$6.87	-$0.32	-$5.28	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$19.98
Jul-14	2011-2014	Q3	0.12%	-$54.11	-$25.31	$74.31	-$3.92	-$8.24	-$0.38	-$6.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$23.98
Aug-14	2011-2014	Q3	0.12%	-$63.13	-$29.53	$86.69	-$4.58	-$9.61	-$0.44	-$7.39	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$27.98
Sep-14	2011-2014	Q3	0.12%	-$72.15	-$33.74	$99.08	-$5.23	-$10.99	-$0.51	-$8.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$31.98
Oct-14	2011-2014	Q4	0.12%	-$81.16	-$37.96	$111.46	-$5.89	-$12.36	-$0.57	-$9.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$35.97
Nov-14	2011-2014	Q4	0.12%	-$90.18	-$42.18	$123.85	-$6.54	-$13.73	-$0.63	-$10.55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$39.97
Dec-14	2011-2014	Q4	0.12%	-$99.20	-$46.40	$136.23	-$7.19	-$15.10	-$0.69	-$11.61	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$43.97
Total for 2014				**-$595.21**	**-$278.38**	**$817.40**	**-$43.16**	**-$90.63**	**-$4.17**	**-$69.64**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**-$263.80**
Amount Cleared																		
Opening Balance for 2015				**-$595.21**	**-$278.38**	**$817.40**	**-$43.16**	**-$90.63**	**-$4.17**	**-$69.64**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**-$263.80**
Jan-15	2011-2015	Q1	0.12%	-$108.22	-$50.61	$148.62	-$7.85	-$16.48	-$0.76	-$12.66	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$47.96
Feb-15	2011-2015	Q1	0.12%	-$114.58	-$52.90	$167.88	-$6.41	-$17.64	-$0.82	-$13.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$38.26
Mar-15	2011-2015	Q1	0.12%	-$120.95	-$55.19	$187.15	-$4.97	-$18.81	-$0.88	-$14.92	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$28.56
Apr-15	2011-2015	Q2	0.09%	-$95.27	-$43.01	$154.46	-$2.65	-$14.95	-$0.70	-$12.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$14.11
May-15	2011-2015	Q2	0.09%	-$100.03	-$44.72	$168.88	-$1.57	-$15.82	-$0.74	-$12.85	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	-$6.85
Jun-15	2011-2015	Q2	0.09%	-$104.79	-$46.43	$183.29	-$0.49	-$16.69	-$0.79	-$13.69	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.41

Jul-15	2011-2015	Q3	0.09%	-$109.56	-$48.14	$197.71	$0.58	-$17.56	-$0.83	-$14.54	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.67
Aug-15	2011-2015	Q3	0.09%	-$114.32	-$49.85	$212.12	$1.66	-$18.43	-$0.87	-$15.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$4.93
Sep-15	2011-2015	Q3	0.09%	-$119.08	-$51.56	$226.54	$2.73	-$19.30	-$0.92	-$16.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.19
Oct-15	2011-2015	Q4	0.09%	-$123.84	-$53.27	$240.96	$3.81	-$20.18	-$0.96	-$17.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$29.45
Nov-15	2011-2015	Q4	0.09%	-$128.61	-$54.98	$255.37	$4.89	-$21.05	-$1.01	-$17.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$36.71
Dec-15	2011-2015	Q4	0.09%	-$133.37	-$56.69	$269.79	$5.96	-$21.92	-$1.05	-$18.75	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$43.97
Total for 2015				**-$1,967.83**	**-$885.75**	**$3,230.17**	**-$47.47**	**-$309.45**	**-$14.49**	**-$249.42**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**-$244.23**
Amount Cleared																	
Opening Balance for 2016				**-$1,967.83**	**-$885.75**	**$3,230.17**	**-$47.47**	**-$309.45**	**-$14.49**	**-$249.42**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**-$244.23**
Jan-16	2011-2016	Q1	0.09%	-$138.13	-$58.41	$284.21	$7.04	-$22.79	-$1.09	-$19.60	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$51.23
Feb-16	2011-2016	Q1	0.09%	-$134.89	-$58.21	$301.08	$8.57	-$9.92	-$1.14	-$20.45	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$85.05
Mar-16	2011-2016	Q1	0.09%	-$131.64	-$58.01	$317.95	$10.11	$2.96	-$1.18	-$21.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$118.88
Apr-16	2011-2016	Q2	0.09%	-$128.39	-$57.81	$334.82	$11.65	$15.83	-$1.23	-$22.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$152.70
May-16	2011-2016	Q2	0.09%	-$125.15	-$57.62	$351.69	$13.18	$28.71	-$1.27	-$23.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$186.53
Jun-16	2011-2016	Q2	0.09%	-$121.90	-$57.42	$368.57	$14.72	$41.58	-$1.32	-$23.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$220.36
Jul-16	2011-2016	Q3	0.09%	-$118.65	-$57.22	$385.44	$16.26	$54.46	-$1.36	-$24.74	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$254.18
Aug-16	2011-2016	Q3	0.09%	-$115.41	-$57.02	$402.31	$17.80	$67.33	-$1.41	-$25.59	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$288.01
Sep-16	2011-2016	Q3	0.09%	-$112.16	-$56.83	$419.18	$19.33	$80.21	-$1.45	-$26.45	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$321.83
Oct-16	2011-2016	Q4	0.09%	-$108.91	-$56.63	$436.06	$20.87	$93.08	-$1.50	-$27.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$355.66
Nov-16	2011-2016	Q4	0.09%	-$105.67	-$56.43	$452.93	$22.41	$105.96	-$1.54	-$28.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$389.49
Dec-16	2011-2016	Q4	0.09%	-$102.42	-$56.23	$469.80	$23.94	$118.83	-$1.59	-$29.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$423.31
Total for 2016				**-$3,411.14**	**-$1,573.59**	**$7,754.20**	**$138.41**	**$266.81**	**-$30.57**	**-$541.13**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$2,602.99**
Amount Cleared																	
Opening Balance for 2017				**-$3,411.14**	**-$1,573.59**	**$7,754.20**	**$138.41**	**$266.81**	**-$30.57**	**-$541.13**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$2,602.99**
Jan-17	2011-2017	Q1	0.09%	-$99.17	-$56.04	$486.67	$25.48	$131.71	-$1.63	-$29.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$457.14
Feb-17	2011-2017	Q1	0.09%	-$94.12	-$55.42	$494.28	$26.56	$144.27	-$1.68	-$30.75	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$483.13
Mar-17	2011-2017	Q1	0.09%	-$89.06	-$54.81	$501.88	$27.64	$156.83	-$1.72	-$31.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$509.13
Apr-17	2011-2017	Q2	0.09%	-$84.01	-$54.20	$509.49	$28.72	$169.39	-$1.77	-$32.49	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$535.13
May-17	2011-2017	Q2	0.09%	-$78.95	-$53.59	$517.09	$29.80	$181.95	-$1.81	-$33.37	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$561.13
Jun-17	2011-2017	Q2	0.09%	-$73.90	-$52.97	$524.70	$30.88	$194.51	-$1.86	-$34.24	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$587.12
Jul-17	2011-2017	Q3	0.09%	-$68.84	-$52.36	$532.30	$31.96	$207.07	-$1.90	-$35.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$613.12
Aug-17	2011-2017	Q3	0.09%	-$63.79	-$51.75	$539.91	$33.04	$219.63	-$1.95	-$35.98	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$639.12
Sep-17	2011-2017	Q3	0.09%	-$58.73	-$51.13	$547.51	$34.13	$232.19	-$1.99	-$36.85	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$665.12
Oct-17	2011-2017	Q4	0.13%	-$73.20	-$68.89	$756.98	$48.01	$333.75	-$2.78	-$51.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$942.43
Nov-17	2011-2017	Q4	0.13%	-$66.31	-$68.05	$767.35	$49.48	$350.88	-$2.84	-$52.63	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$977.88
Dec-17	2011-2017	Q4	0.13%	-$59.41	-$67.22	$777.72	$50.96	$368.01	-$2.91	-$53.82	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,013.33
Total for 2017				**-$4,320.65**	**-$2,260.02**	**$14,710.07**	**$555.07**	**$2,957.01**	**-$55.42**	**-$999.30**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$10,586.76**
Amount Cleared																	
Opening Balance for 2018				**-$4,320.65**	**-$2,260.02**	**$14,710.07**	**$555.07**	**$2,957.01**	**-$55.42**	**-$999.30**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$10,586.76**
Jan-18	2011-2018	Q1	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Feb-18	2011-2018	Q1	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Mar-18	2011-2018	Q1	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Apr-18	2011-2018	Q2	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
May-18	2011-2018	Q2	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Jun-18	2011-2018	Q2	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Jul-18	2011-2018	Q3	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Aug-18	2011-2018	Q3	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Sep-18	2011-2018	Q3	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Oct-18	2011-2018	Q4	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Nov-18	2011-2018	Q4	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Dec-18	2011-2018	Q4	0.13%	-$52.52	-$66.38	$788.09	$52.43	$385.14	-$2.97	-$55.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,048.78
Total for 2018				**-$4,950.90**	**-$3,056.60**	**$24,167.13**	**$1,184.22**	**$7,578.63**	**-$91.02**	**-$1,659.36**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$23,172.11**
Amount Cleared																	
Opening Balance for 2019				**-$4,950.90**	**-$3,056.60**	**$24,167.13**	**$1,184.22**	**$7,578.63**	**-$91.02**	**-$1,659.36**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$23,172.11**
Jan-19	2011-2019	Q1	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-19	2011-2019	Q1	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-19	2011-2019	Q1	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-19	2011-2019	Q2	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-19	2011-2019	Q2	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-19	2011-2019	Q2	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-19	2011-2019	Q3	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-19	2011-2019	Q3	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-19	2011-2019	Q3	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-19	2011-2019	Q4	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-19	2011-2019	Q4	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-19	2011-2019	Q4	0.00%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2019				**-$4,950.90**	**-$3,056.60**	**$24,167.13**	**$1,184.22**	**$7,578.63**	**-$91.02**	**-$1,659.36**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$23,172.11**

Ontario Energy Board

Supporting Documentation:
LDC Persistence Savings Results from IESO

Version 5.0 (2017)

Legend

User Inputs (Green)
Drop Down List (Blue)
Instructions (Grey)

Instructions (Steps)

1. Columns B to H of this tab have been structured in a way to match the formatting of the persistence report provided by the IESO. Please copy and paste the program information by initiative in Columns B to H and the corresponding demand and energy savings data by initiative in Columns I, to BT of this work form.
2. Please identify the source of the report via the dropdown list in Column I
3. To facilate the identification of adjustments that may be available in a prospective year's results report, it will be easier to sort all the savings by implementation year (Column H. This can be done by clicking on the filter button at cell H25 thatHighlighted in orangeh). Before you sort values, please ensure that all table columns have filters.
4. Please identify what the savings value represents (i.e., current year savings for the year or an adjustment to a prior year) via the dropdown list in Column J. Current year savings would be identified with an implementation year that matches the year of the persistence report. A savings adjustment would be identified with a prior year implementation in the future year's results report.
5. Please manually input or link the applicable savings and adjustments (Columns L to BT) for all applicable initiatives in Tabs 4 and 5 of this work form

NOTE: The Net Verified Peak Demand Savings table and Net Verified Energy Savings table below are in the reverse order to the accompanying tables in Tab 4 and Tab 5. The tables below match those provided by the IESO.

Table 7. 2011-2020 Verified Program Results and Persistence into Future Years

| Rate Portfolio | Program | Initiative | LDC | Sector | Conservation Resource Type | Year (Implementation) | Year (Report) | Identify Source of Report | Identify Status of Savings | Net Verified Annual Peak Demand Savings at the End-User Level (MW) | | |

Ontario Energy Board

LRAMVA Work Form:
Documentation for Streetlighting Projects

Version 2.0 (2017)

Instructions

Please provide documentation and/or data to substantiate program savings that were not provided by the IESO (i.e., streetlighting projects) as applicable.

CHP projects

Table 9. 2015 CHP Projects						
Project	TMMC					
NTG factor	1.00	**Persistent load reductions**				
Month	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Jan	-	6,469	4,717	-	-	-
Feb	-	6,293	5,365	-	-	-
Mar	-	2,175	8,484	-	-	-
Apr	-	5,200	1,884	-	-	-
May	-	4,683	6,981	-	-	-
Jun	-	7,978	8,325	-	-	-
Jul	-	6,019	8,286	-	-	-
Aug	-	8,768	8,448	-	-	-
Sep	-	8,393	7,948	-	-	-
Oct	-	5,017	5,524	-	-	-
Nov	-	8,221	1,468	-	-	-
Dec	-	5,666	6,851	-	-	-
Avg. Gross Total	-	6,240	6,190	-	-	-
Avg. Net Total	-	6,248	6,198	-	-	-

Note: Persistent load reductions from monthly maximum load in facility minus amount billed
Net totals get carried to Tab 5 O71:T71

Source: Energy+ monitoring data
NTG is from IESO 2016 verified results for the project

APPENDIX 4-15: PARTICIPATION AND COST REPORT

Program Participation & Cost Report

Message from the IESO Reporting Team

The IESO is pleased to provide LDCs with the Monthly Program Participation & Cost Report.

This report is generally posted on the IESO LDC Extranet by the Friday of the week following the 15th of each month. The report provides province-wide and LDC specific program participation and costs to the extent known based on information received by the IESO from all distribution companies and IESO Value Added Service Provider.

The Monthly Program Participation & Cost Report includes preliminary, unverified results based on information received by the IESO. Upon verification of project information through the IESO Evaluation, Measurement and Verification (EM&V) process, results will be reported as 'verified'. Performance against CDM Plan information is also available in this report and is based on the LDC's approved CDM Plan as at the end of the reporting period. Where two or more LDCs have submitted a joint CDM Plan, the IESO will provide a Monthly Program Participation & Cost Report for each LDC included in the CDM Plan.

The IESO strives to improve on the current reporting processes to provide meaningful and timely information to LDCs. Your feedback is encouraged and appreciated. Should you have any feedback, questions or comments on this report please contact us at LDC.Support@ieso.ca.

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Program Participation & Cost Report
Table of Contents

#	Worksheet Name	Worksheet Description
1	Cover Letter	Provides an overview of the IESO Value Added Services Report.
2	How to Use This Report	Describes the contents and structure of this report.
3	Report Summary	A high level summary of the Program Participation & Cost Report, including: 1) Progress toward the LDC's a) Allocated 2020 Energy Savings Target; b) Allocated 2015-2020 LDC CDM Plan Budget; c) CDM Plan 2015-2020 Forecasts; 3) Annual savings and spending; 4) Annual LDC CDM Plan spending progress; 5) Graphs describing: a) Contribution to 2020 Target Achievement by program; b) Program to Date LDC CDM Plan Budget Spending by Sector; c) Annual energy savings persistence to 2020 by year; d) Allocated Target achievement progress relative to other LDCs; and e) LDC CDM Plan Budget Spending progress relative to other LDCs.
4	LDC Progress	A comprehensive report of 2015-20 conservation results including: 1) Activity; 2) Savings including; a) Net Energy; b) CDM Plan forecasts, verified actuals and relative progress; c) Allocated Target and Target achievement; and 3) Spending, including participant incentives and administrative expenses.
5	Province-Wide Progress	A comprehensive report of 2015-20 conservation results including: 1) Activity; 2) Savings including; a) Net Energy; b) CDM Plan forecasts, verified actuals and relative progress; c) Allocated Target and Target achievement; and 3) Spending, including participant incentives and administrative expenses.
6	IESO Value Added Services Costs	Provision of the LDCs and the Province-Wide aggregated IESO Value Added Services activity and costs for each year.
7	Retrofit Multi-Site Applications	Provision of the LDCs and the Province-Wide aggregated Multi-Site Application activity and costs for each year of the Save on Energy Retrofit Program.
8	Methodology	Description of the methods used to calculate energy savings, financial results and cost-effectiveness.
9	Reference Tables	Consumer Program Province-Wide results allocation to specific LDCs.
10	Glossary	Definitions for the terms used throughout this report.

Program Participation & Cost Report
How to Use This Report

The IESO is pleased to provide you with the Monthly Participation and Cost Report.

This report provides:
1) program participation;
1) electricity savings; and
2) costs

to the extent known based on information received by the IESO in accordance with Section 9.2(c)(i) of the Energy Conservation Agreement.
In addition to the above, this report also provides in greater detail:

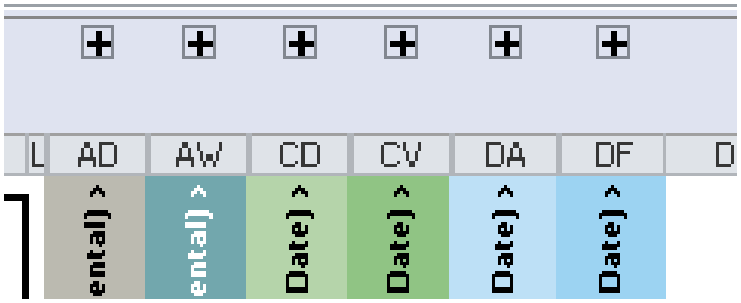
1) program participation results including:
   a) forecasts; b) actuals; and c) progress (forecast versus (vs) actuals);

2) program savings results including:
   a) net 2020 annual energy savings;
   b) allocated target, target achievement and progress towards target;
   c) incremental net first year energy savings;
   and where available reported by: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

3) program spending including:
   a) participation incentive spending;
   b) administrative expense spending (including IESO value-added services costs);
   c) aggregated total spending;
   and for each cost: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

by both the LDC specific level and the province wide aggregated level.

This report's format is a dynamic sheet that can be expanded or collapsed by clicking the + button or "Show Detail" feature under the Data tab. Each of the results categories listed above have been grouped together for easy accessibility.



Please note:

1) Cost Effectiveness Test (CET) results including:
   a) total resource cost test;
   b) program administration cost test;
   c) levelized unit energy cost test;
   will not be available for the 2015 program year in this report but will be provided to LDCs once available.

2) forecasts of: a) activity; b) savings; and c) spending; included in this report are based on LDC submitted and IESO approved CDM Plan - Cost Effectiveness Tools as of the end of the reporting month.
   (from the i) Program Design; ii) Budget Inputs; iii) Savings Results; and iv) CE Results; worksheets);
   Please note that this does not contain data for Legacy Framework program spending or CFF pilot program activity, savings, spending or cost effectiveness.

3) Annual FCR Progress only includes Full Cost Recovery funded program savings. In future reports, any Pay-for-Performance funded programs will be reported as a separate line item.

4) The complete list of programs and pilots launched into market in 2015 has been included, however no programs and pilots were in market for a sufficient period of time to enable a valid EM&V process. Therefore these programs and pilots have nothing to report at this time and have cells greyed out rather than reporting zero savings or spending. Any results in 2015 will be determined in a subsequent EM&V process and will be included in a future year's Annual Verified Results Report as a 2015 adjustment;

5) Pilot program savings are attributed to the LDC where the pilot program project is located in; and

6) This Monthly Participation and Cost Report provides results for the LDC and province only. No aggregated reporting is provided for LDCs that are part of a joint CDM plan;

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Program Participation & Cost Report
Summary

Energy+ Inc.		CDM Plan	vs	Allocated	Paid Pre-Funding
As of:	31-Dec-17	CFF Target (kWh):		173,121,065	100,957,518
		CFF Budget:		$22,281,831	$25,873,071 $1,117,402

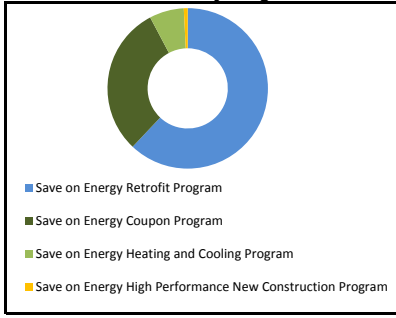
Summary of Performance Metrics

	2017 CDM Results	2017 CDM Plan %	6-year CDM Results	6-year CDM Plan %	6-year Allocated %
Net Energy Savings (kWh) as at 2020	11,769,418	62%	110,165,617	63.6%	109.1%
Total Actual Spending ($)	$ 5,659,074	125%	$ 9,202,435	41.3%	35.6%
Cost-effectiveness: Total Resource Cost Test (Ratio)	4.5		1.9		
Cost-effectiveness: Program Administrator Cost Test (Ratio)	6.6		2.7		
Cost-effectiveness: Levelized Unit Electricity Cost ($/kWh)	0.01		0.03		

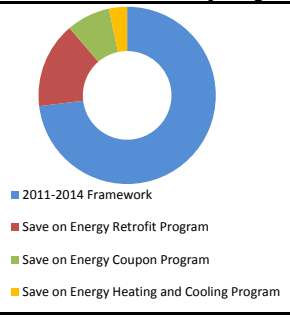
LDC Ranking in the Province out of 68

	6-year CDM Total Cost Effectiveness (PAC)	Total % of 6-year Allocated Budget Spent	Total % of 6-year Allocated Target
This Month:	5	25	4
Last Month:	9	36	4

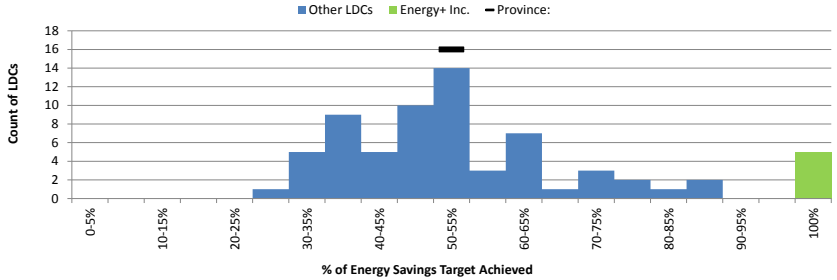
2017 % Contribution by Program



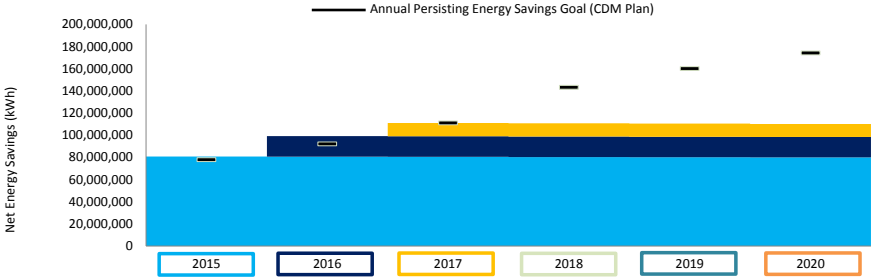
Framework to Date Contribution by Program



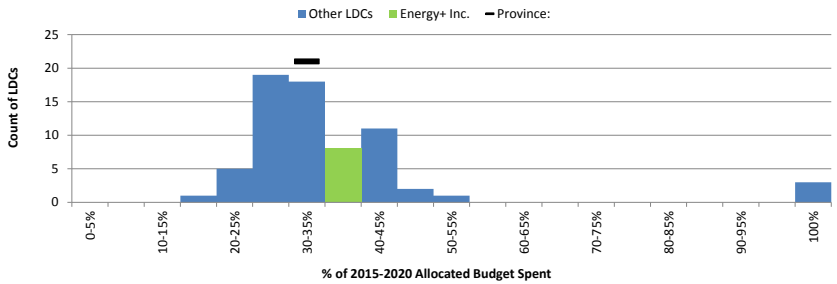
% of 2015-2020 Allocated Energy Savings Target Achieved



Persisting Energy Savings by Year



% of 2015-2020 Allocated Budget Spent



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Energy+ Inc.		2017 CDM Plan Forecast		6-year CDM Plan Forecast		Count (Incremental) >	Energy Savings (Incremental) >	Energy Savings (Persisiting to 2020) >	Spending (Year to Date) >	Spending (Program to Date) >	Cost Effectiveness (Year to Date) >	Cost Effectiveness (Prorgram to Date) >
As of:	31-Dec-17	% kWh Target	% Budget Spent	% kWh Target	% Budget Spent							
	Program											
Residential (Province-Wide)	Save on Energy Coupon Program	72%	142%	35.8%	44.0%							
	Save on Energy Heating and Cooling Program	54%	104%	57.3%	63.6%							
	Instant Discount Program											
	Save on Energy New Construction Program	0%	7832%	0.0%	2452.0%							
	Save on Energy Home Assistance Program	77%	16983%	77.3%	5126.6%							
	Residential Programs Total	**68%**	**124%**	**40.3%**	**53.6%**							
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	0%	0%	25.0%	17.7%							
	Save on Energy Retrofit Program	96%	168%	46.2%	54.6%							
	Save on Energy Retrofit Program - P4P											
	Save on Energy Retrofit Program Enabled Savings											
	Save on Energy Small Business Lighting Program	16%	28%	3.9%	7.3%							
	Business Refrigeration Program	0%	3%	0.0%	0.9%							
	Save on Energy Existing Building Commissioning Program	0%	0%	0.0%	0.0%							
	Save on Energy High Performance New Construction Program	9047%	79364%	147.9%	194.4%							
	Save on Energy Process & Systems Upgrades Program	0%	109%	0.0%	20.0%							
	Save on Energy Process & Systems Upgrades Program - P4P											
	Save on Energy Process & Systems Upgrades Program Enabled Savings											
	Save on Energy Energy Manager Program	0%	0%	0.0%	0.0%							
	Save on Energy Monitoring & Targeting Program	0%	0%	0.0%	0.0%							
	Non-Residential Programs Total	**69%**	**126%**	**30.7%**	**35.9%**							
< Local LDC Programs	**Local LDC Programs Total**											
< Central Services	**LDC Innovation Pilots Total**											
	Provincial Energy Manager Program											
Target Gap												
Non-Approved Program												
Unassigned Program												
Energy Savings from 2011-2014 Framework				**104%**								
< **TOTAL Conservation First (CDM Plan Forecast)**		**62%**	**125%**	**63.6%**	**41.3%**							
TOTAL Conservation First (Target and Budget Allocation)				**109.1%**	**35.6%**							

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Province-Wide Progress		2017 CDM Plan Forecast		6-year CDM Plan Forecast		Count (Incremental) >	Energy Savings (Incremental) >	Energy Savings (Persisiting to 2020) >	Spending (Year to Date) >	Spending (Program to Date) >	Cost Effectiveness (Year to Date) >	Cost Effectiveness (Prorgram to Date) >
As of:	31-Dec-17	% kWh Target	% Budget Spent	% kWh Target	% Budget Spent							
	Program											
Residential (Province-Wide)	Save on Energy Coupon Program	251%	289%	138.6%	108.5%							
	Save on Energy Heating and Cooling Program	89%	129%	90.8%	77.4%							
	Instant Discount Program											
	Save on Energy New Construction Program	30%	105%	14.4%	30.0%							
	Save on Energy Home Assistance Program	118%	92%	45.6%	32.7%							
	Residential Programs Total	**195%**	**189%**	**117.0%**	**79.2%**							
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	34%	121%	14.2%	38.3%							
	Save on Energy Retrofit Program	52%	91%	44.2%	38.7%							
	Save on Energy Retrofit Program - P4P	0%	53%	14.5%	8.1%							
	Save on Energy Retrofit Program Enabled Savings											
	Save on Energy Small Business Lighting Program	42%	69%	16.9%	24.2%							
	Business Refrigeration Program	61%	74%	18.8%	20.7%							
	Save on Energy Existing Building Commissioning Program	0%	41%	0.0%	21.3%							
	Save on Energy High Performance New Construction Program	19%	99%	25.9%	30.9%							
	Save on Energy Process & Systems Upgrades Program	7%	29%	1.7%	9.0%							
	Save on Energy Process & Systems Upgrades Program - P4P			43.1%	0.3%							
	Save on Energy Process & Systems Upgrades Program Enabled Savings											
	Save on Energy Energy Manager Program	48%	69%	25.8%	18.8%							
	Save on Energy Monitoring & Targeting Program	0%	29%	2.0%	10.3%							
	Non-Residential Programs Total	**46%**	**73%**	**37.2%**	**26.3%**							
< Local LDC Programs	**Local LDC Programs Total**	**37%**	**78%**	**17.7%**	**26.2%**							
< Central Services	**LDC Innovation Pilots Total**	**0%**		**672.9%**	**103.4%**							
	Provincial Energy Manager Program											
Target Gap												
Non-Approved Program												
Unassigned Program												
Energy Savings from 2011-2014 Framework				**123%**								
< **TOTAL Conservation First (CDM Plan Forecast)**		**59%**	**98%**	**52.8%**	**34.4%**							
TOTAL Conservation First (Target and Budget Allocation)				**55.0%**	**34.2%**							

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Program Participation & Cost Report
IESO Value Added Services Costs

Energy+ Inc.

Unless otherwise stated, all values are unverified

Year end adjustments for invalid coupons that didn't align with retailer sales data are done in the Decembers IESO reporting period.

*Allocated Coupons includes Instant Discounts - For breakout please see Value Added Services Report

		Activity	Measures Installed	Net Incremental Energy Savings (kWh)	Administrative Expenses (Variable)	Participant Incentives	Total Value Added Services Spending	
Provincial Actuals for the period	Verified Coupon Program (VAS & LDC)	Measures	18,260,821	463,980,654.8	$ 4,233,268	$ 31,727,255	$ 35,960,523	
	Coupon Program - Allocated	Measures	10,721,549	135,672,063.7	$ 1,364,415	$ 21,939,675	$ 23,304,090	*
	Coupon Program - LDC Coded	Measures	1,880,374	23,192,702.2	$ 499,045	$ 6,044,146	$ 6,543,191	
	Coupon Program - Bi-Annual Coupons - Allocated	Measures	15,870,386	205,390,979.4	$ 5,019,222	$ 55,181,103	$ 60,200,326	
	Coupon Total	Measures	46,733,130	828,236,400.1	$ 11,115,950	$ 114,892,180	$ 126,008,129	
	Verified Heating and Cooling Program	Equipment	156,852	87,816,036.1	$ 1,284,894	$ 37,754,200	$ 39,039,094	
	Heating and Cooling Program	Equipment	228,640	113,926,811.7	$ 1,334,809	$ 38,242,200	$ 39,577,009	
	Heating and Cooling Program to Date Total	Equipment	385,492	201,742,847.8	$ 2,619,703	$ 75,996,400	$ 78,616,103	
	LDC Value Added Services Provincial Total			**1,029,979,248.0**	**$ 13,735,653**	**$ 190,888,580**	**$ 204,624,232**	
LDC Actuals for the period	Verified Coupon Program (VAS & LDC)	Measures	180,559	4,849,013.4	$ 28,145	$ 287,769	$ 315,914	
	Coupon Program - Allocated	Measures	120,265	1,521,334.4	$ 15,305	$ 246,101	$ 261,406	*
	Coupon Program - LDC Coded	Measures	3,803	52,024.0	$ 1,417	$ 15,686	$ 17,103	
	Coupon Program - Bi-Annual Coupons - Allocated	Measures	178,019	2,300,019.4	$ 56,301	$ 618,968	$ 675,269	
	Coupon Total	Measures	482,646	8,722,391.2	$ 101,168	$ 1,168,524	$ 1,269,693	
	Verified Heating and Cooling Program	Equipment	2,651	1,480,421.4	$ 16,575	$ 609,400	$ 625,975	
	Heating and Cooling Program	Equipment	4,328	2,137,961.9	$ 24,710	$ 729,050	$ 753,760	
	Heating and Cooling Program to Date Total	Equipment	6,979	3,618,383.3	$ 41,285	$ 1,338,450	$ 1,379,735	
	LDC Value Added Services LDC Total			**12,340,774.5**	**$ 142,453**	**$ 2,506,974**	**$ 2,649,428**	

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Program Participation & Cost Report

Save on Energy Retrofit Program - Multi-Site Applications

Energy+ Inc.

As of: 31-Dec-17

	Program	Count (Incremental) >	Energy Savings (Incremental) >	Energy Savings (Persisiting to 2020) >	2017 Incentive Budget	2017 Year to Date Incentive Actual	2017 Admin Budget	2017 Year to Date Admin Actual	2017 Total Budget	2017 Year to Date Total Actual	Spending (Year to Date) >	Spending (Program to Date) >
Provincial Actuals for the Period	Save on Energy Retrofit Program				$ 72,167,596	$ 81,242,263	$ 35,810,696	$ 40,967,396	$ 134,966,507	$ 122,209,659		
	Multi-Site Applications				-	$ 2,889,481	-	$ 594,512	-	$ 3,483,994		
LDC Actuals for the Period	Save on Energy Retrofit Program				$ 783,120	$ 1,669,816	$ 735,898	$ 877,004	$ 1,519,018	$ 2,546,821		
	Multi-Site Applications				-	$ 30,990	-	$ 6,925	-	$ 37,915		

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Program Participation & Cost Report
Methodology

General

All results are at the end-user level (not including transmission and distribution losses).

Savings Calculations

#	Project Type	Equations
1	Prescriptive Measures and Projects Programs	Gross Reported Savings = Activity * Per Unit Assumption Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
2	Engineered and Custom Projects / Programs	Gross Reported Savings = Reported Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
3	Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the annual effect of energy savings.

2011-2014+2015 Extension Legacy Framework Initiatives

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings	Project Count
1	saveONenergy Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	Based on project completion date. Count is based of the unit of measurement shown beside the program name. Eg Retrofit is the count of Projects.
2	saveONenergy Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.		
3	saveONenergy Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.		
4	saveONenergy HVAC Incentives	Results directly attributed to LDC based on customer applications and postal code.	Savings are considered to begin in the year that the installation occurred.		
5	saveONenergy Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system.	Savings are considered to begin in the year of the project completion date.		
6	saveONenergy Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
7	saveONenergy Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).	
		Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)			
9	saveONenergy Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	
10	saveONenergy New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
11	saveONenergy Existing Building Commissioning Incentive				
12	saveONenergy Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
13	saveONenergy Monitoring & Targeting				
14	saveONenergy Energy Manager		Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.		
14	saveONenergy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	
15	Aboriginal Conservation Program				

2015-2020 Conservation First Framework Programs

#	Program	Attributing Savings to LDCs	Savings 'Start' Date	Calculating Resource Savings	Project Count
1	Save on Energy Coupon Program	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
2	Save on Energy Heating and Cooling Program	Results directly attributed to LDC based on customer applications and postal code. LDCs may see additional participation, savings and spending relative to the March 2016 Value Added Services Report due to previously unassigned applications completed in 2015. Adjustments to reflect final 2015 verified participation will appear in your July 2016 Value Added Services Report to be issued on August 15, 2016	Savings are considered to begin in the year that the installation occurred.		
3	Save on Energy New Construction Program	Results are directly attributed to LDC based on LDC identified in CDM LDC Report Template.	Savings are considered to begin in the year of the project completion date.		
4	Save on Energy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.		
5	Save on Energy Audit Funding Program	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
6	Save on Energy Retrofit Program	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date as reported in the CDM LDC Report Template	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).	
7	Save on Energy Small Business Lighting Program	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date. Count is based off the actual completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	
8	Save on Energy High Performance New Construction Program	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported in the CDM LDC Report Template. Preliminary unverified net savings are calculated by multiplying reported savings by 2014 Net-to-gross ratios and realization rates.	Based on project completion date. Could be a future completion date as incentives are paid before the project is completed.
9	Save on Energy Existing Building Commissioning Program				Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
10	Save on Energy Process and Systems Upgrades Program	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the project was in-service.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
11	Save on Energy Monitoring and Targeting Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013.	Savings are considered to begin in the year in which the incentive project was completed.		
12	Save on Energy Energy Manager Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.		Based on project completion date. Could be a future completion date as incentives are paid before the project is completed.
13	Business Refrigeration Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
14	Social Benchmarking Program		Savings are considered to begin in the year in which the report was sent.	Peak demand and energy savings are determined using the verified measure level (home) per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level (home).	
15	First Nations Conservation Program		Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	

IESO Value Added Services Costs

1) IESO Value Added Services Costs are based on activity reported as of March 31, 2016.

2) Save on Energy Heating & Cooling Program activity may be greater than the March 2016 IESO Value Added Services Report due to previously unassigned applications being assigned to LDCs through the Evaluation, Measurement & Verification Process based on updated
applicant postal code mappings. These additional applications and costs will be reflected in the July 2016 IESO Value Added Services Report.

3) Future years may include adjustments to prior years based on delays of Value-Added Service report submissions to IESO from IESO Value-Added Service providers.

4) IESO Value Added Services costs are calculated based on the prevailing IESO Value Added Services Rates as per the applicable IESO Central Services Strategy and Rate Guideline.

Program Participation & Cost Report
Consumer Program Allocation Methodology

Year	Local Distribution Company	Allocation
2016 03 31 - Current	Algoma Power Inc.	0.1820%
2016 03 31 - Current	Atikokan Hydro Inc.	0.0229%
2016 03 31 - Current	Attawapiskat Power Corporation	0.0149%
2016 03 31 - Current	Bluewater Power Distribution Corporation	0.6152%
2016 03 31 - Current	Brantford Power Inc.	0.6715%
2016 03 31 - Current	Burlington Hydro Inc.	1.3392%
2016 03 31 - Current	Canadian Niagara Power Inc.	0.3472%
2016 03 31 - Current	Centre Wellington Hydro Ltd.	0.1058%
2016 03 31 - Current	Chapleau Public Utilities Corporation	0.0282%
2016 03 31 - Current	COLLUS PowerStream Corp.	0.2546%
2016 03 31 - Current	Cooperative Hydro Embrun Inc.	0.0563%
2016 03 31 - Current	E.L.K. Energy Inc.	0.2455%
2016 03 31 - Current	Energy+ Inc.	1.1217%
2016 03 31 - Current	Enersource Hydro Mississauga Inc.	4.6424%
2016 03 31 - Current	Entegrus Powerlines Inc.	0.7018%
2016 03 31 - Current	EnWin Utilities Ltd.	1.4909%
2016 03 31 - Current	Erie Thames Powerlines Corporation	0.3197%
2016 03 31 - Current	Espanola Regional Hydro Distribution Corporation	0.0637%
2016 03 31 - Current	Essex Powerlines Corporation	0.6061%
2016 03 31 - Current	Festival Hydro Inc.	0.3248%
2016 03 31 - Current	Fort Albany Power Corporation	0.0099%
2016 03 31 - Current	Fort Frances Power Corporation	0.0900%
2016 03 31 - Current	Greater Sudbury Hydro Inc.	0.7993%
2016 03 31 - Current	Grimsby Power Incorporated	0.1813%
2016 03 31 - Current	Guelph Hydro Electric Systems Inc.	0.8531%
2016 03 31 - Current	Halton Hills Hydro Inc.	0.5897%
2016 03 31 - Current	Hearst Power Distribution Company Limited	0.0510%
2016 03 31 - Current	Horizon Utilities Corporation	3.7200%
2016 03 31 - Current	Hydro 2000 Inc.	0.0394%
2016 03 31 - Current	Hydro Hawkesbury Inc.	0.1467%
2016 03 31 - Current	Hydro One Brampton Networks Inc.	3.5920%
2016 03 31 - Current	Hydro One Networks Inc.	27.2865%
2016 03 31 - Current	Hydro Ottawa Limited	6.6052%
2016 03 31 - Current	InnPower Corporation	0.3309%
2016 03 31 - Current	Kashechewan Power Corporation	0.0177%
2016 03 31 - Current	Kenora Hydro Electric Corporation Ltd.	0.0896%
2016 03 31 - Current	Kingston Hydro Corporation	0.2939%
2016 03 31 - Current	Kitchener-Wilmot Hydro Inc.	1.5077%
2016 03 31 - Current	Lakefront Utilities Inc.	0.1128%
2016 03 31 - Current	Lakeland Power Distribution Ltd.	0.2288%
2016 03 31 - Current	London Hydro Inc.	2.6114%
2016 03 31 - Current	Midland Power Utility Corporation	0.1014%
2016 03 31 - Current	Milton Hydro Distribution Inc.	0.6579%
2016 03 31 - Current	Newmarket-Tay Power Distribution Ltd.	0.5977%
2016 03 31 - Current	Niagara Peninsula Energy Inc.	0.8158%
2016 03 31 - Current	Niagara-on-the-Lake Hydro Inc.	0.1304%

2016 03 31 - Current	North Bay Hydro Distribution Limited	0.4153%
2016 03 31 - Current	Northern Ontario Wires Inc.	0.0860%
2016 03 31 - Current	Oakville Hydro Electricity Distribution Inc.	1.5097%
2016 03 31 - Current	Orangeville Hydro Limited	0.2004%
2016 03 31 - Current	Orillia Power Distribution Corporation	0.2220%
2016 03 31 - Current	Oshawa PUC Networks Inc.	1.4845%
2016 03 31 - Current	Ottawa River Power Corporation	0.1225%
2016 03 31 - Current	Peterborough Distribution Incorporated	0.4607%
2016 03 31 - Current	PowerStream Inc.	7.8184%
2016 03 31 - Current	PUC Distribution Inc.	0.6545%
2016 03 31 - Current	Renfrew Hydro Inc.	0.0477%
2016 03 31 - Current	Rideau St. Lawrence Distribution Inc.	0.0670%
2016 03 31 - Current	Sioux Lookout Hydro Inc.	0.0776%
2016 03 31 - Current	St. Thomas Energy Inc.	0.2780%
2016 03 31 - Current	Thunder Bay Hydro Electricity Distribution Inc.	0.8172%
2016 03 31 - Current	Tillsonburg Hydro Inc.	0.1169%
2016 03 31 - Current	Toronto Hydro-Electric System Limited	15.5698%
2016 03 31 - Current	Veridian Connections Inc.	2.3879%
2016 03 31 - Current	Wasaga Distribution Inc.	0.1754%
2016 03 31 - Current	Waterloo North Hydro Inc.	0.9590%
2016 03 31 - Current	Welland Hydro-Electric System Corp.	0.3103%
2016 03 31 - Current	Wellington North Power Inc.	0.0570%
2016 03 31 - Current	West Coast Huron Energy Inc.	0.0585%
2016 03 31 - Current	Westario Power Inc.	0.3654%
2016 03 31 - Current	Whitby Hydro Electric Corporation	1.1240%
2011 - 2016 03 31	Algoma Power Inc.	0.2207%
2011 - 2016 03 31	Atikokan Hydro Inc.	0.0265%
2011 - 2016 03 31	Attawapiskat Power Corporation	0.0255%
2011 - 2016 03 31	Bluewater Power Distribution Corporation	0.6460%
2011 - 2016 03 31	Brant County Power Inc.	0.1979%
2011 - 2016 03 31	Brantford Power Inc.	0.7255%
2011 - 2016 03 31	Burlington Hydro Inc.	1.3757%
2011 - 2016 03 31	Cambridge and North Dumfries Hydro Inc.	0.9578%
2011 - 2016 03 31	Canadian Niagara Power Inc.	0.5110%
2011 - 2016 03 31	Centre Wellington Hydro Ltd.	0.1129%
2011 - 2016 03 31	Chapleau Public Utilities Corporation	0.0379%
2011 - 2016 03 31	COLLUS PowerStream Corp.	0.2858%
2011 - 2016 03 31	Cooperative Hydro Embrun Inc.	0.0494%
2011 - 2016 03 31	E.L.K. Energy Inc.	0.2270%
2011 - 2016 03 31	Enersource Hydro Mississauga Inc.	3.9265%
2011 - 2016 03 31	Entegrus Powerlines Inc.	0.7226%
2011 - 2016 03 31	EnWin Utilities Ltd.	1.5542%
2011 - 2016 03 31	Erie Thames Powerlines Corporation	0.3535%
2011 - 2016 03 31	Espanola Regional Hydro Distribution Corporation	0.0821%
2011 - 2016 03 31	Essex Powerlines Corporation	0.6539%
2011 - 2016 03 31	Festival Hydro Inc.	0.3498%
2011 - 2016 03 31	Fort Albany Power Corporation	0.0212%
2011 - 2016 03 31	Fort Frances Power Corporation	0.0995%
2011 - 2016 03 31	Greater Sudbury Hydro Inc.	1.0276%
2011 - 2016 03 31	Grimsby Power Incorporated	0.2279%
2011 - 2016 03 31	Guelph Hydro Electric Systems Inc.	0.8983%
2011 - 2016 03 31	Haldimand County Hydro Inc.	0.4244%
2011 - 2016 03 31	Halton Hills Hydro Inc.	0.5475%

2011 - 2016 03 31	Hearst Power Distribution Company Limited	0.0667%
2011 - 2016 03 31	Horizon Utilities Corporation	4.0429%
2011 - 2016 03 31	Hydro 2000 Inc.	0.0390%
2011 - 2016 03 31	Hydro Hawkesbury Inc.	0.1394%
2011 - 2016 03 31	Hydro One Brampton Networks Inc.	2.8180%
2011 - 2016 03 31	Hydro One Networks Inc.	29.9788%
2011 - 2016 03 31	Hydro Ottawa Limited	5.5954%
2011 - 2016 03 31	InnPower Corporation	0.3951%
2011 - 2016 03 31	Kashechewan Power Corporation	0.0286%
2011 - 2016 03 31	Kenora Hydro Electric Corporation Ltd.	0.0989%
2011 - 2016 03 31	Kingston Hydro Corporation	0.5014%
2011 - 2016 03 31	Kitchener-Wilmot Hydro Inc.	1.6310%
2011 - 2016 03 31	Lakefront Utilities Inc.	0.1907%
2011 - 2016 03 31	Lakeland Power Distribution Ltd.	0.2906%
2011 - 2016 03 31	London Hydro Inc.	2.7308%
2011 - 2016 03 31	Midland Power Utility Corporation	0.1196%
2011 - 2016 03 31	Milton Hydro Distribution Inc.	0.5695%
2011 - 2016 03 31	Newmarket-Tay Power Distribution Ltd.	0.6607%
2011 - 2016 03 31	Niagara Peninsula Energy Inc.	0.9945%
2011 - 2016 03 31	Niagara-on-the-Lake Hydro Inc.	0.1586%
2011 - 2016 03 31	Norfolk Power Distribution Inc.	0.3495%
2011 - 2016 03 31	North Bay Hydro Distribution Limited	0.5333%
2011 - 2016 03 31	Northern Ontario Wires Inc.	0.1061%
2011 - 2016 03 31	Oakville Hydro Electricity Distribution Inc.	1.4632%
2011 - 2016 03 31	Orangeville Hydro Limited	0.2120%
2011 - 2016 03 31	Orillia Power Distribution Corporation	0.2722%
2011 - 2016 03 31	Oshawa PUC Networks Inc.	1.2283%
2011 - 2016 03 31	Ottawa River Power Corporation	0.1974%
2011 - 2016 03 31	Peterborough Distribution Incorporated	0.7132%
2011 - 2016 03 31	PowerStream Inc.	6.6383%
2011 - 2016 03 31	PUC Distribution Inc.	0.8687%
2011 - 2016 03 31	Renfrew Hydro Inc.	0.0775%
2011 - 2016 03 31	Rideau St. Lawrence Distribution Inc.	0.1120%
2011 - 2016 03 31	Sioux Lookout Hydro Inc.	0.0841%
2011 - 2016 03 31	St. Thomas Energy Inc.	0.2939%
2011 - 2016 03 31	Thunder Bay Hydro Electricity Distribution Inc.	0.8738%
2011 - 2016 03 31	Tillsonburg Hydro Inc.	0.1280%
2011 - 2016 03 31	Toronto Hydro-Electric System Limited	12.7979%
2011 - 2016 03 31	Veridian Connections Inc.	2.3525%
2011 - 2016 03 31	Wasaga Distribution Inc.	0.1799%
2011 - 2016 03 31	Waterloo North Hydro Inc.	1.0019%
2011 - 2016 03 31	Welland Hydro-Electric System Corp.	0.3879%
2011 - 2016 03 31	Wellington North Power Inc.	0.0632%
2011 - 2016 03 31	West Coast Huron Energy Inc.	0.0653%
2011 - 2016 03 31	Westario Power Inc.	0.5411%
2011 - 2016 03 31	Whitby Hydro Electric Corporation	0.8651%
2011 - 2016 03 31	Woodstock Hydro Services Inc.	0.2548%

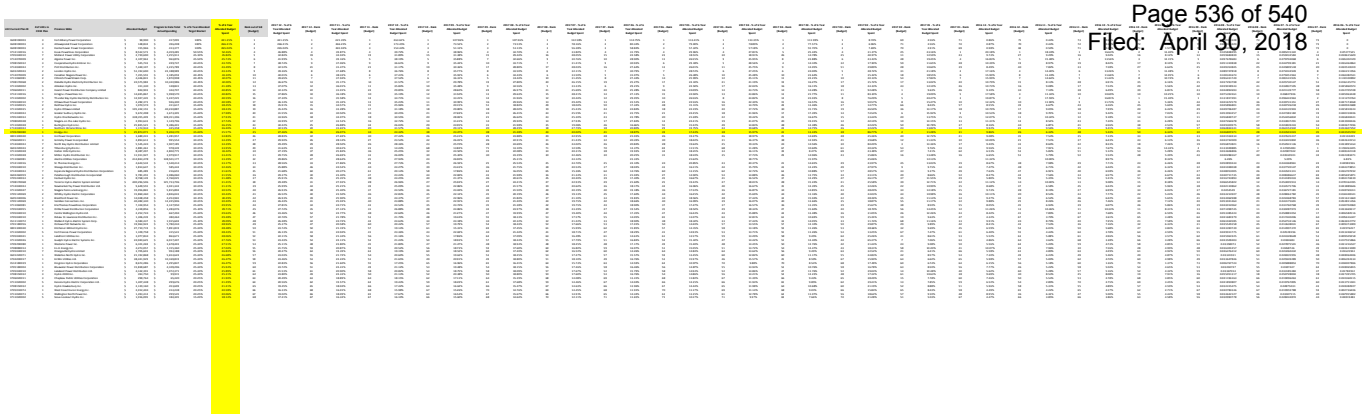
Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

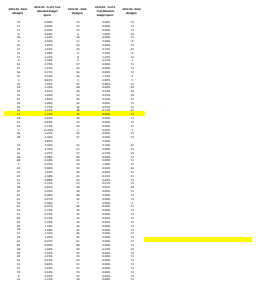
Program Participation & Cost Report
Glossary

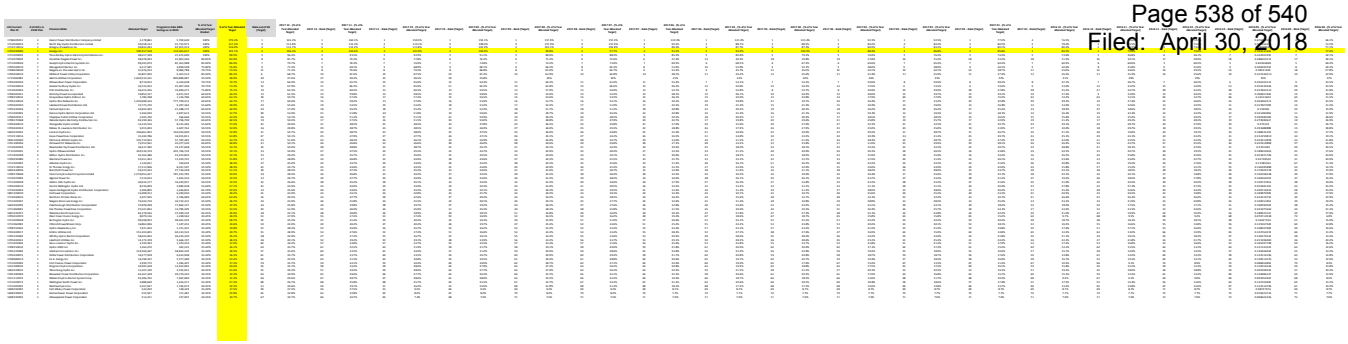
#	Term	Definition
1	2011-2014+2015 Extension Legacy Framework Programs	Programs in market from 2011-2015 resulting from the April 23, 2010 GEA CDM Ministerial Directive and funded separately from 2015-2020 Conservation First Framework Programs but whose savings in 2015 are attributed towards the 2015-2020 Conservation First Framework target.
2	2015-2020 Conservation First Framework Programs	Programs in market from 2015-2020 resulting from the March 31, 2014 CFF Ministerial Directive and funded separately from 2011-2014+2015 Extension Legacy Framework Programs.
3	Allocated Target	Each LDC's assigned portion of the Province's 7 TWh Net 2020 Annual Energy Savings Target of the 2015-2020 Conservation First Framework.
4	Allocated Budget	Each LDC's assigned portion of the Province's $ 1.835 billion CDM Plan Budget of the 2015-2020 Conservation First Framework.
5	Province-Wide Program	Programs available to all LDCs to deliver and that are consistent across the province.
6	Regional Program	Programs designed by LDCs to serve their region and approved by the IESO.
7	Local Program	Programs designed by LDCs to serve their communities and approved by the IESO.
8	Pilot Program	A program pilot that may achieve energy or demand savings and is funded extraneous to an LDC's CDM Plan Budget.
9	Initiative	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup) from the 2011-2014+2015 Extension Legacy Framework.
10	Program	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup) from the 2015-2020 Conservation First Framework.
11	Activity	The number of projects.

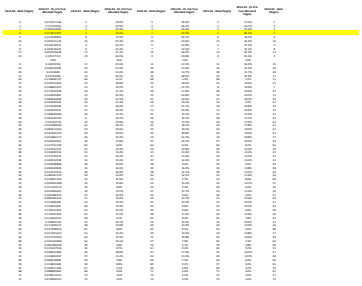
12	Unit	For a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).
13	Forecast	LDC's forecast of activity, savings, expenditures and cost effectiveness as indicated in each LDC's submitted CDM Plan Cost Effectiveness Tools.
14	Actual	The IESO determined final results of activity, savings, expenditures and cost effectiveness.
15	Progress	A comparison of Actuals versus Forecasts.
16	Full Cost Recovery Progress	For a given year, the percentage calculated by dividing: a) the sum of verified electricity savings for all years of the term up to and including the applicable year for all Programs that receive full cost recovery funding, by b) the Cumulative FCR Milestone, multiplied by 100%, as specified in Schedule A of the Energy Conservation Agreement.
17	Reported Savings	Savings determined by the LDC: 1) for prescriptive projects/programs: calculating quantity x prescriptive savings assumptions; and 2) for engineered or custom program projects/programs: calculated using prescribed methodologies.
18	Verified Savings	Savings determined by the IESO's evaluation, measurement and verification that may adjust reported savings by the realization rate.
19	Gross Savings	Savings determined as either: 1) program activity multiplied by per unit savings assumptions for prescriptive programs; or 2) reported savings multiplied by the realization rate for engineered or custom program streams.
20	Net Savings	The peak demand or energy savings attributable to conservation and demand management activities net of free-riders, etc.
21	Realization Rate	A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.
22	Net-to-Gross Adjustment	The ratio of net savings to gross savings, which takes into account factors such as free ridership and spillover.
23	Free-ridership	The percentage of participants who would have implemented the program measure or practice in the absence of the program.

24	Spillover	Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.
25	Incremental Savings	The new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.
26	First Year Savings	The peak demand or energy savings that occur in the year it was achieved (includes resource savings from only new program activity).
27	Annual Savings	The peak demand or energy savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).
28	Demand Savings	Demand savings attributable to conservation and demand management activities.
29	Energy Savings	Energy savings attributable to conservation and demand management activities.
30	Administrative Expenses	Costs incurred in the delivery of a program related to labour, marketing, third-party expenses, value added services or other central services.
31	Participant Incentives	Costs incurred in the delivery of a program related to incenting participants to perform peak demand or energy savings.
32	Total Expenditure	The sum of Administrative Expenses and Participant Incentives
33	Total Resource Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on the total costs of the program including both participants' and utility's costs.
34	Program Administrator Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on costs incurred by the program administrator, including incentive costs and excluding net costs incurred by the participant.
35	Levelized Unit Energy Cost Cost Effectiveness Test	A cost effectiveness test that normalizes the costs incurred by the program administrator per unit of energy or demand reduced.









Target				
Category	Other LDCs	LDC	Province:	50-55%
0-5%	0	0	-5	
5-10%	0	0	-5	
10-15%	0	0	-5	
15-20%	0	0	-5	
20-25%	0	0	-5	
25-30%	1	0	-5	
30-35%	5	0	-5	
35-40%	9	0	-5	
40-45%	5	0	-5	
45-50%	10	0	-5	
50-55%	14	0	16	
55-60%	3	0	-5	
60-65%	7	0	-5	
65-70%	1	0	-5	
70-75%	3	0	-5	
75-80%	2	0	-5	
80-85%	1	0	-5	
85-90%	2	0	-5	
90-95%	0	0	-5	
95-100%	0	0	-5	
100%	5	5	-5	

Budget				
Category	Other LDCs	LDC	Province:	30-35%
0-5%	0	0	-5	
5-10%	0	0	-5	
10-15%	0	0	-5	
15-20%	1	0	-5	
20-25%	5	0	-5	
25-30%	19	0	-5	
30-35%	18	0	21	
35-40%	8	8	-5	
40-45%	11	0	-5	
45-50%	2	0	-5	
50-55%	1	0	-5	
55-60%	0	0	-5	
60-65%	0	0	-5	
65-70%	0	0	-5	
70-75%	0	0	-5	
75-80%	0	0	-5	
80-85%	0	0	-5	
85-90%	0	0	-5	
90-95%	0	0	-5	
95-100%	0	0	-5	
100%	3	0	-5	