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Cochrane, Ontario P0L 1C0

January 31, 2017

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

**Re: 2017 Cost of Service Application EB-2016-0096
IR Responses**

Dear Ms. Walli:

Northern Ontario Wires Inc. is pleased to submit interrogatory responses pursuant to Procedural Order No. 1 in this proceeding. An electronic copy has been submitted to the Board through the RESS system and two hard copies will be delivered to the OEB office.

Please note that a number of the IR's requested information related to 2016 Actual results. At the time of this submission, Northern Ontario Wires Inc. has not yet finalized year-end 2016 financial results; Northern Ontario Wires Inc. plans to provide this requested information and the associated rate impacts in a supplementary filing on February 17, 2017.

Furthermore, as the responses to 4-Staff-37 (b) and (c) contain confidential identifying information with respect to individual salaries, Northern Ontario Wires Inc. will be providing these responses under separate cover consistent with the OEB Practice Direction on Confidential Filings.

Yours truly,

A handwritten signature in blue ink, appearing to read 'Geoffrey Sutton', is written over a light blue horizontal line.

Geoffrey Sutton, CPA, CA
Chief Financial Officer
Tel: (705) 272-6669
Email: geoffs@nowinc.ca

Cc: Mark Rubenstein, SEC
Michael Janigan, VECC
Shelly Grice, AMPCO
Michael Buonaguro, Counsel



Northern Ontario Wires Inc. Response to Interrogatories

EB-2016-0096

Rates Effective: May 1, 2017

Date Filed: January 31, 2017

Northern Ontario Wires Inc.

153 Sixth Avenue

P.O. Box 640

Cochrane, ON P0L 1C0

Interrogatory Responses

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Exhibit 1 – Administration

1-Staff-1

Ref: Responses to Letters of Comment

Preamble:

Following publication of the Notice of Application, the Board received 2 letters of comment. If the applicant has not received a copy of the letters, they may be accessed from the public record for this proceeding.

Question(s):

- a) Please file a response to the matters raised in the letters of comment referenced above.
- b) Going forward, please ensure that responses are filed to any subsequent letters that may be submitted in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

- a) NOW Inc. discussed above mention letters of comment with Board Staff. The letters of comment were not authorized to be on the public record and as such cannot be responded to.
- b) NOW Inc. confirms that if any subsequent letters of comment are received, they will be responded to as part of this proceeding.

1-Staff-2

Ref: Exhibit 1 / Tab 6 / Schedule 1 / p. 5
Exhibit 1 / Tab 6 / Schedule 1 / Attachment 2

Preamble:

Northern Ontario Wires noted that in 2016 it conducted an Electric Utility Customer Engagement Survey to obtain actionable and measureable feedback from Northern Ontario Wires' customers.

Overall, Northern Ontario Wires' customers seem to have responded positively to its Customer Satisfaction Survey. However, there is an area where a number of customers seem to have concerns.

Question(s):

- a) Please advise whether the survey was developed in-house or was developed by a third-party? If the survey was developed by a third-party, please provide the total cost of the survey.
- b) 10.85% customers responded that they experience problems with their electricity service "sometimes" and 0.71% responded that they experience problems with their electricity service "very often." Please provide any insight that Northern Ontario Wires may have into this perception.

Response:

- a) NOW primarily developed the survey in house. A survey from another LDC was used as the initial template. NOW then used the template as to focus and develop questions toward NOW's application.

NOW Inc. retained a third-party (IndeCo) to review and assist in ensuring questions were worded correctly and would meet all regulatory requirements. The third-party costs were \$1,590.

- b) NOW Inc. has taken a closer look at the survey results of the 0.71% in order to gain further insight. The 3 of 499 customers that responded that they experience problems with their electricity service "very often" also rated NOW as extremely, and somewhat reliable. In addition, two of the three respondents are very satisfied with NOW service.

Two of the three respondents live in Kapuskasing which is fed through Hydro
One which can be a cause of loss of supply for NOW customers.

The respondents of “sometimes” felt that NOW is reliable and are satisfied with
NOW service.

1-Staff-3

Ref: Exhibit 1 / Tab 6 / Schedule 1 / p. 10

Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 16

Preamble:

Northern Ontario Wires described a virtual town hall held in July 2016 to collect feedback on the investment and spending plan for 2017 to 2021. Northern Ontario Wires received 10 responses compared to 450 for its customer satisfaction survey.

Question(s):

- a) Northern Ontario Wires noted that it was unable to track the number of views of the presentation. Please advise whether Northern Ontario Wires intends to begin tracking the number of views for future virtual town hall presentations to determine whether they are useful.
- b) What are potential reasons for the significant difference in responses to the virtual town hall compared to the customer satisfaction survey?
- c) Did Northern Ontario Wires find the virtual town hall an effective means to communicate its investment and spending plan to its customers?
- d) Did Northern Ontario Wires consider holding a live town hall in each of the communities it served to communicate its investment and spending plan to its customers? If so, why was the virtual town hall chosen?
- e) Does Northern Ontario Wires have any plans to hold future town hall meetings?

Response:

- a) NOW plans to begin tracking the number of views for future virtual town hall presentations.
- b) Potential reasons for the significant difference in the virtual town hall and customer survey responses are:
 - i. The survey by its very purpose and nature required a response, whereas the purpose of the virtual town hall was to communicate information and solicit response/comments where the customer felt

a need to do,

- ii. The difference in number of responses may be attributable to the length of material that the customer would need to be informed of in the Virtual Town Hall, whereas the survey merely asked for their thoughts without the time required to read a presentation. Those that did not complete the entire town hall presentation may not have seen the link to the survey, or may have elected not to complete the survey, and
 - iii. NOW provided an ultimate fishing prize which was drawn from customer survey respondents. The Virtual Town Hall did not have any contest/prize associated with the responses.
- c) Yes, Northern Ontario Wires thinks that the virtual town hall was an effective means of communication. It provided an opportunity for customers to be informed of utility plans from the comfort of their own homes and at timing of their own convenience, without having to go out to a meeting.
- d) Northern Ontario Wires did consider holding live town hall meetings in each community. Given the success of the customer survey response, it was thought that the company would be able to connect with more customers through an on-line presentation than would actually attend a live town hall meeting. An opportunity was provided for feedback as part of the virtual presentation.
- e) Northern Ontario Wires believes in the importance of customer communication and feedback and will consider additional channels of contact including live town hall meetings. There are currently no specific plans or dates for a live town hall meeting, however the company is committed to having such a meeting prior to its next cost of service hearing.

1-Staff-4

Ref: Exhibit 1 / Tab 3 / Schedule 13 / p. 1

Preamble:

Northern Ontario Wires noted that the current version of its Conditions of Service is available on its website.

Northern Ontario Wires stated that the rates and charges which are the subject of this rate application are not contained in the Conditions of Service, therefore no changes will result from the Cost of Service application.

Northern Ontario Wires also stated that there have been no changes to the Conditions of Service since its last Cost of Service Application.

Question(s):

- a) OEB staff was unable to locate the Conditions of Service on Northern Ontario Wires' website. Please advise where Northern Ontario Wires' Conditions of Service are available publically and provide a reference.
- b) If applicable, please identify any rates and charges that are included in Northern Ontario Wires' Conditions of Service but do not appear on the OEB-approved tariff sheet. Please provide an explanation for the nature of the costs being recovered through the rates and charges that are set out only in Northern Ontario Wires' Conditions of Service.
- c) If applicable, please provide a schedule outlining the revenues recovered from these rates and charges for the past 3 historical years and the bridge and test years.
- d) If applicable, please explain whether, in Northern Ontario Wires' view, these rates and charges should be included on Northern Ontario Wires' tariff sheet of approved rates and charges.

Reponses:

- a) The Conditions of Service can be found on Northern Ontario Wires Inc.'s website through the following path: Home Page => Corporations => Regulatory.

<http://www.northernontariowires.com/Conditions%20of%20Services.pdf>

- b) Not applicable
- c) Not applicable
- d) Not applicable

1-Staff-5

Ref: Exhibit 1 / Tab 9 / Schedule 1 / pp. 2-5

Preamble:

Northern Ontario Wires stated that the upgrade to its Outage Management System (OMS) system in 2017 will result in lower costs to restore power.

Northern Ontario Wires stated that cost savings due to the planned decommissioning of two substations will not be realized over the forecast period as those savings fall outside of the five-year window.

Northern Ontario Wires stated that sharing facilities and staff resources with its affiliate (Cochrane Telecom Services) results in cost savings.

Question(s):

- a) Please provide an estimate of the cost savings related to restoring power after outages on a per outage basis expected due to the upgrade of the OMS system.
- b) Please provide the total cost of the voltage conversion projects and provide a high-level estimate of the future savings (outside the forecast 5-year term) related to the voltage conversion projects.
- c) Please provide an estimate of the annual cost savings associated with sharing resources with Northern Ontario Wires' affiliate.

Response:

- a) Trouble locations will be identified sooner thus resulting in reduced investigation time, which translates to less time/wages. The estimated savings is \$225 per outage, the cost savings of customers is not included in the total as business customers lose revenue when they are idle.
- b) The Kapuskasing 5kV Conversion Upgrade is projected to cost \$1,155,000 over the planning period (2016-2012). The Iroquois Falls 2.4 to 12kV Upgrade is projected to cost \$897,000 over the planning period (2016-2021). It is difficult to determine the future savings of these projects as the primary reason for the projects was to help ensure reliability.

- c) The estimated annual cost savings associated with sharing resources with NOW Inc.'s affiliate less the management fee is approximately \$90,000. This is based on savings of labour costs. These labour costs are incurred by the affiliate. Without the sharing of resources, NOW Inc. would need additional labour costs in the amount of the savings. These savings are based on the cost of NOW Inc. hiring and managing staff related billing, collecting, accounts payable, inventory, payroll and IT. These functions require diverse skill sets. As such it is more difficult to have cross functionality. The cost of contracting out services would also be an additional cost and internal IT resources that are shared provide value to NOW Inc.

1-Staff-6

Ref: PEG Benchmarking Model

Question(s):

- a) Please provide references to the pre-filed evidence and / or file additional evidence supporting the amounts included on the sheet titled, "model inputs."
- b) If Northern Ontario Wires identifies any errors its review of the PEG Benchmarking Model, please file a corrected version.

Responses:

- a) References for the Model Inputs for the PEG Benchmarking Model are as follows.
 - All History Column G amounts are automatically pulled from RRR data.
 - H9: \$995,964 REF: E2/T1/S1/Att1/p4
 - I9: \$827,500 REF: E2/T1/S1/Att1/p5
 - H13: 6074 REF: E3/T1/S2/Att1/p7 – Residential + GS<50 + GS>50
 - I13: 6071 REF: E3/T1/S2/Att1/p7 – Residential + GS<50 + GS>50
 - H14: 119,147,496 REF: E3/T1/S2/p2
 - I14: 118,967,287 REF: E3/T1/S2/p2
 - H15:I15 REF: 2016 actual to date and 2017 forecast
 - H16:I16: 370km REF: Same as 2015 with no changes
 - H17: $=(H13/6135)-1$: 6135 is the customer count from 10 years ago per RRR
 - I17: $=(I13/6112)-1$: 6112 is the customer count from 10 years ago per RRR
 - H20:I21: Standard Model inputs
 - H22: Same as 2015
 - I22: 6.03% REF: E5/T1/S1/Att1/p2
 - H115:I121: REF: E4/T1/S1/p1 OM&A less USoA Excluded per Model (5335,5030,5660,6105,6205)
 - H122:I122: The LV expenses to add (if any) are the following charges paid to Hydro One for low voltage service: LVDS Low Facility Charge, Specific ST Lines Facility Charge, Meter Charge, and 45% of the HVDS Low Facility Charge.
- b) NOW Inc. has not identified any errors in the PEG Model.

1-SEC-1

[Ex.1] Please provide a copy of the Applicant's most recent business plan.

Response:

NOW Inc. does not have a formal business plan document. The closest to such a document is the "NOW Inc. Cost of Service" presentation provided in Attachment 1.

1-SEC-1
Attachment 1

NOW Inc. Cost of Service

May 1, 2017 Rates

Timeline

- Last rebasing was for May 1, 2013 rates
- Small inflationary increases for years 2014-2016
- Cost of Service is the time for adjusting rates to reflect operational costs, while looking at future plans
- Filing due August 26, 2016

- After application, intervenors will question and try and reduce Bill impacts to customers
- NOW Inc. will defend the application and answer intervenor interrogatories
- Settlement will likely be reached as a result of NOW Inc. reducing OM&A and/or Capital

Customer Engagement

- Survey – indicated that there was support for increased bill with maintained reliability.
 - No overwhelming desire for e-billing
 - Customers indicated the need for outage management solution that involved electronic notifications
 - High customer satisfaction with NOW Inc. service

Capital Budget

- Capital budget consistent with 2013 application in amount.
- Increased computer software costs for outage management solution (corroborated by customer feedback)
- Value of 2017 Capex is approximately \$830,000

Capital Budget

OEB Category	Capital Project		Expenditure						
			OEB Appr.	Actual					Bridge
			2013	2012	2013	2014	2015	2016	Test 2017
System Renewal	Program:								
		Pole Changes - Cochrane	53,560	80,318	105,504	49,270	58,096	55,000	105,000
		Pole Changes - Kapuskasing	53,560	67,997	2,013	14,050	8,103	55,000	55,000
		Pole Changes - Iroquois Falls	53,560	16,557	8,323	3,229	419	27,500	55,000
	Project:								
		Cochrane - 5kV Upgrade - Laneway reconstructi	172,578	13,839	129,232				
		Cochrane - 11th Ave. Relocate Upgrade		87,623					
		Cochrane Primary (11th and Maple)				38,660	7,334		
		Cochrane Station					4,875		
		Cochrane Lakefront Rebuild						50,000	
		Cochrane 5Kv Upgrade							90,000
		Cochrane Line Transformers				3,584			
		Cochrane Substation Feeder		11,206		686		25,000	50,000
		Cochrane Station Transformer							
		Kapuskasing Line Transformers					2,310		
		Iroquois Falls Station Transformer							
		Iroquois Falls Transformers				2,959			
		Smart Meter In-Service Recognized							
		Distribution Station Equipment		5,049			6,868		
		Iroquois Falls Poles - Contributed					52,253		
		Cochrane Poles - Contributed					29,665		
		Kapuskasing Poles - Contributed					9,232		

Capital Budget

General Plant										
		Transportation Equipment		176,500	218,112	224,313	261,375		85,000	
		Tools & Equipment		20,600	24,265	12,485	5,007	2,500	12,500	17,500
		Computer Hardware		10,300	3,982		1,800	6,000	30,000	10,000
		Computer Software		5,150			87,493	160,557	120,914	115,000
		Buildings			116,245	17,535	10,228	1,165		
		Capital in Inventory						456		
System Access										
		Metering				40,344	8,210	5,089	15,000	15,000
		Cochrane - CGV Seniors Complex						20,506		
		Cochrane Overhead Conductor - Contributed						2,431		
		Cochrane Line Transformers - Contributed						18,176		
		Iroquois Falls - Services Overhead - Contributed						11,655		
System Service										
		Kapuskasing - 5Kv to 25Kv Conv. Upgrade		101,351	103,372	205,501	203,393	94,251	140,000	175,000
		Iroquois Falls - 2.4 to 12 Kv Upgrade		77,920	81,730	63,936	31,322	83,829	87,000	140,000
		Total		725,079	830,295	809,186	721,266	585,770	702,914	827,500

OM&A

- OM&A set based on current operations and forecasting for future costs
 - Union Contract increases
 - Increase in GIS and outage management costs
 - Bad debt forecast taking into account increasing cost of power and past experience

OM&A Budget

	2017	2016	2015
TRANSFORMER/SUBSTATION	36,327	35,127	33,422
CUSTOMER PREMISES	262,861	210,008	190,479
LOAD DISPATCHING	284,124	222,079	245,549
ENG & OPS ADMINISTRATION	202,892	129,286	132,045
METER EXPENSES	27,032	18,308	16,574
Total OPERATIONS EXPENSES	813,236	614,808	618,070
MAINTENANCE O/H LINES	489,202	413,964	346,016
MAINTENANCE OF LINE TRANSFORMERS	21,655	20,345	16,422
MAINTENANCE U/G CONDUCTORS	56,989	52,732	58,615
TREE TRIMMING AND VEGETATION CONTROL	113,272	103,971	88,758
Total MAINTENACE EXPENSES	681,118	591,012	509,810
BILLING/FINALS/COLLECTIONS	481,650	466,290	418,112
METER READING	198,123	191,476	182,394
BAD DEBT	75,000	64,874	151,514
Total CUSTOMER SERVICE EXPENSES	754,773	722,640	752,020
ADMINISTRATION	438,857	423,553	402,849
REGULATORY EXPENSES	107,305	203,608	31,528
OUTSIDE SERVICES	53,133	51,585	51,545
PROPERTY EXPENSE	40,112	38,944	36,366
Total ADMINISTRATION EXPENSES	639,407	717,690	522,288
	2,888,534	2,646,150	2,402,188
Adjust for One Time in OM&A	50,886		
	2,939,420	2,646,150	2,402,188

2015

- Return on Equity
 - Achieved ROE was \$198,809 or 6.20%
 - Deemed ROE per 2013 COS was \$261,250 or 8.98%
 - ROE Variance was \$62,441
- Regulated Deemed Equity
 - Achieved \$3,206,532
 - Deemed \$2,909,242
 - Variance \$297,290
- ROE % for 2015 was 6.20% (within +/- 3% deadband)

Deemed Equity Variance

- 2013 COS (40%)
 - Costs of Power \$12.3M + Operating \$2.3M
 - Avg PPE \$5.6M, Working Capital at 11.4% = \$1.66M
 - Rate Base \$7.27M
- 2015 Achieved (40%)
 - Variance 297,290 (\$3,206,532-\$2,909,242)
 - Cost of Power \$14.4M + Operating \$2.4M
 - Avg PPE \$6.1M, Working Capital at 11.4% = \$1.91M
 - Rate Base \$8.016M
- 2017 COS (40%)
 - Cost of Power \$16.5M + Operating \$2.9M
 - Avg PPE \$6.3M, Working Capital at 7.5% = \$1.45M
 - Rate Base \$7.8
 - 2017 Amounts may change for new CoP rates

Impact if no Rate Increase

- Figures Represent 12 Months of Rates vs NOW's typical 8 months New Rates 4 months old rates
 - 2016 Projection Income \$273k per COS
 - 2017 Projected Loss if No Rate Adjustment (\$113k)
 - 2016 Rev Deficiency \$(198k)
 - 2017 Rev Deficiency \$(604k)
 - result is combination of Utility Income and Rate Base
 - Deemed Return on Equity on 2017 Rates \$287k

Estimated Bill Impacts

- Residential (Rate Rider over 1 Year)
 - Distribution | 16.97% or \$5.68/mo
 - Distribution less Rate Riders | 2.76% or \$1.20/mo
 - Total Bill impact | 0.85% or \$1.33/mo

- Residential (Rate Rider over 2 Year) *
 - Distribution | 16.97% or \$5.68/mo
 - Distribution less Rate Riders | 4.37% or \$1.89/mo
 - Total Bill impact | 1.35% or \$2.12/mo

- Excludes LRAMVA, updated load forecast and cost allocation
- * = Recommended to rate mitigate for 2018 Rates

Estimated Bill Impacts

- GS<50 (Rate Rider over 1 Year)
 - Distribution | 18.27% or \$10.94/mo
 - Distribution less Rate Riders | (1.25%) or \$(1.07)/mo
 - Total Bill impact | (0.33%) or \$(1.28)/mo
- GS<50 (Rate Rider over 2 Year)*
 - Distribution | 18.27% or \$10.94/mo
 - Distribution less Rate Riders | 1.07% or \$0.92/mo
 - Total Bill impact | 0.26% or \$0.98/mo
- Excludes LRAMVA, updated load forecast and cost allocation
- * = Recommended to rate mitigate for 2018 Rates

Estimated Bill Impacts

- GS>50 (Rate Rider over 1 Year)
 - Distribution | 15.27% or \$59.26/mo
 - Distribution less Rate Riders | (28.47%) or \$(371.89)/mo
 - Total Bill impact | (3.79%) or \$(422.54)/mo
 - GS>50 (Rate Rider over 2 Year)*
 - Distribution | 15.27% or \$59.26/mo
 - Distribution less Rate Riders | (23.92%) or \$(312.40)/mo
 - Total Bill impact | (3.19%) or \$(355.31)/mo
- Excludes LRAMVA, updated load forecast and cost allocation
 - * = Recommended to rate mitigate for 2018 Rates

Estimated Bill Impacts

- Unmetered Scattered Load (Rate Rider over 1 Year)
 - Distribution | 18.11% or \$4.79/mo
 - Distribution less Rate Riders | 2.47% or \$0.88/mo
 - Total Bill impact | 0.67% or \$0.97/mo
 - Unmetered Scattered Load (Rate Rider over 2 Year)*
 - Distribution | 18.11% or \$4.79/mo
 - Distribution less Rate Riders | 4.31% or \$1.53/mo
 - Total Bill impact | 1.18% or \$1.71/mo
- Excludes LRAMVA, updated load forecast and cost allocation
 - * = Recommended to rate mitigate for 2018 Rates

Estimated Bill Impacts

- Streetlighting (Rate Rider over 1 Year)
 - Distribution | 18.13% or \$1.55/mo
 - Distribution less Rate Riders | 12.00% or \$1.14/mo
 - Total Bill impact | 5.93% or \$1.28/mo

- Streetlighting (Rate Rider over 2 Year)*
 - Distribution | 18.13% or \$1.55/mo
 - Distribution less Rate Riders | 12.74% or \$1.21/mo
 - Total Bill impact | 6.29% or \$1.36/mo

- Excludes LRAMVA, updated load forecast and cost allocation
- * = Recommended to rate mitigate for 2018 Rates

Challenges

- Geography
 - Non-contiguous service territory 170km apart
- Customer Base
 - Smaller, non-growing customer base
 - Smaller industry base
 - Estimated 86% Residential, 14% Commercial
- Cost of Power
 - Cost has risen significantly since last rebasing and have under-earned on Rate Base as a result

- NOW Inc. has been under earning since the last cost of service
- Costs of Power has increased significantly which reduced Achieved ROE
- NOW has reduced costs since the last COS and is in the most efficient quartile of utilities (Ranked #3 in Ontario)
- By returning to a sustainable profitability, NOW MAY avoid the next Cost of Service if Inflation rate can sustain operations

What will Result

- Having rates rebased and revenue restored to updated Rate Regulated level will allow for
 - Maintained high quality customer service
 - Continued customer engagement and focus
 - Continuation on Capital and Operational plans
 - Maintained reliability of distribution system
 - Shareholder contributions

1-SEC-2

- a) [Ex.1] Please provide a copy of all documents provided to the Applicant's Board of Directors for the purposes of approving the application and the underlying budget.

Response:

- a) The application was presented to the NOW Inc. Board at its regular meeting of June 23, 2016, wherein it passed Resolution 2016-27 "*That the Board approve the Cost of Service Application in principle as presented which has identified estimated bill impacts and any subsequent minor (non-material) changes that may hereby result.*"

The "NOW Inc. Cost of Service" presentation was made via Powerpoint, a copy of which is provided in response to 1-SEC-1.

1-SEC-3

- a) [Ex.1] Please provide copies of all benchmarking studies, reports, and analysis that the Applicant has undertaken or participated in since 2013, and are not already included in the application.

Response:

- a) Northern Ontario Wires participated in the annual MEARIE management salary surveys and copies are provided as follows:

Attachment 1: 2014 MEARIE Management Salary Survey

Attachment 2: 2015 MEARIE Management Salary Survey

Attachment 3: 2016 MEARIE Management Salary Survey

Other than the above and the Reporting and Recordkeeping Requirements that support the annual OEB Yearbook of Electricity Distributors, Northern Ontario Wires has not participated in any other benchmarking studies, reports or analysis.



The MEARIE Group

2014 Management Salary Survey Of Local Distribution Companies

SURVEY REPORT

August 2014

SURVEY ADMINISTRATOR: HAY GROUP LIMITED

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1. Introduction

The MEARIE Group is pleased to present this report of the 2014 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, LDCs are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. The MEARIE Group established the Management Salary Survey of Ontario's Local Distribution Companies to assist LDCs in understanding the competitive landscape and to support your efforts to develop pay practices that attract, motivate and retain high quality, high performing employees.

The survey was updated in 2012 through the combined efforts of The MEARIE Group's *HR Information Solutions* team, outside consultants and representatives of our members, all working together to ensure that the Survey continues to meet the evolving needs of member LDCs.

The Survey was further enhanced in 2013 & 2014 through our partnership with Hay Group, a globally renowned compensation consulting firm. Drawing on their expertise and experience in developing and managing salary surveys across all sectors of the economy and in numerous countries around the world.

The 2014 survey includes:

- Geographic, Number of Employees, Number of Customer and Revenue size reporting.
- Fifty (50) benchmark descriptions, supported by the Hay Group job evaluation methodology for improved reporting and greater ability to identify the impact of organization size and structure.
- Continued reporting of "total cash compensation" to provide greater depth of information regarding market pay practices.
- An overview of local distribution company market trends and compensation projections for 2015 budget planning.
- MS Excel survey reporting including versions of position salary tables by All Organizations, Geography, Revenue and Customers to support those organizations that wish to conduct further analysis of the results and to assist in transferring survey results into internal reporting.

The survey includes two presentation documents and Excel data tables in formats as follows:

- PDF Documents:
 - Survey Report Executive Summary containing a complete analysis and a data summary of all the positions.
 - Survey Report addendum which includes a complete analysis of each position, presented on one page.
- Excel Documents which are provided for easy data export and printable to one legal sized page, showing LDC Survey data by:
 - All Organizations
 - Region
 - Customer Base
 - Revenue
 - Number of Employees

We would like to thank you for your participation. As a result of the strong response, we are able to provide you with an informative and detailed survey that will help you in the support of your organization's compensation programs.

CONFIDENTIALITY POLICY

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey (a “Survey”), as well as Hay Group Limited (Hay Group) (survey administrators) and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission for a Survey. This will result in the LDC’s data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the Survey to determine the relevance of Survey data cuts (e.g., by geography or size).

All of the information obtained through a Survey will be treated with the utmost confidentiality. Data will be reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither Hay Group nor MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the Survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the Survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of a Survey will not be disclosed/sold to or shared with organizations that have not participated in that Survey, whether by The MEARIE Group or Hay Group or Survey participants. **Participants may not share the Survey reports/results with non-participant LDCs or any entity under any circumstances.**

The data collected for a Survey will also be included in the Hay Group's Canadian compensation database. Information in the Hay Group database is maintained with the highest standards of confidentiality; analysis and reporting of data is on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified or attributed. As of January 2014, there are over 550 employers represented in the Hay Group database. Should you have any questions or for further information, please contact Deirdre Chong Smith, Consultant at Hay Group at 416-815-6344 or Deirdre.Chong@haygroup.com.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law and LDCs may disclose the results of the Survey to any regulatory body (or other person) if compelled by law to do so. If an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required.

The MEARIE Group will not be liable for breaches by participating LDCs or Hay Group of this Confidentiality Policy.

2. Survey Overview

Survey Benchmark Positions

The survey covers 50 benchmark positions representing a cross-section of the functions within member organizations. The benchmark positions were reviewed in 2012 by a working group of LDC sector Human Resources professionals. Job profiles for each benchmark job were developed and reviewed by the consultants and the HR group.

Senior Management	0000	President & CEO
	0001	Chief Operating Officer (COO)
	0002	Head of Operations and/or Engineering
	0003	CFO / Head of Finance
	0004	Head of Customer Service
	0005	Head of Regulatory Affairs
Administration	0006	Head of Human Resources
	1000	Executive Assistant
Engineering	1001	Administrative Assistant
	2000	Director Engineering
	2001	Engineering Manager and/or Distribution Engineer
	2002	Project Engineer
Operations	2003	Supervisor Engineering
	2500	Director Operations
	2501	Manager Operations
	2502	Manager Control Centre
	2503	Supervisor Control Centre
	2504	Supervisor Protection and Control
	2505	Supervisor Station Maintenance
	2506	Line Supervisor
	2507	Manager Meter Department
	2508	Supervisor Meter Department

Supply Chain / Procurement	3000	Director Supply Chain Management
	3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet
	3002	Supervisor Stores / Inventory / Warehouse
Accounting / Finance	4000	Controller or Director Finance
	4001	Manager Accounting
	4002	Manager Risk Management
	4003	Supervisor Accounting
	4004	Financial or Business Analyst
	4005	Accountant
Customer Service	5000	Director Customer Service
	5001	Manager Customer Service and/or Billing
	5002	Supervisor Customer Service and/or Billing and/or Collections
Communications	5500	Director Communications
	5501	Manager Communications
Regulatory Affairs	6000	Director Regulatory Affairs
	6001	Manager Regulatory Affairs
	6002	Regulatory Accountant
Conservation / Demand	7000	Settlement or Rate Analyst
	7001	Director or Officer, Conservation and Demand Management
	7002	Manager Conservation & Demand / Marketing
Information Systems	8000	Director Information Systems
	8001	Manager Information Systems and/or Security
	8002	Systems / Program Administrator or Applications / Systems Support Professional
Human Resources	9000	Human Resources Manager
	9001	Human Resources Generalist
	9002	Human Resources Coordinator
	9003	Payroll
	9004	Manager, Health & Safety

Participants

All organizations in the LDC sector in Ontario were invited to participate in the survey. The following forty-five (45) organizations submitted data:

- Bluewater Power Distribution Corporation
- Brantford Power Inc.
- Cambridge and North Dumfries Hydro Inc.
- Collus PowerStream Corp.
- E.L.K. Energy Inc.
- Enersource Corporation
- Entegrus Inc.
- Essex Power
- Festival Hydro Inc.
- Fort Frances Power Corporation
- Greater Sudbury Utilities
- Grimsby Power Incorporated
- Guelph Hydro Electric Systems Inc.
- Haldimand County Hydro Inc.
- Halton Hills Hydro Inc.
- Horizon Utilities Corporation
- Hydro Ottawa Limited
- Innisfil Hydro Distribution Systems Limited
- Kenora Hydro Electric Corporation Ltd.
- Kitchener-Wilmot Hydro Inc.
- Lakeland Holding Ltd.
- London Hydro Inc.
- Midland Power Utility Corporation
- Milton Hydro Distribution Inc.
- Niagara Peninsula Energy Inc.
- North Bay Hydro Distribution Limited
- Northern Ontario Wires Inc.
- Oakville Hydro
- Orangeville Hydro Limited
- Orillia Power Distribution Corporation
- Oshawa PUC Networks, Inc.
- Ottawa River Power Corporation
- Peterborough Utilities Group
- PowerStream Inc.
- PUC Services Inc.
- Renfrew Hydro Inc.
- Sioux Lookout Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Utilities Kingston / Kingston Hydro
- Veridian Connections Inc.
- Wasaga Resource Services
- Waterloo North Hydro Inc.
- Welland Hydro-Electric System Corp.
- Westario Power Inc.
- Woodstock Hydro Services Inc.

Participant Group Profile

All participants provided information regarding their organizational profile. The statistical references for the profile of the organizations are as follows:

Note that the figures reported below are as provided by the participating organizations. Hay Group and MEARIE Group have not independently verified or confirmed the values, especially with regard to whether the values reflect only the LDC business or include other business ventures.

Statistic	P25	P50	P75	Average *
Annual Operating Budget (\$ millions, less the cost of power)	4.5	10.9	18.0	17.9
Annual Operating Budget (\$ millions, including the cost of power)	30.9	61.7	143.3	148.8
Number of Employees (full time equivalent)	33	51	128	111
Number of Customers	12,800	31,485	52,607	56,887
Gross Revenue (\$ millions, less the cost of power)	5.7	14.6	33.2	32.8
Gross Revenue (\$ millions, including the cost of power)	28.4	69.0	173.7	165.0

*Analyst's note: "average" values are near or above the 75th percentile for several data elements, indicating that there are a small number of organizations that are significantly larger than the rest of the population.

The majority of organizations noted that the fiscal year ends December 31st.

3. Salary Administration

Salary Range Adjustments – 2014 & 2015

The most common month for adjusting salary ranges is January (over 75% of reporting organizations).

Survey participants report adjusting their salary ranges in 2014 by an overall average of 2.6%.

Survey participants report planning to adjust salary ranges in 2015 by an overall average of 2.3%.

The salary range adjustments by employee level and overall are noted in the table below:

Year	CEO (n=25)	Executive (n=24)	Director (n=19)	Management (n=28)	Professional / Technical (n=25)	Admin. (n=25)	Overall (n=31)
2014	2.7	2.6	2.4	2.5	2.6	2.4	2.6
2015	2.3	2.3	2.3	2.3	2.2	2.3	2.3

Base Salary Increases – 2014 & 2015

The most common timing for adjusting salaries is January (over 75% of reporting organizations grant annual salary increases in that month).

Survey participants report adjusting actual salaries in 2014 by an overall average of 2.7%.

For 2015, survey participants reported projected average salary increases of 2.4%.

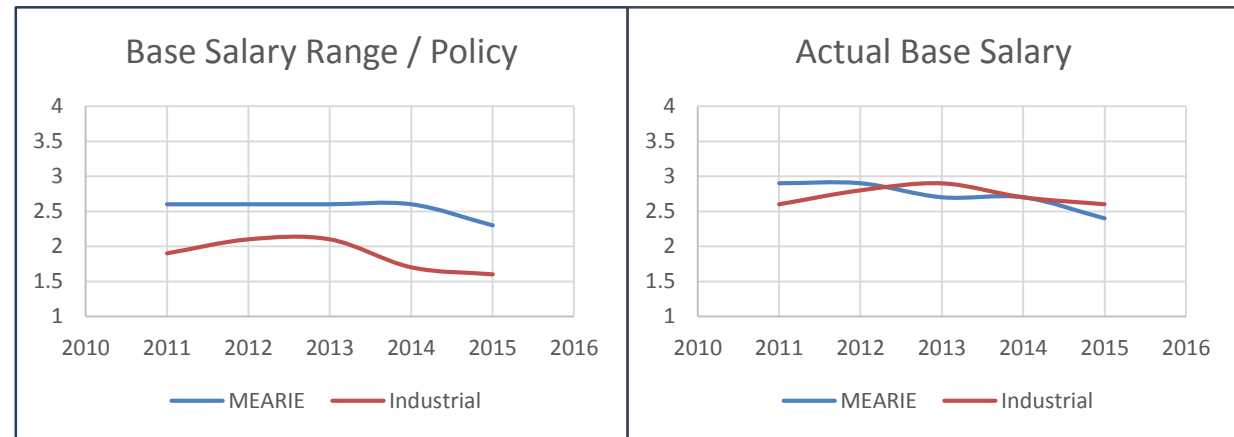
The base salary adjustments by employee level are noted in the table below.

Year	CEO (n=32)	Executive (n=27)	Director (n=22)	Management (n=39)	Professional / Technical (n=29)	Admin. (n=30)	Overall (n=40)
2014	2.8	2.6	2.6	2.6	2.7	2.5	2.7
2015	2.7	2.3	2.4	2.3	2.2	2.2	2.4

Salary Trends

Hay Group compiles an annual compensation forecast survey across Canada, with over 400 participants annually.

The graph below depicts how the overall Canadian all industrial organization market has tracked from a range and actual salary perspective versus The MEARIE Group Management Salary Survey trend information over the past 5 years.



Generally, local distribution companies track very close to the all industrial market for actual salary adjustments; generally within 0.2%.

Surprisingly, local distribution companies track above that of the all industrial market for salary range adjustments. This indicates that the majority of salary budgets within the distribution companies may be allocated to range movements, as the differential between range and actual forecasts is typically 0.1%.

The differential in all industrial organizations is 0.7 %– 1.0% generally, which indicates that the all industrial organization may be allocating greater proportions of salary budgets to differentiation by merit, and enabling high performers to perhaps be paid above job rate and/or moving people through the range faster).

Incentive Programs

A majority of organizations (26 of 45 or 68%) indicated that they offer short term incentive pay opportunities to at least some portion of their employees.

Twenty-one (21) of the twenty-six (26) organizations who offer short term incentive pay provided information about their incentive plans.

- a. Employee participation in short term incentive (STI) plans:
 - Eight (8) of the organizations indicated that all employee groups participated in STI.
 - The data indicates that five (5) organizations have STI plans for designated senior management and/or executives that do not extend to non-management staff.
- b. Weighting of performance factors (corporate versus individual versus team/department performance) in the determination of individual bonus payments:
 - The average plan mix, by employee level, is provided in the table below. Totals may not equal 100% due to rounding.
 - Typical plan mix is a combination of corporate and individual metrics with a heavier weighting on corporate for senior management and/or executives and a heavier weighting on individual metrics for non-management staff.

Performance Factor	CEO	Executive	Director	Management	Professional / Technical	Admin.
Corporate	61.3 %	50.3 %	43.4 %	33.1 %	42.9 %	38.8 %
Team / Department	1.0%	5.3 %	4.4 %	9.8 %	0.0 %	0.0 %
Individual	37.7 %	44.3 %	52.2 %	58.8 %	57.1 %	61.2 %

Incentive Programs
(continued)

Threshold Bonus Payouts

Formulaic or “target based” bonus programs typically do not pay out until a minimum level of performance (corporate, team and/or individual) has been achieved (i.e., if the threshold performance is not achieved, there is no pay out). Once this threshold performance has been achieved, incentive plans will pay out a minimum level of bonus; pay out levels typically then increase as performance / results increase, up to a “target” bonus rate when performance goals have been “met”.

Twelve (12) of the 27 organizations with incentive plans reported that they define minimum levels of performance required before any bonuses are generated. The typical bonus rate at the threshold performance is set at 50% of “target” bonus.

Maximum Bonus

Bonus programs are often designed such that there is a maximum level of payout. For example: if a position has a 10% bonus and the maximum payout is 200%, or 2x, then the maximum amount the employee can achieve regardless of performance (i.e., how much targets are exceeded by), is 20% of their current base salary.

The average maximum bonus is provided by employee level in the table below, though the typical bonus pay maximum is 100% of target.

Maximum Bonus Payout %	CEO (n = 18)	Executive (n = 15)	Director (n = 12)	Management (n = 16)	Professional / Technical (n = 12)	Admin. (n = 12)
Average	123 %	129 %	127 %	123 %	134 %	138 %

In the broader market, it is more common to find higher maximum bonus levels (as a % of target) at higher levels of the organization, to reflect the greater influence on organizational performance that more senior roles are perceived to have.

**Special (Project)
Bonuses**

Organizations were asked if they provide any project bonuses for participation in key / special projects, paid on successful achievement of specific milestones and/or on completion of the project, separate and distinct from annual incentive plans.

Three (3) organizations reported providing such bonuses, but only one provided a value and as such there is insufficient data to provide the average value.

4. Benefit Policies

Car Benefit

The majority of organizations (33 of 45 or 73%) provide a car benefit to some level of employee.

The tables below summarize the value of car benefits, by position, where provided. An asterisk (*) indicates insufficient data to report:

		Company Owned Car (Value)	Monthly Lease Payment	Car Allowance
CEO	P75	*	*	925
	P50	42,500	*	750
	P25	*	*	586
	Average	41,375	*	793
	Number	4	2	24
Executive / VP	P75	*	*	675
	P50	*	*	505
	P25	*	*	338
	Average	39,983	*	546
	Number	3	2	12
Sr. Management / Director	P75	*	*	500
	P50	*	*	375
	P25	*	*	238
	Average	*	*	361
	Number	2	0	8

Four (4) organizations reported providing a car benefit to specified positions below Senior Management. Specifically, three (3) organizations provide use of a company-owned vehicle and one (1) provide an allowance where the incumbent is required to be available for off-hours call-in, such as operations supervisors, line superintendents, engineers and meter supervisors.

Mileage

The market statistics for mileage rates provided to employees as reimbursement for personal vehicle use are detailed in the table below.

N = 45	Mileage Reimbursement (¢ per km)
P75	54
P50	52
P25	48
Average	51

The most frequently reported mileage rate (12 organizations) is 54 cents per kilometer; the next most frequent reported rates are 55, 52, 51, 48, and 47 cents per kilometer (4 organizations each).

Perquisites

Club Memberships – Fitness

Twenty (20) organizations reported providing a subsidy for fitness club fees or provide a fitness facility on site. The typical policy is to provide a reimbursement of a fixed percentage (either 50 or 100%) up to a maximum amount per year. For eighteen (18) organizations, the same policy and maximum reimbursement applies regardless of job level; for one (1) organization, executives participate in a Discretionary Spending Plan that includes fitness, and so are not included in the reporting. One (1) organization provides access to an on-site fitness facility.

	Maximum Reimbursement per year
P75	\$ 275
P50	\$ 200
P25	\$ 150
Average	\$ 215

Club Memberships – Social

None of the organizations reported having a separate policy / program for reimbursement of social club fees.

**Perquisites
(cont'd)**

Health Spending Account

Ten (10) organizations reported providing a Health Spending Account (i.e. discretionary spending within a defined range of services / benefits).

Of the ten organizations, one (1) provides this perquisite to senior officers only while nine (9) provide an HSA at all levels. Of those nine, six (6) provide the same funding for all jobs levels while three (3) differentiate by job level.

	CEO	Executive	Director	Management	Professional / Technical
P75	1,075	1,075	1000	750	750
P50	875	875	750	500	500
P25	438	413	350	300	300
Average	1,220	1,210	639	578	575
Number	10	10	9	9	9

2nd Opinion Medical Advice

Only three (3) organizations in the survey reported having a separate policy / program for this benefit.

Personal Financial / Legal Counseling

Three (3) organizations reported that financial and legal counseling is available via their Employee Assistance Program, which is provided to all employees.

Executive Medical Plan

Five (5) organizations reported providing enhanced medical coverage for executive levels only. Four (4) organizations reported a maximum dollar value, with an average maximum value of \$1,134.

**Perquisites
(cont'd)**

Personal Computer / Cell Phone / Internet

Thirteen (13) organizations provided information regarding policies and practices related to computers and internet.

The most common policies/practices are:

- Low / no interest rate loans to purchase computer equipment for personal / home office use
- Provision of laptops for particular levels of employee, in addition to office desktop, to allow for mobile work (note: may be a perquisite if personal use of computer is allowed, but not a perquisite if for business use only)
- Reimbursement for cell phone and/or home internet connection for selected employees (either full reimbursement or 50% reimbursement were both provided in the market place)
- Cash allowance intended to coverage cell phone and/or internet service

The value of these benefits varies dramatically by level within organizations and between organizations; the data does not lend itself to reporting of the value of typical practices. Excluding monthly cell phone allowances, allowances / loans are provided up to a maximum of \$5,000 with an average value of \$1,000 - \$1,500.

Other Perquisites

Other programs / practices reported, by eight (8) organizations, include:

- Reimbursement of dues / fees for professional associations such as Engineers (P.Eng) and Accountants (CGA/CMA/CA)
- Provision of an Employee Assistance Program

Enhanced Life Insurance Coverage for Senior Officers

Organizations were asked if, for senior level jobs, there was additional, employer paid, life insurance coverage. For example, if the typical life insurance plan was 1.5x employee salary, was this enhanced to above 1.5x to some greater number such as 2x, or even 3x, for senior level jobs.

Eighteen (18) organizations provided information about their basic / standard life insurance coverage where the typical coverage is 2x annual salary (average coverage of 1.8x). Enhanced benefits are provided by seven (7) organizations, where senior roles receive coverage typically at 3x annual salary (average coverage of 2.4x).

**Vacation
Entitlement**

Organizations provided the number of years of service required by various levels of employee in order to be entitled to a certain number of weeks vacation.

The following table below details the range, average and typical (i.e., most common) number of years of service required per weeks of entitlement.

Several organizations noted that for executive level jobs, vacations are typically negotiated versus following a schedule for entitlement.

	2 weeks	3 weeks	4 weeks	5 weeks	6 weeks +
CEO					
Range	N/A	Start – 6	Start – 11	Start – 18	Start – 27
Average	Start	2.3	6.1	12.7	20.5
Typical	Start	3	9	15	25
Executive / VP Level					
Range	N/A	Start – 6	Start – 11	3 – 18	15 – 27
Average	Start	2.4	5.7	14.1	22.6
Typical	Start	3	Start	16	25
Director Level					
Range	N/A	Start – 6	Start – 11	3 – 18	6 – 27
Average	Start	2.1	6.3	14.1	22.1
Typical	Start	Start	9	16	25
Manager Level					
Range	N/A	Start – 6	Start – 11	3 – 18	6 – 27
Average	Start	1.9	7.0	14.2	22.3
Typical	Start	Start	9	15	25
Professional Level					
Range	N/A	Start – 6	Start – 11	5 – 18	15 – 28
Average	Start	2.3	7.4	14.6	23.1
Typical	Start	3	9	16	25

Unused Vacation

Organizations provided information about their policies and practices with regard to vacation time that was not fully utilized in the year in which it was earned.

Policy Regarding Carry Over	Number	%
Unused vacation entitlement at year end is paid out (vacation pay adjustment) – no carry over.	4	9%
Any/All unused vacation entitlement may be carried-over with no restrictions.	7	16%
Unused vacation entitlement may be carried over, subject to maximum total accumulated balance.	11	24%
A maximum amount of unused vacation may be carried over.	21	47%
No unused vacation may be carried over	2	4%
Total	45	100%

Maximum Number of Days to Carry Over (n=25)	Number of Days
Range	5 - 15
Average	8
Typical	5

Time Limit for Utilizing Carried-Over Vacation Time	Number
No limit	10
One Year	14
Six Months	13
Total	37

Note:

Some organizations reported variations to the above policies such as:

- Six (6) of the thirty-two (32) organizations who have a maximum amount of days that can be carried over specified it as either one year entitlement or a portion of the years entitlement. One (1) organization did provided the maximum amount of days that can be carried over.
- Differences by job level, such as more senior officers may carry over a greater number of days
- Differences by vacation eligibility, such as carrying over 10 days if eligible for up to 3 weeks' vacation but 20 days if eligible for 4 weeks' vacation
- Exception policies where workload or special projects caused the employee to be unable to fully utilize vacation time, or where carry forward beyond standard policy is regularly allowed but must be approved by senior management
- Cash out policies where some vacation time may be paid out instead of being carried over

**Educational
Assistance /
Reimbursement**

Twenty-five participating organizations (25) provided details with regards to education assistance / reimbursement policies ranging from eligibility criteria to pay back provisions. There are a wide variety of types of programs and reimbursement rates. Key highlights are provided below:

- Nineteen (19) organizations stated that there is a policy for education assistance / reimbursement; though typically there are limiters such as (1) education or training courses must be job related and (2) are subject to managerial approval
- Six (6) organizations stated that there is no formal policy, however, approval for educational assistance or reimbursement happens regularly and is on a case by case basis.
- Seven (7) organizations provided an annual reimbursement maximum, the average is \$5,000 and the median is \$2,000.
- Four (4) organizations provided a lifetime reimbursement maximum, the average is \$21,400 and the median is \$22,500.
- Payback provisions were provided by sixteen (16) organizations. The average time to not trigger any pay back provision is 2.4 years, the median is 2.0 years. The range of time is generally between 1 - 5 years and four (4) organizations noted they have some form of partial payment plan for leaving within a designated time period after completion of education. For example, if 4 years for no repayment, if the employee leaves in 2 years, they will be asked for 50% pay back.

5. Benchmark Position Survey Results

Survey Results

This section reports the information collected in aggregate values for each benchmark position. The values reported in this table reflect “All Ontario” data in that the data for all organizations matching to the position are included (regardless of size and geographic location).

Additional summaries, on a job by job basis, are provided in the accompanying “Addendum”.

Detailed analysis, with expanded statistical data (i.e., including P25 and P75 data points) as well as analysis of survey results by geographic region, by customer base and by revenue, are reported in Excel files accompanying this report.

ALL ORGANIZATIONS

Code	Survey Job Title	JOB MATCHES			COMPENSATION DESIGN						ACTUAL COMPENSATION				
		Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
0000	President & CEO	39	39	1292	148,200	183,500	202,500	20%	194,100	226,000	183,600	187,000	22%	189,400	222,200
0001	Chief Operating Officer (COO)	11	11	994	126,000	162,500	162,500	10%	170,600	191,200	162,500	162,200	19%	170,600	197,800
0002	Head of Operations/Engineering	29	38	904	112,600	131,800	145,200	15%	135,000	148,900	133,700	135,800	14%	144,400	150,900
0003	CFO / Head of Finance	38	38	830	111,000	134,500	143,600	15%	140,600	159,000	138,200	143,600	14%	142,500	162,700
0004	Head of Customer Service	15	15	805	106,900	137,000	144,400	20%	144,200	151,300	141,300	137,100	19%	144,400	151,300
0005	Head of Regulatory Affairs	8	8	864	121,700	149,300	165,300	19%	174,700	170,000	151,400	153,000	17%	178,800	180,200
0006	Head of Human Resources	17	17	677	105,300	125,700	128,800	15%	142,100	147,200	124,500	131,100	14%	140,400	146,500
1000	Executive Assistant	30	48	245	57,400	68,700	76,900	5%	70,400	71,100	70,800	70,800	5%	71,800	72,900
1001	Administrative Assistant	15	30	198	50,400	59,700	64,300	5%	59,700	61,900	63,300	61,500	5%	63,800	62,900
2000	Director Engineering	14	15	744	103,400	126,200	127,100	13%	134,400	138,400	126,100	126,700	10%	131,000	138,000
2001	Engineering Manager	27	39	588	88,900	105,400	114,000	7%	107,900	111,500	105,900	105,700	5%	108,800	110,100
2002	Project Engineer	15	33	432	77,000	96,000	105,900	8%	99,000	96,100	93,600	92,500	8%	98,500	95,700
2003	Supervisor Engineering	19	30	432	82,600	94,400	103,300	5%	96,500	98,000	96,300	93,600	5%	100,700	97,100
2500	Director Operations	9	10	732	107,800	133,400	137,100	15%	146,900	142,200	128,000	132,800	15%	145,600	146,600
2501	Manager Operations	27	42	516	91,000	106,400	114,200	7%	109,200	112,300	104,400	105,500	7%	107,800	111,100
2502	Manager Control Centre	6	6	524	92,800	113,500	119,200	10%	123,100	123,200	116,400	116,000	10%	129,100	127,600
2503	Supervisor Control Centre	12	13	448	81,800	96,100	105,600	6%	98,400	101,300	97,900	100,400	7%	102,200	103,900
2504	Supervisor Protection and Control	5	5	466	92,100	95,700	107,900	*	100,400	108,700	98,800	103,800	*	98,800	110,600
2505	Supervisor Station Maintenance	9	13	466	80,500	97,300	108,700	8%	103,200	105,100	97,900	101,700	8%	100,000	106,700
2506	Line Supervisor	32	120	366	79,300	94,600	99,800	5%	96,900	96,500	96,800	96,400	5%	99,800	99,100
2507	Manager Meter Department	14	14	551	93,000	115,000	116,700	8%	121,900	117,600	107,200	106,800	7%	116,300	114,200
2508	Supervisor Meter Department	13	17	406	81,800	96,000	105,900	8%	99,800	98,700	97,100	97,200	5%	100,700	100,300

Minimum data requirements for information disclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

ALL ORGANIZATIONS

		JOB MATCHES			COMPENSATION DESIGN						ACTUAL COMPENSATION				
Code	Survey Job Title	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		Orgs	Incs						P50	AVG	P50	AVG		P50	AVG
3000	Director Supply Chain Management	3	3		*	*	*	*	*	144,800	*	136,800	*	*	158,700
3001	Manager Procurement/Inventory	17	19	451	82,200	94,700	106,900	8%	99,800	101,800	96,400	99,100	8%	102,200	104,600
3002	Supervisor Stores/Inventory	9	10	342	69,100	85,500	96,500	6%	85,500	89,100	85,900	86,400	6%	86,600	89,900
4000	Controller or Director Finance	17	27	588	92,200	108,200	113,600	10%	115,200	125,400	115,200	116,500	10%	121,000	125,500
4001	Manager Accounting	22	24	479	85,500	101,200	115,200	8%	107,800	109,500	92,600	98,600	6%	95,000	104,400
4002	Manager Risk Management	3	3		*	*	*	*	*	138,800	*	127,000	*	*	143,400
4003	Supervisor Accounting	10	16	363	71,500	88,600	94,800	5%	89,400	90,500	88,200	88,400	5%	91,500	91,300
4004	Financial or Business Analyst	14	25	342	71,400	85,100	90,700	5%	90,600	89,500	81,800	83,300	5%	84,700	86,700
4005	Accountant	11	20	332	63,900	77,800	86,400	4%	78,400	78,200	75,700	74,800	3%	75,800	76,000
5000	Director Customer Service	5	5	677	111,300	139,200	153,100	10%	160,000	145,300	140,100	135,000	14%	161,100	151,800
5001	Manager Customer Service	28	31	466	79,100	93,000	101,500	8%	93,000	94,900	93,400	91,800	6%	93,400	96,400
5002	Supervisor Customer Service	26	49	348	69,800	84,700	91,100	5%	87,300	86,200	81,400	82,300	4%	83,800	85,000
5500	Director Communications	8	8	677	102,200	131,500	153,400	15%	151,200	137,300	128,100	123,800	18%	150,400	141,700
5501	Manager Communications	11	11	393	73,800	87,000	98,300	8%	91,400	95,600	87,800	87,200	8%	94,700	92,600
6000	Director Regulatory Affairs	6	6	677	106,700	131,600	153,400	15%	151,300	152,100	140,900	140,700	16%	163,500	161,200
6001	Manager Regulatory Affairs	20	22	459	79,700	94,400	101,000	9%	96,800	97,900	94,700	94,800	6%	98,500	97,800
6002	Regulatory Accountant	15	18	342	65,400	81,200	96,500	7%	81,200	83,500	79,400	81,100	*	79,400	82,300
7000	Settlement or Rate Analyst	10	14	363	67,700	81,000	90,600	5%	85,600	88,600	85,500	82,900	7%	88,700	86,100
7001	Director or Officer, Conservation	7	7	805	106,100	131,600	149,000	18%	157,200	159,600	131,400	134,000	19%	141,100	150,000
7002	Manager Conservation & Demand	22	26	393	76,800	90,000	99,600	10%	91,100	94,500	89,200	90,100	8%	92,800	94,600
8000	Director Information Systems	15	15	830	106,800	129,300	139,700	15%	148,700	145,100	125,700	130,800	13%	138,300	146,600
8001	Manager Information Systems	16	27	488	84,300	97,100	104,200	8%	102,800	104,000	99,400	99,200	8%	100,300	106,600
8002	Systems/Program Administrator	21	34	332	67,100	80,600	87,700	5%	83,800	82,700	86,400	83,300	4%	90,400	85,800
9000	Human Resources Manager	8	10	479	88,400	104,700	104,700	8%	109,900	105,200	95,500	95,200	6%	106,500	101,200
9001	Human Resources Generalist	14	27	328	66,100	79,200	85,000	5%	80,000	84,100	77,600	77,800	6%	79,000	81,500
9002	Human Resources Coordinator	7	7	233	57,700	72,100	72,100	7%	75,700	73,900	66,600	68,100	8%	66,600	71,000
9003	Payroll	18	20	245	59,000	70,800	78,000	5%	72,500	74,400	71,600	72,600	4%	72,800	75,000
9004	Manager, Health & Safety	20	23	479	83,400	99,800	107,800	7%	101,000	105,400	103,400	100,500	6%	105,700	105,800

Minimum data requirements for information disclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

APPENDICES

A. Survey Methodology

A brief profile was developed for each benchmark position. These profiles were incorporated into a survey package and distributed to each participant along with a data submission spreadsheet requesting data on survey benchmark positions, as well as the organization's profile and selected salary administration & benefits policies.

Participants matched their jobs to the profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, the data were aggregated and an average figure was used for that organization. By using this methodology, all organizations carry equal weighting, and no one single organization excessively influences the market statistics by virtue of the size of its employee population.

Once the completed surveys were returned to Hay Group, participants were contacted for data verification as necessary. Hay Group also initiated a number of follow-up actions to clarify information provided by the participants. All of the matches submitted by the participants were reviewed by Hay Group to determine their appropriateness versus the job profiles and the market. If deemed inappropriate, the matches, or outlier data, were removed from the survey results.

Where possible, organization charts or details regarding reporting relationships were provided to Hay Group to enable understanding of the roles. From the job match information, plus a review of organization charts and other contextual information provided, Hay Group has estimated at which Hay Reference Level each organizations' roles fall to facilitate point-based comparisons.

B. Definitions – Compensation Elements

Salary Range

Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	Typically the midpoint of the salary range, intended to reflect the salary the organization is prepared to pay for sustained competent performance by a fully trained / qualified incumbent.
Maximum	The highest point in the salary range (or step progression). Note: might be the same as "job rate".

Short Term Incentive

Short Term Incentive (STI) refers to any incentive arrangement designed to reward an individual for performance/results achieved over a performance cycle/period of up to one year.

Target	Target bonus is the level of award (either a % of salary or a fixed dollar amount) that an employee in this position would expect to receive if all corporate, team and individual performance goals are "met" (as planned). This rate/amount is often communicated to employees as part of the incentive/bonus plan design, e.g. "the target bonus for jobs in grade/band 6 is 8% of salary".
Discretionary	Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executive/board.

Current Salary

The amount paid for work performed on a regular, ongoing basis.
Does not include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments.

Actual STI (Paid)

Total of all STI awards paid to the incumbent(s) for performance/results over the latest completed fiscal year.
May be paid during the year or after year end. (Note: recorded and reported on an annual basis)

C. Definitions – Statistical Elements

Market data are reported using the following statistics:

	Definition	Reporting Requirement (# of Observations Necessary to Report)
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90 th percentile and 90% would fall below	11
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below	7
P50	50th percentile, also referred to as “median” If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below	4
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below	7
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below	11
Average	The arithmetic mean of all values, calculated by adding up all of the values and dividing by the number of observations	3

D. Benchmark Position Profiles

Job Title	Description
President & CEO	Directs the development of short and long term strategic plans, operational objectives, policies, budgets and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.
Chief Operating Officer (COO)	Highest ranking operations position. Reporting to the President/CEO, directs the operational elements of the organization, could include operations & engineering, customer services, metering and information technology. Develops the short and long term strategic plans, directs the development of operational objectives, policies, budgets for his/her areas of accountability. The position reports directly to the President/CEO.
Head of Operations and/or Engineering	Highest ranking operations/engineering position. Reporting to COO or President. Directs both the operations and engineering functions. Develops the short and long term strategic plans, formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Establishes clear controls, objectives and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.
CFO / Head of Finance	Highest ranking financially-oriented position within the company. Reporting to the President & CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.
Head of Customer Service	The highest-ranking customer service position in the utility. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the development, implementation and integration of all customer service related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies and procedures; manages and coordinates budgets.
Head of Regulatory Affairs	Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to President & CEO or a senior executive.
Head of Human Resources	The highest-ranking human resources position in the organization. Provides direction, support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors.

Administration

Executive Assistant	Performs advanced, diversified and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares and distributes minutes of meetings, including Board of Director minutes. Reports to the President & CEO and may provide support to other executives.
Administrative Assistant	Performs advanced, diversified and confidential administrative duties for executives and/or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. Reports to a senior executive or executive team.

Engineering

Director Engineering	Plans and directs the overall engineering activities and engineering staff of the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.
Engineering Manager and/or Distribution Engineer	Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications and designs, including the supervision, planning and scheduling of work within the division – Requires a P. Eng. <u>OR</u> Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction and maintenance of distribution systems. Consults with other department management on plant design, construction and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P. Eng.
Project Engineer	Non-supervisory position. Directs and coordinates activities related to utility engineering project work, such as smart grid systems, renewables, large utility projects, asset renewal, etc. Requires a P. Eng.
Supervisor Engineering	Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores and maintains the integrity of hard copy file records, digital formats and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to an engineering manager.

Operations

Director Operations	NOT the head of function. Plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.
Manager Operations	NOT the head of function. Supervises, co-ordinates, directs, schedules and controls the construction, maintenance and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role.
Manager Control Centre	Supervises, co-ordinates, directs, schedules and controls the control centre and technical staff. Provides leadership in the planning and coordination of the control centre relative to safety, reliability and control of the distribution system. Is responsible for budgets, and the direct operations of the control centre approving system outages, switching and maintenance requirements to maintain and improve system reliability.
Supervisor Control Centre	Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.
Supervisor Protection and Control	Responsible for the management of all Protection & Controls activities related to the installation, maintenance and commissioning of: Protective Relaying Schemes and Station Automation Systems; SCADA System, Visual Display System and Remote Terminal Units; Operations Ethernet and system-wide Area Communications Networks; Distribution Automation Systems, Sectionalizing Devices and Remote Supervisory Controlled Devices. Prepares and administers reports, budgets, Policies and Procedures, record keeping systems.
Supervisor Station Maintenance	Responsible for the planning, coordinating both maintenance and installation of substations, as well as ensuring reliability of the underground plant, through testing and troubleshooting. Supervises, coordinates and schedules the activities of Station Maintenance Electricians and Protection and Control Technicians, Reviews work assignments, daily logs, reports and orders. Co-ordinate crews and plan jobs, assigns work per shift, long-term work and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.
Line Supervisor	Coordinates and directs the lead journey person and/or crews in the construction and maintenance of distribution lines and equipment (overhead and/or underground). Works with lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications and managing construction.
Manager Meter Department	Supervises the overall operations of the Meter department, prepares budgets, directs the purchase and maintenance of equipment and technology related to the department. Provides direction on the supervision of meter staff, the assignment of work and productivity of staff. Supervises the work related to interactions with electronic meter programming and interaction with/or the operation of the MV90 or similar data collection systems.

Supervisor Meter Department	Responsible for overall operation of the Meter department, including operations, budgeting and supervision of meter technicians or other operations staff. Assigns, monitors and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.

Supply Chain / Procurement

Director Supply Chain Management	Responsible for the overall operation of the Procurement, Inventory, Fleet and/or Facilities programs and initiatives in the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Oversees the establishment of user service level agreements, and provides contract management expertise and acts as a resource for contract negotiation, review and approval. Directs the effective capital acquisition and maintenance of the corporate fleet and/or directs the effective maintenance and capital investment of the organizations facilities and assets.
Manager Procurement and/or Inventory and/or Facilities and/or Fleet	Responsible for all purchasing and/or inventory and/or facilities and/or fleet for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Is responsible for budgets, policies and procedures and directs the work of the purchasing or buyers and/or stores and/or facilities and/or fleet personnel. Works with the organization in setting partnership relationships to understand and meet the needs of the organization, its operations and risk associated with the effective and efficient operations of the company.
Supervisor Stores/Inventory/Warehouse	Supervises inventory control, records and stores operation. Orders material to maintain on-hand quantities with procurements approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists procurement department in the sale of obsolete equipment and material.

Accounting / Finance

Controller or Director Finance	NOT the head of function. Responsible for all financial reporting, accounting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends and increased profit opportunities. Reports to a CFO/VP Finance.
Manager Accounting	Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Reports to Controller/Director Finance or CFO/VP Finance.
Manager Risk Management	Responsible for risk management activities including cash flow management, credit facilities management, insurance and support for credit and collection policies throughout the corporation. May be responsible for ensuring that cash liquidity risk is managed in an appropriate fashion such that bank account balances are sufficient to meet operational, capital expenditures and debt servicing requirements while minimizing short-term borrowings or surplus investing. Provides leadership in the developing new and refining existing risk management policies to respond to changes in risk tolerances and business conditions and as financial risks are better understood in accordance with industry best practices. Reports to Head of Finance or COO or CEO.

Supervisor Accounting	Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.
Financial or Business Analyst	Conducts analysis of information for budgeting, investment and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; processes and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents. Holds a financial designation, either CA, CMA or CGA.
Accountant	Supports the organization decisions through financial information and relevant analysis. Ensures the integrity between the CS work order systems and general ledger system is maintained. Initiate corrective measures when discrepancies occur between the systems. Collects and combines information for the decision making process by management, including financial statements and special projects as assigned (e.g. preparation of rate submission supplemental information).

Customer Service

Director Customer Service	NOT the head of function. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the implementation and integration of all customer service related activities. Oversees the implementation of customer service standards, policies and procedures; manages budgets; manages activities of CS managers and/or supervisory staff.
Manager Customer Service and/or Billing	NOT the head of function. Manages a team of customer service and/or billing representatives in providing information, receiving and responding to customer inquiries, complaints or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls.
Supervisor Customer Service and/or Billing and/or Collections	Supervises customer service representatives (billing clerks and/or collections clerks) and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated workflow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.

Regulatory Affairs

Director Regulatory Affairs	NOT the head of function. Supports the VP or may represent the organization on regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for or supports the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Manager Regulatory Affairs	NOT the head of function. Manages the organization's regulatory staff, programs and activities to ensure compliance. Assists the organization on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Coordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).

Regulatory Accountant	Ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Act as a key resource to provide expert advice and recommendations in the implantation of all OEB, OPA and IESO codes and regulations in order to ensure corporate compliance. Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudence review (i.e. conservation, smart meters) and the cost side of Ontario Power Authority (OPA) programs.

Conservation / Demand

Settlement or Rate Analyst	Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models.
Director or Officer, Conservation and Demand Management	This position is responsible for planning, coordinating, evaluating and delivering energy and water conservation and demand management programs. Develops plans for programs in accordance with the OEB's conservation and demand management code to ensure achievement of OEB mandated energy consumption and demand conservation targets.
Manager Conservation & Demand/Marketing	Responsible for managing the development and implementation of CDM initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's Conservation and Demand Management (CDM) programs. Marketing communication plans may include, but are not limited to advertising, media conferences, program launch events, workshops, event displays. Liaising with, as needed, senior marketing and/or communications personnel representing organizations and groups involved in conservation and sustainability including, but not limited to, the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), Ministry of Energy, municipal and regional governments, etc.

Information Systems / Technology

Director Information Systems	Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of organization objectives and imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, security, programming and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets and resource requirements. Typically reports to President & CEO, or CFO.
Manager Information Systems and/or Security	Manages and directs staff in areas of computer operations, systems planning, design, security, programming and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets and resource requirements.
Systems/Program Administrator or Applications/Systems Support Professional	Responsible for maintenance of software systems including system analysis, programming and design, updates and changes. Makes a preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware.

Human Resources

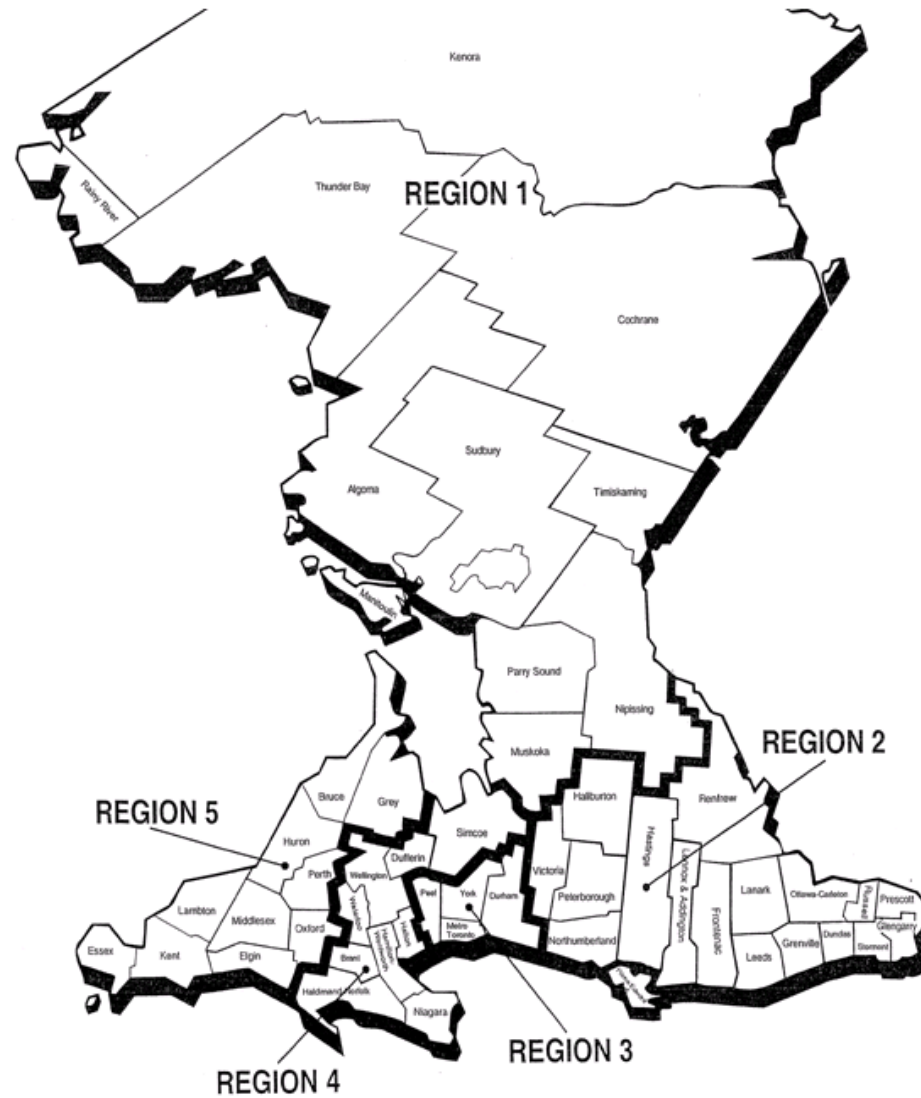
Human Resources Manager	NOT the head of function. Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. Reports to a senior HR professional (Director or VP or equivalent).
Human Resources Generalist	Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. Acts as a business partner to the organization in the areas of human capital. May assist in the preparation of negotiations.
Human Resources Coordinator	Administrative support to one or more functional areas of HR and/or Safety. Processes, coordinates and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications.
Payroll	Performs the payroll coordination and administration. Maintains the organizations internal or external payroll system. Prepares monthly requisitions for WSIB, Employee Health Tax, Receiver General, OMERS Pension and Union Dues. Administers employee pension program and provides pension calculation estimates as requested. Reconciles monthly payroll for year-end finance procedures. Prepares annual T4's and T4A's and OMERS Pension and responds to inquiries from employees and pensioners regarding the pension plan.
Manager, Health & Safety	Accountable for the development and implementation of occupational health, safety and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

Communications

Director Communications	Directs the development, management and execution of internal and external corporate communications strategies for the company, and marketing and public relations initiatives. Acts as the Chief Spokesperson for the organization. Leads the management and development of the corporate brand and identity. Oversees the development, production and distribution of corporate publications including, but not limited to, the annual report, customer newsletters, information brochures, bill inserts, CDM/Green marketing materials, employee newsletters and media releases. Directs the development and management of the company's external (corporate internet site) and internal (corporate intranet site) web presence and strategy. Oversees the management and execution of internal and external corporate events as well as community-relations activities such as sponsorship and donation programs.
Manager Communications	Responsible for managing the development and implementation of all customer communications initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's CDM and customer communications materials/systems. Communication materials may include, but are not limited to, customer newsletters, information brochures, bill form design, employee intranet, LCD information monitors, and website communications. Working in conjunction with Regulatory Affairs, develop materials or other communication methods to communicate regulatory changes/issues that may directly impact the customer. Manages event planning for internal and external company events.

E. Regions

The map below identifies the 5 regions that will be used for reporting on a geographic basis.





The MEARIE Group

2015 Management Salary Survey Of Local Distribution Companies

SURVEY REPORT

August 2015

SURVEY ADMINISTRATOR: HAY GROUP LIMITED

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1. Introduction

The MEARIE Group is pleased to present this report of the 2015 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, LDCs are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. The MEARIE Group established the Management Salary Survey of Ontario's Local Distribution Companies to assist LDCs in understanding the competitive landscape and to support your efforts to develop pay practices that attract, motivate and retain high quality, high performing employees.

The survey was updated in 2012 through the combined efforts of The MEARIE Group's *HR Information Solutions* team, outside consultants and representatives of our members, all working together to ensure that the Survey continues to meet the evolving needs of member LDCs.

The Survey was further enhanced from 2013 to 2014 through our partnership with Hay Group, a globally renowned compensation consulting firm. Hay Group drew upon their expertise and experience in developing and managing salary surveys across all sectors of the economy and in numerous countries around the world.

There are no substantial changes to the survey in 2015.

The 2015 survey includes:

- Geographic, Number of Employees, Number of Customer and Revenue size reporting.
- Fifty (50) benchmark descriptions, supported by the Hay Group job evaluation methodology for improved reporting and greater ability to identify the impact of organization size and structure.
- Continued reporting of "total cash compensation" to provide greater depth of information regarding market pay practices.
- An overview of local distribution company market trends and compensation projections for 2016 budget planning.
- MS Excel survey reporting including versions of position salary tables by All Organizations, Geography, Revenue and Customers to support those organizations that wish to conduct further analysis of the results and to assist in transferring survey results into internal reporting.

The survey includes two presentation documents and Excel data tables in formats as follows:

- PDF Documents:
 - Survey Report Executive Summary containing a complete analysis and a data summary of all the positions.
 - Survey Report addendum which includes a complete analysis of each position, presented on one page.
- Excel Documents which are provided for easy data export and printable to one legal sized page, showing LDC Survey data by:
 - All Organizations
 - Region
 - Customer Base
 - Revenue
 - Number of Employees

We would like to thank you for your participation. As a result of the strong response, we are able to provide you with an informative and detailed survey that will help you in the support of your organization's compensation programs.

CONFIDENTIALITY POLICY

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey (a “Survey”), as well as Hay Group Limited (Hay Group) (survey administrators) and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission for a Survey. This will result in the LDC’s data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the Survey to determine the relevance of Survey data cuts (e.g., by geography or size).

All of the information obtained through a Survey will be treated with the utmost confidentiality. Data will be reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither Hay Group nor MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the Survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the Survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of a Survey will not be disclosed/sold to or shared with organizations that have not participated in that Survey, whether by The MEARIE Group or Hay Group or Survey participants. **Participants may not share the Survey reports/results with non-participant LDCs or any entity under any circumstances.**

The data collected for a Survey will also be included in the Hay Group's Canadian compensation database. Information in the Hay Group database is maintained with the highest standards of confidentiality; analysis and reporting of data is on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified or attributed. As of Dec 2014, there are over 540 employers represented in the Hay Group database. Should you have any questions or for further information, please contact Paul Wong, Associate Consultant at Hay Group at 416-815-6353 or paul.wong@haygroup.com.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law and LDCs may disclose the results of the Survey to any regulatory body (or other person) if compelled by law to do so. If an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required.

The MEARIE Group will not be liable for breaches by participating LDCs or Hay Group of this Confidentiality Policy.

2. Survey Overview

Survey Benchmark Positions

The survey covers 50 benchmark positions representing a cross-section of the functions within member organizations. The benchmark positions were reviewed in 2012 by a working group of LDC sector Human Resources professionals. Job profiles for each benchmark job were developed and reviewed by the consultants and the HR group.

Senior Management	0000	President & CEO
	0001	Chief Operating Officer (COO)
	0002	Head of Operations and/or Engineering
	0003	CFO / Head of Finance
	0004	Head of Customer Service
	0005	Head of Regulatory Affairs
Administration	0006	Head of Human Resources
	1000	Executive Assistant
	1001	Administrative Assistant
Engineering	2000	Director Engineering
	2001	Engineering Manager and/or Distribution Engineer
	2002	Project Engineer
	2003	Supervisor Engineering
Operations	2500	Director Operations
	2501	Manager Operations
	2502	Manager Control Centre
	2503	Supervisor Control Centre
	2504	Supervisor Protection and Control
	2505	Supervisor Station Maintenance
	2506	Line Supervisor
	2507	Manager Meter Department
	2508	Supervisor Meter Department

Supply Chain / Procurement	3000	Director Supply Chain Management
	3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet
	3002	Supervisor Stores / Inventory / Warehouse
Accounting / Finance	4000	Controller or Director Finance
	4001	Manager Accounting
	4002	Manager Risk Management
	4003	Supervisor Accounting
	4004	Financial or Business Analyst
Customer Service	4005	Accountant
	5000	Director Customer Service
	5001	Manager Customer Service and/or Billing
	5002	Supervisor Customer Service and/or Billing and/or Collections
Communications	5500	Director Communications
	5501	Manager Communications
Regulatory Affairs	6000	Director Regulatory Affairs
	6001	Manager Regulatory Affairs
	6002	Regulatory Accountant
Conservation / Demand	7000	Settlement or Rate Analyst
	7001	Director or Officer, Conservation and Demand Management
	7002	Manager Conservation & Demand / Marketing
Information Systems	8000	Director Information Systems
	8001	Manager Information Systems and/or Security
	8002	Systems / Program Administrator or Applications / Systems Support Professional
Human Resources	9000	Human Resources Manager
	9001	Human Resources Generalist
	9002	Human Resources Coordinator
	9003	Payroll
	9004	Manager, Health & Safety

Participants

All organizations in the LDC sector in Ontario were invited to participate in the survey. The following thirty-seven (37) organizations submitted data:

- Bluewater Power Distribution Corp.
- Cambridge and North Dumfries Hydro Inc.
- Collus PowerStream Corp.
- E.L.K. Energy Inc.
- Entegrus Inc.
- Essex Power Corp.
- Festival Hydro Inc.
- Fort Frances Power Corp.
- Greater Sudbury Utilities Inc.
- Grimsby Power Inc.
- Guelph Hydro Electric Systems Inc.
- Halton Hills Hydro Inc.
- InnPower Corp.
- Kenora Hydro Electric Corporation Ltd.
- Kitchener-Wilmot Hydro Inc.
- Lakeland Power Distribution Ltd.
- London Hydro Inc.
- Midland Power Utility Corp.
- Milton Hydro Distribution Inc.
- North Bay Hydro Distribution Ltd.
- Northern Ontario Wires Inc.
- Niagara Peninsula Energy Inc.
- Oakville Hydro
- Orangeville Hydro Ltd.
- Orillia Power Distribution Corp.
- Oshawa PUC Networks, Inc.
- Ottawa River Power Corp.
- Peterborough Utilities Group
- PUC Services Inc.
- Renfrew Hydro Inc.
- Sioux Lookout Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Utilities Kingston
- Veridian Corp.
- Waterloo North Hydro Inc.
- Welland Hydro-Electric System Corp.
- Westario Power Inc.

Due to the changes in the participant mix, data values in the report can fluctuate from one year to another. Therefore, participants are reminded of these factors when comparing data of 2015 over 2014.

Participant Group Profile

All participants provided information regarding their organizational profile. The summary statistics of the participating organizations are detailed below. Please note that two new questions were included in 2015 to differentiate between regulated and unregulated revenue.

The figures reported below are assessed on an “as provided” basis. Hay Group and MEARIE Group have not independently or exhaustively verified the values presented below.

Statistic	P25	P50	P75	Average
Annual Operating Budget (\$ millions, less the cost of power)	4.7	8.8	15.6	14.2
Annual Operating Budget (\$ millions, including the cost of power)	26.5	62.8	136.2	95.7
Number of Employees (full time equivalent)	28	47	123	84
Number of Customers	11,776	23,000	52,171	36,953
Gross Revenue (\$ millions, less the cost of power)	5.0	14.6	28.4	20.0
Gross Revenue (\$ millions, including the cost of power)	26.7	67.0	129.7	96.7
Regulated Gross Revenue	90%	99%	100%	85%
Unregulated Gross Revenue	0%	1%	2%	6%

All organizations noted the fiscal year ends in December.

3. Salary Administration

Salary Range Adjustments – 2015 & 2016

The most common month for adjusting salary ranges is January (over 75% of reporting organizations).

Survey participants report adjusting their salary ranges in 2015 by an overall average of 2.6%.

Survey participants report planning to adjust salary ranges in 2016 by an overall average of 2.3%.

The salary range adjustments by employee level and overall are noted in the table below:

Year	CEO (n=19)	Executive (n=20)	Director (n=18)	Management (n=25)	Professional / Technical (n=22)	Admin. (n=21)	Overall (n=26)
2015	3.3	2.7	2.4	2.2	2.3	2.5	2.6
2016	2.2	2.1	2.4	2.1	2.1	2.3	2.3

Base Salary Increases – 2015 & 2016

The most common timing for adjusting salaries is January (over 75% of reporting organizations grant annual salary increases in that month).

Survey participants report adjusting actual salaries in 2015 by an overall average of 2.8%.

For 2016, survey participants reported projected average salary increases of 2.6%.

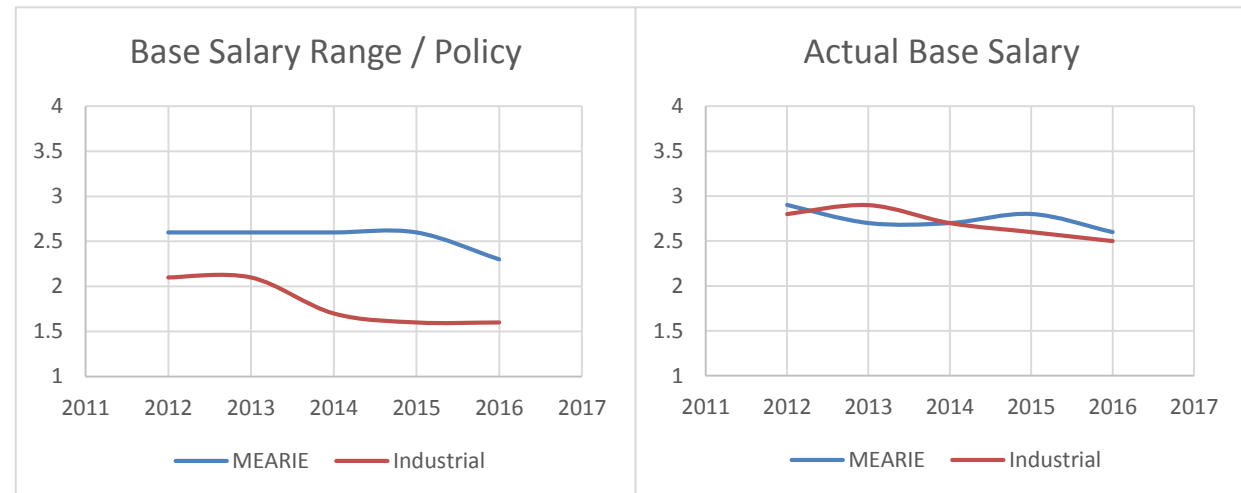
The base salary adjustments by employee level are noted in the table below.

Year	CEO (n=24)	Executive (n=18)	Director (n=11)	Management (n=27)	Professional / Technical (n=20)	Admin. (n=17)	Overall (n=29)
2015	3.4	2.7	2.3	2.7	2.4	2.2	2.8
2016	2.7	2.6	2.2	2.4	2.3	2.2	2.6

Salary Trends

Hay Group compiles an annual compensation forecast survey across Canada, with over 400 participants annually.

The graph below depicts how the overall Canadian all industrial organization market has tracked from a range and actual salary perspective versus The MEARIE Group Management Salary Survey trend information over the past 5 years.



Generally, local distribution companies track very close to the all industrial market for actual salary adjustments; generally within 0.2 percentage points. Surprisingly, local distribution companies track above the all industrial market for salary range adjustments by 0.5 - 1.0 percentage points.

The differential between actual base salary increases and salary range adjustments among local distribution companies is 0.1 - 0.3 percentage points. This same differential among all industrial organizations is 0.7 - 1.0 percentage points. This indicates that organizations may be allocating greater portions of salary budgets to differentiation by merit, and enabling high performers to perhaps be paid above job rate and/or moving people through the range faster.

Incentive Programs

A majority of organizations (22 of 37 or 59%) indicated that they offer short term incentive pay to at least some of their employees.

Sixteen (16) of the twenty-two (22) organizations who offer short term incentive pay provided information about their incentive plans.

- a. Employee participation in short term incentive (STI) plans:
 - Six (6) of the organizations indicated that all employee groups participated in STI.
 - Five (5) organizations have STI plans for designated senior management and/or executives that do not extend to non-management staff.
- b. Weighting of performance factors (corporate versus individual versus team/department performance) in the determination of individual bonus payments:
 - The average plan mix, by employee level, is provided in the table below.
 - Typical plan mix is a combination of corporate and individual metrics with a heavier weighting on corporate for senior management and/or executives and a heavier weighting on individual metrics for non-management staff.

Performance Factor	CEO	Executive	Director	Management	Professional / Technical	Admin.
Corporate	64.6 %	50.4%	49.6%	36.1%	37.0%	32.8%
Team / Department	2.7%	6.7%	2.7%	11.8%	0.0%	0.0 %
Individual	32.7%	42.9%	47.7%	52.1%	63.0%	67.2%

Incentive Programs
(continued)

Threshold Bonus Payouts

Formulaic or “target based” bonus programs typically do not pay out until a minimum level of performance (corporate, team and/or individual) has been achieved (i.e., if the threshold performance is not achieved, there is no pay out). Once this threshold performance has been achieved, incentive plans will pay out a minimum level of bonus; pay out levels typically then increase as performance / results increase, up to a “target” bonus rate when performance goals have been “met”.

Seven (7) of the twenty-two (22) organizations with incentive plans reported that they define minimum levels of performance required before any bonuses are generated. The typical bonus rate at the threshold performance is set at 50% of “target” bonus.

Maximum Bonus

Bonus programs are often designed such that there is a maximum level of payout. For example: if a position has a 10% bonus and the maximum payout is 200%, or 2x, then the maximum amount the employee can achieve regardless of performance (i.e., how much targets are exceeded by), is 20% of their current base salary.

The average maximum bonus is provided by employee level in the table below, though the typical bonus pay maximum is 150% of target.

Maximum Bonus Payout %	CEO (n = 11)	Executive (n = 9)	Director (n = 6)	Management (n = 10)	Professional / Technical (n = 6)	Admin. (n = 6)
Average	125%	124%	133%	119%	145%	142%

In the broader market, it is more common to find higher maximum bonus levels (as a % of target) at higher levels of the organization, to reflect the greater influence on organizational performance that more senior roles are perceived to have.

**Special (Project)
Bonuses**

Organizations were asked if they provide any project bonuses for participation in key / special projects, paid on successful achievement of specific milestones and/or on completion of the project, separate and distinct from annual incentive plans.

Three organizations reported providing such bonuses. There is insufficient data to provide the average value as no employee level has at least three data observations.

4. Benefit Policies

Car Benefit

The majority of organizations (29 of 37 or 78%) provide a car benefit to some level of employee.

The tables below summarize the value of car benefits, by position, where provided. An asterisk (*) indicates insufficient data to report:

		Company Owned Car (Value)	Monthly Lease Payment	Car Allowance (monthly)
CEO	P75	*	*	813
	P50	32,500	*	600
	P25	*	*	500
	Average	30,004	*	661
	Number	4	2	20
Executive / VP	P75	*	*	533
	P50	*	*	475
	P25	*	*	300
	Average	36,667	*	488
	Number	3	1	12
Sr. Management / Director	P75	*	*	528
	P50	*	*	450
	P25	*	*	300
	Average	*	*	407
	Number	2	0	7

Four (4) organizations reported providing a car benefit to specified positions below Senior Management. Specifically, two (2) organizations provide use of a company-owned vehicle and two (2) provide an allowance where the incumbent is required to be available for off-hours call-in, such as operations supervisors, line superintendents, engineers and meter supervisors.

Mileage

The market statistics for mileage rates provided to employees as reimbursement for personal vehicle use are detailed in the table below.

N = 35	Mileage Reimbursement (¢ per km)
P75	55
P50	53
P25	48
Average	51

The most frequently reported mileage rate (11 organizations) is 55 cents per kilometer; the next most frequent reported rates are 54 cents per kilometer (4 organizations).

Perquisites

Club Memberships – Fitness

Fifteen (15) organizations reported providing a subsidy for fitness club fees or provide a fitness facility on site. The typical policy is to provide a reimbursement of a fixed percentage (either 50 or 100%) up to a maximum amount per year. For eight (8) organizations, the same policy and maximum reimbursement applies regardless of job level. One (1) organization provides access to an on-site fitness facility.

	Maximum Reimbursement per year
P75	\$ 275
P50	\$ 200
P25	\$ 150
Average	\$ 215

Club Memberships – Social

None of the organizations reported having a separate policy / program for reimbursement of social club fees.

**Perquisites
(cont'd)**

Health Spending Account

Nine (9) organizations reported providing a Health Spending Account (i.e. discretionary spending within a defined range of services / benefits).

Of the nine organizations, eight (8) provide the same funding for all jobs levels while one (1) differentiates by job level.

	CEO	Executive	Director	Management	Professional / Technical
P75	1,000	625	*	1,000	1,000
P50	500	475	450	500	450
P25	400	375	*	300	294
Average	617	556	592	589	597
Number	9	8	6	9	8

2nd Opinion Medical Advice

Three (3) organizations in the survey reported having a separate policy / program for this benefit.

Personal Financial / Legal Counseling

Three (3) organizations reported that financial and legal counseling is available via their Employee Assistance Program, which is provided to all employees.

Executive Medical Plan

Four (4) organizations reported providing enhanced medical coverage for executive levels only. Three (3) organizations reported a maximum dollar value, with an average maximum value of \$1,336.

**Perquisites
(cont'd)**

Personal Computer / Cell Phone / Internet

Six (6) organizations provided information regarding policies and practices related to computers and internet.

The most common policies/practices are:

- Low / no interest rate loans to purchase computer equipment for personal / home office use.
- Provision of laptops for particular levels of employee, in addition to office desktop, to allow for mobile work (note: may be a perquisite if personal use of computer is allowed, but not a perquisite if for business use only).
- Reimbursement for cell phone and/or home internet connection for selected employees (either full reimbursement or 50% reimbursement were both provided in the market place).
- Cash allowance intended to cover cell phone and/or internet service.

The value of these benefits varies dramatically by level within organizations and between organizations; the data does not lend itself to reporting of the value of typical practices. Excluding monthly cell phone allowances, allowances / loans are provided at an average value of \$795.

Other Perquisites

Other programs / practices reported, by ten (10) organizations, include:

- Reimbursement of dues / fees for professional associations such as Engineers (P.Eng) and Accountants (CGA/CMA/CA).
- Provision of an Employee Assistance Program.

Enhanced Life Insurance Coverage for Senior Officers

Organizations were asked if, for senior level jobs, there was additional, employer paid, life insurance coverage. For example, if the typical life insurance plan was 1.5x employee salary, was this enhanced to above 1.5x to some greater number such as 2x, or even 3x, for senior level jobs.

Fourteen (14) organizations provided information about their basic / standard life insurance coverage where the typical coverage is 2x annual salary (average coverage of 1.8x). Enhanced benefits are provided by four (4) organizations, where senior roles receive coverage at an average of 2.25x annual salary.

**Vacation
Entitlement**

Organizations provided the number of years of service required by various levels of employee in order to be entitled to a certain number of weeks of vacation.

The following table below details the range, average and typical (i.e., most common) number of years of service required per weeks of entitlement.

Several organizations noted that for executive level jobs, vacations are typically negotiated versus following a schedule for entitlement.

	2 weeks	3 weeks	4 weeks	5 weeks	6 weeks +
CEO					
Range	Start – 1	Start – 6	Start – 15	Start – 19	5 – 27
Average	0.9	2.3	6.6	13.1	21.8
Typical	1	3	9	17	25
Executive / VP Level					
Range	1 – 2	Start – 4	Start – 10	Start – 19	15 – 27
Average	1.1	2	6.4	13.4	22.6
Typical	1	3	10	17	25
Director Level					
Range	Start – 3	Start – 7	Start – 5	Start – 19	15 – 27
Average	1.1	2.2	7	13.6	22
Typical	1	1	9	17	25
Manager Level					
Range	0– 4	Start – 4	Start – 10	8 – 20	15 – 27
Average	1.2	2.0	7.5	15.1	22.9
Typical	1	3	9	15	25
Professional Level					
Range	Start – 1	Start – 6	Start – 15	8 – 19	15 – 28
Average	0.9	2.3	8.1	15.4	23.6
Typical	1	3	9	17	25

Unused Vacation

Organizations provided information about their policies and practices with regard to vacation time that was not fully utilized in the year in which it was earned.

Policy Regarding Carry Over	Number	%
Unused vacation entitlement at year end is paid out (vacation pay adjustment) – no carry over.	4	11%
Any/All unused vacation entitlement may be carried-over with no restrictions.	3	8%
Unused vacation entitlement may be carried over, subject to maximum total accumulated balance.	13	35%
A maximum amount of unused vacation may be carried over.	13	35%
No unused vacation may be carried over	4	11%
Total	37	100%

Maximum Number of Days to Carry Over (n=21)	Number of Days
Range	5 - 15
Average	8
Typical	5

Time Limit for Utilizing Carried-Over Vacation Time	Number
No limit	8
One Year	8
Six Months or less	14
Total	30

Note:

Some organizations reported variations to the above policies such as:

- Six (6) of the twenty-six (26) organizations who have a maximum amount of days that can be carried over specified it as either one year entitlement or a portion of the years entitlement.
- Differences by job level exist where senior officers may carry over a greater number of days than non-senior officers.
- Differences by vacation eligibility, such as carrying over 10 days if eligible for up to 3 weeks' vacation but 20 days if eligible for 4 weeks' vacation.
- Exception policies where workload or special projects caused the employee to be unable to fully utilize vacation time, or where carry forward beyond standard policy is regularly allowed but must be approved by senior management.
- Cash out policies where some vacation time may be paid out instead of being carried over.

**Educational
Assistance /
Reimbursement**

Eighteen participating organizations (18) provided details with regards to education assistance / reimbursement policies ranging from eligibility criteria to pay back provisions. There are a wide variety of types of programs and reimbursement rates. Key highlights are provided below:

- Fourteen (14) organizations stated that there is a policy for education assistance / reimbursement; though typically there are limiters such as education or training courses which must be job related, and are subject to managerial approval.
- Four (4) organizations stated that there is no formal policy, however, approval for educational assistance or reimbursement happens regularly and is on a case by case basis.
- Three (3) organizations provided an annual reimbursement maximum, the average is \$1,625 and the median is \$1,500.
- Three (3) organizations provided a lifetime reimbursement maximum, the average is \$18,333 and the median is \$20,000.
- Payback provisions were provided by thirteen (13) organizations. The average time to not trigger any pay back provision is 2.4 years, the median is 2.0 years. The range of time is generally between 1 - 5 years and twelve (12) organizations noted they have some form of partial payment plan for leaving within a designated time period after completion of education. For example, if 4 years for no repayment, if the employee leaves in 2 years, they will be asked for 50% pay back.

5. Benchmark Position Survey Results

Survey Results

This section reports the information collected in aggregate values for each benchmark position. The values reported in this table reflect “All Ontario” data in that the data for all organizations matching to the position are included (regardless of size and geographic location).

Additional summaries, on a job by job basis, are provided in the accompanying “Addendum”.

Detailed analysis, with expanded statistical data (i.e., including P25 and P75 data points) as well as analysis of survey results by geographic region, by customer base and by revenue, are reported in the Excel files accompanying this report.

All Organizations

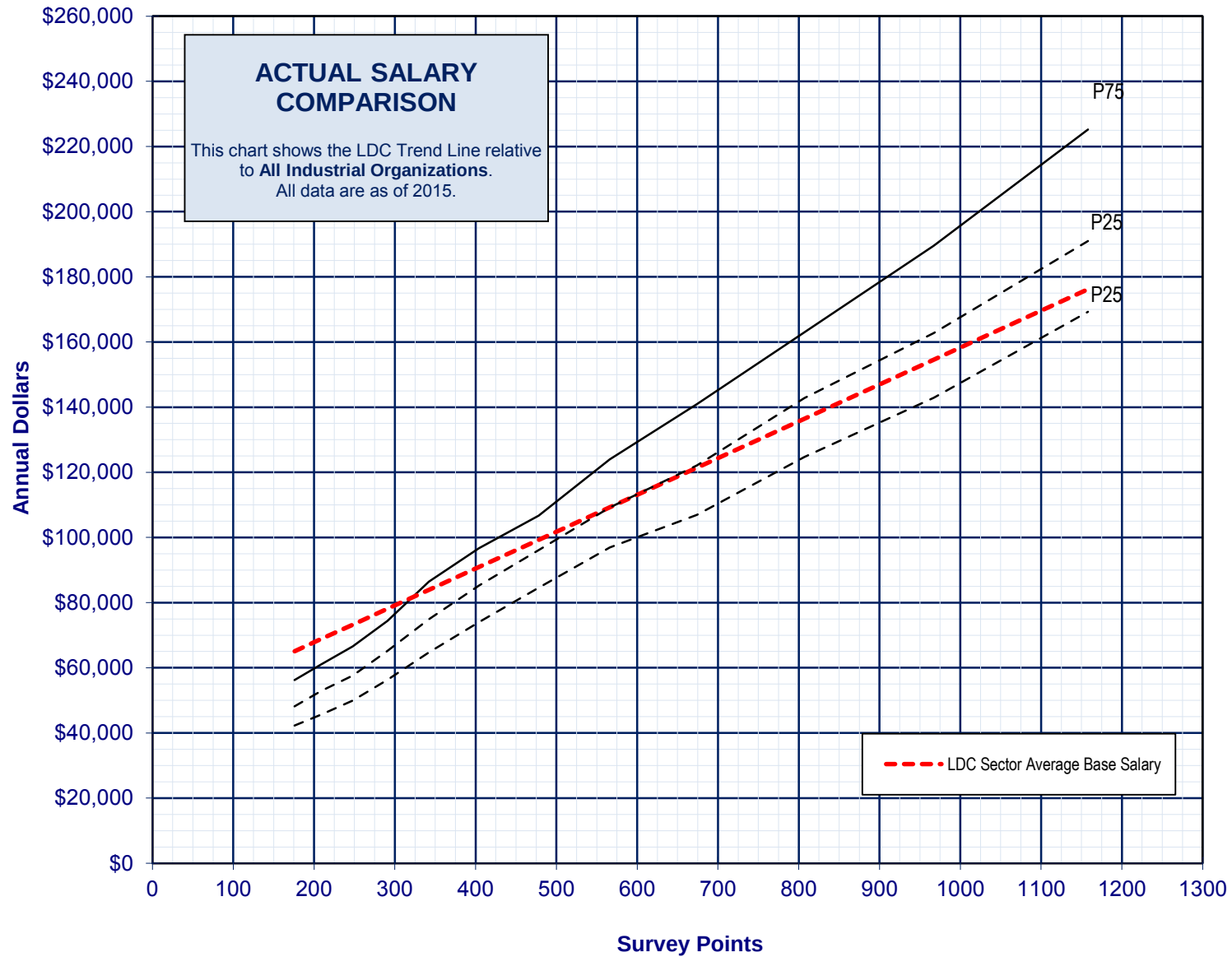
		Job Matches			Compensation Design						Actual Compensation				
Code	Survey Job Title	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
0000	President & CEO	34	34	1192	148,500	185,000	197,900	25%	195,700	211,400	185,100	187,400	22%	205,500	219,600
0001	Chief Operating Officer (COO)	11	11	864	130,400	144,000	160,200	15%	157,800	174,700	151,500	149,900	11%	161,700	171,000
0002	Head of Operations/Engineering	20	25	872	118,700	136,900	148,900	15%	140,800	153,100	138,600	138,500	11%	142,400	148,500
0003	CFO / Head of Finance	29	29	830	121,200	141,800	148,100	15%	149,600	158,800	141,900	142,900	13%	149,900	163,100
0004	Head of Customer Service	11	11	702	108,600	127,700	146,000	14%	137,800	143,700	127,500	135,400	10%	147,500	146,300
0005	Head of Regulatory Affairs	5	5	677	111,200	120,500	138,600	14%	132,600	147,700	137,400	141,100	*	150,800	155,300
0006	Head of Human Resources	13	13	677	108,600	123,600	131,500	15%	142,200	142,400	127,900	129,300	14%	144,900	144,900
1000	Executive Assistant	25	32	245	59,500	70,100	77,500	5%	72,500	72,400	72,600	72,300	4%	74,800	75,700
1001	Administrative Assistant	12	21	184	51,400	59,100	63,600	6%	59,100	62,100	64,300	62,800	4%	64,300	63,900
2000	Director Engineering	10	11	702	104,100	130,700	137,000	10%	136,100	138,600	133,100	128,800	11%	140,100	137,600
2001	Engineering Manager	19	25	588	88,400	103,900	115,400	8%	109,100	111,000	105,900	106,300	5%	110,800	109,800
2002	Project Engineer	9	11	417	71,800	85,300	91,500	*	87,100	87,200	84,500	83,500	*	84,500	84,900
2003	Supervisor Engineering	13	16	421	80,900	92,600	101,100	6%	94,600	96,700	92,600	92,000	3%	94,500	95,100
2500	Director Operations	8	9	732	108,300	135,400	135,900	10%	141,300	139,200	132,700	128,300	10%	138,200	135,500
2501	Manager Operations	20	21	516	92,600	104,700	116,800	7%	109,800	110,600	107,200	108,500	6%	111,200	116,900
2502	Manager Control Centre	4	4	534	92,800	111,000	114,800	9%	120,000	120,200	110,400	110,600	*	121,500	119,700
2503	Supervisor Control Centre	8	8	436	79,900	94,100	101,100	5%	96,300	95,600	97,600	97,400	*	97,600	99,300
2504	Supervisor Protection and Control	5	5	496	83,400	97,900	104,200	*	99,700	104,800	99,700	98,600	*	99,700	103,400
2505	Supervisor Station Maintenance	7	7	496	83,100	99,700	103,300	*	99,700	106,300	101,100	105,900	*	103,300	109,700
2506	Line Supervisor	26	67	366	82,700	95,900	101,100	5%	96,600	98,500	97,000	97,200	4%	98,600	103,000
2507	Manager Meter Department	8	8	551	95,700	105,900	110,700	8%	116,200	117,200	109,300	108,700	6%	118,700	115,100
2508	Supervisor Meter Department	8	11	406	83,400	93,700	96,700	7%	98,300	98,200	96,900	96,600	6%	101,700	100,200

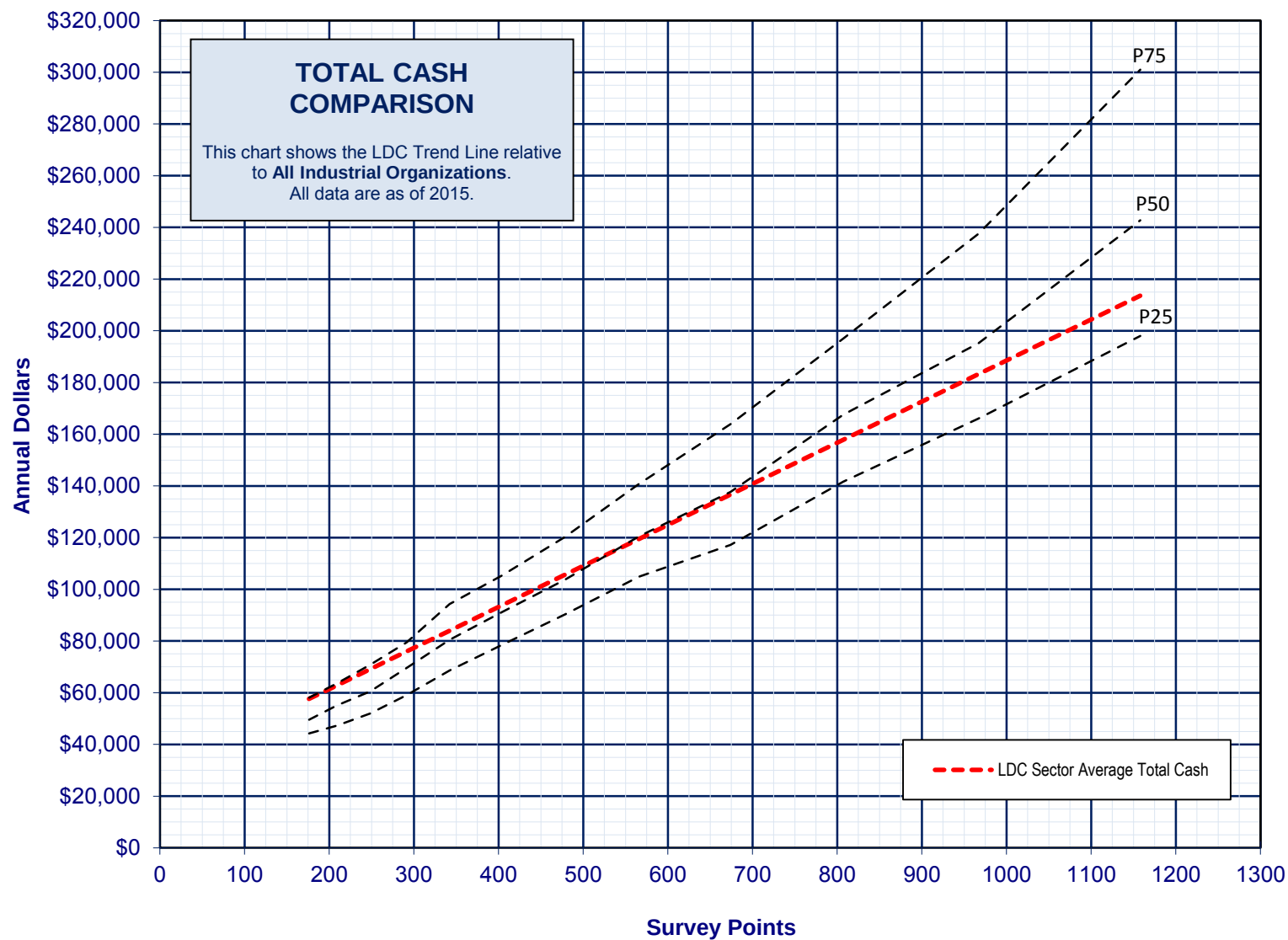
Minimum data requirements for information disclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

All Organizations

		Job Matches			Compensation Design						Actual Compensation				
Code	Survey Job Title	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		Orgs	Incs						P50	AVG	P50	AVG		P50	AVG
3000	Director Supply Chain Management	1	1	*	*	*	*	*	*	*	*	*	*	*	*
3001	Manager Procurement /Inventory	13	13	393	82,400	95,600	103,600	7%	101,400	98,900	97,300	97,800	6%	101,500	101,700
3002	Supervisor Stores/Inventory/Warehouse	5	8	342	70,100	81,400	88,500	*	87,100	86,300	83,200	85,500	*	87,700	88,200
4000	Controller or Director Finance	14	14	588	92,700	109,500	115,000	7%	113,600	116,100	113,900	111,500	8%	120,300	117,400
4001	Manager Accounting	14	14	479	85,900	101,700	116,600	8%	106,200	106,400	95,800	98,100	6%	98,300	102,700
4002	Manager Risk Management	1	1	*	*	*	*	*	*	*	*	*	*	*	*
4003	Supervisor Accounting	6	7	377	75,800	91,100	96,800	6%	91,100	94,200	94,200	91,600	4%	95,200	95,600
4004	Financial or Business Analyst	11	12	342	73,100	86,900	92,400	5%	88,900	90,000	83,800	85,000	4%	86,900	87,700
4005	Accountant	9	14	332	67,100	79,500	83,700	4%	79,600	80,700	79,500	76,900	2%	79,500	77,900
5000	Director Customer Service	3	3	*	*	*	*	*	*	128,200	*	116,400	*	*	123,200
5001	Manager Customer Service/Billing	20	20	479	81,200	92,600	100,300	8%	94,300	95,800	95,500	93,100	6%	97,900	99,800
5002	Supervisor Customer Service	21	31	353	70,800	86,800	89,800	5%	87,600	86,600	82,200	84,200	4%	85,600	86,500
5500	Director Communications	3	3	*	*	*	*	*	*	112,200	*	106,300	*	*	115,400
5501	Manager Communications	8	8	342	75,800	83,100	89,200	6%	87,400	87,600	84,400	83,900	5%	87,700	87,000
6000	Director Regulatory Affairs	4	4	666	117,900	132,900	143,100	15%	152,800	153,800	138,000	136,000	14%	161,800	153,400
6001	Manager Regulatory Affairs	11	11	393	81,200	92,600	96,000	8%	95,500	96,400	92,400	94,000	8%	95,500	97,900
6002	Regulatory Accountant	12	13	337	69,600	81,800	94,500	7%	82,500	85,300	81,800	84,000	5%	83,800	86,700
7000	Settlement or Rate Analyst	5	7	342	74,300	89,800	92,100	*	89,800	90,700	89,800	88,300	*	91,700	90,900
7001	Director or Officer, Conservation	7	7	805	109,900	127,700	139,100	13%	141,100	144,800	122,400	124,600	17%	139,900	148,600
7002	Manager Conservation & Demand/Marketing	12	12	393	77,900	90,900	92,800	9%	93,000	88,800	89,900	86,400	8%	95,700	93,200
8000	Director Information Systems	9	9	677	108,600	126,100	132,100	14%	138,700	135,100	128,200	126,200	13%	139,400	138,700
8001	Manager Information Systems and/or Security	14	18	479	86,000	96,100	103,200	5%	99,100	100,800	97,500	98,000	5%	101,100	101,500
8002	Systems/Program Administrator	15	19	332	68,700	80,100	89,900	5%	80,100	83,700	88,500	83,800	4%	93,100	90,100
9000	Human Resources Manager	5	5	479	77,900	92,100	98,900	*	92,100	95,200	97,200	89,800	*	97,200	90,900
9001	Human Resources Generalist	9	11	289	62,600	73,600	80,900	5%	75,800	79,800	79,400	77,900	3%	79,400	81,100
9002	Human Resources Coordinator	5	5	245	61,900	76,100	76,100	6%	79,400	77,000	68,200	70,500	*	71,100	73,000
9003	Payroll	12	12	245	60,600	71,400	79,500	4%	74,200	74,500	75,100	73,400	3%	77,000	75,500
9004	Manager, Health & Safety	16	16	479	83,300	97,600	107,700	7%	99,100	103,700	98,900	100,000	5%	102,400	104,900

Minimum data requirements for information disclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).





APPENDICES

A. Survey Methodology

A brief profile was developed for each benchmark position. These profiles were incorporated into a survey package and distributed to each participant along with a data submission spreadsheet requesting data on survey benchmark positions, as well as the organization's profile and selected salary administration & benefits policies.

Participants matched their jobs to the profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, the data were aggregated and an average figure was used for that organization. By using this methodology, all organizations carry equal weighting, and no one single organization excessively influences the market statistics by virtue of the size of its employee population.

Once the completed surveys were returned to Hay Group, participants were contacted for data verification as necessary. Hay Group also initiated a number of follow-up actions to clarify information provided by the participants. All of the matches submitted by the participants were reviewed by Hay Group to determine their appropriateness versus the job profiles and the market. If deemed inappropriate, the matches, or outlier data, were removed from the survey results.

Where possible, organization charts or details regarding reporting relationships were provided to Hay Group to enable understanding of the roles. From the job match information, plus a review of organization charts and other contextual information provided, Hay Group has estimated at which Hay Reference Level each organizations' roles fall to facilitate point-based comparisons.

B. Definitions – Compensation Elements

Salary Range

Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	Typically the midpoint of the salary range, intended to reflect the salary the organization is prepared to pay for sustained competent performance by a fully trained / qualified incumbent.
Maximum	The highest point in the salary range (or step progression). Note: might be the same as "job rate".

Short Term Incentive

Short Term Incentive (STI) refers to any incentive arrangement designed to reward an individual for performance/results achieved over a performance cycle/period of up to one year.

Target	Target bonus is the level of award (either a % of salary or a fixed dollar amount) that an employee in this position would expect to receive if all corporate, team and individual performance goals are "met" (as planned). This rate/amount is often communicated to employees as part of the incentive/bonus plan design, e.g. "the target bonus for jobs in grade/band 6 is 8% of salary".
Discretionary	Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executive/board.

Current Salary

The amount paid for work performed on a regular, ongoing basis.
Does not include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments.

Actual STI (Paid)

Total of all STI awards paid to the incumbent(s) for performance/results over the latest completed fiscal year.
May be paid during the year or after year end. (Note: recorded and reported on an annual basis)

C. Definitions – Statistical Elements

Market data are reported using the following statistics:

	Definition	Reporting Requirement (# of Observations Necessary to Report)
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90 th percentile and 90% would fall below	11
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below	7
P50	50th percentile, also referred to as “median” If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below	4
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below	7
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below	11
Average	The arithmetic mean of all values, calculated by adding up all of the values and dividing by the number of observations	3

D. Benchmark Position Profiles

Job Title	Description
President & CEO	Directs the development of short and long term strategic plans, operational objectives, policies, budgets and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.
Chief Operating Officer (COO)	Highest ranking operations position. Reporting to the President/CEO, directs the operational elements of the organization, could include operations & engineering, customer services, metering and information technology. Develops the short and long term strategic plans, directs the development of operational objectives, policies, budgets for his/her areas of accountability. The position reports directly to the President/CEO.
Head of Operations and/or Engineering	Highest ranking operations/engineering position. Reporting to COO or President. Directs both the operations and engineering functions. Develops the short and long term strategic plans, formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Establishes clear controls, objectives and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.
CFO / Head of Finance	Highest ranking financially-oriented position within the company. Reporting to the President & CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.
Head of Customer Service	The highest-ranking customer service position in the utility. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the development, implementation and integration of all customer service related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies and procedures; manages and coordinates budgets.
Head of Regulatory Affairs	Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to President & CEO or a senior executive.
Head of Human Resources	The highest-ranking human resources position in the organization. Provides direction, support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors.

Administration

Executive Assistant	Performs advanced, diversified and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares and distributes minutes of meetings, including Board of Director minutes. Reports to the President & CEO and may provide support to other executives.
Administrative Assistant	Performs advanced, diversified and confidential administrative duties for executives and/or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. Reports to a senior executive or executive team.

Engineering

Director Engineering	Plans and directs the overall engineering activities and engineering staff of the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.
Engineering Manager and/or Distribution Engineer	Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications and designs, including the supervision, planning and scheduling of work within the division – Requires a P. Eng. <u>OR</u> Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction and maintenance of distribution systems. Consults with other department management on plant design, construction and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P. Eng.
Project Engineer	Non-supervisory position. Directs and coordinates activities related to utility engineering project work, such as smart grid systems, renewables, large utility projects, asset renewal, etc. Requires a P. Eng.
Supervisor Engineering	Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores and maintains the integrity of hard copy file records, digital formats and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to an engineering manager.

Operations

Director Operations	NOT the head of function. Plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.
Manager Operations	NOT the head of function. Supervises, co-ordinates, directs, schedules and controls the construction, maintenance and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role.
Manager Control Centre	Supervises, co-ordinates, directs, schedules and controls the control centre and technical staff. Provides leadership in the planning and coordination of the control centre relative to safety, reliability and control of the distribution system. Is responsible for budgets, and the direct operations of the control centre approving system outages, switching and maintenance requirements to maintain and improve system reliability.
Supervisor Control Centre	Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.
Supervisor Protection and Control	Responsible for the management of all Protection & Controls activities related to the installation, maintenance and commissioning of: Protective Relaying Schemes and Station Automation Systems; SCADA System, Visual Display System and Remote Terminal Units; Operations Ethernet and system-wide Area Communications Networks; Distribution Automation Systems, Sectionalizing Devices and Remote Supervisory Controlled Devices. Prepares and administers reports, budgets, Policies and Procedures, record keeping systems.
Supervisor Station Maintenance	Responsible for the planning, coordinating both maintenance and installation of substations, as well as ensuring reliability of the underground plant, through testing and troubleshooting. Supervises, coordinates and schedules the activities of Station Maintenance Electricians and Protection and Control Technicians, Reviews work assignments, daily logs, reports and orders. Co-ordinate crews and plan jobs, assigns work per shift, long-term work and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.
Line Supervisor	Coordinates and directs the lead journey person and/or crews in the construction and maintenance of distribution lines and equipment (overhead and/or underground). Works with lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications and managing construction.
Manager Meter Department	Supervises the overall operations of the Meter department, prepares budgets, directs the purchase and maintenance of equipment and technology related to the department. Provides direction on the supervision of meter staff, the assignment of work and productivity of staff. Supervises the work related to interactions with electronic meter programming and interaction with/or the operation of the MV90 or similar data collection systems.

Supervisor Meter Department	Responsible for overall operation of the Meter department, including operations, budgeting and supervision of meter technicians or other operations staff. Assigns, monitors and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.

Supply Chain / Procurement

Director Supply Chain Management	Responsible for the overall operation of the Procurement, Inventory, Fleet and/or Facilities programs and initiatives in the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Oversees the establishment of user service level agreements, and provides contract management expertise and acts as a resource for contract negotiation, review and approval. Directs the effective capital acquisition and maintenance of the corporate fleet and/or directs the effective maintenance and capital investment of the organizations facilities and assets.
Manager Procurement and/or Inventory and/or Facilities and/or Fleet	Responsible for all purchasing and/or inventory and/or facilities and/or fleet for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Is responsible for budgets, policies and procedures and directs the work of the purchasing or buyers and/or stores and/or facilities and/or fleet personnel. Works with the organization in setting partnership relationships to understand and meet the needs of the organization, its operations and risk associated with the effective and efficient operations of the company.
Supervisor Stores/Inventory/Warehouse	Supervises inventory control, records and stores operation. Orders material to maintain on-hand quantities with procurements approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists procurement department in the sale of obsolete equipment and material.

Accounting / Finance

Controller or Director Finance	NOT the head of function. Responsible for all financial reporting, accounting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends and increased profit opportunities. Reports to a CFO/VP Finance.
Manager Accounting	Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Reports to Controller/Director Finance or CFO/VP Finance.
Manager Risk Management	Responsible for risk management activities including cash flow management, credit facilities management, insurance and support for credit and collection policies throughout the corporation. May be responsible for ensuring that cash liquidity risk is managed in an appropriate fashion such that bank account balances are sufficient to meet operational, capital expenditures and debt servicing requirements while minimizing short-term borrowings or surplus investing. Provides leadership in the developing new and refining existing risk management policies to respond to changes in risk tolerances and business conditions and as financial risks are better understood in accordance with industry best practices. Reports to Head of Finance or COO or CEO.

Supervisor Accounting	Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.
Financial or Business Analyst	Conducts analysis of information for budgeting, investment and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; processes and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents. Holds a financial designation, either CA, CMA or CGA.
Accountant	Supports the organization decisions through financial information and relevant analysis. Ensures the integrity between the CS work order systems and general ledger system is maintained. Initiate corrective measures when discrepancies occur between the systems. Collects and combines information for the decision making process by management, including financial statements and special projects as assigned (e.g. preparation of rate submission supplemental information).

Customer Service

Director Customer Service	NOT the head of function. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the implementation and integration of all customer service related activities. Oversees the implementation of customer service standards, policies and procedures; manages budgets; manages activities of CS managers and/or supervisory staff.
Manager Customer Service and/or Billing	NOT the head of function. Manages a team of customer service and/or billing representatives in providing information, receiving and responding to customer inquiries, complaints or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls.
Supervisor Customer Service and/or Billing and/or Collections	Supervises customer service representatives (billing clerks and/or collections clerks) and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated workflow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.

Regulatory Affairs

Director Regulatory Affairs	NOT the head of function. Supports the VP or may represent the organization on regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for or supports the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Manager Regulatory Affairs	NOT the head of function. Manages the organization's regulatory staff, programs and activities to ensure compliance. Assists the organization on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Coordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).

Regulatory Accountant	Ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Act as a key resource to provide expert advice and recommendations in the implantation of all OEB, OPA and IESO codes and regulations in order to ensure corporate compliance. Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudence review (i.e. conservation, smart meters) and the cost side of Ontario Power Authority (OPA) programs.

Conservation / Demand

Settlement or Rate Analyst	Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models.
Director or Officer, Conservation and Demand Management	This position is responsible for planning, coordinating, evaluating and delivering energy and water conservation and demand management programs. Develops plans for programs in accordance with the OEB's conservation and demand management code to ensure achievement of OEB mandated energy consumption and demand conservation targets.
Manager Conservation & Demand/Marketing	Responsible for managing the development and implementation of CDM initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's Conservation and Demand Management (CDM) programs. Marketing communication plans may include, but are not limited to advertising, media conferences, program launch events, workshops, event displays. Liaising with, as needed, senior marketing and/or communications personnel representing organizations and groups involved in conservation and sustainability including, but not limited to, the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), Ministry of Energy, municipal and regional governments, etc.

Information Systems / Technology

Director Information Systems	Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of organization objectives and imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, security, programming and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets and resource requirements. Typically reports to President & CEO, or CFO.
Manager Information Systems and/or Security	Manages and directs staff in areas of computer operations, systems planning, design, security, programming and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets and resource requirements.
Systems/Program Administrator or Applications/Systems Support Professional	Responsible for maintenance of software systems including system analysis, programming and design, updates and changes. Makes a preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware.

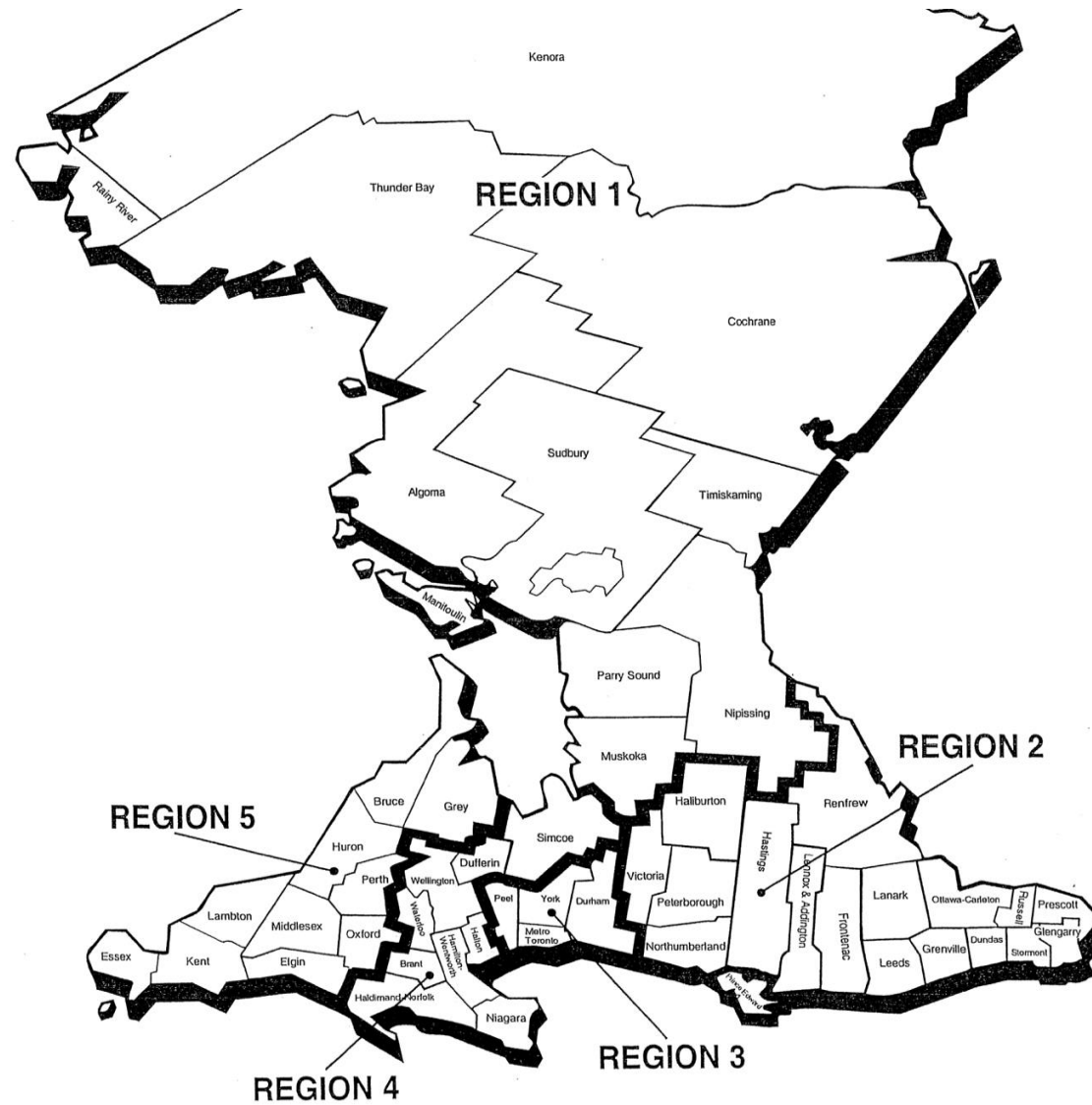
Human Resources

Human Resources Manager	NOT the head of function. Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. Reports to a senior HR professional (Director or VP or equivalent).
Human Resources Generalist	Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. Acts as a business partner to the organization in the areas of human capital. May assist in the preparation of negotiations.
Human Resources Coordinator	Administrative support to one or more functional areas of HR and/or Safety. Processes, coordinates and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications.
Payroll	Performs the payroll coordination and administration. Maintains the organizations internal or external payroll system. Prepares monthly requisitions for WSIB, Employee Health Tax, Receiver General, OMERS Pension and Union Dues. Administers employee pension program and provides pension calculation estimates as requested. Reconciles monthly payroll for year-end finance procedures. Prepares annual T4's and T4A's and OMERS Pension and responds to inquiries from employees and pensioners regarding the pension plan.
Manager, Health & Safety	Accountable for the development and implementation of occupational health, safety and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

Communications

Director Communications	Directs the development, management and execution of internal and external corporate communications strategies for the company, and marketing and public relations initiatives. Acts as the Chief Spokesperson for the organization. Leads the management and development of the corporate brand and identity. Oversees the development, production and distribution of corporate publications including, but not limited to, the annual report, customer newsletters, information brochures, bill inserts, CDM/Green marketing materials, employee newsletters and media releases. Directs the development and management of the company's external (corporate internet site) and internal (corporate intranet site) web presence and strategy. Oversees the management and execution of internal and external corporate events as well as community-relations activities such as sponsorship and donation programs.
Manager Communications	Responsible for managing the development and implementation of all customer communications initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's CDM and customer communications materials/systems. Communication materials may include, but are not limited to, customer newsletters, information brochures, bill form design, employee intranet, LCD information monitors, and website communications. Working in conjunction with Regulatory Affairs, develop materials or other communication methods to communicate regulatory changes/issues that may directly impact the customer. Manages event planning for internal and external company events.

E. Regions





The MEARIE Group

2016 Management Salary Survey Of Local Distribution Companies

SURVEY REPORT

August 2016

SURVEY ADMINISTRATOR: Korn Ferry Hay Group

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1. Introduction

The MEARIE Group is pleased to present this report of the 2016 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, LDCs are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. The MEARIE Group established the Management Salary Survey of Ontario's Local Distribution Companies to assist LDCs in understanding the competitive landscape and to support your efforts to develop pay practices that attract, motivate and retain high quality, high performing employees.

The survey was updated in 2012 through the combined efforts of The MEARIE Group's *HR Information Solutions* team, outside consultants and representatives of our members, all working together to ensure that the Survey continues to meet the evolving needs of member LDCs.

The Survey was further enhanced from 2013 to 2014 through our partnership with Korn Ferry Hay Group ("Hay Group"), a globally renowned compensation consulting firm. Hay Group drew upon their expertise and experience in developing and managing salary surveys across all sectors of the economy and in numerous countries around the world.

There are no substantial changes to the survey in 2015 or 2016.

The 2016 survey includes:

- Geographic, Number of Employees, Number of Customer and Revenue size reporting.
- Fifty (50) benchmark descriptions, supported by the Hay Group job evaluation methodology for improved reporting and greater ability to identify the impact of organization size and structure.
- Continued reporting of "total cash compensation" to provide greater depth of information regarding market pay practices.
- An overview of local distribution company market trends and compensation projections for 2017 budget planning.
- MS Excel survey reporting including versions of position salary tables by All Organizations, Geography, Revenue and Customers to support those organizations that wish to conduct further analysis of the results and to assist in transferring survey results into internal reporting.

The survey includes two presentation documents and Excel data tables in formats as follows:

- PDF Documents:
 - Survey Report Executive Summary containing a complete analysis and a data summary of all the positions.
 - Survey Report addendum which includes a complete analysis of each position, presented on one page.
- Excel Documents which are provided for easy data export and printable to one legal sized page, showing LDC Survey data by:
 - All Organizations
 - Region
 - Customer Base
 - Revenue
 - Number of Employees

We would like to thank you for your participation. As a result of the strong response, we are able to provide you with an informative and detailed survey that will help you in the support of your organization's compensation programs.

CONFIDENTIALITY POLICY

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey (a “Survey”), as well as Hay Group (survey administrators) and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission for a Survey. This will result in the LDC’s data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the Survey to determine the relevance of Survey data cuts (e.g. by geography or size).

All of the information obtained through a Survey will be treated with the utmost confidentiality. Data will be reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither Hay Group nor MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the Survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the Survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of a Survey will not be disclosed/sold to or shared with organizations that have not participated in that Survey, whether by The MEARIE Group or Hay Group or Survey participants. **Participants may not share the Survey reports/results with non-participant LDCs or any entity under any circumstances.**

The data collected for a Survey may also be included in the Hay Group's Canadian compensation database. Information in the Hay Group database is maintained with the highest standards of confidentiality; analysis and reporting of data is on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified or attributed. As of January 2016, there are over 540 employers represented in the Hay Group database. Should you have any questions or for further information, please contact Deirdre Chong Smith, Consultant at Korn Ferry Hay Group at 416-815-6344 or deirdre.chong@kornferry.com.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law. However, LDCs may not disclose the existence or results of a Survey to any regulatory body (or other person) unless compelled by law to do so, and if an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required. In such circumstances, the LDC will take such steps as The MEARIE Group reasonably requests, or will co-operate with respect to any steps The MEARIE Group reasonably wishes to take, to contest or limit the scope of the disclosure.

The MEARIE Group will not be liable for breaches by participating LDCs or Hay Group of this Confidentiality Policy.

2. Survey Overview

Survey Benchmark Positions

The survey covers 50 benchmark positions representing a cross-section of the functions within member organizations. The benchmark positions were reviewed in 2012 by a working group of LDC sector Human Resources professionals. Job profiles for each benchmark job were developed and reviewed by the consultants and the HR group.

Senior Management	0000	President & CEO
	0001	Chief Operating Officer (COO)
	0002	Head of Operations and/or Engineering
	0003	CFO / Head of Finance
	0004	Head of Customer Service
	0005	Head of Regulatory Affairs
	0006	Head of Human Resources
Administration	1000	Executive Assistant
	1001	Administrative Assistant
Engineering	2000	Director Engineering
	2001	Engineering Manager and/or Distribution Engineer
	2002	Project Engineer
	2003	Supervisor Engineering
Operations	2500	Director Operations
	2501	Manager Operations
	2502	Manager Control Centre
	2503	Supervisor Control Centre
	2504	Supervisor Protection and Control
	2505	Supervisor Station Maintenance
	2506	Line Supervisor
	2507	Manager Meter Department
	2508	Supervisor Meter Department

Supply Chain / Procurement	3000	Director Supply Chain Management
	3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet
	3002	Supervisor Stores / Inventory / Warehouse
Accounting / Finance	4000	Controller or Director Finance
	4001	Manager Accounting
	4002	Manager Risk Management
	4003	Supervisor Accounting
	4004	Financial or Business Analyst
	4005	Accountant
Customer Service	5000	Director Customer Service
	5001	Manager Customer Service and/or Billing
	5002	Supervisor Customer Service and/or Billing and/or Collections
Communications	5500	Director Communications
	5501	Manager Communications
Regulatory Affairs	6000	Director Regulatory Affairs
	6001	Manager Regulatory Affairs
	6002	Regulatory Accountant
Conservation / Demand	7000	Settlement or Rate Analyst
	7001	Director or Officer, Conservation and Demand Management
	7002	Manager Conservation & Demand / Marketing
Information Systems	8000	Director Information Systems
	8001	Manager Information Systems and/or Security
	8002	Systems / Program Administrator or Applications / Systems Support Professional
Human Resources	9000	Human Resources Manager
	9001	Human Resources Generalist
	9002	Human Resources Coordinator
	9003	Payroll
	9004	Manager, Health & Safety

Participants

All organizations in the LDC sector in Ontario were invited to participate in the survey. The following forty-one (41) organizations submitted data:

- Bluewater Power Distribution
- Brantford Power Inc.
- Burlington Hydro
- Collus PowerStream Corp.
- E.L.K. Energy Inc.
- Energy+ Inc.
- Entegrus Inc.
- Enwin Utilities Ltd.
- Espanola Regional Hydro Distribution
- Essex Power
- Festival Hydro Inc.
- Fort Frances Power Corp.
- Greater Sudbury Utilities
- Grimsby Power Inc.
- Guelph Hydro Electric Systems Inc.
- Halton Hills Hydro Inc.
- Hydro Ottawa
- InnPower Corp.
- Kitchener-Wilmot Hydro Inc.
- Lakefront Utilities Inc.
- Lakeland Power Distribution Ltd.
- London Hydro Inc.
- Midland Power Utility Corp.
- Milton Hydro Distribution Inc.
- Niagara Peninsula Energy Inc.
- North Bay Hydro Distribution Ltd.
- Northern Ontario Wires Inc.
- Oakville Hydro
- Orangeville Hydro Ltd.
- Orillia Power Distribution Corp.
- Oshawa PUC Networks, Inc.
- Peterborough Utilities Group
- PUC Services Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Utilities Kingston
- Veridian
- Wasaga Resource Services
- Waterloo North Hydro Inc.
- Welland Hydro-Electric System Corp.
- Westario Power Inc.
- Whitby Hydro Energy Services Corp.

Due to the changes in the participant mix, data values in the report can fluctuate from one year to another. Therefore, participants are reminded of these factors when comparing data from 2016 over 2015.

Participant Group Profile

All participants provided information regarding their organizational profile. The summary statistics of the participating organizations are detailed below.

The figures reported below are assessed on an “as provided” basis. Hay Group and the MEARIE Group have not independently or exhaustively verified the values presented below.

Statistic	P25	P50	P75	Average
Annual Operating Budget (\$ millions, less the cost of power)	4.5	10.0	19.0	18.2
Annual Operating Budget (\$ millions, including the cost of power)	37.4	102.5	172.5	139.6
Number of Employees (full time equivalent)	32	65	135	102
Number of Customers	13,516	36,280	55,433	48,529
Gross Revenue (\$ millions, less the cost of power)	8.5	17.1	32.2	28.3
Gross Revenue (\$ millions, including the cost of power)	41.0	109.1	198.8	151.6
Regulated Gross Revenue	97%	99%	100%	90%
Unregulated Gross Revenue	0%	1%	3%	10%

All organizations noted the fiscal year ends in December.

Analyst Note: where average is significantly higher or lower than the median of the market, this indicates a small number of observations which skew the data either high or low. For example, unregulated gross revenue average is 10%, which is substantially higher than the 1% median or 3% 75th percentile, indicating that within the top 25% of organizations there is a significant portion of unregulated Gross revenue in excess of 10% in a few organizations.

3. Salary Administration

Salary Range Adjustments – 2015, 2016 & 2017

Thirty-four (34, or 83%) organizations reported data for salary ranges while 7 (17%) indicated they did not use ranges. The most common month for adjusting salary ranges is January (over 50% of reporting organizations).

Survey participants report adjusting their salary ranges in 2015 by an overall average of 1.9% (n = 32). Excluding the 3 organizations who froze ranges (i.e., provided 0%), the overall average is 2.1%.

Survey participants report adjusting their salary ranges in 2016 by an overall average of 2.1% (n=30). Excluding 2 organizations who intend to freeze ranges this year, the overall average is 2.2%.

Survey participants report planning to adjust salary ranges in 2017 by an overall average of 2.5% (n=11). No organization has projected a freeze to salary ranges at this time.

The salary range adjustments by employee level and overall are noted in the table below:

Year	CEO (n=27)	Executive (n=27)	Director (n=24)	Management (n=29)	Professional / Technical (n=29)	Admin. (n=27)	Overall (n=32)
2015	2.0%	1.9%	1.9%	1.9%	1.9%	1.8%	1.9%
2016	2.6%	2.0%	1.8%	1.9%	1.9%	1.9%	2.1%
2017	2.9%	2.5%	2.2%	2.2%	2.2%	2.2%	2.5%

*n indicates maximum number of organizations reporting.

**Base Salary
Increases –
2015, 2016 & 2017**

The most common timing for adjusting salaries is January (over 70% of reporting organizations grant annual salary increases in that month).

Survey participants report adjusting actual salaries in 2015 by an overall average of 2.6% (n=37).

Survey participants report adjusting actual salaries in 2016 by an overall average of 2.4% (n=34).

For 2017, survey participants reported projected average salary increases of 2.2% (n=13).

The base salary adjustments by employee level are noted in the table below.

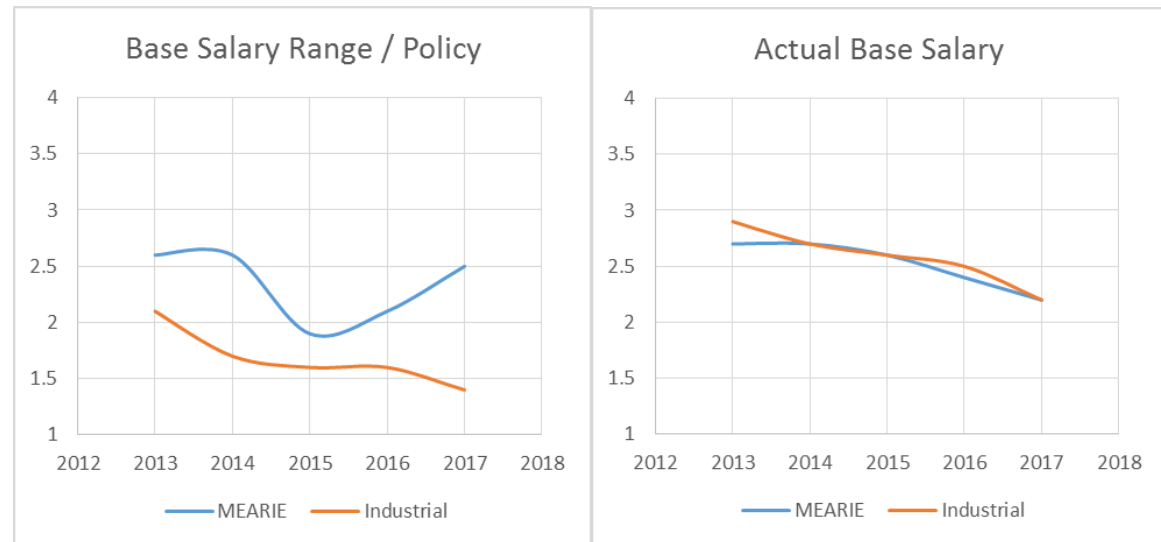
Year	CEO (n=29)	Executive (n=24)	Director (n=22)	Management (n=33)	Professional / Technical (n=28)	Admin. (n=27)	Overall (n=37)
2015	3.2%	2.1%	2.5%	2.3%	2.7%	2.0%	2.6%
2016	2.7%	2.2%	2.2%	2.3%	2.2%	2.1%	2.4%
2017	2.2%	2.2%	2.2%	2.2%	2.3%	2.3%	2.2%

*n indicates maximum number of organizations reporting.

Salary Trends

Hay Group compiles an annual compensation forecast survey across Canada, with over 500 participants annually.

The graph below depicts how the overall Canadian all-industrial organization market has tracked from a range and actual salary perspective versus The MEARIE Group Management Salary Survey trend information over the past 5 years.



Generally, local distribution companies track very close to the all-industrial market for actual salary adjustments; generally within 0.2 percentage points. Local distribution companies track above the all-industrial market for salary range adjustments by 0.3 – 1.1 percentage points.

The differential between actual base salary increases and salary range adjustments among local distribution companies is generally small, this year the average differential is 0.3 percentage points. The average differential among industrial organizations is 0.8 percentage points.

This indicates that industrial organizations may be allocating greater portions of salary budgets to differentiation by merit, and enabling high performers to perhaps be paid above job rate and/or moving people through the range faster. That is, industrial organizations are likely increasing their overall compa-ratios, whereas LDCs are generally maintaining or movement through range is very conservative.

Incentive Programs

- a. The majority of organizations (28 of 41 or 68%) indicated that they offer short term incentive pay to at least some of their employees.
 - Seventeen (17) of the organizations indicated that all employee groups participated in STI.
 - Eleven (11) organizations have STI plans for designated senior management and/or executives that do not extend to non-management staff.
- b. Twenty (20) of the twenty-eight (28) organizations who offer short term incentive pay provided information about their incentive plans. Weighting of performance factors (corporate versus individual versus team/department performance) in the determination of individual bonus payments:
 - The average plan mix, by employee level, is provided in the table below.
 - Typical plan mix is a combination of corporate and individual metrics with a heavier weighting on corporate for senior management and/or executives and a heavier weighting on individual metrics for non-management staff.
 - For example:
 - The most common CEO incentive plan is 80% Corporate, 20% Individual
 - The most common Director plan is 60% Corporate, 40% Individual
 - The most common Admin plan is 20% Corporate and 80% Individual

Performance Factor	CEO	Executive	Director	Management	Professional / Technical	Admin.
Corporate	67.5%	59.8%	53.6%	42.7%	46.3%	42.0%
Team / Department	5.0%	28.0%	22.5%	26.4%	*	*
Individual	35.4%	38.8%	43.6%	53.9%	56.1%	60.2%

NOTE: As organizations are counted for each response, weightings will not add up to 100%.

**Indicates insufficient data to report.*

Incentive Programs
(continued)

Threshold Bonus Payouts

Formulaic or “target based” bonus programs typically do not pay out until a minimum level of performance (corporate, team and/or individual) has been achieved (i.e., if the threshold performance is not achieved, there is no pay out). Once this threshold performance has been achieved, incentive plans will pay out a minimum level of bonus; pay out levels typically then increase as performance / results increase, up to a “target” bonus rate when performance goals have been “met”.

Twelve (12) of the twenty-eight (28) organizations with incentive plans reported that they define minimum levels of performance required before any bonuses are generated. The typical bonus rate at the threshold performance is set at 50% of “target” bonus.

Maximum Bonus

Bonus programs are often designed such that there is a maximum level of payout. For example: if a position has a 10% bonus and the maximum payout is 200%, or 2x, then the maximum amount the employee can achieve regardless of performance (i.e., how much targets are exceeded by), is 20% of their current base salary.

The average maximum bonus is provided by employee level in the table below, though the typical bonus pay maximum is 100% of target.

Maximum Bonus Payout %	CEO (n =15)	Executive (n =13)	Director (n =11)	Management (n =16)	Professional / Technical (n = 9)	Admin. (n =9)
Average	1.2	1.2	1.2	1.1	1.2	1.2

In the broader market, it is more common to find higher maximum bonus levels (as a % of target) at higher levels of the organization, to reflect the greater influence on organizational performance that more senior roles are perceived to have.

**Special (Project)
Bonuses**

Organizations were asked if they provide any project bonuses for participation in key / special projects, paid on successful achievement of specific milestones and/or on completion of the project, separate and distinct from annual incentive plans.

Three (3) organizations reported providing such bonuses. There is insufficient data to provide the average value as no employee level has at least three data observations.

4. Benefit Policies

Car Benefit

The majority of organizations (34 of 41 or 83%) provide a car benefit to some level of employee.

The tables below summarize the value of car benefits, by position, where provided. An asterisk (*) indicates insufficient data to report:

		Company Owned Car (Value)	Monthly Lease Payment	Car Allowance (monthly)
CEO	P75	*	*	838
	P50	42,500	*	750
	P25	*	*	600
	Average	41,999	956	738
	Number	5	3	22
Executive / VP	P75	*	*	700
	P50	*	*	510
	P25	*	*	400
	Average	36,667	*	547
	Number	3	2	13
Sr. Management / Director	P75	*	*	517
	P50	*	*	475
	P25	*	*	350
	Average	*	*	432
	Number	2	0	8

Four (4) organizations reported providing a car benefit to specified positions below Senior Management. Specifically, three (3) organizations provide use of a company-owned vehicle and one (1) provides a vehicle allowance.

Mileage

The market statistics for mileage rates provided to employees as reimbursement for personal vehicle use are detailed in the table below.

N = 38	Mileage Reimbursement (¢ per km)
P75	54
P50	53
P25	49
Average	51

The most frequently reported mileage rate (11 organizations) is 54 cents per kilometer; the next most frequent reported rates are 55 cents per kilometer (4 organizations).

Perquisites

Club Memberships – Fitness

Seventeen (17) organizations reported providing a subsidy for fitness club fees. The typical policy is to provide a reimbursement of a fixed dollar amount per year. For all organizations, the same policy and maximum reimbursement applies regardless of job level.

N = 17	Maximum Reimbursement per year
P75	300
P50	200
P25	150
Average	224

Club Memberships – Social

None of the organizations reported having a separate policy / program for reimbursement of social club fees.

**Perquisites
(cont'd)**

Health Spending Account

Eleven (11) organizations reported providing a Health Spending Account (i.e. discretionary spending within a defined range of services / benefits).

Of the eleven (11) organizations, seven (7) provide the same funding for all jobs levels while four (4) differentiates by job level.

	CEO	Executive	Director	Management	Professional / Technical
P75	950	1,025	1,000	875	1,000
P50	525	475	500	400	400
P25	363	363	375	313	300
Average	720	810	650	555	569
Number	10	10	7	10	9

2nd Opinion Medical Advice

Three (3) organizations in the survey reported having a separate policy / program for this benefit.

Personal Financial / Legal Counseling

Four (4) organizations reported that financial and legal counseling is available via their Employee Assistance Program, which is provided to all employees. One (1) of these organizations reported a maximum dollar value.

Executive Medical Plan

Four (4) organizations reported providing enhanced medical coverage for executive levels only. Three (3) organizations reported a maximum dollar value, with an average maximum value of \$1,336.

**Perquisites
(cont'd)**

Personal Computer / Cell Phone / Internet

Thirteen (13) organizations provided information regarding policies and practices related to computers and internet.

The most common policies/practices are:

- Low / no interest rate loans to purchase computer equipment for personal / home office use.
- Provision of laptops for particular levels of employee, in addition to office desktop, to allow for mobile work (note: may be a perquisite if personal use of computer is allowed, but not a perquisite if for business use only).
- Reimbursement for cell phone and/or home internet connection for selected employees (either full reimbursement or 50% reimbursement were both provided in the market place).
- Cash allowance intended to cover cell phone and/or internet service.

The value of these benefits varies dramatically by level within organizations and between organizations; the data does not lend itself to reporting of the value of typical practices.

Other Perquisites

Other programs / practices reported, by eight (8) organizations, include:

- Reimbursement of dues / fees for professional associations such as Engineers (P.Eng) and Accountants (CGA/CMA/CA).
- Provision of an Employee Assistance Program.

Enhanced Life Insurance Coverage for Senior Officers

Organizations were asked if, for senior level jobs, there was additional, employer paid, life insurance coverage. For example, if the typical life insurance plan was 1.5x employee salary, was this enhanced to above 1.5x to some greater number such as 2x, or even 3x, for senior level jobs.

Seventeen (17) organizations provided information about their basic / standard life insurance coverage where the typical coverage is 2x annual salary (average coverage of 1.65x). Enhanced benefits are provided by seven (7) organizations, where senior roles receive coverage at an average of 1.87x annual salary.

**Vacation
Entitlement**

Forty (40) organizations provided the number of years of service required by various levels of employee in order to be entitled to a certain number of weeks of vacation.

The following table below details the range, average and typical (i.e., most common) number of years of service required per weeks of entitlement.

Several organizations noted that for executive level jobs, vacations are typically negotiated versus following a schedule for entitlement.

	2 weeks	3 weeks	4 weeks	5 weeks	6 weeks +
CEO					
Range	<i>No range</i>	<i>Start - 6</i>	<i>Start - 15</i>	<i>Start - 18</i>	<i>5 - 28</i>
Average	<i>Start</i>	3	6	13	22
Typical	<i>Start</i>	3	9	17	25
<i>sample</i>	n = 16	n = 23	n = 31	n = 32	n = 31
Executive / VP Level					
Range	<i>No range</i>	<i>Start - 4</i>	<i>Start - 10</i>	3 - 18	8 - 28
Average	<i>Start</i>	2	6	14	23
Typical	<i>Start</i>	3	9	17	25
<i>sample</i>	n = 15	n = 23	n = 29	n = 29	n = 29
Director Level					
Range	<i>No range</i>	<i>Start - 6</i>	<i>Start - 15</i>	8 - 18	15 - 28
Average	<i>Start</i>	2	7	15	23
Typical	<i>Start</i>	3	9	17	25
<i>sample</i>	n = 17	n = 29	n = 36	n = 34	n = 34
Manager Level					
Range	<i>No range</i>	<i>Start - 4</i>	<i>Start - 10</i>	8 - 18	15 - 28
Average	<i>Start</i>	2	7	15	23
Typical	<i>Start</i>	3	9	17	25
<i>sample</i>	n = 16	n = 32	n = 36	n = 34	n = 33
Professional Level (n = 37)					
Range	<i>No range</i>	<i>Start - 6</i>	<i>Start - 15</i>	8 - 18	15 - 28
Average	<i>Start</i>	2	7	15	24
Typical	<i>Start</i>	3	9	17	25
<i>sample</i>	n = 20	n = 33	n = 36	n = 34	n = 34

Unused Vacation

Organizations provided information about their policies and practices with regard to vacation time that was not fully utilized in the year in which it was earned.

Policy Regarding Carry Over	Number	%
Unused vacation entitlement at year end is paid out (vacation pay adjustment) – no carry over.	2	5%
Any/All unused vacation entitlement may be carried-over with no restrictions.	4	11%
Unused vacation entitlement may be carried over, subject to maximum total accumulated balance.	12	32%
A maximum amount of unused vacation may be carried over.	20	50%
No unused vacation may be carried over	1	3%
Total	39	100%

Maximum Number of Days to Carry Over (n = 24)	Number of Days
Range	3 - 15
Average	7.4
Typical	5

Time Limit for Utilizing Carried-Over Vacation Time	Number
No limit	9
One Year	8
Six Months or less	19
Total	36

Note:

Some organizations reported variations to the above policies such as:

- Seven (7) of the thirty-one (31) organizations who have a maximum amount of days that can be carried over specified it as either one year entitlement or a portion of the years entitlement.
- Exception policies where workload or special projects caused the employee to be unable to fully utilize vacation time, or where carry forward beyond standard policy is regularly allowed but must be approved by senior management.
- Cash out policies where some vacation time may be paid out instead of being carried over.
- Differences by vacation eligibility, such as carrying over 10 days if eligible for up to 3 weeks' vacation but 20 days if eligible for 4 weeks' vacation.

**Educational
Assistance /
Reimbursement**

Twenty participating organizations (20) provided details with regards to education assistance / reimbursement policies ranging from eligibility criteria to pay back provisions. There are a wide variety of types of programs and reimbursement rates. Key highlights are provided below:

- Seventeen (17) organizations stated that is education assistance / reimbursement; though typically there are limiters such as education or training courses which must be job related, and are subject to managerial approval.
- Three (3) organizations stated that there is no formal policy, however, approval for educational assistance or reimbursement happens regularly and is on a case by case basis.
- Five (5) organizations provided an annual reimbursement maximum, the average is \$1,600 and the median is \$1,500.
- Two (2) organizations provided a lifetime reimbursement maximum, there is insufficient data to report average/median.
- Payback provisions were provided by twelve (12) organizations. The average time to not trigger any pay back provision is 2.6 years, the median is 2.5 years. The range of time is between 90 days to 5 years. Eight (8) organizations noted they have some form of partial payment plan for leaving within a designated time period after completion of education. For example, if the employee leaves after 4 years, they will not be asked for any repayment; if the employee leaves in 2 years, they will be asked for 50% pay back.

5. Benchmark Position Survey Results

Survey Results

This section reports the information collected in aggregate values for each benchmark position. The values reported in this table reflect “All Ontario” data in that the data for all organizations matching to the position are included (regardless of size and geographic location).

Additional summaries, on a job by job basis, are provided in the accompanying “Addendum”.

Detailed analysis, with expanded statistical data (i.e., including P25 and P75 data points) as well as analysis of survey results by geographic region, by customer base and by revenue, are reported in the Excel files accompanying this report.

ALL ORGANIZATIONS

Code	Survey Job Title	Job Matches			Compensation Design						Actual Compensation				
		Sample Statistics		Hay Points	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Bonus % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		# Orgs	# Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
0000	President & CEO	34	34	1192	148,500	185,000	197,900	25%	195,700	211,400	185,100	187,400	22%	205,500	219,600
0001	Chief Operating Officer (COO)	11	11	864	130,400	144,000	160,200	15%	157,800	174,700	151,500	149,900	11%	161,700	171,000
0002	Head of Operations and/or Engineering	20	25	872	118,700	136,900	148,900	15%	140,800	153,100	138,600	138,500	11%	142,400	148,500
0003	CFO / Head of Finance	29	29	830	121,200	141,800	148,100	15%	149,600	158,800	141,900	142,900	13%	149,900	163,100
0004	Head of Customer Service	11	11	702	108,600	127,700	146,000	14%	137,800	143,700	127,500	135,400	10%	147,500	146,300
0005	Head of Regulatory Affairs	5	5	677	111,200	120,500	138,600	14%	132,600	147,700	137,400	141,100	*	150,800	155,300
0006	Head of Human Resources	13	13	677	108,600	123,600	131,500	15%	142,200	142,400	127,900	129,300	14%	144,900	144,900
1000	Executive Assistant	25	32	245	59,500	70,100	77,500	5%	72,500	72,400	72,600	72,300	4%	74,800	75,700
1001	Administrative Assistant	12	21	184	51,400	59,100	63,600	6%	59,100	62,100	64,300	62,800	4%	64,300	63,900
2000	Director Engineering	10	11	702	104,100	130,700	137,000	10%	136,100	138,600	133,100	128,800	11%	140,100	137,600
2001	Engineering Manager and/or Distribution Engineer	19	25	588	88,400	103,900	115,400	8%	109,100	111,000	105,900	106,300	5%	110,800	109,800
2002	Project Engineer	9	11	417	71,800	85,300	91,500	*	87,100	87,200	84,500	83,500	*	84,500	84,900
2003	Supervisor Engineering	13	16	421	80,900	92,600	101,100	6%	94,600	96,700	92,600	92,000	3%	94,500	95,100
2500	Director Operations	8	9	732	108,300	135,400	135,900	10%	141,300	139,200	132,700	128,300	10%	138,200	135,500
2501	Manager Operations	20	21	516	92,600	104,700	116,800	7%	109,800	110,600	107,200	108,500	6%	111,200	116,900
2502	Manager Control Centre	4	4	534	92,800	111,000	114,800	9%	120,000	120,200	110,400	110,600	*	121,500	119,700
2503	Supervisor Control Centre	8	8	436	79,900	94,100	101,100	5%	96,300	95,600	97,600	97,400	*	97,600	99,300
2504	Supervisor Protection and Control	5	5	496	83,400	97,900	104,200	*	99,700	104,800	99,700	98,600	*	99,700	103,400
2505	Supervisor Station Maintenance	7	7	496	83,100	99,700	103,300	*	99,700	106,300	101,100	105,900	*	103,300	109,700
2506	Line Supervisor	26	67	366	82,700	95,900	101,100	5%	96,600	98,500	97,000	97,200	4%	98,600	103,000
2507	Manager Meter Department	8	8	551	95,700	105,900	110,700	8%	116,200	117,200	109,300	108,700	6%	118,700	115,100
2508	Supervisor Meter Department	8	11	406	83,400	93,700	96,700	7%	98,300	98,200	96,900	96,600	6%	101,700	100,200
3000	Director Supply Chain Management	1	1	*	*	*	*	*	*	*	*	*	*	*	*
3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet	13	13	393	82,400	95,600	103,600	7%	101,400	98,900	97,300	97,800	6%	101,500	101,700
3002	Supervisor Stores/Inventory/Warehouse	5	8	342	70,100	81,400	88,500	*	87,100	86,300	83,200	85,500	*	87,700	88,200

ALL ORGANIZATIONS

Code	Survey Job Title	Job Matches			Compensation Design						Actual Compensation				
		Sample Statistics		Hay Points	Salary Range Minimum	Job Rate	Salary Range Maximum	Target Bonus % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
		# Orgs	# Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
4000	Controller or Director Finance	14	14	588	92,700	109,500	115,000	7%	113,600	116,100	113,900	111,500	8%	120,300	117,400
4001	Manager Accounting	14	14	479	85,900	101,700	116,600	8%	106,200	106,400	95,800	98,100	6%	98,300	102,700
4002	Manager Risk Management	1	1	*	*	*	*	*	*	*	*	*	*	*	*
4003	Supervisor Accounting	6	7	377	75,800	91,100	96,800	6%	91,100	94,200	94,200	91,600	4%	95,200	95,600
4004	Financial or Business Analyst	11	12	342	73,100	86,900	92,400	5%	88,900	90,000	83,800	85,000	4%	86,900	87,700
4005	Accountant	9	14	332	67,100	79,500	83,700	4%	79,600	80,700	79,500	76,900	2%	79,500	77,900
5000	Director Customer Service	3	3	*	*	*	*	*	*	128,200	*	116,400	*	*	123,200
5001	Manager Customer Service and/or Billing	20	20	479	81,200	92,600	100,300	8%	94,300	95,800	95,500	93,100	6%	97,900	99,800
5002	Supervisor Customer Service and/or Billing and/or Collections	21	31	353	70,800	86,800	89,800	5%	87,600	86,600	82,200	84,200	4%	85,600	86,500
5500	Director Communications	3	3	*	*	*	*	*	*	112,200	*	106,300	*	*	115,400
5501	Manager Communications	8	8	342	75,800	83,100	89,200	6%	87,400	87,600	84,400	83,900	5%	87,700	87,000
6000	Director Regulatory Affairs	4	4	666	117,900	132,900	143,100	15%	152,800	153,800	138,000	136,000	14%	161,800	153,400
6001	Manager Regulatory Affairs	11	11	393	81,200	92,600	96,000	8%	95,500	96,400	92,400	94,000	8%	95,500	97,900
6002	Regulatory Accountant	12	13	337	69,600	81,800	94,500	7%	82,500	85,300	81,800	84,000	5%	83,800	86,700
7000	Settlement or Rate Analyst	5	7	342	74,300	89,800	92,100	*	89,800	90,700	89,800	88,300	*	91,700	90,900
7001	Director or Officer, Conservation and Demand Management	7	7	805	109,900	127,700	139,100	13%	141,100	144,800	122,400	124,600	17%	139,900	148,600
7002	Manager Conservation & Demand/Marketing	12	12	393	77,900	90,900	92,800	9%	93,000	88,800	89,900	86,400	8%	95,700	93,200
8000	Director Information Systems	9	9	677	108,600	126,100	132,100	14%	138,700	135,100	128,200	126,200	13%	139,400	138,700
8001	Manager Information Systems and/or Security	14	18	479	86,000	96,100	103,200	5%	99,100	100,800	97,500	98,000	5%	101,100	101,500
8002	Systems/Program Administrator or Applications/Systems Support Professional	15	19	332	68,700	80,100	89,900	5%	80,100	83,700	88,500	83,800	4%	93,100	90,100
9000	Human Resources Manager	5	5	479	77,900	92,100	98,900	*	92,100	95,200	97,200	89,800	*	97,200	90,900
9001	Human Resources Generalist	9	11	289	62,600	73,600	80,900	5%	75,800	79,800	79,400	77,900	3%	79,400	81,100
9002	Human Resources Coordinator	5	5	245	61,900	76,100	76,100	6%	79,400	77,000	68,200	70,500	*	71,100	73,000
9003	Payroll	12	12	245	60,600	71,400	79,500	4%	74,200	74,500	75,100	73,400	3%	77,000	75,500
9004	Manager, Health & Safety	16	16	479	83,300	97,600	107,700	7%	99,100	103,700	98,900	100,000	5%	102,400	104,900

APPENDICES

A. Survey Methodology

A brief profile was developed for each benchmark position. These profiles were incorporated into a survey package and distributed to each participant along with a data submission spreadsheet requesting data on survey benchmark positions, as well as the organization's profile and selected salary administration & benefits policies.

Participants matched their jobs to the profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, the data were aggregated and an average figure was used for that organization. By using this methodology, all organizations carry equal weighting, and no one single organization excessively influences the market statistics by virtue of the size of its employee population.

Once the completed surveys were returned to Hay Group, participants were contacted for data verification as necessary. Hay Group also initiated a number of follow-up actions to clarify information provided by the participants. All of the matches submitted by the participants were reviewed by Hay Group to determine their appropriateness versus the job profiles and the market. If deemed inappropriate, the matches, or outlier data, were removed from the survey results.

Where possible, organization charts or details regarding reporting relationships were provided to Hay Group to enable understanding of the roles. From the job match information, plus a review of organization charts and other contextual information provided, Hay Group has estimated at which Hay Reference Level each organizations' roles fall to facilitate point-based comparisons.

B. Definitions – Compensation Elements

Salary Range

Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	Typically the midpoint of the salary range, intended to reflect the salary the organization is prepared to pay for sustained competent performance by a fully trained / qualified incumbent.
Maximum	The highest point in the salary range (or step progression). Note: might be the same as "job rate".

Short Term Incentive

Short Term Incentive (STI) refers to any incentive arrangement designed to reward an individual for performance/results achieved over a performance cycle/period of up to one year.

Target	Target bonus is the level of award (either a % of salary or a fixed dollar amount) that an employee in this position would expect to receive if all corporate, team and individual performance goals are "met" (as planned). This rate/amount is often communicated to employees as part of the incentive/bonus plan design, e.g. "the target bonus for jobs in grade/band 6 is 8% of salary".
Discretionary	Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executive/board.

Current Salary

The amount paid for work performed on a regular, ongoing basis.
Does not include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments.

Actual STI (Paid)

Total of all STI awards paid to the incumbent(s) for performance/results over the latest completed fiscal year.
May be paid during the year or after year end. (Note: recorded and reported on an annual basis)

C. Definitions – Statistical Elements

Market data are reported using the following statistics:

	Definition	Reporting Requirement (# of Observations Necessary to Report)
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90 th percentile and 90% would fall below	11
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below	7
P50	50th percentile, also referred to as “median” If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below	4
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below	7
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below	11
Average	The arithmetic mean of all values, calculated by adding up all of the values and dividing by the number of observations	3

D. Benchmark Position Profiles

Job Title	Description
President & CEO	Directs the development of short and long term strategic plans, operational objectives, policies, budgets and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.
Chief Operating Officer (COO)	Highest ranking operations position. Reporting to the President/CEO, directs the operational elements of the organization, could include operations & engineering, customer services, metering and information technology. Develops the short and long term strategic plans, directs the development of operational objectives, policies, budgets for his/her areas of accountability. The position reports directly to the President/CEO.
Head of Operations and/or Engineering	Highest ranking operations/engineering position. Reporting to COO or President. Directs both the operations and engineering functions. Develops the short and long term strategic plans, formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Establishes clear controls, objectives and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.
CFO / Head of Finance	Highest ranking financially-oriented position within the company. Reporting to the President & CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.
Head of Customer Service	The highest-ranking customer service position in the utility. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the development, implementation and integration of all customer service related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies and procedures; manages and coordinates budgets.
Head of Regulatory Affairs	Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to President & CEO or a senior executive.
Head of Human Resources	The highest-ranking human resources position in the organization. Provides direction, support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors.

Administration

Executive Assistant	Performs advanced, diversified and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares and distributes minutes of meetings, including Board of Director minutes. Reports to the President & CEO and may provide support to other executives.
Administrative Assistant	Performs advanced, diversified and confidential administrative duties for executives and/or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. Reports to a senior executive or executive team.

Engineering

Director Engineering	Plans and directs the overall engineering activities and engineering staff of the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.
Engineering Manager and/or Distribution Engineer	Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications and designs, including the supervision, planning and scheduling of work within the division – Requires a P. Eng. <u>OR</u> Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction and maintenance of distribution systems. Consults with other department management on plant design, construction and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P. Eng.
Project Engineer	Non-supervisory position. Directs and coordinates activities related to utility engineering project work, such as smart grid systems, renewables, large utility projects, asset renewal, etc. Requires a P. Eng.
Supervisor Engineering	Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores and maintains the integrity of hard copy file records, digital formats and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to an engineering manager.

Operations

Director Operations	NOT the head of function. Plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.
Manager Operations	NOT the head of function. Supervises, co-ordinates, directs, schedules and controls the construction, maintenance and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role.
Manager Control Centre	Supervises, co-ordinates, directs, schedules and controls the control centre and technical staff. Provides leadership in the planning and coordination of the control centre relative to safety, reliability and control of the distribution system. Is responsible for budgets, and the direct operations of the control centre approving system outages, switching and maintenance requirements to maintain and improve system reliability.
Supervisor Control Centre	Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.
Supervisor Protection and Control	Responsible for the management of all Protection & Controls activities related to the installation, maintenance and commissioning of: Protective Relaying Schemes and Station Automation Systems; SCADA System, Visual Display System and Remote Terminal Units; Operations Ethernet and system-wide Area Communications Networks; Distribution Automation Systems, Sectionalizing Devices and Remote Supervisory Controlled Devices. Prepares and administers reports, budgets, Policies and Procedures, record keeping systems.
Supervisor Station Maintenance	Responsible for the planning, coordinating both maintenance and installation of substations, as well as ensuring reliability of the underground plant, through testing and troubleshooting. Supervises, coordinates and schedules the activities of Station Maintenance Electricians and Protection and Control Technicians, Reviews work assignments, daily logs, reports and orders. Co-ordinate crews and plan jobs, assigns work per shift, long-term work and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.
Line Supervisor	Coordinates and directs the lead journey person and/or crews in the construction and maintenance of distribution lines and equipment (overhead and/or underground). Works with lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications and managing construction.
Manager Meter Department	Supervises the overall operations of the Meter department, prepares budgets, directs the purchase and maintenance of equipment and technology related to the department. Provides direction on the supervision of meter staff, the assignment of work and productivity of staff. Supervises the work related to interactions with electronic meter programming and interaction with/or the operation of the MV90 or similar data collection systems.

Supervisor Meter Department	Responsible for overall operation of the Meter department, including operations, budgeting and supervision of meter technicians or other operations staff. Assigns, monitors and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.

Supply Chain / Procurement

Director Supply Chain Management	Responsible for the overall operation of the Procurement, Inventory, Fleet and/or Facilities programs and initiatives in the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Oversees the establishment of user service level agreements, and provides contract management expertise and acts as a resource for contract negotiation, review and approval. Directs the effective capital acquisition and maintenance of the corporate fleet and/or directs the effective maintenance and capital investment of the organizations facilities and assets.
Manager Procurement and/or Inventory and/or Facilities and/or Fleet	Responsible for all purchasing and/or inventory and/or facilities and/or fleet for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Is responsible for budgets, policies and procedures and directs the work of the purchasing or buyers and/or stores and/or facilities and/or fleet personnel. Works with the organization in setting partnership relationships to understand and meet the needs of the organization, its operations and risk associated with the effective and efficient operations of the company.
Supervisor Stores/Inventory/Warehouse	Supervises inventory control, records and stores operation. Orders material to maintain on-hand quantities with procurements approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists procurement department in the sale of obsolete equipment and material.

Accounting / Finance

Controller or Director Finance	NOT the head of function. Responsible for all financial reporting, accounting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends and increased profit opportunities. Reports to a CFO/VP Finance.
Manager Accounting	Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Reports to Controller/Director Finance or CFO/VP Finance.

Manager Risk Management	Responsible for risk management activities including cash flow management, credit facilities management, insurance and support for credit and collection policies throughout the corporation. May be responsible for ensuring that cash liquidity risk is managed in an appropriate fashion such that bank account balances are sufficient to meet operational, capital expenditures and debt servicing requirements while minimizing short-term borrowings or surplus investing. Provides leadership in the developing new and refining existing risk management policies to respond to changes in risk tolerances and business conditions and as financial risks are better understood in accordance with industry best practices. Reports to Head of Finance or COO or CEO.
Supervisor Accounting	Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.
Financial or Business Analyst	Conducts analysis of information for budgeting, investment and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; processes and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents. Holds a financial designation, either CA, CMA or CGA.
Accountant	Supports the organization decisions through financial information and relevant analysis. Ensures the integrity between the CS work order systems and general ledger system is maintained. Initiate corrective measures when discrepancies occur between the systems. Collects and combines information for the decision making process by management, including financial statements and special projects as assigned (e.g. preparation of rate submission supplemental information).

Customer Service

Director Customer Service	NOT the head of function. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the implementation and integration of all customer service related activities. Oversees the implementation of customer service standards, policies and procedures; manages budgets; manages activities of CS managers and/or supervisory staff.
Manager Customer Service and/or Billing	NOT the head of function. Manages a team of customer service and/or billing representatives in providing information, receiving and responding to customer inquiries, complaints or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls.
Supervisor Customer Service and/or Billing and/or Collections	Supervises customer service representatives (billing clerks and/or collections clerks) and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated workflow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.

Regulatory Affairs

Director Regulatory Affairs	NOT the head of function. Supports the VP or may represent the organization on regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for or supports the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Manager Regulatory Affairs	NOT the head of function. Manages the organization's regulatory staff, programs and activities to ensure compliance. Assists the organization on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Coordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Regulatory Accountant	Ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Act as a key resource to provide expert advice and recommendations in the implantation of all OEB, OPA and IESO codes and regulations in order to ensure corporate compliance. Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudence review (i.e. conservation, smart meters) and the cost side of Ontario Power Authority (OPA) programs.

Conservation / Demand

Settlement or Rate Analyst	Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models.
Director or Officer, Conservation and Demand Management	This position is responsible for planning, coordinating, evaluating and delivering energy and water conservation and demand management programs. Develops plans for programs in accordance with the OEB's conservation and demand management code to ensure achievement of OEB mandated energy consumption and demand conservation targets.
Manager Conservation & Demand/Marketing	Responsible for managing the development and implementation of CDM initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's Conservation and Demand Management (CDM) programs. Marketing communication plans may include, but are not limited to advertising, media conferences, program launch events, workshops, event displays. Liaising with, as needed, senior marketing and/or communications personnel representing organizations and groups involved in conservation and sustainability including, but not limited to, the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), Ministry of Energy, municipal and regional governments, etc.

Information Systems / Technology

Director Information Systems	Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of organization objectives and imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, security, programming and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets and resource requirements. Typically reports to President & CEO, or CFO.
Manager Information Systems and/or Security	Manages and directs staff in areas of computer operations, systems planning, design, security, programming and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets and resource requirements.
Systems/Program Administrator or Applications/ Systems Support Professional	Responsible for maintenance of software systems including system analysis, programming and design, updates and changes. Makes a preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware.

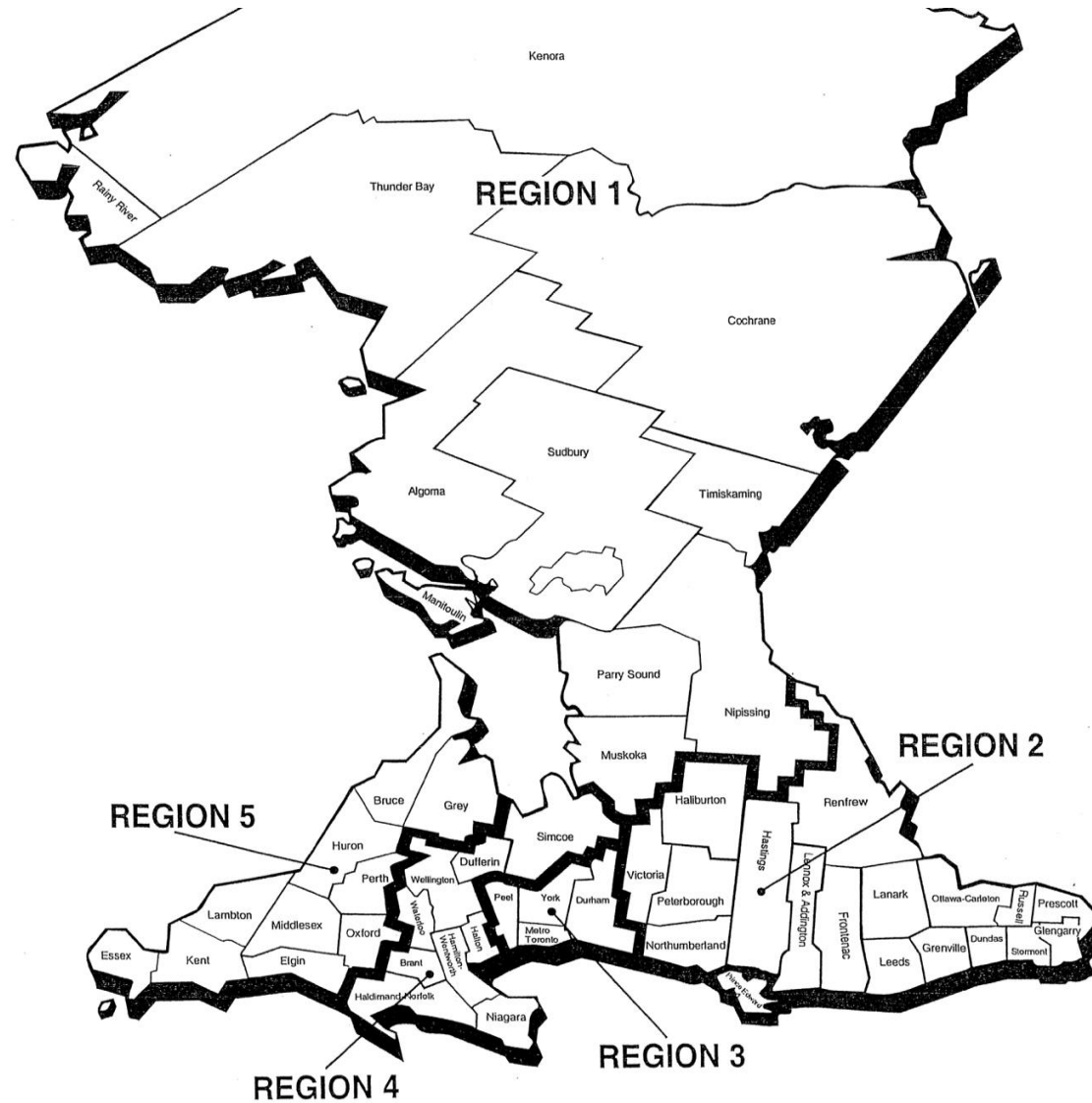
Human Resources

Human Resources Manager	NOT the head of function. Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. Reports to a senior HR professional (Director or VP or equivalent).
Human Resources Generalist	Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. Acts as a business partner to the organization in the areas of human capital. May assist in the preparation of negotiations.
Human Resources Coordinator	Administrative support to one or more functional areas of HR and/or Safety. Processes, coordinates and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications.
Payroll	Performs the payroll coordination and administration. Maintains the organizations internal or external payroll system. Prepares monthly requisitions for WSIB, Employee Health Tax, Receiver General, OMERS Pension and Union Dues. Administers employee pension program and provides pension calculation estimates as requested. Reconciles monthly payroll for year-end finance procedures. Prepares annual T4's and T4A's and OMERS Pension and responds to inquiries from employees and pensioners regarding the pension plan.
Manager, Health & Safety	Accountable for the development and implementation of occupational health, safety and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

Communications

Director Communications	Directs the development, management and execution of internal and external corporate communications strategies for the company, and marketing and public relations initiatives. Acts as the Chief Spokesperson for the organization. Leads the management and development of the corporate brand and identity. Oversees the development, production and distribution of corporate publications including, but not limited to, the annual report, customer newsletters, information brochures, bill inserts, CDM/Green marketing materials, employee newsletters and media releases. Directs the development and management of the company's external (corporate internet site) and internal (corporate intranet site) web presence and strategy. Oversees the management and execution of internal and external corporate events as well as community-relations activities such as sponsorship and donation programs.
Manager Communications	Responsible for managing the development and implementation of all customer communications initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's CDM and customer communications materials/systems. Communication materials may include, but are not limited to, customer newsletters, information brochures, bill form design, employee intranet, LCD information monitors, and website communications. Working in conjunction with Regulatory Affairs, develop materials or other communication methods to communicate regulatory changes/issues that may directly impact the customer. Manages event planning for internal and external company events.

E. Regions



1-SEC-4

- a) [Ex.1] Please provide a list of measurable outcomes that ratepayers can expect the Applicant to achieve during the test year. Please explain how those outcomes are incremental and commensurate with the rate increase the Applicant is seeking in this application.

Response:

- a) NOW Inc. key measurable outcomes are recorded in the Scorecard results that are provided annually to the OEB. Through the funding provided by the applied for revenue requirement and associated rate increase NOW Inc. expects to maintain the high level of performance that has been achieved and improve in areas such as service reliability (SAIDI, SAIFI), customer satisfaction and operational efficiency. The high ranking of productivity as measured by the PEG model (Cohort 1) is expected to continue with the level of funding requested. NOW Inc. is concerned that lower than applied for funding could lead to a decline in performance over the subsequent IRM period. It is noted that NOW Inc. has had to absorb large unforeseen one-time costs (e.g. bad debt expense) that have contributed to under-earning since the last COS in 2013. This has negatively impacted financial results. Through the applied for level of funding, a measurable outcome will be improvement in financial ratios which are important for the ongoing viability of the utility.

With the implementation of the Outage Management System NOW Inc. maintenance practices will be improved and customers will be better informed through outage communications functionality.

As the NOW Inc. system is aging there are higher maintenance and repair costs on assets (e.g. maintaining overhead lines) with no resulting measurable increase in performance. Such a spending increase helps to avoid a reliability decrease.

A portion of the increase requested is to provide for higher costs to complete the same level of work as in the past. These inflationary increases do not result in any measurable performance improvement.

1-SEC-5

- a) [Ex 1] Please provide a step by step explanation of the Applicant's budgeting and capital planning process.

Response:

- a) As stated in Exhibit 1, Tab 5, Schedule 2, NOW Inc.'s budget is prepared by the Chief Financial Officer and the General Manager and reviewed/approved by the Board of Directors. Typically the budget is prepared in the fourth quarter of the year and finalized/approved in the first quarter of the subsequent year. Key steps in the process are as follows:
- the CFO and General Manager consider high level strategic issues impacting NOW Inc., either from within the company, customers, industry or government
 - CFO and GM review OM&A program requirements to identify what work needs to be done
 - review changes in work circumstances (e.g. volume of contributed capital work)
 - consider longer term capital needs, as more recently identified in DSP
 - develop capital budget based on DSP project ranking and overall consideration of affordability
 - priority projects determined from NOW Inc.'s asset management plan – now the DSP
 - review regular maintenance and priority work
 - review financial and non-financial results from prior year and year-to-date
 - significant variances in spending from prior years are identified and consideration given to any trend impact (e.g. bad debt increase)
 - develop financial and non-financial targets and outcomes for the budget year
 - review performance objectives and targets. Identify what needs to be improved.
 - consideration is given to identified customer needs (e.g. reliability, communication)
 - check work deficiency reports identify problem areas
 - prepare a labour budget using projected wage and benefit costs. Overtime is based on projected need and historical comparisons with an expectation that it is closely managed to reduce costs where possible.
 - Establish a standard hourly “charge out” rates for Transportation and Work Equipment based on full costs (maintenance, fuel, depreciation) being recovered over the number of expected hours of usage during the year
 - price out the budget using resource based planning. Labour, material,

- equipment, purchased services
- determine overtime costs based on estimated workload and outage scheduling
- factor in collective agreement settlement assumptions for labour pricing
- review succession/labour planning and potential resource gaps
- factor in wage increase for non-union staff
- factor in inflationary increases for non-labour costs
- review purchased services to determine whether the service is required and whether there are opportunities for cost minimization or service level improvement;
- calculate overhead rates for Stores and ensure applied to the applicable work programs both operating and capital.
- identify resource gaps, affordability and re-balance work
- confirm level of service/support from CTS affiliate
- receive budget input (e.g. labour costs) from CTS affiliate
- review information from CTS and ensure calculations are correct
- in an effort to contain costs and explore efficiencies and still provide an acceptable level of reliability and customer service, review discretionary costs and identifies cost areas that can be delayed or addressed with alternative approaches
- prepare Excel based budget
- reiterate financial numbers in budget to achieve desired work and spending levels, being mindful of customer rate impact and maintaining sound financial performance
- consideration is given to confirming that capital and operating budgets support NOW Inc.'s core business objectives and that they are prudent, financially sustainable and also consider customer rate impact
- prepare budget presentation to NOW Inc. Board of Directors
- deliver presentation and receive approval
- use approved OM&A and Capital budget as baseline budget reference against which actual spending will be reported in the budget year

1-SEC-6

[Ex.1, Ex. 2-2-1, Attachment 1] With respect to metrics and outcomes:

- a) Does the Applicant have a corporate scorecard? If so, please provide copies of each of the 2013 to 2017 versions.
- b) If not, please explain what metrics the management and Board of Directors uses to measure and monitor the Applicant's activities.
- c) The Applicant includes an identified number of performance metrics in its Distribution System Plan (p.19). Please explain how the Applicant will utilize these metrics within the business.
- d) Please provide a version of the table included on (p.19) that provides the 2017 test year targets for each metric.

Response:

- a) NOW Inc. does not have its own corporate scorecard, but utilizes the scorecard established by the OEB.
- b) Management and the Board of Directors utilize the scorecard developed by the OEB along with other metrics such as Debt to Equity Ratios, cashflow, reliability and bill impacts. The OEB scorecard is a useful tool and provides a good cross section of utility performance measures.
- c) In general, metrics are used to measure past business performance and drive future business strategy and investment.

Reliability metrics are used to measure the reliability of electrical service provided to customers and to identify the root cause of outages. Northern Ontario Wires continues to view reliability of electricity service as a high priority for its customers and as such developed a program several years ago for the continuous improvement of reliability, which has been incorporated into the DSP.

Service quality metrics are used to measure Northern Ontario Wires' performance in a number of critical activities including call centre functions, new connections, professional appointments, billing accuracy, emergency response, and reconnection performance standards. Northern Ontario Wires continues to monitor service quality results to identify opportunities for improvement.

DSP implementation is used to assess Northern Ontario Wires' effectiveness at planning and implementing the DSP.

Total cost is used to monitor trends in spending. Northern Ontario Wires continues to strive to lower operating costs in order to provide the most cost effectiveness to its customers. Province-wide programs such as Time of Use pricing, growth in wage and benefits costs for our employees, as well as investments in new information systems technology and the renewal and growth of the distribution system, have all contributed to increased operating and capital costs. However, Northern Ontario Wires has mitigated these increases with effective planning and cost sharing. Northern Ontario Wires will continue to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements.

The Pacific Economics Group efficiency assessment is used to measure the efficiency of Northern Ontario Wires' spending by comparing its actual and predicted costs. Northern Ontario Wires is continually working to ensure its favourable rating continues.

The distribution losses metric is used to monitor the performance of the distribution system and identify unacceptable performance.

The progress of voltage conversions metric is used to ensure the voltage conversions in Iroquois Falls and Kapuskasing proceed on schedule in order to decommission the respective substations at the right time.

d) See response to 2-Staff-13.

1-SEC-7

- a) [Ex.1-5-2, p.2] Please provide a more through breakdown of how the Applicant made the assumption that material costs will increase by 3% in the test year, including full details regarding the cost trends evaluation “based on invoices and suppliers costs provided to NOW”.

Response:

- a) NOW Inc. evaluated historic costs trends for material and recurring charges for vendors and services. This comparison evaluated past trends during IRM periods where NOW cost increases outpaced the IRM rate increase. As such, NOW Inc. fell behind in covering the costs which is reflected in the achieved ROE.

The evaluation was a result of actual invoices provided to NOW Inc. for the current periods and the test year period for those that are available.

The evaluation of costs from 2015 -2016 resulted in an increase of 6.6% and for 2017 the preliminary forecast are that supplier costs will increase 4.3%. Although the material suppliers' increases are forecasted to be higher than the assumed 3%, NOW Inc. believes that the aggregate of some smaller suppliers will fall below the 3% threshold. As such the 3% was determined to be reasonable and prudent even though it is less than the estimated inflation for material suppliers.

1-SEC-8

Ref: Exhibit 2 / Tab 1 / Schedule 4 / p. 1

Question(s):

- a) Please provide a breakdown of table 1, by each of the Applicant's three service territories.

Response:

- a) Northern Ontario Wires Inc. does not track historic consumption by rate class and service territory. Gathering this information would be a significant effort, and cannot be done within the timeframe allowed for interrogatory responses.

1-SEC-9

[Ex.1-6-1, p.5] With respect to the Electric Utility Customer Survey:

- a) Did the Applicant design and conduct the entire survey themselves, or did they utilize the services of a third-party? If they did utilize the services of a third-party, please provide details.
- b) Please explain what changes, if any, were made to the application as a result of the survey.

Response:

- a) NOW primarily developed the survey in house. A survey from a fellow utility was used as the initial template. NOW then used the template to focus and develop questions toward NOW's application.

NOW Inc. retained a third-party (IndeCo) to review and assist in ensuring questions were worded correctly and would meet all regulatory requirements. The third-party costs were \$1,590.

- a) The need for an outage management system was reinforced by the survey responses. Additionally, initial steps are being included in the plan that will allow for potential future e-billing and information options.

1-SEC-10

[Ex.1-9-1, p.2] Please quantify the forecast test year expected savings from the listed productivity initiatives.

Response:

The quantified forecast test year expected savings are provided in the following table.

Initiatives	Savings
Distribution Plant Life Extension	Hard to quantify
GIS	Time savings, creating productivity gains
OMS	\$ 7,300
Voltage conversion	Futures savings will be achieved once project complete
Buying consortium	\$76k-\$102k
Standardized design	\$ 12,000
Compliance audits	\$ 3,000
Resource Sharing	*, 1-STAFF-5 c
*Includes Buying Consortium	30-50%

1-SEC-11

[Ex.1-9-1, p.2] Please provide a similar list of productivity initiatives undertaken since 2013 and quantify the savings.

Response:

The following tables provide the estimated savings from the productivity initiatives in the listing.

2013	
Initiatives	Savings
Distribution Plant Life Extension	Hard to quantify
Voltage conversion	Futures savings will be achieved once project complete
Buying consortium	45-50% savings
Standardized design	\$ 12,000
Compliance audits	\$ 3,000
Resource Sharing	*, \$207k
*Includes Buying Consortium	30-50%

2014	
Initiatives	Savings
Distribution Plant Life Extension	Hard to quantify
Voltage conversion	Futures savings will be achieved once project complete
Buying consortium	45-50% savings
Standardized design	\$ 12,000
Compliance audits	\$ 3,000
Resource Sharing	*, \$211k
*Includes Buying Consortium	30-50%

2015	
Initiatives	Savings
Distribution Plant Life Extension	Hard to quantify
Voltage conversion	Futures savings will be achieved once project complete
Buying consortium	45-50% savings
Standardized design	\$ 12,000
Compliance audits	\$ 3,000
Resource Sharing	*, \$215k
*Includes Buying Consortium	30-50%

1.0-VECC-1

Reference: E1/T2/S1/pg. 6

- a) Please provide for each year 2013 through 2016 the cost of:
- i. EDA membership;
 - ii. Customer First Inc. Membership.

Responses:

- a) i) EDA Membership costs are provided in the following table:

EDA Membership	
Year	Cost
2013	\$15,300
2014	\$16,000
2015	\$16,500
2016	\$16,700

- ii) There are no annual membership fees for Customer First Inc.

1.0-VECC-2

Reference: E1/T6/S1

- a) Please provide the cost of the Electric Utility Customer Engagement Survey.

Responses:

- a) The cost of the Customer Engagement Survey was \$2,200. These costs include the consultant Indeco along with the survey platform, and prize. Costs associated with internal labour resources are not included.

1.0-VECC-3

Reference: E1/T6/S1/Attachment 2/pg.15

- a) In response to the question of electricity outages or power quality (flickering) approximately 11% of residential customers reported occurrences of “once a month or so”. In NOW’s experience does is this percentage reasonably representative of actual outages and power quality issues for its customers?

Response:

- a) In NOW Inc’s experience the 11% result appears to be high. However, NOW Inc. believes that this reflects our customers experience and that there could be a variety of reasons for this response such as issues with customer owned equipment. In a smaller number of circumstances outages and power quality issues could relate to the NOW Inc. system. It is noted that the frequency of outages as measured by SAIFI is in the range of 0.61 – 2.19 average interruptions per year over the 2011-2015 period.

Exhibit 2 – Rate Base

2-Staff-7

Ref: Exhibit 2 / Tab 1 / Schedule 1 / p. 1
Chapter 2 Appendices / Tab 2-BA

Question(s):

- a) Please explain the differences between the rate base continuity provided in Table 1 (Exhibit 2 / Tab 1 / Schedule 1 / p. 1) and the information provided as part of the Chapter 2 Appendices / Tab 2-BA. Please update the evidence if there are any errors.

Responses:

- a) The rate base continuity in Table 1 is consistent with the Chapter 2 Appendix 2-BA.

Apparent differences in the two Tables are explained as follows:

2013: The closing Net Book Value for 2013 of \$6,164,080 is the same in Table 1 and Appendix 2-BA.

2014: Table 1 is on a CGAAP basis and Appendix 2-BA is on a MIFRS basis.

2015-2017: The closing Net Book Values on Table 1 and Appendix 2-BA are the same, as summarized in the following reconciliation table:

Reconciliation	2015	2016	2017
Per Table 1			
Closing Net Book Value	\$5,874,970	\$6,259,912	\$6,438,745
Per Tab 2-BA			
Total PP&E NBV	\$5,874,970	\$6,259,912	\$6,438,745

In Table 1 for the years 2015-2017, the Gross Fixed Asset balances and the Accumulated Depreciation balances are each \$113,322 higher than the Appendix 2-BA balances due to the \$113,322 value in the 2014 year Disposals column. This was recorded in duplicate in Appendix 2-BA, as the \$113,322 was also included in the IFRS Adjustment in 2014. This has no bearing on the rate base calculation as the amounts are offsetting. The Average Net Book Value calculated for 2017 rate base purposes is as follows:

[The 2016 closing NBV (\$6,259,912) + the 2017 closing NBV (\$6,438,745)] / 2.
The resulting value is \$6,349,329 which is shown in Table 1 (line 10) and in the
RRWF Tab 9, line 3.

2-Staff-8

Ref: Exhibit 2 / Tab 1 / Schedule 4 / p. 1

Preamble:

Northern Ontario Wires stated that the commodity price estimate used to calculate the Cost of Power was determined in a way that bases the split between RPP and the non-RPP customers on actual data and uses the most recent current RPP price.

The Cost of Power forms part of the Working Capital Allowance calculation.

Question(s):

- a) Please provide the detailed calculation for the Cost of Power. Please provide supporting evidence.

Response:

- a) The Cost of Power is calculated as the cost of the energy commodity plus all other pass-through charges.

The average cost of the commodity is calculated to be \$0.11004 as follows:

Customer Class Name	2015 ACTUAL kWh's					
	Total	non-RPP	TOU Off-Peak	TOU Mid-Peak	TOU On-Peak	RPP
Residential	41,096,056	1,383,728	25,851,701	6,770,575	7,079,372	10,680
General Service < 50 kW	19,602,981	2,854,717	8,846,696	3,204,967	3,318,183	1,378,418
General Service > 50 to 4999 kW	59,289,165	59,289,165				
Unmetered Scattered Load	168,348	23,806				144,542
Street Lighting	745,147	745,147				
TOTAL	120,901,697	64,296,563	34,698,397	9,975,542	10,397,555	1,533,640
%	100.00%	53.18%	28.70%	8.25%	8.60%	1.27%
Forecast Price						
HOEP (\$/MWh)		\$ 16.86				
Global Adjustment (\$/MWh)		\$ 90.86				
TOTAL (\$/MWh)		\$107.72	\$ 87.00	\$ 132.00	\$ 180.00	\$ 111.41
\$/kWh		\$0.10772	\$0.08700	\$0.13200	\$0.18000	\$0.11141
%		53.18%	28.70%	8.25%	8.60%	1.27%
WEIGHTED AVERAGE PRICE	\$0.11004	\$0.0573	\$0.0250	\$0.0109	\$0.0155	\$0.0014

The HOEP and Global Adjustment rates were based on the RPP Price Report dated April 14, 2016

The total Cost of Power is calculated to be \$15,984,891 as follows:

Electricity (Commodity)		Volume		Amount
kWh	TOTAL	125,716,585	\$ 0.11004	13,833,809
Transmission - Network				
	Customer		2017	
	Class Name	Volume	Rate	Amount
kWh	Residential	43,530,886	\$ 0.0062	269,891
kWh	General Service < 50 kW	21,111,406	\$ 0.0059	124,557
kW	General Service > 50 to 4999 kW	166,531	\$ 2.3529	391,831
kWh	Unmetered Scattered Load	176,689	\$ 0.0059	1,042
kW	Street Lighting	1,576	\$ 1.7746	2,797
	TOTAL	64,987,088		790,119
Transmission - Connection				
	Customer		2017	
	Class Name	Volume	Rate	Amount
kWh	Residential	43,530,886	\$ 0.0028	121,886
kWh	General Service < 50 kW	21,111,406	\$ 0.0027	57,001
kW	General Service > 50 to 4999 kW	166,531	\$ 1.0401	173,209
kWh	Unmetered Scattered Load	176,689	\$ 0.0027	477
kW	Street Lighting	1,576	\$ 0.8040	1,267
	TOTAL	64,987,088		353,840
Wholesale Market Service				
	Customer		2017 rate (\$/kWh):	
	Class Name	Volume		Amount
kWh	TOTAL	125,716,585	\$ 0.0047	590,868
Rural Rate Protection				
	Customer		2017 rate (\$/kWh):	
	Class Name	Volume		Amount
kWh	TOTAL	125,716,585	0.0013	163,432
Low Voltage Charges				
	Customer		2017	
	Class Name	Volume	Rate	Amount
kWh	Residential	40,704,801	0.0017	69,198
kWh	General Service < 50 kW	19,740,824	0.0016	31,585
kW	General Service > 50 to 4999 kW	166,531	0.5657	94,207
kWh	Unmetered Scattered Load	165,218	0.0016	264
kW	Street Lighting	1,576	0.4368	688
	TOTAL	60,778,950		195,943
Smart Meter Entity				
	Customer		2017	
	Class Name	Volume	Rate	Amount
Cust	Residential	5,216	0.79	49,448
Cust	General Service < 50 kW	784	0.79	7,432
	TOTAL			56,880
GRAND TOTAL				15,984,891

Please see Exhibit 8, Tab 3, Schedule 1, and the completed OEB RTSR model for the Transmission rates.

Please see Exhibit 8, Tab 3, Schedule 5 for the Low Voltage Rates.

2-Staff-9

Ref: Exhibit 2 / Tab 2 / Schedule 1 / p. 1

Preamble:

Northern Ontario Wires stated that, as part of the planning process, it considered the possibility of the potential impacts of incremental Conservation and Demand Management (CDM) initiatives, however, none were identified.

Question(s):

- a) Please explain the above cited statement and provide additional details.

Response:

- a) In collaboration with CustomerFirst Inc., NOW Inc. is at the preliminary stage of considering incremental CDM for Residential customers. However as these initiatives and associated are not yet identified it was premature to incorporate the impact in the plan. A pilot program for Residential customers is currently underway and once complete will be measured to determine average savings. NOW Inc. is predominantly Residential-based, therefore the results of the pilot program will better ascertain any savings and potential impacts.

2-Staff-10

Ref: Exhibit 2 / Tab 2 / Schedule 1 / p. 5
Exhibit 2 / Tab 2 / Schedule 1 / Attachments 4-6

Preamble:

Northern Ontario Wires stated that its capital plans have been informed by the annual O.Reg 22/04 Audit Report, the site inspection samples report and the fleet matrix.

Question(s):

- a) Please advise whether the recommendations set out in the cited reports (attachments 4-6 to Exhibit 2 / Tab 2 / Schedule 1) will be implemented by Northern Ontario Wires during the test year (or the forecast period). For example, the Site Inspection, Oil Samples Report includes a number of findings. Please explain how Northern Ontario Wires intends to respond to each of the findings.
- b) If possible, please provide the cost of implementing each of the recommendations set out in the cited reports.
- c) In regard to the Fleet Matrix report (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 6), there seems to be a number of vehicles that currently require, or are very close to requiring, replacement. Please advise whether Northern Ontario Wires has budgeted for the replacement of these vehicles during the test year (or the forecast period). If not, please explain.

Responses:

- a) Repairs completed and to be done are summarized as follows:

Iroquois Falls Detroyes Substation

- broken barb wire stand- repaired
- ground erosion – repaired
- corrosion causing paint to peel – cabinet is scheduled to be painted in 2017
- tap changer and oil filled cable tap box leaking – awaiting contractor availability in 2017 to assist in repairing

Iroquois Falls Mill Gate Substation

- No barb wire – to be repaired in 2017 (fencing contractor not available in 2016)
- No fence/barb wire bond- repaired
- Ground surface covering layer- no vegetation shall exist- vegetation control was completed in August
- Tap changer leaking oil - awaiting contractor availability in 2017 to assist in repairing

Cochrane Main Substation

- Spaces in fence – has been repaired
- No gravel – gravel to be added in spring 2017
- Transformer bushing leaking - awaiting contractor availability in 2017 to assist in repairing
- Fan control - awaiting contractor availability in 2017 to assist in repairing

Kapuskasing Main Substation

- Broken level gauge- awaiting contractor availability in 2017 to assist in repairing
- Ground erosion – gravel to be added in spring 2017
- Fence bonding – has been repaired

NOW Inc. has been in communication with a contractor, who will assist in the recommended repairs in 2017.

- b) Costs are not yet available as NOW Inc. is waiting for pricing from the contractor. Given NOW Inc.'s geographical location, it is limited on the number of service providers, which has always been challenging for the utility.
- c) On the Fleet Matrix, Units 510, 511 and 513 are trailers. Although they have been in-service for a number of years, they are in reasonable condition and replacement is not required at this time. Units 517 (pickup truck) and Unit 525 (van) have subsequently been removed from NOW Inc.'s fleet as these two units were replaced with one vehicle, Unit 537. NOW Inc. agrees that the fleet of vehicles is aging but did not budget for the replacement of Fleet during the test year because major equipment is expected to last beyond the planning period. NOW Inc. recognizes that some of the fleet at end of life (eg. Pickup truck) will likely need to be replaced during the forecast period and should have identified such in the DSP.

2-Staff-11

Ref: Exhibit 2 / Tab 2 / Schedule 1 / pp. 10-30

Question(s):

- a) For every multi-year project listed in Exhibit 2 / Tab 2 / Schedule 1, please provide the total cost of the project and the spending per year in a table.
- b) For 2016 capital spending, please provide actual year-to-date spending and explain any differences between actual and budgeted. If there are any material differences, please explain whether those differences will impact capital spending during the test year and forecast period.
- c) Northern Ontario Wires stated that it noticed climate change and different weather patterns impacting equipment that was historically not affected (Exhibit 2 / Tab 2 / Schedule 1 / p. 11). Please provide relevant examples.
- d) What was the original cost of the bucket truck (Unit 526) (Exhibit 2 / Tab 2 / Schedule 1 / p. 12)?
- e) Please provide a detailed breakdown of the \$30,000 of capital spending on computer hardware for 2016 (Exhibit 2 / Tab 2 / Schedule 1 / p. 12). Please provide the newly installed server capacity and Northern Ontario Wires' actual 2015 (and 2016, if available) data storage requirements.
- f) Please provide a detailed breakdown of the \$120,914 of capital spending on computer software (Exhibit 2 / Tab 2 / Schedule 1 / p. 13).
- g) Please provide a detailed breakdown of the \$115,000 of 2017 computer software capital spending (Exhibit 2 / Tab 2 / Schedule 1 / p. 17). Please provide the expected implementation timelines for each of the projects incorporated in the computer software spending (e.g. OMS, electronic billing option).
- h) Please provide the actual capital spending on tools and equipment for the period 2014-2016 (to-date). Please explain the variance between the test year

Response:

- a) Capital Expenditures for 2016-2021 are summarized in the following table. The four multi-year projects are highlighted. Other capital expenditures represent either ongoing programs (e.g. pole replacement) or projects that are completed within one year.

Capital Expenditures 2016-2021								
Summary of Exhibit 2/Tab 2/Schedule 1 Projects								
		2016	2017	2018	2019	2020	2021	Total
System Access								
Metering		15,000	15,000	15,000	20,000	20,000	20,000	105,000
		15,000	15,000	15,000	20,000	20,000	20,000	
System Renewal								
Cochrane Pole Changes		55,000	105,000	55,000	55,000	55,000	55,000	380,000
Kapuskasing Pole Changes		55,000	55,000	55,000	55,000	55,000	55,000	330,000
Iroquois Falls Pole Changes		27,500	55,000	55,000	55,000	55,000	55,000	302,500
Cochrane Lakefront Rebuild		50,000						50,000
Cochrane Substation Feeder		25,000						25,000
Cochrane 5kV Upgrade			90,000	180,000	130,000	135,000	140,000	675,000
Cochrane Substation Feeder			50,000					50,000
Cochrane Substation Transformer				50,000	75,000	50,000	75,000	250,000
Iroquois Falls Substation (Detroyes) Switch Gear						50,000		50,000
		212,500	355,000	395,000	370,000	350,000	380,000	
System Service								
Kapuskasing 5kV to 25 kV Conversion Upgra		140,000	175,000	200,000	205,000	215,000	220,000	1,155,000
Iroquois Falls 2.4 to 12 kV Upgrade		87,000	140,000	155,000	165,000	170,000	180,000	897,000
		227,000	315,000	355,000	370,000	385,000	400,000	
General Plant								
Transportation & Work Equipment		85,000						85,000
Tools & Equipment		12,500	17,500	17,500	17,500	17,500	17,500	100,000
Computer Hardware		30,000	10,000	10,000	10,000	10,000	10,000	80,000
Computer Software		120,914	115,000	5,000	5,000	5,000	5,000	255,914
		248,414	142,500	32,500	32,500	32,500	32,500	
Total Capital		702,914	827,500	797,500	792,500	787,500	832,500	

- b) The 2016 unaudited actual figures will be provided by February 17, 2017. However, any material difference between actual and budget for 2016 will not materially impact capital spending during the test year and forecast period. The plans for the test year and forecast period are distinct from the 2016 year end as far as planning and scope. Should 2016 projects not be as far along as expected, the dollars spent in the test year and forecast period are not anticipated to differ, although project priorities may vary. The capital spending for 2017 and forecast is not expected to be materially impacted by 2016 results.

- c) In Jan-Feb 2016, Cochrane experienced a sustained cold front. At extreme temperatures, frost penetrates deeper into the ground. As depicted in the photo below, heaving has occurred to the concrete pad under equipment at NOW Inc.'s Cochrane Substation. This makes for an uneven surface for equipment and potential safety hazards. Other examples include leaning and/ or damage poles and other assets located on or in the ground.



- d) The original cost of the bucket truck (Unit 526) was \$276,423.
- e) New servers were purchased to replace the old ones for multiple reasons. The main reason is the depreciation and the useful life of the equipment. The operating system of the old server reached the end of life and is no longer being supported, which means this product will no longer be receiving Security patches to help protect servers from harmful viruses, spyware, and other malicious software. This makes our system vulnerable, less reliable and increases the total cost of ownership (TCO).

The new operational system platform has a higher requirement than the equipment we currently have in place. Its functionality requires several servers, here are the required servers: Application Server, Database Server Production, Production Server for Reports Anywhere / eDocs, Production Server for Client / Connection) and Database Test Server. The technical server requirements are provided in Attachment 1.

- f) The breakdown of the \$120,914 capital spending on computer software is for the finalization of the GIS Project. This cost includes approximately \$70,000 labour and burden, \$35,000 vehicle and equipment costs and 16,000 in material costs.
- g) As per E2/E2/S1/Att 1 p.85, the breakdown of the \$115,000 in 2017 computer software expenditures is as follows:
Outage Management System: \$40,000
CIS: \$75,000
The implementation timelines vary. With approval in rates, the process would be started in May and anticipated completion by year end 2017.
- h) Capital spending on tools and equipment for 2014-2016 to date is included in the table below. The 2016 to date balances are pending finalization of the year end results. NOW Inc. currently has tools that have been in service for a number of years which need to be replaced in order to ensure their safe and reliable operation. There is no material variance in spending 2014 to 2016 and the test year. Tool replacements are paced and acquired on an as needed basis which results in staggered acquisition as opposed to a cyclical replacement schedule.

	2014	2015	2016
Capital Spending on Tools	\$ 5,007	\$ 2,500	\$ 10,485

1 APPENDIX A - NORTHSTAR 6.4 – TYPICAL HARDWARE RECOMMENDATIONS

Optimal Hardware	Optimal Software
NorthStar CIS v6.4 Application Server • Quad Xeon Processor • 16GB Memory • 4 X 146GB 15K SAS Drives	NorthStar CIS v6.4 Application Server • Redhat Enterprise Linux 6.X 64 Bit / Windows 2012 R2 64 Bit • JBoss 5.1 • Tomcat 6.0 • Java 6
NorthStar CIS v6.4 Prod Database Server • Quad Xeon Processor • 32GB Memory • 8 X 146GB 15K SAS Drives	NorthStar CIS v6.4 Database Server • Redhat Enterprise Linux 5.7 64 Bit • Oracle 10-11g / SQL Server 2012 R2/ Informix SE / Informix Dynamic Server 11
NorthStar CIS Production Extension Server (Reports Anywhere, eDocs) • Dual Xeon Processor • 16GB Memory • 2 X 72GB 15K SAS Drives	NorthStar CIS Production Extension Server • Windows 2012 R2 64 Bit
NorthStar CIS Production Extension Server (Customer Connect) • Dual Xeon Processor • 32GB Memory • 500GB 15K SAS Drives	NorthStar CIS Production Extension Server (Customer Connect) • Windows 2012 R2 64 Bit
NorthStar CIS v6.4 Client Computer • Dual Core CPU (Intel Core2, AMD Phenom...) • 40GB hard drive (or higher) • 4GB Memory	NorthStar CIS v6.4 Client Computer • Windows XP (32 or 64) • Windows 7 or 8 (32 or 64) • JRE 6.0 • Microsoft Office 2010

2-Staff-12

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 6

Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 11

Preamble:

At Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 6, Northern Ontario Wires stated that growth is expected in Cochrane in the near future due to the opening of the Detour Lake Gold Mine.

At Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 11, Northern Ontario Wires stated that it has not budgeted for any capital expenditures for customer service requests.

Question(s):

- a) Please explain why Northern Ontario Wires has not budgeted for any capital expenditures for customer service requests despite expecting growth in Cochrane in the near future.

Response:

- a) The expected growth is from a developed subdivision, wherein the infrastructure is already in place and paid for by the developer. The infrastructure in this subdivision will be turned over to the NOW Inc. at no cost.

2-Staff-13

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 19

Preamble:

Northern Ontario Wires provided a table of performance metrics and the relevant motivation at Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 19.

Question(s):

- a) Please add the following to the table in your response:
 - i. Desired outcome for each performance metric;
 - ii. Linkage to the relevant project that will address the performance metric and lead to the desired outcome (where applicable).

Responses:

- a) See updated table on the following page. Please be advised this information is included in the section text and the details remain in that section. Each sub-section of Section 2.3 followed a pattern of:
 - .1 - Description and Target
 - .2 - Historical performance (where applicable)
 - .3 - Impact on Capital Plan/DSP (if any)

Customer oriented performance	Reliability	Consumer Regulatory	SAIFI	2.19 or less	Replacement of assets at the end of their service life – SR1, SR2, SR3, SR4A, SR4B, SR4C, SR4D, SR4E, SR5, SR6, SR7, SR8, SS1A, SS1B, SS1C, SS1D, SS1E, SS2A, SS2B, SS2C, SS2D, SS2E
			SAIDI	4.63 or less	
			CAIDI	2.11 or less	
			Customer outages by cause code	Identify root cause of outages	
	Service quality	Consumer Regulatory	Telephone accessibility	65% or greater	N/A
			Telephone abandon rate	10% or less	
			Low voltage connections	90% or greater	
			High voltage connections	90% or greater	
			Appointments scheduling	90% or greater	
			Appointments met	90% or greater	
			Missed appointment rescheduling	100%	
			Written response to enquiries	80% or greater	
			Emergency response – rural	N/A	
			Emergency response – urban	80% or greater	
			Reconnection performance standards	85% or greater	
			Billing accuracy	98% or greater	
Cost efficiency & effectiveness	DSP implementation	Regulatory Corporate	Physical progress vs. plan	100% of budgeted projects / programs completed in the year budgeted	All material projects / programs
			Financial progress vs. plan	Less than 10% variance between actual and budgeted DSP expenditure level	
			Actual vs. planned cost of work completed	Less than 10% variance between actual and	

				budgeted project / program costs	
	Total cost	Consumer Corporate	Total cost per customer Total cost per km of line	Monitor spending trends Monitor spending trends	Improve operational efficiency through IT investments – GP1 Decommission substations – SR8, SS1A, SS1B, SS1C, SS1D, SS1E, SS2A, SS2B, SS2C, SS2D, SS2E Proactive asset replacements – SR1, SR2, SR3, SR4A, SR4B, SR4C, SR4D, SR4E, SR5, SR6, SR7
	Efficiency assessment	Regulatory Consumer Corporate	PEG efficiency assessment	Group 1	
Asset & systems operations performance	Distribution losses	Corporate	Percentage line loss	Monitor the distribution system performance	Voltage conversions – SS2A, SS2B, SS2C, SS2D, SS2E, SS1A, SS1B, SS1C, SS1D, SS1E Replace transformers with more efficient models – SR4A, SR4B, SR4C, SR4D, SR4E, SR6
	Progress of voltage conversions	Corporate	2.4 kV delta conversion progress (Iroquois Falls) 4.16/2.4 kV conversion progress (Kapuskasing)	Complete Iroquois Falls voltage conversion by 2022 Complete Kapuskasing voltage conversion by 2025	Iroquois Falls voltage conversion – SS2A, SS2B, SS2C, SS2D, SS2E Kapuskasing voltage conversion – SS1A, SS1B, SS1C, SS1D, SS1E

2-Staff-14

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 25

Preamble:

Northern Ontario Wires provided its historical service quality measure performance in a table at Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 25.

Question(s):

- a) Please explain the 0% figure listed for telephone accessibility for 2012.

Responses:

- a) Northern Ontario Wires Inc. has a very good rapport with customers and all telephone calls are answered by a live customer service agent. NOW Inc. does not have an automated answering system. In order to record incoming calls and respond to the SQI requirements, a manual reporting system was implemented. In 2012, the OEB questioned whether the manual reporting system met the requirements and disallowed the original entry of 100% until further examination and decision. Subsequent years have been reported on the manual tracking system.

2-Staff-15

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 26

Preamble:

Northern Ontario Wires provided its DSP Implementation Metrics and Targets in a table at Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 26.

Question(s):

- a) Please better explain the metric related to financial DSP progress.
- b) Please better explain the metric related to actual vs. planned cost of work completed.
- c) Please explain the difference between these two metrics.

Responses:

- a) Financial DSP progress” measures the variance between total actual and budgeted capital spending for each year of the DSP.
- b) “Actual vs. planned cost of work completed” measures the variance between actual and budgeted capital spending for each individual project/program.
- c) For “Financial DSP progress” variance is calculated for the total annual capital spending, while for “Actual vs. planned cost of work completed” variance is calculated for each individual project/program.

2-Staff-16

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 27

Preamble:

Northern Ontario Wires provided historical total cost per customer and per km of line for the period from 2012 to 2014 but not 2015.

Question(s):

- a) Please provide a detailed explanation of increase in total cost per customer and total cost per km of line for 2013. Please include a detailed discussion of what Northern Ontario Wires means by “experienced an atypical bad debt expense in conjunction with accounting treatment required by regulators.”
- b) Please provide amended Figures 2-6 and 2-7 that add 2015 total costs per customer and per km of line, respectively. If this is not possible, please explain why.

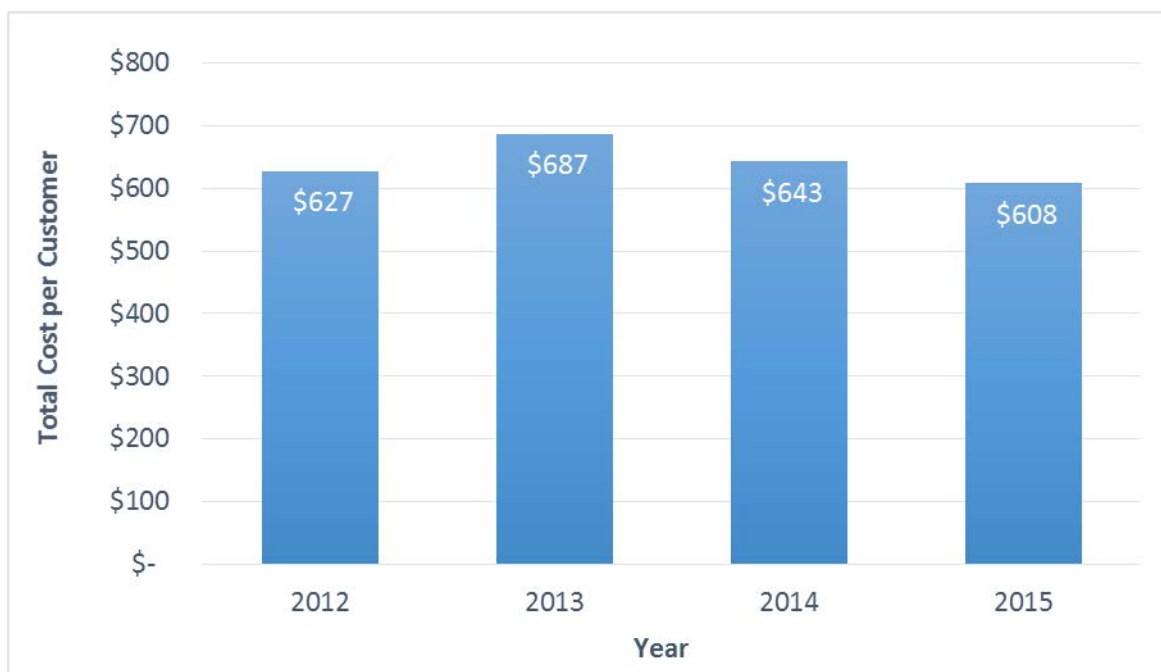
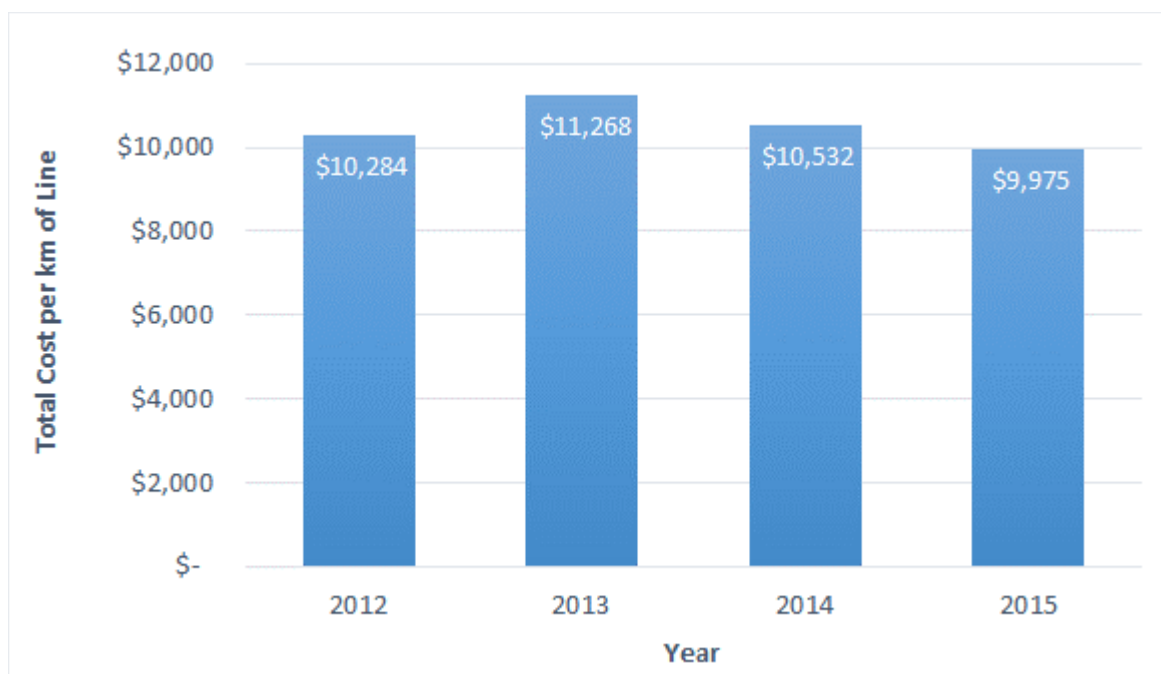
Responses:

- a) Please refer to 4-Staff-36 a).
Also, in NOW's application (E4/T3/S1/pg.21) NOW Inc. discussed the atypical bad debt expense which resulted from one large customer declaring bankruptcy which left NOW Inc. with a bad debt expense of \$381,362 including cost of power.

The reference to accounting treatment required by regulators is the disposition of smart meters that took place in 2013. These costs were held in deferral and variance accounts during smart meter implementation and were allocated to expenses as a result of the decision in EB-2012-0353. The smart meter disposition impact on NOW Inc, cost per km of line amount to \$492,500 to OM&A and \$1,432k to Gross Capital costs. According to the 'Scorecard – Performance Measure Descriptions' “Total cost is calculated as the sum of a distributor's capital costs and OM&A costs, ...” .

As such, these added costs increased the total cost per km of line for 2013.

- b) See updated figures below.



2-Staff-17

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 29

Preamble:

Northern Ontario Wires has shown that historical electrical losses have been trending downward. Northern Ontario Wires indicates that proposed future projects will reduce electrical losses further.

Question(s):

- a) Please explain whether the benefits of Northern Ontario Wires' proposed voltage conversion projects are reflected in Northern Ontario Wires' proposed test year line losses (%).
- b) Does Northern Ontario Wires have a forecast of the percentage line losses during the future years of the Distribution System Plan (DSP) (2017-2021)? If so, please provide that estimate.

Response:

- a) No. The line losses are calculated on the OEB Chapter 2 Appendix 2-R. The line losses are calculated using the 5-year average methodology provided in that appendix.
- b) No.

2-Staff-18

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 32-33

Preamble:

Northern Ontario Wires noted that it has demographic and condition data on 50% of its pole-mounted transformers and 90% of its pad-mounted transformers. Northern Ontario Wires stated that it will obtain the missing data by the end of the DSP period.

In Figure 3-2, Northern Ontario Wires presented its planning process for system renewable projects. It is unclear in this process where pad-mounted and pole-mounted transformers are considered.

Question(s):

- a) How are pad-mounted and pole-mounted transformers considered in the planning process shown in Figure 3-2?
- b) Please explain how the limited demographic and condition data for these assets affects Northern Ontario Wires' planning of System Renewal investments.

Responses:

- a) As noted in Table 3-6 (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 48) pad-mounted and pole-mounted transformers are inspected on a three-year cycle. These correspond to the "Underground Inspections" and "Overhead Rebuilds", respectively, that are inputs into the planning process for system renewal projects noted in Figure 3-2 (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 33).

As noted in the bottom paragraph of Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 45, Northern Ontario Wires treats pad-mounted transformers and pole-mounted are run-to-failure assets and replaces them reactively where failures are inspection defined or cause an outage. Therefore Northern Ontario Wires does not specifically plan system renewal projects/programs for distribution transformer replacements. Although distribution transformers are replaced as part of the project scopes for overhead and underground rebuilds, their replacements are not the primary drivers for these projects.

- b) The demographics and condition data are known for 100% of pad-mounted transformers as shown in Figure 3-1 (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 32).

As stated in the response to question (a) above, pole-mounted transformers are run-to-failure assets, and are therefore not included in the planning process for system renewal investments.

Assuming Board Staff would like to know how the limited demographic and condition data for poles – shown as 90% in the reference above – affects Northern Ontario Wires' planning of system renewal investments, as noted in Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 46: "Pole replacements are budgeted each year and the inspection process identifies individual poles for replacement." Therefore, poles whose condition are not known currently can be replaced under the planned Pole Replacement Programs (SR1, SR2, and SR3) if they are identified for replacement during inspection.

2-Staff-19

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 39

Preamble:

Northern Ontario Wires noted that the most recent (2015) Substation Oil Analysis report identified 11 substation transformers, load tap changers, and reactors with concerning results from the dissolved gas analysis and the oil quality tests.

Question(s):

- a) Please advise whether all of the recommendations in the noted report have been addressed during 2015-2016?
- b) Please advise when the next report of this nature will be completed.

Response:

- a) NOW Inc. has addressed the priority issue of low oil in the tap changer. The other recommendations in the noted report have not yet been addressed. NOW Inc. is in the process of engaging a contractor to undertake this work and address the other identified issues.
- b) NOW Inc. expects the next report late summer 2017.

2-Staff-20

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / pp. 59-60

Preamble:

Northern Ontario Wires provided a numeric weighting for project prioritization at Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 59.

Northern Ontario Wires provided the prioritization list of its major projects / programs over the forecast period at Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 60.

Question(s):

- a) Please provide a detailed explanation for the numeric weightings and provide rationale.
- b) Please explain why engaging in environmental protection has a higher numeric weighting than reliability projects.
- c) Please advise who will be constructing the projects – Northern Ontario Wires internal staff or third-party contractors? Please provide a detailed explanation for each project.

Responses:

- a) Table 4-3 (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 59) provides numeric weightings for Northern Ontario Wires' asset management objectives, which are based on its corporate objectives. As stated in Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 31:

NOW Inc. is committed to providing its customers with a safe and reliable electricity supply while operating effectively and efficiently at an equitable cost. NOW Inc. strives for excellence and continuous improvement in order to maximize shareholder value. Based on these corporate goals, NOW Inc.'s asset management objectives are prioritized as follows:

- 1. Operating a safe electrical system for employees and the public.
- 2. Meeting regulatory requirements.
- 3. Engaging in environmental protection.

4. Accommodating load growth and new customer connections.
5. Delivering a reliable supply of electricity.
6. Managing costs and rate stability.

Safety is NOW Inc.'s top priority in every aspect of its business. NOW Inc. always strives to maintain and operate its electrical system in such a way that poses minimal hazard to its employees and the public. Meeting regulatory requirements set out by the OEB is the next priority, since the OEB's mandate comes directly from the provincial government. Thirdly, NOW Inc. prioritizes environmental protection, but this is not usually a driver for investment due to the nature of NOW Inc.'s system. NOW Inc.'s fourth priority is to provide power to its customers by accommodating load growth and new customer connections, which relates to its fifth priority of delivering power reliably. Finally, NOW Inc. aims to improve its operational efficiency and manage costs in order to keep electricity prices low for its customers.

Therefore, the numeric weightings shown in Table 4-3 (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 59) were assigned based on this priority. Since safety is the highest priority it was assigned a numeric weighting of 10. The next priority is meeting regulatory requirements, which was assigned a numeric weighting of 8. The priorities and numeric weightings follow in order: engaging in environmental protection (7), accommodating load growth and new customer connections (6), delivering a reliable supply of electricity (5), and managing costs and rate stability (4).

- b) The numeric weighting is derived from Northern Ontario Wires' asset management objectives, which ranks "engaging in environmental protection" higher than "delivering a reliable supply of electricity". Environmental stewardship is of great importance for Northern Ontario Wires. For instance a theoretical project to install an oil containment system at a substation in close proximity to a waterway would have higher priority than a theoretical project to install sectionalizing switches to improve reliability. The numeric weighting reflects this priority.
- c) All of the labour for the reported projects will be completed by Northern Ontario Wires' internal staff.

2-Staff-21

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / pp. 82-84

Preamble:

Northern Ontario Wires set out its spending by year and by service area for pole replacements in a table at Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 82. \$115,000 is budgeted for pole replacements in Cochrane in 2017. The budgeted spending for the other service areas in all years and for Cochrane during the 2018-2021 period is \$55,000.

Question(s):

- a) Please advise which service area has poles in the worst condition.
- b) Please explain why the budget is significantly higher for pole replacements in Cochrane in 2017 than in other years and in other service areas.
- c) In regard to table 4-9 (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 82), please explain why the forecast cost is different in the years 2018-2021 when the project description is the same.
- d) In regard to Table 4-10 (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 83), please explain the difference between the substation transformer bank replacements in 2018 and 2019.
- e) In regard to the voltage conversion project, Northern Ontario Wires stated that “the voltage conversion of the delta system is planned from the outside in; the innermost areas have the oldest poles and higher span lengths due to the wider lots” (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 83). Please further explain this statement. Please advise why working from the outside in is the best course of action.
- f) In regard to Table 4-13 (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 84), please explain in detail what software is being purchased in each year and in each category.

Responses:

- a) The municipality of Cochrane has the worst pole conditions. This is not only due to age, but due to yellow pine poles which are prematurely deteriorating along with clearance issues that create a safety concern. The poles in Iroquois Falls are older, but the conditions in Cochrane require pole replacement sooner.
- b) Please note that as per Table 4-8 on the referenced page 82 of E2/T2/S1/Att1, Cochrane pole replacements in 2017 are planned to be \$105,000, not \$115,000 as per the interrogatory reference.

Planned pole replacements of \$105,000 in Cochrane in 2017 are higher than other years and locations due to a) the identification of additional poles that will require installation as a result of requirements related to clearance issues which are covered by O.Reg 22-04, b) during the course of line patrols, NOW Inc. has identified a number of southern yellow pine poles, which are deteriorating at a faster pace than the normal red cedar and jack pine poles, and c) the Cochrane pole replacement program has a number of corner-poles which are more costly to replace than typical poles.

- c) Table 4-9 project descriptions do not include two pad mount transformers in 2018. The cost in the table are correct.
- d) The difference in the substation transformer bank replacements in 2018 and 2019 are a result of one bank being replaced in 2018 and the second bank being replaced in 2019. The work in 2019 requires more infrastructure work resulting in greater costs.
- e) The 12kv circuit (outside) surrounds the 2.4kv Delta (inside). In order to bring the 12kV to the inside area, a connection is required to extend the existing 12kv line which is transferred as completed, minimizing customer service interruptions. By having 12kv transformers installed and ready for energizing, the secondary bus can be disconnected from the existing 2.4kv transformer and connected to the new 12kv transformer.
- f) Please refer to the response for 2-Staff-11 g) in regards to 2017 purchases for the Outage Management System, and upgrade to CIS software. For 2018 through 2021, NOW Inc. intends to upgrade software and licensing and server software upgrades, such as: remote desktop software, translation software, PDF writers, anti-virus software, spam filters, server backup

software. With the evolving risks associated with IT security, upgrades and security are becoming more important.

2-Staff-22

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 12
Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / Appendix A / SR4A
Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / Appendix A / SR6
Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 13
Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / Appendix A / SS1A
Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 6

Preamble:

At the first reference, one of Northern Ontario Wires' major System Renewal projects is a rebuild of certain sections of the 4.16/2.4 kV lines in the Town of Cochrane because they have reached the end of the service life. At the second reference, Northern Ontario Wires stated that the proposed project is preferred based on the trade-off between costs and benefits.

At the first reference, Northern Ontario Wires also explained that it is replacing transformers at the T2 transformer bank of the 4.16/2.4 kV Cochrane DS. The third reference does not include any alternatives for this project.

At the fourth reference, one of Northern Ontario Wires' major System Service projects is upgrading the 4.16/2.4 kV system in the Town of Kapuskasing to 25/14.4 kV because it will allow the 4.16/2.4 kV Kapuskasing DS to be retired and reduce O&M costs. At the fifth reference Northern Ontario Wires stated that the proposed project is preferred based on the trade-off between costs and benefits.

At the sixth reference, Northern Ontario Wires stated that growth is expected in Cochrane in the near future due to the opening of the Detour Lake Gold Mine.

Question(s):

- a) How much unused capacity will there be on the 4.16/2.4 kV lines in the Town of Cochrane?
- b) Would upgrading the 4.16/2.4 kV system in the Town of Cochrane assist Northern Ontario Wires in meeting expected load growth following the opening of the Detour Lake Gold Mine?

- c) Could the need to replace the transformers at the T2 bank of the Cochrane DS be eliminated or deferred if Northern Ontario Wires started converting the 4.16/2.4 kV system in the Town of Cochrane to a higher voltage?
- d) Did Northern Ontario Wires assess the value of the potential reduction in losses if the Cochrane 4.16/2.4 kV system in the Town of Cochrane was converted to a higher voltage?
- e) Please provide the dollar value for each of the costs and benefits assessed to determine that the second and fourth alternatives assessed in the second reference.
- f) Please provide the dollar value for each of the costs and benefits assessed to determine that the second and fourth alternatives assessed in the fifth reference.

Responses:

- a) Recent loading data (Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 43) depicts a peak load of 2,714 kVA on the 4.16/2.4 kV system in the Town of Cochrane. This equates to 3,286 kVA of unused capacity out of the nominal 6 MVA.
- b) The expected load growth following the opening of the Detour Lake Gold Mine can be served by the existing infrastructure in the Town of Cochrane. Note that the additional load is residential, since the mine itself is not in Northern Ontario Wires' service territory. A new subdivision was built by a developer in anticipation of the residential load increase on the 25/14.4 kV system. This infrastructure has yet to be turned over to NOW Inc.
- c) The transformers at the T2 bank of Cochrane DS require upgrades in 2018/2019. As noted in the Project Narrative SR6: "The transformer bank consists of three 1 MVA transformers that were installed in 1953 and are over 60 years old. The cooling fins exhibit severe rusting and the foundation is cracked." A voltage conversion of the 4.16/2.4 kV system in the Town of Cochrane would take more than a decade to complete due to resource and budget constraints. Therefore, the need to replace the transformers at the T2 bank of the Cochrane DS could not be eliminated or deferred if Northern Ontario Wires started converting the 4.16/2.4 kV system in the Town of Cochrane to a higher voltage.

Furthermore, the voltage conversion of the 4.16/2.4 kV system in the Town of Cochrane is not the preferred option irrespective of the condition of the 4.16 kV power transformers. The conversion would decrease reliability, since the two voltage systems in Cochrane can presently meet demand with contingency in case of a loss of a power transformer. Transferring all of the load onto the 25/14.4 kV system would constrain it past the point of being able to supply power in a contingency situation.

- d) Northern Ontario Wires did not assess the value of the potential reduction in line losses if the 4.16/2.4 kV system in the Town of Cochrane was converted to a higher voltage. Since distribution losses are proportional to the square of the current, converting the feeder from 4.16/2.4 kV to 25/14.4 kV would reduce losses by $1 - (4.16)^2/(25)^2$, or 97%. Assuming that distribution lines losses are about 1% of energy sold for an urban feeder¹, the energy savings is 97 % of 1%, or 0.97%.

Cochrane has about 30% of the load in Northern Ontario Wires' service territory and 20% of the Town of Cochrane's load is on the 4.16/2.4 kV system. Using the 2015 energy consumption, the energy savings would be $130 \text{ GWh} \times 0.2 \times 0.3 \times 0.0097 = 75 \text{ MWh}$. At \$0.0123/kWh this is about \$1,000 per year.

- e) Northern Ontario Wires did not perform a detailed cost-benefit analysis since the conclusion was stated in the Project Narrative SR4A. The 25/14.4 kV system in Cochrane does not have capacity to pick up the entire 4.16/2.4 kV system; therefore a voltage conversion would negatively impact the reliability of power supply and would also be more expensive than an overhead rebuild (the planned project). A rough analysis is shown below to support the decision:

Overhead Rebuild – Cochrane – 2017

Option #	2	4
Description	Rebuild the 4.16/2.4 kV overhead feeder;	Replace the 4.16/2.4 kV feeder with a 25 kV feeder
Cost of Circuit Replacement	\$128,000/km x 0.7 km = \$90,000	\$175,000/km x 0.7 km = \$122,500
Cost of 25 kV Feeder Tap	None	\$175,000/km
Reliability Benefit	Presently the 4.16/2.4 kV and 25/14.4 kV systems can both supply power in case of a loss of one	Moving load onto the 25/14.4 kV system will constrain its ability to supply power in case of a

¹ "Distribution Line Losses," Hydro One Networks Inc., EB-2007-0681, Ex. A, Tab 15, Schedule 3

	transformer.	loss of one transformer.
Other Benefits	- Replace short and end-of-life poles. - Higher line losses	- Replace short and end-of-life poles - Less line losses

- f) Northern Ontario Wires did not perform a detailed cost-benefit analysis since the conclusion was stated in the Project Narrative SS1A. The 4.16/2.4 kV system in the Town of Kapuskasing is already on the 25/14.4 kV system, but stepped down through a distribution substation. Therefore there are no reliability constraints unlike in Cochrane. The incremental cost savings of rebuilding at 4.16/2.4 kV is much less than the cost savings of eliminating the 4.16 kV substation following the voltage conversion. A rough analysis is shown below to support the decision:

Voltage Conversion – Kapuskasing – 2017

Option #	2	4
Description	Upgrade 4.16/2.4 kV to 25/14.4 kV;	Rebuild at 4.16/2.4 kV
Cost of Circuit Replacement	\$175,000/km x 1 km = \$170,000	\$128,000/km x 1 km = \$128,000
Annual Substation O&M Cost	Eliminated after 2025	
Substation Capital Cost	Cost of decommissioning substation: \$75,000	Cost of rebuilding substation in near future: \$2,500,000
Reliability Benefit	Replace deteriorated poles, conductors, and transformers.	Replace deteriorated poles, conductors, and transformers.
Other Benefits	Less line losses	Higher line losses

2-Staff-23

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / Appendix A / p. 33

Question(s):

- a) Please explain why there are no specific start dates or in-service dates for the Cochrane DS substation feeder upgrade project. Please provide an update on this project.

Response:

- a) The DS substation feeder upgrade project requires the assistance of Hydro One to install openers on the incoming 115kV feeder in order to isolate the substation so as to not impact Hydro One customers. NOW Inc. is waiting for a response from Hydro One with regard to a date in order to complete this project. It is expected to occur in 2017.

2-Staff-24

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 41

Preamble:

Northern Ontario Wires stated that wood poles have a typical useful life of 45 years and therefore that poles greater than 40 years of age have a significant probability of failure.

Question(s):

- a) Does Northern Ontario Wires conduct statistical analyses of its asset demographics, asset conditions and asset failures? If so, please summarize those analyses. If not, please explain the basis for Northern Ontario Wires' view that poles greater than 40 years old having a significant probability of failure.

Response:

- a) NOW Inc. is aware of the age demographic of its assets (e.g. Figure 3.6 on the cited pg. 41). However, NOW Inc. does not conduct statistical analyses of its asset demographics, asset conditions and asset failures. When conducting routine line patrols, experienced senior staff is able to identify deteriorating poles with accuracy and typically these are the older poles.

2-Staff-25

Ref: Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 43-44

Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 6

Preamble:

At the first reference, Northern Ontario Wires stated that the 4.16 kV Cochrane DS has sufficient capacity to supply customers in the event of a transformer outage. Northern Ontario Wires also stated that the 25 kV Cochrane DS does not have sufficient capacity to supply customers close if a transformer suffers an outage during times of high load.

At the second reference, Northern Ontario Wires stated that it expects loads in the Town of Cochrane to grow.

Question(s):

- a) Does Northern Ontario Wires expect the 25 kV Cochrane DS to serve the new load additions in the Town of Cochrane?
- b) How often is the Cochrane DS forecast to be unable to serve customers in the event of a transformer outage during the period from 2017 to 2021?
- c) Is Northern Ontario Wires concerned about its capability to supply consumers from the 25 kV Cochrane DS in the event of a transformer outage?

Response:

- a) NOW Inc. expects that the 25 kV Cochrane DS will be able to serve the new load additions in Cochrane. There are no concerns with adding additional load to Cochrane's 25kV station.
- b) NOW Inc. does not forecast any inability to serve customers in the event of a transformer outage. NOW Inc. currently has two transformers and in the event of a failure, can still serve customers on one transformer until the failed transformer is repaired/replaced.
- c) There are no concerns at this time.

2-Staff-26

Ref: Exhibit 2 / Tab 2 / Schedule 1 / p. 45-46

Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 48

Preamble:

At the first reference, Northern Ontario Wires indicated that small deficiencies on distribution transformers are repaired but more severe deterioration requires replacement. Northern Ontario Wires stated that it does not implement life extension programs for distribution transformers outside of its three-year inspection cycle and that this keeps system O&M low.

At the second reference, Northern Ontario Wires indicated that it has no maintenance programs for pole-mounted transformers.

Question(s):

- a) Please explain whether the repairs of small deficiencies for distribution transformers are part of a maintenance program.
- b) Has Northern Ontario Wires assessed the reduction in system O&M costs attributable to its policy of not using life extension outside of the three-year inspection cycle? If so, please provide that assessment.
- c) Has Northern Ontario Wires assessed the cost impact of replacing transformers reactively instead of spending more to extend the lives of transformers? If so, please provide that assessment.
- d) Has Northern Ontario Wires compared its practice not to use life extension to the practices of other utilities? If so, please summarize any similarities and differences between Northern Ontario Wires' practice and the practices of other utilities.

Response:

- a) Small deficiencies such as broken transformer bushings are part of NOW Inc.'s maintenance program. These repairs are generally completed in the field.

- b) NOW Inc. has not assessed the reduction in system O&M costs attributable to not using life extension outside of the three-year inspection cycle.
- c) NOW Inc. currently replaces transformers only in the event of complete failure. In NOW Inc.'s experience, transformers can last approximately 50 years (plus). Minimal work, such as bushing replacements, will extend transformer life. It is not cost effective to change a transformer that can readily be repaired at a minimal cost.
- d) NOW Inc. has not made any life extension comparisons with other utilities.

2-Staff-27

**Ref: Exhibit 2 / Tab 2 / Schedule 7 / pp. 1-3
Chapter 2 Appendices / 2-G**

Preamble:

Northern Ontario Wires stated that it developed its service reliability targets based on an average of the previous 5-years in accordance with the OEB's Report of the Board in EB-2014-0189.

Question(s):

- a) Please explain the difference between the 2017 service reliability targets at Exhibit 2 / Tab 2 / Schedule 7 / p. 3 and the 5-year reliability averages set out in Chapter 2 Appendices / 2-G.

Responses:

- a) The service reliability targets in Figure 4, in E02/T02/S07 p. 3 are the same as provided on the 2015 Scorecard for Northern Ontario Wires Inc. (E01/T07/S01/Att2). Appendix 2-G values reflect historical five-year averages for SAIDI (3.046) and SAIFI (1.412) and should have been included in Figure 4.

2-SEC-12

[Ex.2, Appendix 2-AB] Please provide a completed version of Appendix which shows the Applicant's internal budgeted amounts in the 'Plan' columns. Please also indicate the date basis of the internal budget used.

Response:

NOW Inc. is unable to provide the internal budget in the 'Plan' columns as the historic budgets are not prepared on that basis. The total expenditure row was provided in the application. Typically the budget is presented to the Board in the first quarter.

2-SEC-13

[Ex.2] Please update the following tables to provide 2016 year-end actuals and explain all material differences from the forecasted amounts:

- a) Appendix 2-AA
- b) Appendix 2-AB
- c) Appendix 2-BA (2016 and 2017)

Response:

- a) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.
- b) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.
- c) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.

2-SEC-14

[Ex-2-2-1, p.15] Please provide the forecasted in-service date for each material 2017 capital project.

Response:

The material projects listed below are over the \$50k threshold. With the exception of Computer Software, all projects are ongoing. For ongoing projects, 2017 planned work will be in-service throughout the year with all work completed and in-service in the fall prior to inclement weather arriving. The project related to Computer Software is expected to be in service mid-year.

- Cochrane Pole Changes (\$105,000)
- Kapuskasing Pole Changes (\$55,000)
- Iroquois Falls Pole Changes (\$55,000)
- Cochrane 5kV Upgrade (\$90,000)
- Cochrane Substation Feeder (\$50,000)
- Kapuskasing 5kV to 25 kV Conversion Upgrade (\$175,000)
- Iroquois Falls 2.4 to 12kV Upgrade (\$140,000)
- Computer Software (\$115,000)

2-SEC-15

[Ex. 2-2-1, Attachment 1] For each major asset category, please provide:

- a) The number of assets,
- b) The number of assets in each of, i) good, ii) fair, and iii) poor condition
- c) The number of assets NOW has or plans to replace in each year between 2013 and 2021

Responses:

- a) The following table can be found in Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 37:

Asset Class	Count
Substation transformers	12
Pole-mounted transformers	570
Pad-mounted transformers	6
Wood poles	2,721
Gang-operated overhead switches	5
Pad-mounted switchgear	5
Overhead conductors (km)	366.7
Underground cables (km)	3.18

- b) As noted in Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 37: "NOW Inc. does not have an Asset Condition Assessment report and instead relies on asset age and demographics data". The results of visual inspections are used to identify specific assets for replacement based on condition. In addition, DGA and oil quality tests are performed on substation transformers, which are included on Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 39 and as Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / Appendix E.
- c) See tables below for Northern Ontario Wires' asset replacement rate for the years 2013 to 2016 and forecast for the years 2017 to 2021.

Historical Asset Replacement Rates (2013 to 2016)

Year	2013	2014	2015	2016
Poles (#)	54	72	62	68
Conductor (m)	3600	482	4013	3964
Distribution Transformers (#)	28	13	17	15
Substation Transformers (#)	0	0	0	0
Substation Primary Switchgear (#)	0	0	0	0

Planned Asset Replacement Rates (2017 to 2021)

Year	2017	2018	2019	2020	2021
Poles (#)	72	81	76	76	77
Conductor (m)	2700	3000	2900	2900	3000
Distribution Transformers (#)	20	19	18	18	18
Substation Transformers (#)	0	0	3	0	0
Substation Primary Switchgear (#)	0	0	0	1	0

2-SEC-16

[Ex. 2-2-1, Attachment 1] For each major asset category that the Applicant does not collect condition data or regularly assess their condition, please explain how it determines the need to replace a given asset.

Response:

System Access asset replacement is primarily driven by Measurement Canada requirements to re-verify/replace meters.

System Renewal and System Service assets are evaluated by line patrols which target areas that have been assessed as potential problematic zones. These patrols identify age, condition, and circumstances that indicate the likelihood of failure and need for asset replacement. Through line patrols, crews are able to scan the whole distribution system every year which helps identify problem areas.

General Plant is replaced based on asset age and assessment of condition. For transportation and work equipment, the fleet matrix provides an overall summary of age and usage. This combined with physical observation and a review of maintenance and repair expenditures helps to inform the decision to replace an asset. For computer equipment, age, vendor support and functionality are considerations in the replacement decision.

2-SEC-17

[Ex. 2-2-1, Attachment, p.87] With respect to the GIS update project, please:

- a) Confirm the total cost of the project is \$368,964.
- b) Provide an update of the status of the project.
- c) Provide details regarding procurement method for the project.
- d) Provide copies of the original business case and project budget.
- e) Please explain any variance between the forecast final project cost and the original budget.

Response:

- a) NOW Inc. confirms that the forecast project cost for the GIS upgrade project is \$368,964. NOW Inc. is in the process of completing year-end financial activities and actual results for 2016 are not yet available.
- b) As of January 2017, the project is completed and in-service. All current assets have been catalogued and uploaded to the CGIS site. NOW Inc. is waiting for the outcome of the Cost of Service Application in order to proceed with the next phase, which is linking the CGIS system with the Outage Management System.
- c) NOW Inc. determined that the project could be completed with internal resources. The qualifications of the personnel required to work on the project were considered in order to ensure that the most accurate information would be obtained. As a result of this evaluation, NOW Inc. utilized internal resources to perform the GIS upgrades, along with the support of the GIS provider. Materials were sourced from a preferred supplier when necessary.
- d) There is no formal business case. The need for the project was identified and assessed by management in order to keep up with industry standards and the need to formalize documentation. NOW Inc. attended conferences and training courses that emphasized the need for an updated GIS mapping initiative. This was identified in the previous Asset Management Plan that was filed with the last cost of service application.

This project was the first step in NOW Inc.'s plan to implement the outage management system that is included in this application. Without the GIS project, the outage management system implementation would not have been possible due the lack of information. As such the benefits of the project relate to

maintaining a safe and reliable system and better operational and spending decisions being made.

The budget for the GIS project was approximately \$304k.

- e) The variance between the forecast final project cost and the original budget is presented in the following table.

	Budget	Actual	Variance
GIS Project	354,116.00	368,964.00	14,848.00

The variance is a result of more labour required due to effort to obtain the data. All three geographically disperse territories were mapped by a NOW Inc. crew member. This entailed mapping the system in winter months that took longer than anticipated. Additionally more material resources were required in order to ensure accurate tracking of assets.

2-SEC-18

[Ex. 2-2-1, Attachment, p.87] With respect to the CIS upgrade, please provide further details regarding the project, including but not limited to, the scope of the new system, the procurement method, and the status of the project.

Responses:

The rate of change in the industry demands changes to the operations of critical systems. One such change is to the billing systems. New requirements such as OESP, Smart Meters and more require modifications and updates to the system. NOW is currently running an old version of the software while other utilities have upgraded to the newer version. As a result, future updates to the version NOW is running will become unsupported as the providers effort will not be worth supporting the older platform.

As such the scope of the project initially is to install the new version of the billing system on new hardware that will allow NOW billing functions to operate effectively in the changing environment. This upgrade will also serve as a first step towards e-billing and allow NOW customers to access and utilize their smart meter information. NOW Inc. has worked with a major third party provider with its billing systems, and is continuing with the provider which allows for continuous support and familiarity with the systems. The hardware for the project has been acquired and scheduling is being evaluated for the ideal time to commence the technical aspects of the project.

2-SEC-19

[Ex.4] Please update the following tables to provide 2016 year-end actuals and explain all material differences from the forecasted amounts:

- a) Appendix 2-JA
- b) Appendix 2-JB
- c) Appendix 2-JC

Responses:

- a) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.
- b) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.
- c) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.

2.0 -VECC - 4

Reference: E2/T2/S1/pg. 4

- a) Please explain why 2015 capital expenditures were significantly lower than both the year prior and the year after.

Responses:

- a) Capital work in 2015 was not typical for NOW Inc.. NOW Inc. had the opportunity to undertake other projects that were funded by a third party (telecommunications contributed capital). As such, capital plans were adjusted to undertake more contributed capital work which is beneficial to NOW Inc. ratepayers. The contributed work in all three communities resulted in aged assets being replaced at no cost to the utility. These contributions will extend asset useful lives which results in cost savings to ratepayers.

Additionally in 2014 NOW Inc. acquired Freightliner Digger Derrick and 2015 did not have any vehicle additions.

In 2016 NOW Inc. continued working on the Capital Plans as outlined in the DSP. More is being spent on capital projects, and more transportation equipment was purchased. Additionally, more work on the GIS project was being done along with the hardware necessary to replace end of life assets. Fewer contributed capital projects were undertaken in 2016 and this results in more work on NOW Inc. capital projects. The 2016 Bridge Year and 2017 Test Year capital expenditures are in line with the 2013 Approved and 2013 Actual capital expenditures.

2.0-VECC-5

Reference: E2/T1/S1/pg.4

- a) Please explain why services (overhead and underground) were \$103k less than Board approved in 2013.

Responses:

- a) The underage is primarily due to an account mapping issue and spending less than planned. In NOW Inc.'s prior COS application (EB-2012-0153), Appendix 2-B 2013 Fixed Asset Continuity Schedule, the balance for this account was \$0 with the associated note 1 stating that "Services acct 1855 included in Acct 1835 and 1840". Subsequent to this, relevant asset values from accounts 1835 and 1840 were removed and restated to account 1855 as presented in this application. When comparing to 2013 OEB Approved Net Book Value it is important to view these three accounts together. The account balance in the current Appendix 2-BA was established after the Decision and Order in EB-2012-0153. It should be noted that this is an allocation of assets amongst USofA accounts and that the overall Total Net Book Value of assets remained the same. When looking at the consolidated Net Book Value for accounts 1835, 1840 and 1855, on the referenced Table 4, Actual NBV is lower than planned primarily due to lower capital spending related to the Cochrane 5kV upgrade project.

2.0-VECC-6

Reference: E2/T1/S1 & E2/T2/Attachment 6 (PDF pg. 361)

- a) Please provide a table in the same format as the NOW Fleet 2015 showing the projected fleet at year end 2017.

Responses:

- a) Please find attached a completed 2016 Fleet Matrix (Attachment 1) and a projected 2017 Fleet Matrix (Attachment 2). 2015.

Fleet Replacement Schedule

Unit #	Year	In Service Date mm/dd/yy	Original Book Value	Description	Score	2012	2013	2014	2015	2016	2017	2018	2019	2020
Small Trucks (8 Year Cycle)														
514	2004	3/15/2004	\$ 37,664.24	Dodge 1500 ST QD 4X4 LBX		removed from fleet								
517	2006	5/23/2006	\$ 28,305.47	Dodge Dakota ST Club	38	removed from fleet								
521	2008	5/23/2008	\$ 27,313.43	Ford F150 4X4 SS REG	28									
524	2010	5/7/2010	\$ 29,218.00	Chev Silverado	25									
525	2010	3/26/2010	\$ 27,683.00	Dodge Grand Caravan SE Wagon	27	removed from fleet								
527	2011	2/16/2011	\$ 31,706.00	Chev Silverado 1500	21									
537	2016	4/18/2016	\$ 34,370.00	Dodge Ram 1500	5									
Large Trucks (15 Year Cycle)														
506	2000	xx/xx/xx	?	International Digger Derrick		removed from fleet								
519	2008	2/22/2010	\$ 54,329.00	Ford F550 4X4 Dump Box	20									
520	2007	9/4/2007	\$ 202,295.00	International Digger Derrick	23									
522	2008	1/6/2009	\$ 220,800.00	International Bucket Truck w/ Altec	20									
526	2011	4/6/2011	\$ 276,423.00	Freightliner M2-106 Bucket Truck	15									
529	2011	11/15/2011	\$ 220,005.00	Kenworth T300 4X2 Digger Derrick	14									
530	2012	3/26/2012	\$ 281,345.00	Freightliner Bucket Truck w/ Posi-Plus	13									
536	2013	3/28/2014	\$ 261,375.00	Freightliner Digger Terex C4047 PG	12									
Other Equipment (As Required based on Condition)														
510	1962	xx/xx/xx	?	Cable (Reel) Trailer	61									
511	1991	xx/xx/xx	?	Pole Trailer	40									
513	1982	xx/xx/xx	?	Cable (Reel) Trailer	29									
516	2005	11/15/2005	\$ 15,114.60	Bandit Chipper Model 65XL	14									
523	2008	2009	\$ 20,142.00	Pole Trailer	12									
528	2011	5/17/2011	\$ 15,012.00	Brooks Bros. Pole Trailer PTB112XL-10KHD	9									
531	2012	6/27/2012	\$ 20,767.00	Brooks Bros. Reel Trailer SLR	8									
Total														

Scoring Results	
Point Ranges	Action
Under 18	Excellent - Continue to Monitor
18-22	Good - Continue to Monitor
23-27	Qualifies for Replacement Detailed Evaluation Schedule
Over 27	Needs Immediate Consideration Detailed Evaluation Perform

Fleet Evaluation Matrix for 2016

Factor	Description of Evaluation Criteria					Small Trucks							Large Trucks							Other Equipment								
						# 514	# 517	# 521	# 524	# 525	537	# 527	# 506	# 519	# 520	# 522	# 526	# 529	# 530	# 536	# 510	# 511	# 513	# 516	# 523	# 528	# 531	
Age	One point for each year of service based on "in service" date					8	10	8	6	6	1	5	12	8	9	8	5	5	4	3	50	30	21	7	3	1	1	
Mileage	One point for each 16,093 kilometers (10,000 miles) of use					#REF!	12	10	10	10	1	10	#REF!	3	2	3	2	1	1	1	0	0	0	1	0	0	0	
	1 Point	2 Points	3 Points	4 Points	5 Points																							
Type of Service	Light duty Small Vehicles: Engineering or Administration use Large Vehicles: on road use only and lightly loaded.	n/a	Medium duty Small Vehicles: trucks used by trades which are commonly loaded; Large Vehicles: mainly on road use and with average payload.	n/a	Heavy duty Small & Large Vehicles: trades use and commonly loaded for road and off road use	3	3	3	3	1	1	3	5	5	5	5	5	5	5	5	5	3	3	5	5	5		
Reliability	Repair once every 3 months or less	n/a	Repair two or three times in 3-month period	n/a	Repair two or more times per month on average	5	5	2	2	3	1	1	1	1	3	1	1	1	1	1	1	1	1	1	1	1		
Maintenance and Repair Costs	Accumulated cost as compared to original purchase cost is ≤ 20%	Accumulated costs as compared to original purchase cost is > 20% & ≤ 47%	Accumulated costs as compared to original purchase cost is > 47% & ≤ 74%	Accumulated costs as compared to original purchase cost is > 74% & ≤ 100%	Accumulated costs as compared to original purchase cost is ≥ 100%	0	3	2	2	3	0	0	0	1	2	1	1	1	1	1	0	0	0	0	0	0		
Take into consideration body condition, rust, interior condition, anticipated repairs and accident history.																												
Condition	Excellent Truck has no signs of deterioration and is close to like new condition	Very Good Truck is no longer in new condition but is still in very good shape	Good Truck has signs of regular use	Fair Truck is showing signs of early deterioration with advanced signs of rust and worn interior components.	Poor Truck has signs of rust perforation, seat covers are worn thru and repairs have been postponed due to age and cost benefit.	5	5	3	2	4	1	2	3	2	2	2	1	1	1	1	5	4	4	2	3	2	1	
Total Score						#REF!	38	28	25	27	5	21	#REF!	20	23	20	15	14	13	12	61	40	29	14	12	9	8	

Scoring Results	
Point Ranges	Action
Under 18	Excellent - Continue to Monitor
18-22	Good - Continue to Monitor
23-27	Qualifies for Replacement Schedule Detailed Evaluation
Over 27	Needs Immediate Consideration Perform Detailed Evaluation

NOW Fleet - 2016										
Unit #	Year	Make	Model	Description	Plate No.	Serial No./V.I.N.	G/L#	Kms as of 2016	Town	Pic
510	1962	WEST	RH4	REEL TRAILER	V72702	362850	5255-1510	-	Cochrane	510
511	1982	TJWE	PT4	POLE TRAILER	35277H	2042131	5255-1513	-	Cochrane	511
513	1991	HMDE	TY	REEL TRAILER	J94829	FILE-147907685	5255-1511	-	Ifalls	513
516	2005	BANDIT	65XL	CHIPPER	-		5255-1516	391	Cochrane	516
517	2006	DODGE	DAKOTA	PICKUP	4589RX	1D7HW22K26S683981	5255-1517	193,632	Cochrane	517
519	2008	FORD	DRW	DUMP TRUCK	9730YC	1FDAF57R68EA18999	5255-1519	41,219	Cochrane	519
520	2007	INTL	40S	BUCKET TRUCK	4499VC	1HTMMAAN57H434919	5255-1520	25,223	Cochrane	520
521	2008	FORD	C0F	PICKUP	7253WJ	1FTRF14WX8KD43411	5255-1521	153,000	Ifalls	521
522	2008	INTL	70S	BUCKET TRUCK	1358WJ	1HTWGAZR48J652951	5255-1522	46,499	Cochrane	522
523	2008	BRIN	UNK	POLE TRAILER	H8310B	1L9MP40148G085368	5255-1523	-	Kap	523
524	2010	CHEV	SILVERADO	PICKUP	1297YL	1GCPKPE0XAZ141472	5255-1524	153,454	Cochrane	524
525	2010	DODGE	CARAVAN	VAN	BHSV845	2D4RN4DE0AR258115	5255-1525	153,093	CEO	525
526	2011	FRHT	FM2	BUCKET TRUCK	6869ZL	1FVHCYBS1BHAZ4392	5255-1526	26,291	Kap	526
527	2011	CHEV	SILVERADO	PICKUP	9918ZF	1GCRKPE0XBZ272458	5255-1527	159,095	Super	527
528	2011	BROOKS BRO.	FB112 XL-10KHD	POLE TRAILER	J44320	1B9BS1125BM274032	5255-1528	-	Ifalls	528
529	2011	KW	CON	DIGGER DERRICK	AA38652	2NKHMM7X4BM293010	5255-1529	19,881	Kap	529
530	2012	FRHT	FM2	BUCKET TRUCK	AB55466	1FVHCYBS4CHBN5784	5255-1530	19,000	Ifalls	530
RT531	2012	BROOKS BRO.	SLR	REEL TRAILER	K547OC	1B9US0820CM274207	5255-1531	-	Cochrane	531
532	2013	CHEV	SILVERADO	4 X 4 PICKUP	AD17876	1GC1KVC2DF170030	5255-1532	70,601	Kap	532
RT533	2013	COMMERCIAL	SLRT	SELF LOADING TRAILER	13453C	1B9US0826DM274214	1-4-5255-3010			533
534	2013	COMMERCIAL	SUPER 6000	SKYLIFT MINI-DERRICK	L3454C	43YDC2724DC096793	1-4-5255-3010		KAP	534
535	2013	COMMERCIAL	TRAILER	AILER FOR MINI-DERRICK	L3454C	43YDC2724DC096793	1-4-5255-3010		Kap	535
536	2013	WAJAX	C4047 PG	DIGGER TEREX	AF50482	1FVACYCYXEHF7347	1-4-5255-3010	22,514	IFALLS	536
537	2016	DODGE	RTR	4 X 4 PICKUP	AN30973	1C6RR7FG6GS285111	1-4-5255-3010	10,311	Cochrane	537

Fleet Replacement Schedule

Unit #	Year	In Service Date mm/dd/yy	Original Book Value	Description	Score	2012	2013	2014	2015	2016	2017	2018	2019	2020
Small Trucks (8 Year Cycle)														
514	2004	3/15/2004	\$ 37,664.24	Dodge 1500 ST QD 4X4 LBX		removed from fleet								
517	2006	5/23/2006	\$ 28,305.47	Dodge Dakota ST Club	40	removed from fleet								
521	2008	5/23/2008	\$ 27,313.43	Ford F150 4X4 SS REG	30									
524	2010	5/7/2010	\$ 29,218.00	Chev Silverado	28									
525	2010	3/26/2010	\$ 27,683.00	Dodge Grand Caravan SE Wagon	29	removed from fleet								
527	2011	2/16/2011	\$ 31,706.00	Chev Silverado 1500	24									
537	2016	4/18/2016	\$ 34,370.00	Dodge Ram 1500	6									
Large Trucks (15 Year Cycle)														
506	2000	xx/xx/xx	?	International Digger Derrick		removed from fleet								
519	2008	2/22/2010	\$ 54,329.00	Ford F550 4X4 Dump Box	22									
520	2007	9/4/2007	\$ 202,295.00	International Digger Derrick	24									
522	2008	1/6/2009	\$ 220,800.00	International Bucket Truck w/ Altec	21									
526	2011	4/6/2011	\$ 276,423.00	Freightliner M2-106 Bucket Truck	16									
529	2011	11/15/2011	\$ 220,005.00	Kenworth T300 4X2 Digger Derrick	14									
530	2012	3/26/2012	\$ 281,345.00	Freightliner Bucket Truck w/ Posi-Plus	13									
536	2013	3/28/2014	\$ 261,375.00	Freightliner Digger Terex C4047 PG	13									
Other Equipment (As Required based on Condition)														
510	1962	xx/xx/xx	?	Cable (Reel) Trailer	61									
511	1991	xx/xx/xx	?	Pole Trailer	40									
513	1982	xx/xx/xx	?	Cable (Reel) Trailer	29									
516	2005	11/15/2005	\$ 15,114.60	Bandit Chipper Model 65XL	14									
523	2008	2009	\$ 20,142.00	Pole Trailer	12									
528	2011	5/17/2011	\$ 15,012.00	Brooks Bros. Pole Trailer PTB112XL-10KHD	9									
531	2012	6/27/2012	\$ 20,767.00	Brooks Bros. Reel Trailer SLR	8									
Total														

Scoring Results	
Point Ranges	Action
Under 18	Excellent - Continue to Monitor
18-22	Good - Continue to Monitor
23-27	Qualifies for Replacement Detailed Evaluation Schedule
Over 27	Needs Immediate Consideration Detailed Evaluation Perform

Fleet Evaluation Matrix for 2017

Factor	Description of Evaluation Criteria					Small Trucks							Large Trucks							Other Equipment								
						# 514	# 517	# 521	# 524	# 525	537	# 527	# 506	# 519	# 520	# 522	# 526	# 529	# 530	# 536	# 510	# 511	# 513	# 516	# 523	# 528	# 531	
Age	One point for each year of service based on "in service" date					8	11	9	7	7	2	6	12	10	10	9	6	5	4	4	50	30	21	7	3	1	1	
Mileage	One point for each 16,093 kilometers (10,000 miles) of use					#REF!	13	11	12	11	1	12	#REF!	3	2	3	2	1	1	1	0	0	0	1	0	0	0	
	1 Point	2 Points	3 Points	4 Points	5 Points																							
Type of Service	Light duty Small Vehicles: Engineering or Administration use Large Vehicles: on road use only and lightly loaded.	n/a	Medium duty Small Vehicles: trucks used by trades which are commonly loaded; Large Vehicles: mainly on road use and with average payload.	n/a	Heavy duty Small & Large Vehicles: trades use and commonly loaded for road and off road use																							
						3	3	3	3	1	1	3	5	5	5	5	5	5	5	5	5	5	3	3	5	5	5	
Reliability	Repair once every 3 months or less	n/a	Repair two or three times in 3-month period	n/a	Repair two or more times per month on average	5	5	2	2	3	1	1	1	1	3	1	1	1	1	1	1	1	1	1	1	1		
Maintenance and Repair Costs	Accumulated cost as compared to original purchase cost is ≤ 20%	Accumulated costs as compared to original purchase cost is > 20% & ≤ 47%	Accumulated costs as compared to original purchase cost is > 47% & ≤ 74%	Accumulated costs as compared to original purchase cost is > 74% & ≤ 100%	Accumulated costs as compared to original purchase cost is ≥ 100%	0	3	2	2	3	0	0	0	1	2	1	1	1	1	0	0	0	0	0	0	0		
Take into consideration body condition, rust, interior condition, anticipated repairs and accident history.																												
Condition	Excellent Truck has no signs of deterioration and is close to like new condition	Very Good Truck is no longer in new condition but is still in very good shape	Good Truck has signs of regular use	Fair Truck is showing signs of early deterioration with advanced signs of rust and worn interior components.	Poor Truck has signs of rust perforation, seat covers are worn thru and repairs have been postponed due to age and cost benefit.	5	5	3	2	4	1	2	3	2	2	2	1	1	1	1	5	4	4	2	3	2	1	
Total Score						#REF!	40	30	28	29	6	24	#REF!	22	24	21	16	14	13	13	61	40	29	14	12	9	8	

Scoring Results	
Point Ranges	Action
Under 18	Excellent - Continue to Monitor
18-22	Good - Continue to Monitor
23-27	Qualifies for Replacement Schedule Detailed Evaluation
Over 27	Needs Immediate Consideration Perform Detailed Evaluation

NOW Fleet - 2017										
Unit #	Year	Make	Model	Description	Plate No.	Serial No./V.I.N.	G/L#	Kms as of 2016	Town	Pic
510	1962	WEST	RH4	REEL TRAILER	V72702	362850	5255-1510	-	Cochrane	510
511	1982	TJWE	PT4	POLE TRAILER	35277H	2042131	5255-1513	-	Cochrane	511
513	1991	HMDE	TY	REEL TRAILER	J94829	FILE-147907685	5255-1511	-	Ifalls	513
516	2005	BANDIT	65XL	CHIPPER	-		5255-1516	391	Cochrane	516
517	2006	DODGE	DAKOTA	PICKUP	4589RX	1D7HW22K26S683981	5255-1517	210,000	Cochrane	517
519	2008	FORD	DRW	DUMP TRUCK	9730YC	1FDAF57R68EA18999	5255-1519	54,250	Cochrane	519
520	2007	INTL	40S	BUCKET TRUCK	4499VC	1HTMMAAN57H434919	5255-1520	32,000	Cochrane	520
521	2008	FORD	C0F	PICKUP	7253WJ	1FTRF14WX8KD43411	5255-1521	185,000	Ifalls	521
522	2008	INTL	70S	BUCKET TRUCK	1358WJ	1HTWGAZR48J652951	5255-1522	53,250	Cochrane	522
523	2008	BRIN	UNK	POLE TRAILER	H8310B	1L9MP40148G085368	5255-1523	-	Kap	523
524	2010	CHEV	SILVERADO	PICKUP	1297YL	1GCPKPE0XAZ141472	5255-1524	187,500	Cochrane	524
525	2010	DODGE	CARAVAN	VAN	BHSV845	2D4RN4DE0AR258115	5255-1525	185,000	CEO	525
526	2011	FRHT	FM2	BUCKET TRUCK	6869ZL	1FVHCYBS1BHAZ4392	5255-1526	31,250	Kap	526
527	2011	CHEV	SILVERADO	PICKUP	9918ZF	1GCRKPE0XBZ272458	5255-1527	187,500	Super	527
528	2011	BROOKS BRO.	FB112 XL-10KHD	POLE TRAILER	J44320	1B9BS1125BM274032	5255-1528	-	Ifalls	528
529	2011	KW	CON	DIGGER DERRICK	AA38652	2NKHMM7X4BM293010	5255-1529	22,500	Kap	529
530	2012	FRHT	FM2	BUCKET TRUCK	AB55466	1FVHCYBS4CHBN5784	5255-1530	21,250	Ifalls	530
RT531	2012	BROOKS BRO.	SLR	REEL TRAILER	K547OC	1B9US0820CM274207	5255-1531	-	Cochrane	531
532	2013	CHEV	SILVERADO	4 X 4 PICKUP	AD17876	1GC1KVC2DF170030	5255-1532	92,500	Kap	532
RT533	2013	COMMERCIAL	SLRT	SELF LOADING TRAILER	13453C	1B9US0826DM274214	1-4-5255-3010			533
534	2013	COMMERCIAL	SUPER 6000	SKYLIFT MINI-DERRICK	L3454C	43YDC2724DC096793	1-4-5255-3010		KAP	534
535	2013	COMMERCIAL	TRAILER	AILER FOR MINI-DERRICK	L3454C	43YDC2724DC096793	1-4-5255-3010		Kap	535
536	2013	WAJAX	C4047 PG	DIGGER TEREX	AF50482	1FVACYCYXEHN7347	1-4-5255-3010	26,400	IFALLS	536
537	2016	DODGE	RTR	4 X 4 PICKUP	AN30973	1C6RR7FG6GS285111	1-4-5255-3010	17,500	Cochrane	537

2.0-VECC-7

Reference: E2/T1/S1/Appendix 2-BA

- a) Please update the 2016 Fixed Asset Continuity Schedule to reflect year-end actuals.
- b) Please update the 2017 Fixed Asset Continuity Schedules if necessary due to changes in 2016.

Responses:

- a) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.
- b) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.

2.0-VECC-8

Reference: E2/T2/S1

- a) Excluding vehicle purchases, NOW's proposed 2017 capital expenditure budget is significantly larger than in the past. Please explain how the Utility expects to execute this ambitious plan without increasing permanent staff.

Response:

- a) NOW Inc. intends to complete the planned capital work with internal resources. Even though the 2017 capital expenditure appears to be higher, there will be a similar level of internal resources as was utilized in previous years. In previous years, NOW Inc. internal staff resources were working on contributed capital projects that were funded by a third party, hence the expenditure did not appear as part of NOW Inc.'s capital expenditure. In addition, part of the increase in 2017 capital expenditures (as compared to previous years) is comprised of increased material costs which do not require additional NOW Inc. resources. Should there be an unforeseen issue regarding project resourcing internally, NOW Inc. would seek project resources from local qualified electrical contract service provider(s).

2.0-VECC-9

Reference: E2/T2/S1/pg.1

- a) At page 4 it indicates that there was a contributed capital amount (\$123,412). Please explain what this amount was for.
- b) Please explain how any road allowance changes for plant are shared with the municipalities.

Responses:

- a) NOW Inc. had contributed capital in 2015 as a result of third-party requests for capital work which resulted in the third parties paying to replace NOW Inc. assets. There were various projects in the year, some related to pole replacements, line extensions, and transformers upgrades. These contributed amounts replaced existing assets and provide benefit to ratepayers as it extends the useful life of the assets that will not need to be replaced as soon.
- b) NOW Inc. does not currently anticipate any work associated with road allowance changes. Should such work occur it would be in accordance with NOW Inc.'s Conditions of Service.

2.0-VECC-10

Reference: E2/T2/S1/pgs. 10-14

- a) Please update pages 10 through 14 (2016 Capital Projects) and indicate which projects/amounts are in-service as of December 31, 2016, the amounts carried forward to 2017 and any cancelled projects (i.e. post 2017).

Responses:

- a) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.

2.0-VECC-11

Reference: E2/T2/S1/pgs.15-17 & pg. 81

- a) With respect to the Cochrane pole changes please identify the third parties referred to, explain how do they assist NOW and how assets are reduced due to their participation?
- b) As shown in Table 4-8 through 4-12 NOW will be replacing poles as part of a number of separate projects. Please provide the total pole population and show the total number of poles being replaced in each year 2012 through 2021.

Response:

- a) The third party is a telecommunications company, that was actively increasing their fibre optic circuits in the NOW Inc. service territory. All upgrades required, primarily pole replacements, were paid by this third party and NOW Inc. recorded these upgrades as contributed capital. NOW Inc. customers use the poles which have third party attachments, thus NOW Inc. customers benefit by avoiding the future replacement cost of the pole that was replaced/funded by the telecommunications company.
- b) Please see the following table:

Actual Replacement						
Asset Class	Count	2012	2013	2014	2015	2016
Wood poles	2,721	90	54	72	62	68

Projected Replacement						
Asset Class	Count	2017	2018	2019	2020	2021
Wood poles	2,721	72	81	65	65	65

2.0-VECC-12

Reference E2/T2/S1/pg.17

- a) At page 17 it states that NOW is replacing computers on an annual basis. Please provide the number of computers replaced each year. Why is an annual computer replacement program necessary?

Response:

- a) Each year we replace 2 computers. Our goal of the computer replacement plan is to replace the staff computers on a six-year replacement cycle. Monitors, keyboards, and mice are reviewed periodically and replaced as needed. These replacement cycles have been developed to ensure that all computers meet current functional requirements, that standardized configurations can be deployed for more sustainable and efficient desktop support, that effective network operations are well supported, that the security of desktop computers can be maintained, and that effective budget planning can occur.

2.0-VECC-13

Reference: E2/T2/S1/ Needs Assessment Report – North & East of Sudbury Region

- a) Are there any incremental capital costs arising out of the Regional Needs Assessment Report? If so please identify these and their costs for the 2017 – 2021 period.

Response:

- a) There have been no incremental capital costs identified as a result of the Regional Needs Assessment Report.

2.0-VECC-14

Reference: E2/T2/S1/Attachment 1 DSP/pg.19- E2/T2/S7

- a) What are the consequences of failing to meet the new SAIDI/SAIFI targets (compensation and otherwise)?
- b) Does NOW propose to include the DSP implementation metrics shown at Table 2-4 in its Scorecard? If not please explain why not.

Responses:

- a) There would be management and Board discussion, identifying reasons and identifying steps needed to achieve targets (e.g. work program spending re-prioritization). Furthermore, the results would be reflected in NOW Inc.'s Scorecard and trend rating.
- b) As per Section 2.1.19e "Asset Management Measure" in the RRR Filing Guide, "The OEB is in the process of developing a quantifiable measure relating to the efficacy of distributors' asset management. As of now, the Distribution System Plan (DSP) Implementation Progress is used as a placeholder and temporary measure for the Scorecard Asset Management measure until the OEB develops a uniform measure. In the interim, distributors will be permitted discretion as to how they implement this measure, but will be required to describe their measure in the notes". Pending further direction from the OEB, NOW Inc. will factor in the implementation metrics into the overall DSP implementation progress rating.

2.0-VECC-15

Reference: E2/T2/S1/Attachment 1 DSP/pg. 22 & T2/S7/pg.2

- a) Please provide the customer outages SAIFI and SAIDI for 2012 through 2016 by cause code.

Responses:

- a) Please see following table:

	2011	2012	2013	2014	2015
Tree Contacts	5	2	2	1	2
Lightning	1	4	1	0	0
Adverse Weather	3	2	0	1	10
Defective Equipment	18	12	7	8	12
Scheduled	3	4	5	7	0
Loss of Supply	2	3	6	1	3
Foreign Interference	9	10	6	7	21
Human Element	2	1	0	0	0
Unknown	1	3	2	1	0
Total	44	41	29	26	48

2016 results are not available at the time of this submission and will be provided along with 2016 year-end actual information on February 17, 2017.

2.0-VECC-16

Reference: E2/T2/S1/Attachment 1 DSP/pgs. 37, 81-

- a) For each of the asset classes shown in Table 3-3 (pg.37) please provide a table showing the number of assets and the percentage of that number found to be in good, fair, or poor condition. Please add a column which briefly explains how that asset assessment was determined (e.g. physical testing, age determined, etc.).
- b) NOW has proposed an ambitious plan to replace at risk assets. Using the table created in (a) please show the number of assets of “poor” condition that will be replaced each year and the number of assets remaining in “poor” condition at the end of the rate plan (2021)

Responses:

- a) As noted in Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 37: “NOW Inc. does not have an Asset Condition Assessment report and instead relies on asset age and demographics data”. The results of visual inspections are used to identify specific assets for replacement based on condition. In addition, DGA and oil quality tests are performed on substation transformers, which are included on Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 39 and as Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / Appendix E.
- b) See previous response

2.0-VECC-17

Reference: E2/T2/S1/Attachment 1 DSP/pg.57 & 84

- a) Please explain the difference between the amount of IT software shown in Table 4-2 (110k) and that shown in Table 4-13 (115k) for 2017.
- b) Please modify Table 4-13 to add a row showing all other IT hardware and IT software costs for the rate period.

Responses:

- a) The difference is due to \$5k for OS software that should have been included in Table 4-13, with the remaining \$110k allocated to CIS and OMS upgrades.
- b) Table 4-13 has been amended to reflect this change and include IT hardware investments.

Table 4-1: Computer hardware and software investments over the forecast period

Year	2017	2018	2019	2020	2021
IT Hardware	\$10,000	\$10,000	\$10,000	\$10,000	\$10,000
OS Software	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
OMS Upgrades	\$40,000				
CIS Upgrades	\$70,000				
Total	\$125,000	\$15,000	\$15,000	\$15,000	\$15,000

2.0-VECC-18

Reference: E2/

- a) Please provide the number of meters by customer class, forecast to be replaced over the 2016-2021 period.

Responses

- a) NOW Inc. is forecasting to re-verify/replace approximately 1,000 Residential meters from 2016-2021. The reverification process will include batch testing which will result in not all meters requiring reverification or replacement.

Over the same period, approximately 60 GS<50 meters are forecasted to be re-verified/replaced as a result of batch testing. Similar to Residential batch testing, not all meters will require reverification or replacement.

2-AMPCO-1

Ref: Ex 2 T2 S1, Page 9

Preamble: The evidence provides a summary of improvements by town and indicates “These improvements are expected to reduce future maintenance costs and increase service reliability”.

- a) Has NOWI quantified the reduced future maintenance costs due to these improvements? If yes, please provide the forecast reductions by year.
- b) Has NOWI quantified an improvement in reliability due to these improvements? If yes, please provide by year.

Responses:

- a) NOW Inc. has not formally quantified the reduced future maintenance costs due to the improvements. The station is nearing end of life and costs associated with extending the life are expected to increase. These improvements will allow NOW Inc. to avoid the capital replacement of the substation and avoid easement costs for the substation location.
- b) NOW Inc. has not quantified the reliability improvements. There is an expected improvement in reliability due to the replacement of aging infrastructure that has a higher probability of failure. NOW Inc. has experienced the impact of such failures in the past.

2-AMPCO-2

Ref: Ex 2 T2 S1 DSP, Attachment #1

- a) Please provide NOWI's asset replacement rate for the years 2013 to 2016 and forecast for the years 2017 to 2021.
- b) Please provide a list of assets that are run to failure.
- c) Please explain how project contingencies are determined.

Response:

- a) See tables below for Northern Ontario Wires' asset replacement rate for the years 2013 to 2016 and forecast for the years 2017 to 2021.

Historical Asset Replacement Rates (2013 to 2016)

Year	2013	2014	2015	2016
Poles (#)	54	72	62	68
Conductor (m)	3600	482	4013	3964
Distribution Transformers (#)	28	13	17	15
Substation Transformers (#)	0	0	0	0
Substation Primary Switchgear (#)	0	0	0	0

Planned Asset Replacement Rates (2017 to 2021)

Year	2017	2018	2019	2020	2021
Poles (#)	72	81	76	76	77
Conductor (m)	2700	3000	2900	2900	3000
Distribution Transformers (#)	20	19	18	18	18
Substation Transformers (#)	0	0	3	0	0
Substation Primary Switchgear (#)	0	0	0	1	0

- b) Exhibit 2 / Tab 2 / Schedule 1 / Attachment 1 / p. 37 lists major assets owned by Northern Ontario Wires (as shown below). Out of these assets, only distribution transformers (whether pole- or pad- mounted) are run to failure, which may be a defined by field failure or inspection.

Asset Class	Count
Substation transformers	12
Pole-mounted transformers	570
Pad-mounted transformers	6
Wood poles	2,721
Gang-operated overhead switches	5
Pad-mounted switchgear	5
Overhead conductors (km)	366.7
Underground cables (km)	3.18

- c) Cost contingencies for third party infrastructure development projects are paid by the respective Municipalities, which cover the full costs for relocating Northern Ontario Wires' assets.

2-AMPCO-3

Ref 1: Ex 2 T2 S2 Attachment #1, Page 12

Ref 2: Ex 2 T2 S2 Attachment #1, Page 13

At Reference #1, the evidence states “Capital investments in the system renewal category over the forecast period are driven by assets at the end of their service life.”

At Reference #2, the evidence states “NOW Inc. utilizes its pole inspection program to identify poles that have reached end-of-life.”

- a) Please provide the definition of the terms “end of service life” and “end-of-life”, explain the difference, and explain how each one drives capital investment expenditures.

Response:

- a) There is no distinction between an asset at the end of its service life and an end-of-life asset. Capital investment expenditures are driven as described in Ref 1: Ex 2 T2 S2 Attachment #1, Page 12:

Capital investments in the system renewal category over the forecast period are driven by assets at the end of their service life. NOW Inc. has three pole replacement programs – one for each Town – to replace poles that have reached the end of their service life, which is budgeted each year. In addition, there is an overhead rebuild project to replace sections of the 4.16/2.4 kV line in the Town of Cochrane, which will take place each year from 2017 to 2021.

Investments in substations have been planned for each year of the historical period. In 2017 there is a capital upgrade project at Cochrane DS to replace a frosted support structure and the existing glass insulators with silicone insulators. Substation transformer refurbishments will be made at Cochrane DS in 2018 and 2019: the transformer bank T2 will be replaced and its base and the bus work will be reconstructed. In 2020 the primary switchgear and underground cables at the Detroyes substation in Iroquois Falls require replacement. In 2021 the Mill Gate substation (2.4 kV delta) will be retired from service and the ground remediated.

2-AMPCO-4

Ref 1: Ex 2 T2 S2 Attachment #1, Page 15

- a) Please explain how the DSP and expenditures in 2017 to 2021 respond to the needs and requirements of Large Customers.
- b) Please confirm the number of large customers.
- c) Please discuss how NOWI monitors and responds to power quality issues that impact Large customers.

Responses:

- a) The DSP and expenditures in 2017 to 2021 respond to the needs and requirements of large customers by continuing Northern Ontario Wires' commitment to provide cost effective, reliable electricity service at a reasonable price. As noted in the above reference: "Generally, large customers are satisfied with NOW Inc.'s service and remark that electricity is more affordable compared to neighbouring electrical utilities."
- b) Northern Ontario Wires Inc. does not have any Large User Customers, however NOW Inc. has 69 customers in the GS>50 class and three streetlight accounts (1,650 connections).
- c) Northern Ontario Wires does not directly monitor power quality, but issues such as a downed wires are identified immediately and are repaired. Larger customers have the cell phone numbers of Northern Ontario Wires' crew hands and the General Manager. If a larger customer has a power quality issue they contact Northern Ontario Wires directly and Northern Ontario Wires will send a crew to investigate within a day. Usually the issues identified are on the customer's premises. In the event that there is an issue on Northern Ontario Wires' distribution system, steps will be taken to restore power quality as soon as possible. There are no open Power Quality issues affecting our customers.

2-AMPCO-5

Ref 1: Ex 2 T2 S2 Attachment #1, Page 16

- a) Please provide a copy of the town hall presentation.

Responses:

- a) The Town Hall presentation can be found at E01/T06/S01/A04.

2-AMPCO-6

Ref 1: Ex 2 T2 S2 Attachment #1, Page 16

Preamble: With respect to Hydro One Coordination and Consultation, NOWI indicates the most recent meeting was in 2015, so HONI's outage schedule for 2017 is not available at this time.

- a) When does NOWI expect to meet with Hydro One and obtain information on HONI's outage schedule for 2017?

Response:

- a) NOW Inc. has been in communication with HONI and expects to finalize the schedule by the end of February 2017.

2-AMPCO-7

Ref 1: Ex 2 T2 S2 Attachment #1, Page 20-21

Ref 2: Ex 2 T2 S7 Attachment #1, Page 1

- a) The SAIFI and SAIDI figures including loss of supply are inconsistent at References #1 and 2. Please reconcile.
- b) Does NOWI track the number of Momentary outages (MAIFI)? If yes, please provide MAIFI performance for the years 2011 to 2016.

Responses:

- a) Subsequent to providing information to the consultant preparing NOW Inc.'s Distribution System Plan, the OEB communicated some minor errors in the 2012-2014 reporting. NOW Inc. corrected this and it is reflected appropriately in Appendix 2-G. The updated information will be provided to the consultant in order to adjust the DSP.
- b) NOW Inc. does not track momentary outages.

2-AMPCO-8

Ref 1: Ex 2 T2 S2 Attachment #1, Page 20

- a) Please provide the total number of customer interruptions for the years 2011 to 2016.
- b) Please provide the total number of customer interruption hours for the years 2011 to 2016.
- c) NOW Inc.'s SAIFI target is 2.19 or less and its SAIDI target is 4.63 or less. Please explain how these targets were derived.
- d) Please provide the SAIFI and SAIDI targets for 2017 to 2021.

Responses:

- a) Please see the following table:

	2011	2012	2013	2014	2015
Tree Contacts	5	2	2	1	2
Lightning	1	4	1	0	0
Adverse Weather	3	2	0	1	10
Defective Equipment	18	12	7	8	12
Scheduled	3	4	5	7	0
Loss of Supply	2	3	6	1	3
Foreign Interference	9	10	6	7	21
Human Element	2	1	0	0	0
Unknown	1	3	2	1	0
Total	44	41	29	26	48

2016 results are not yet available and will be provided on February 17, 2017 along with 2016 financial results.

- b) Please see the following table:

Including Loss of Supply	2011	2012	2013	2014	2015
Interruption Hours	43,889	63,990	77,159	13,324	25,265

2016 results are not yet available and will be provided on February 17, 2017 along with 2016 financial results.

- c) These targets were derived to align with the OEB scorecard at the time of filing the DSP, which targeted SAIFI and SAIDI performance at least within the values

over the historical period.

- d) As noted in the above reference, "NOW Inc.'s SAIFI target is 2.19 or less and its SAIDI target is 4.63 or less."

2-AMPCO-9

Ref 1: Ex 2 T2 S2 Attachment #1, Page 22

- a) Please provide the percentage and number of customer outages due to defective equipment and tree contact for each of the years 2012 to 2016.
- b) Please provide a further breakdown of defective equipment by providing the number of customer outages by types of equipment under defective equipment for the years 2012 to 2016.
- c) Please explain the causes of foreign interference.

Responses:

- a) Please see the following table:

	2011	%	2012	%	2013	%	2014	%	2015	%
Tree Contacts	5	11%	2	5%	2	7%	1	4%	2	4%
Lightning	1	2%	4	10%	1	3%	0	0%	0	0%
Adverse Weather	3	7%	2	5%	0	0%	1	4%	10	21%
Defective Equipment	18	41%	12	29%	7	24%	8	31%	12	25%
Scheduled	3	7%	4	10%	5	17%	7	27%	0	0%
Loss of Supply	2	5%	3	7%	6	21%	1	4%	3	6%
Foreign Interference	9	20%	10	24%	6	21%	7	27%	21	44%
Human Element	2	5%	1	2%	0	0%	0	0%	0	0%
Unknown	1	2%	3	7%	2	7%	1	4%	0	0%
Total	44	100%	41	100%	29	100%	26	100%	48	100%

2016 results are not yet available and will be provided on February 17, 2017 along with 2016 financial results.

- b) Please see the following table:

Defective Equipment	2011	2012	2013	2014	2015	Total
Fuse	4	5	4	5	4	30
Conductor	1					2
Insulator		1	1	1	2	6
Cut-out, switch, circuit interruptor	5	3	2	2	6	29
Stirrup/ clamp	1					2
Transformer	2	1				5
Wire	1	1				4
Pole						1
Other	4	1				10
Total	18	12	7	8	12	89

2016 results are not yet available and will be provided on February 17, 2017 along with 2016 financial results.

- c) Most foreign interferences are caused by crows, however there are unique situations, such as tinfoil balloons, snow removal equipment contact and vehicular accidents that occur from time to time.

Please note that 2016 outage information will be provided along with 2016 financial results on February 17, 2017.

2-AMPCO-10

Ref 1: Ex 2 T2 S2 Attachment #1, Page 26

- a) Please provide the ratio of unplanned work to planned work for the years 2010 to 2016.

Responses:

- a) NOW Inc. did not specifically track the ratio of unplanned to planned capital work for 2010-2016. However it is estimated that on average 5% of capital work is unplanned.

2-AMPCO-11

Ref 1: Ex 2 T2 S1 Attachment #1, Page 27

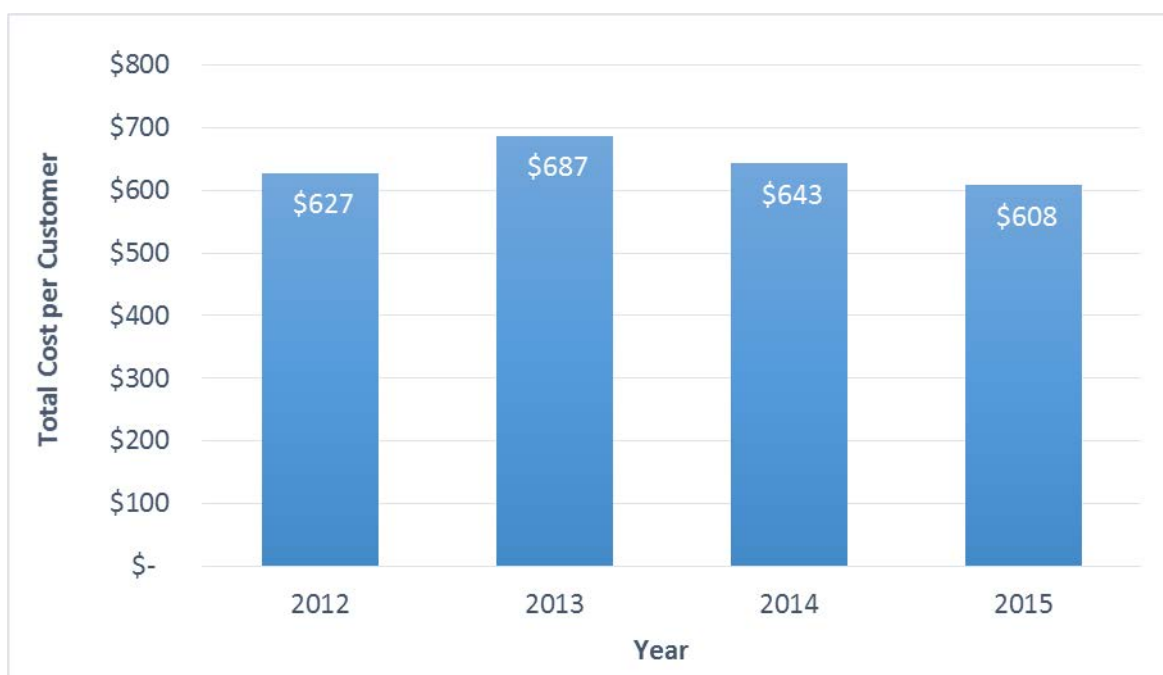
a) Figure 2-6: Please add data for 2015 and 2016.

b) Figure 2-7: Please add data for 2015 and 2016.

Responses:

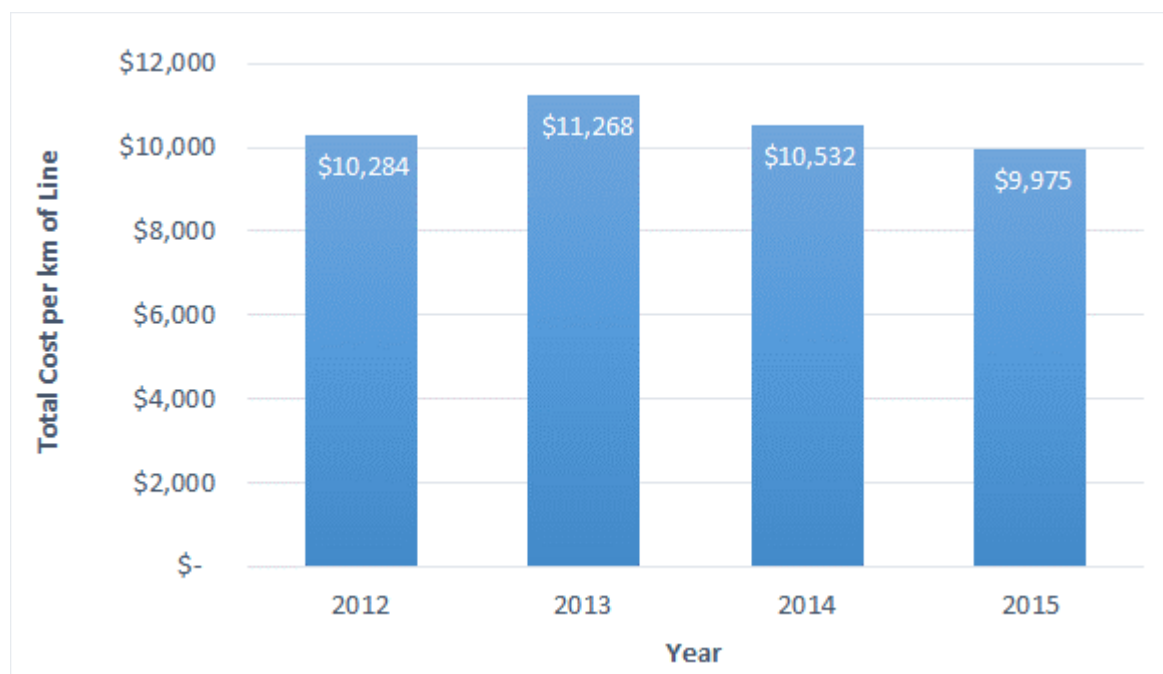
a) Please find 2015 data in the following graph. 2016 results are not yet available and will be provided on February 17, 2017 along with 2016 financial results.

Total Cost per Customer



b) Please find 2015 data in the following graph. 2016 results are not yet available and will be provided on February 17, 2017 along with 2016 financial results.

Total Cost per km of Line



2-AMPCO-12

Ref 1: Ex 2 T2 S2 Attachment #1, Page 32, Figure 3-1

- a) Please provide the demographics and condition data for Overhead Conductors.
- b) Please provide the number of failures by asset type for the years 2010 to 2016.
- c) Please provide the number of customer interruption hours by asset type for the years 2010 to 2016.

Responses:

- a) NOW Inc. does not track demographic nor condition information for its overhead conductors. Overhead conductors are replaced as part of overhead rebuild or voltage conversion projects, neither of which are driven by the condition of the conductors.
- b) Please see the following table:

Defective Equipment	2010	2011	2012	2013	2014	2015
Fuse	1	4	5	4	5	4
Conductor		1				
Insulator	1		1	1	1	2
Cut-out, switch, circuit interruptor	3	5	3	2	2	6
Stirrup/ clamp		1				
Transformer		2	1			
Wire		1	1			
Pole						
Other		4	1			
Total	5	18	12	7	8	12

- c) NOW Inc. can provide the total number of customer interruptions hours, including loss of supply, however information by asset type is unavailable.

Including Loss of Supply	2010	2011	2012	2013	2014	2015
Customer Interruption Hours	31259.5	43888.5	63989.75	77158.75	13324	25264.5

2-AMPCO-13

Ref 1: Ex 2 T2 S2 Attachment #1, Page 37, Figure 3-3

- a) For each of the asset classes in Figure 3-3, please provide the number of assets replaced for the five-year period 2012 to 2016 compared to 2017 to 2021.

Response:

a)

		Actual Replacement				
Asset Class	Count	2012	2013	2014	2015	2016
Substation transformers	12	0	0	0	0	0
Pole-mounted transformers	570	19	28	13	17	15
Pad-mounted transformers	6	0	0	0	0	0
Wood poles	2,721	90	54	72	62	68
Gang-operated overhead switches	5	0	0	0	0	0
Pad-mounted switchgear	5	0	0	0	0	0
Overhead conductors (km)	366.7					
Underground cables (km)	3.18	0	0	0	0	0

		Projected Replacement				
Asset Class	Count	2017	2018	2019	2020	2021
Substation transformers	12	0	3	0	0	0
Pole-mounted transformers	570	18	18	18	18	18
Pad-mounted transformers	6	1	1	1	1	2
Wood poles	2,721	65	65	65	65	65
Gang-operated overhead switches	5	0	0	0	0	0
Pad-mounted switchgear	5	0	0	0	0	0
Overhead conductors (km)	366.7	3	3	3	3	3
Underground cables (km)	3.18	0	0	0	0	0

2-AMPCO-14

Ref 1: Ex 2 T2 S2 Attachment #1, Page 46

Preamble: NOW Inc. does not see value in the testing or maintenance of poles.

a) Please explain.

Response:

a) As noted in the above reference, Northern Ontario Wires' inspection process identifies individual poles for replacement. As noted in Ex 2 T2 S2 Attachment #1, Page 42, short poles requiring pole-top extensions, leaning poles, and other poor condition poles exhibiting insect infestation, woodpecker damage, pole rot, and broken cross arms are identified during line patrols and scheduled for replacement. Using this condition-based pole replacement methodology, Northern Ontario Wires ensures that pole replacements are focussed on the worst condition poles to ensure cost effective and reliable operation of Northern Ontario Wires' distribution system.

Pole testing also checks for poor condition poles due to insect infestation, woodpecker damage, pole rot, etc. – conditions which are all assessed during visual inspections. Although pole testing is considered by some to be more accurate from a quantitative perspective, the presence of heart rot can just as effectively be detected using a hammer test performed by skilled personnel.

The condition benefit of maintaining wood poles (i.e. ground line treatment, above-ground treatment, woodpecker/ant/termite damage repair) is limited and relatively expensive compared to the cost of replacing a pole.

2-AMPCO-15

Ref 1: Ex 2 T2 S2 Attachment #1, Page 46

Response:

2-AMPCO-15 does not contain a question and is a duplicate of the reference in 2-AMPCO-14.

2-AMPCO-16

Ref 1: Ex 2 T2 S2 Attachment #1, Page 48 Table 3-6

Preamble: NOW Inc.'s inspection and maintenance programs for each asset are summarized in Table 3-6.

- a) Please discuss if NOWI has adjusted the inspection or maintenance programs or frequencies since its last Cost of Service application.

Responses:

- a) As a result of the purchase of a thermal imaging camera, hot spots are better detected through line patrols. This would be the only adjustment to inspection and maintenance programs. There has been no increase in frequency.

2-AMPCO-17

Ref 1: Ex 2 T2 S2 Attachment #1, Page 81, Table 4-7

a) Please define failure risk.

Response:

- a) The definition of drivers in the reference above is based on Table 1 of the *Chapter 5 Consolidated Distribution System Plan Filing Requirements*, “investment categories and example drivers and projects/activities”. Failure risk refers to an asset that is still able to perform its function but is in poor condition. For instance, a pole in poor condition has not necessarily failed, but is a failure risk.

2-AMPCO-18

Ref 1: Ex 2 T2 S2 Attachment #1, Page 82, Table 4-9

- a) Please provide the age and condition of each of the 10 poles to be replaced in 2017.
- b) Please provide the age and condition of each of the transformers to be replaced in 2017.

Responses:

- a) 6 of the poles are in the 50yrs plus range (unable to accurately tell as poles in this range the date stamp is no longer visible) and 4 are in the 40yrs plus range. These assets are in very poor condition.
- b) All transformers are from the late 50's and are thus almost 60 years old and in very poor condition.

2-AMPCO-19

Ref: Ex 2 T2 S2 Attachment #1 Appendix A: Project Narratives for Material Investment, SR1 Page 1 Cochrane

- a) Please provide the number of planned versus actual pole replacements for the years 2012 to 2016.
- b) Please provide the forecast number of pole replacements for the years 2017 to 2021.
- c) Please provide the number of pole failures in Cochrane for the years 2010 to 2016.
- d) Please provide the number of pole failures in part (c) for poles over 40 years in age.
- e) Please provide the number of pole failures in part (c) for poles under 20 years in age.
- f) Please provide the total number of poles in Cochrane.
- g) Please provide the total number of poles in Cochrane in very poor condition, poor condition and fair condition.
- h) Please provide the number of poles scheduled for replacement in the years 2017 to 2021 in very poor or poor condition.
- i) Please provide the number of poles scheduled for replacement in the years 2017 to 2021 over 40 years old.

Responses:

a)

Pole Replacements		
Year	Planned	Actual
2012	8-10	10
2013	8-10	8
2014	8-10	8
2015	8-10	10
2016	8-10	10

b)

Pole Replacements		
Year	Planned	
2017	10-14	
2018	8-10	
2019	8-10	
2020	8-10	
2021	8-10	

- c) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- d) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- e) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- f) Now Inc has 739 poles in Cochrane as of December 31, 2016.
- g) It has been determined that approximately 19 poles are in very poor condition and approximately 29 are in poor condition and 209 are in good condition.
- h) It is estimated approximately it is estimated that 50 poles scheduled for replacement in each of the corresponding years the years 2017 to 2021 in very poor or poor condition.
- i) Approximately 90% of the poles to be replaced from 2017 to 2021 are over 40 years old in each of the corresponding years.

2-AMPCO-20

Ref: Ex 2 T2 S2 Attachment #1 Appendix A: Project Narratives for Material Investment, SR2 Page 1 Kapuskasing

- a) Please provide the number of planned versus actual pole replacements for the years 2012 to 2016.
- b) Please provide the forecast number of pole replacements for the years 2017 to 2021.
- c) Please provide the number of pole failures in Kapuskasing for the years 2010 to 2016.
- d) Please provide the number of pole failures in part (c) for poles over 40 years in age.
- e) Please provide the number of pole failures in part (c) for poles under 20 years in age.
- f) Please provide the total number of poles in Kapuskasing.
- g) Please provide the total number of poles in Kapuskasing in very poor condition, poor condition and fair condition.
- h) Please provide the number of poles scheduled for replacement in the years 2017 to 2021 in very poor or poor condition.
- i) Please provide the number of poles scheduled for replacement in the years 2017 to 2021 over 40 years old.

Response:

a)

Pole Replacements		
Year	Planned	Actual
2012	8-10	10
2013	8-10	8
2014	8-10	8
2015	8-10	10
2016	8-10	10

b)

Pole Replacements		
Year	Planned	
2017	8-10	
2018	8-10	
2019	8-10	
2020	8-10	
2021	8-10	

- c) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- d) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- e) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- f) NOW Inc. has 991 poles in Kapuskasing as of December 31, 2016.
- g) It has been determined that approximately 169 poles are in very poor condition and approximately 95 are in poor condition and 365 are in good condition.
- h) It is estimated approximately it is estimated that 40 poles scheduled for replacement in each of the corresponding years the years 2017 to 2021 in very poor or poor condition.
- i) Approximately 90% of the poles to be replaced from 2017 to 2021 are over 40 years old in each of the corresponding years.

2-AMPCO-21

Ref: Ex 2 T2 S2 Attachment #1 Appendix A: Project Narratives for Material Investment, SR3 Page 1 Iroquois Falls

- a) Please provide the number of planned versus actual pole replacements for the years 2012 to 2016.
- b) Please provide the forecast number of pole replacements for the years 2017 to 2021.
- c) Please provide the number of pole failures in Iroquois Falls for the years 2012 to 2016.
- d) Please provide the number of pole failures in part (c) for poles over 40 years in age.
- e) Please provide the number of pole failures in part (c) for poles under 20 years in age.
- f) Please provide the total number of poles in Iroquois Falls.
- g) Please provide the total number of poles in Iroquois Falls in very poor condition, poor condition and fair condition.
- h) Please provide the number of poles scheduled for replacement in the years 2017 to 2021 in very poor or poor condition.
- i) Please provide the number of poles scheduled for replacement in the years 2017 to 2021 over 40 years old.

Responses:

a)

Pole Replacements		
Year	Planned	Actual
2012	8-10	10
2013	4-6	4
2014	4-6	4
2015	4-6	5
2016	4-6	5

b)

Pole Replacements		
Year	Planned	
2017	8-10	
2018	8-10	
2019	8-10	
2020	8-10	
2021	8-10	

- c) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- d) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- e) NOW Inc. does not have this information on a historic basis. The GIS project implemented in 2016 will allow for future tracking of this information.
- f) NOW Inc. has 877 poles in Iroquois Falls as of December 31, 2016.
- g) It has been determined that approximately 358 poles are in very poor condition and approximately 86 are in poor condition and 136 are in good condition
- h) It is estimated approximately it is estimated that 45 poles scheduled for replacement in each of the corresponding years the years 2017 to 2021 in very poor or poor condition.
- i) Approximately 90% of the poles to be replaced from 2017 to 2021 are over 40 years old in each of the corresponding years.

2-AMPCO-22

Ref: Ex 2 T2 S2 Attachment #1 Appendix A: Project Narratives for Material Investment, SR4A Cochrane

- a) Please provide the cost of a 45 foot wood pole compared to a 35 foot and 40 foot wood pole.

Response:

- a) The cost of wood poles based on prices in 2016 is as follows:
- 45' pole : \$451
 - 40' pole : \$382
 - 35' pole : \$283

2-AMPCO-23

Ref: Ex 2 T2 S7 Attachment #1, Page 1

- a) Please provide SAIDI and SAIFI for the years 2011 to 2016 excluding the following: loss of supply, Major Event Days and Scheduled Outages.

Responses:

- a) Please see the following table:

	All Causes of Interruption			All Interruptions Except Loss of Supply (Cause Code 2)		
YEAR	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2011	7.23	1.89	3.82	3.42	1.23	2.77
2012	10.49	3.27	3.32	4.63	2.19	2.23
2013	7.43	3.10	4.10	3.89	1.62	5.76
2014	5.44	1.77	1.66	2.19	1.41	1.64
2015	4.16	1.66	2.51	1.10	0.61	1.82

Northern Ontario Wires Inc. has not experienced any Major Event Days. It also does track Scheduled Outages separately from the overall reliability reporting. The figures above include Scheduled Outages.

2016 information is not yet available and will be provided along with 2016 financial results on February 17, 2017.

Exhibit 3 – Operating Revenue

3-Staff-28

Ref: Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / p. 1

Preamble:

Elenchus used monthly heating degree days and cooling degree days as measured at Environment Canada's Timmins Airport weather station in its regression equations. Timmins Airport is within 100 km of two of the three communities in Northern Ontario Wires' service territory.

Elenchus found that employment level does not exhibit a significant relationship to energy use.

Question(s):

- a) Please advise whether there are any weather stations closer to Northern Ontario Wires' three service areas.
- b) If applicable, please advise how many years of data is available from any closer weather stations.
- c) If applicable, please advise whether using data from a closer weather station could have material impacts on the weather normalized load forecast.
- d) Please confirm that there are no economic variables included in the regression analysis.

Response:

- a) There is a weather station in Kapuskasing, however the weather station results from Timmins provide a more meaningful indicator of NOW Inc. weather as Timmins is closer to both Cochrane and Iroquois Falls where the majority of NOW Inc. customers reside. Kapuskasing is about 135 km from Timmins and 110 km from Cochrane. Whereas Timmins is about 45km from Cochrane and 60km from Iroquois Falls.
- b) Not applicable as Timmins weather station is closer, however Kapuskasing would have sufficient years of data.

- c) Not applicable.
- d) There are no economic variables included in the regression analysis.
Employment for Sudbury (the nearest centre with data), and the province of Ontario were tested as economic indicators in the regression analysis, however, neither exhibited a statistically significant relationship to energy for any rate class.

3-Staff-29

**Ref: Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / pp. 2-3
Chapter 2 Appendices / 2-IB**

Question(s):

- a) For the tables titled "Normal Forecast," please provide 5-years of historical actual (2011-2015) kWh and kW data.
- b) The 2015 actual and weather normal kWh presented in the first table at Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / p. 2 does not match the information provided at Chapter 2 Appendices / 2-IB. Please explain the difference and / or make corrections to the evidence if necessary.
- c) For the 2016 kWh, kW forecast, and customer count please provide the best available information at the time that the interrogatory responses are drafted.
- d) For the customer count information provided at Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / p. 3, please provide 5-years of historical actual information.
- e) If possible, please provide a breakdown kWh, kW, and customer count for the historical years and forecast period by service area and rate class.

Response:

- a) Please see the tables below:

Normal Forecast

kWh	Residential	GS < 50	GS > 50	Street Light	USL	Total
2011 Actual	41,936,263	20,088,297	51,199,910	1,610,563	127,637	114,962,670
2012 Actual	41,580,385	20,381,841	54,630,822	1,543,417	146,700	118,283,165
2013 Actual	43,317,250	20,406,290	61,406,393	1,531,779	166,144	126,827,856
2014 Actual	42,817,440	20,089,108	55,041,599	1,400,857	161,162	119,510,166
2015 Actual	41,096,056	19,602,981	59,289,165	745,147	168,348	120,901,697
2015 Normalized	41,427,318	20,051,827	59,289,165	745,147	165,218	121,678,675
2016 Forecast	41,247,109	20,013,177	57,165,382	556,610	165,218	119,147,496
2017 Forecast	41,066,900	20,013,177	57,165,382	556,610	165,218	118,967,287

Normal Forecast

kW	GS > 50	Street Light	Total
2011 Actual	167,396	4,315	171,711
2012 Actual	167,376	4,403	171,779
2013 Actual	191,639	4,306	195,945
2014 Actual	165,499	4,034	169,533
2015 Actual	171,931	1,986	173,917
2016 Forecast	168,829	1,576	170,405
2017 Forecast	168,829	1,576	170,405

- b) The correct values are in Exhibit 3/Tab 1/Schedule 2 reference. These forecast values were used in the determination of rate impacts. There was a transcription error in Appendix 2-IB. The corrected Appendix 2-IB is provided as Attachment 1.

- c) At this time, the 2016 billed energy and demand are available by class. This reflects one elapsed year of energy and demand consumed approximately from December 2015 to November 2015.

2016 Actual	Residential	GS < 50	GS > 50	Street Light	USL	Total
kWh	38,772,512	18,437,592	60,749,111	525,802	164,178	118,649,195
kW	0	0	177,343	1,503	0	178,846
Customer Count	5,234	762	60	3	23	6,082

- d) Please see the table below:

Customer Connections

	Residential	GS < 50	GS > 50	Street Light	USL	Total
2011 Actual	5,241	771	70	1,546	18	7,646
2012 Actual	5,249	751	68	1,580	23	7,671
2013 Actual	5,249	748	68	1,593	23	7,681
2014 Actual	5,237	755	70	1,600	23	7,685
2015 Actual	5,219	785	71	1,650	23	7,748
2016 Forecast	5,218	785	71	1,650	23	7,747
2017 Forecast	5,216	784	71	1,650	23	7,745

- e) Northern Ontario Wires Inc. is not currently able track usage by rate class and service territory without a significant manual undertaking.

Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells: Data input Drop-down List
 No data entry required Blank or calculated value

Distribution System (Total)

	Calendar Year (for 2017 Cost of Service)		Consumption (kWh) ⁽³⁾			
				Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2011		Actual	114,962,670	115,099,441	
Historical	2012		Actual	118,283,165	118,340,711	
Historical	2013		Actual	126,827,856	124,943,879	Board-approved 118,300,604
Historical	2014		Actual	119,510,166	118,301,622	
Historical	2015		Actual	120,901,697	121,678,675	
Bridge Year	2016		Forecast		119,147,496	
Test Year	2017		Forecast		118,967,287	

Variance Analysis	Year	Year-over-year		Versus Board- approved
	2011			
	2012	2.9%	2.8%	
	2013	7.2%	5.6%	
	2014	-5.8%	-5.3%	
	2015	1.2%	2.9%	
	2016		-2.1%	
	2017		-0.2%	0.6%
	Geometric Mean		97.4%	0.2%

Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)

1 Customer Class: **Residential** Is the customer class billed on consumption (kWh) or demand (kW or kVA)? **kWh**

	Calendar Year (for 2017 Cost of Service)	Customers			Consumption (kWh) ⁽³⁾				Consumption (kWh) per Customer			
					Actual (Weather actual)	Weather- normalized		Weather- normalized	Actual (Weather actual)	Weather- normalized		Weather- normalized
Historical	2011	Actual	5,241		Actual	41,936,263	42,148,154		Actual	8001.5766	8042.00611	
Historical	2012	Actual	5,249		Actual	41,580,385	41,967,945		Actual	7921.5822	7995.41722	
Historical	2013	Actual	5,249	Board-approved	Actual	43,317,250	41,787,736	Board-approved	Actual	8252.4767	7961.08516	Board-approved 8085.745005
Historical	2014	Actual	5,237		Actual	42,817,440	41,607,527		Actual	8175.9481	7944.91636	
Historical	2015	Actual	5,219		Actual	41,096,056	41,427,318		Actual	7874.3162	7937.78847	
Bridge Year	2016	Forecast	5,218		Forecast		41,247,109		Forecast	0	7904.77367	
Test Year	2017	Forecast	5,216		Forecast		41,066,900		Forecast	0	7873.25537	

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board- approved
	2011			2011			2011		
	2012	0.2%		2012	-0.8%	-0.4%	2012	-1.0%	-0.6%
	2013	0.0%		2013	4.2%	-0.4%	2013	4.2%	-0.4%
	2014	-0.2%		2014	-1.2%	-0.4%	2014	-0.9%	-0.2%
	2015	-0.3%		2015	-4.0%	-0.4%	2015	-3.7%	-0.1%
	2016	0.0%		2016		-0.4%	2016		-0.4%
	2017	0.0%	-0.7%	2017		-0.4%	2017		-0.4%
	Geometric Mean	#NUM!	-0.2%	Geometric Mean		102.1%	Geometric Mean		101.7%
						-3.4%			-2.6%
						-1.1%			-0.9%

	Calendar Year (for 2017 Cost of Service)	Revenues		
Historical	2011	Actual	\$ 1,663,929	
Historical	2012	Actual	\$ 1,705,711	
Historical	2013	Actual	\$ 1,863,355	Board-approved \$ 1,868,695
Historical	2014	Actual	\$ 1,958,674	
Historical	2015	Actual	\$ 1,959,913	
Bridge Year (Forecast)	2016	Forecast	\$ 2,025,777	
Test Year (Forecast)	2017	Forecast	\$ 2,381,807	

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved
	2011		
	2012	2.5%	
	2013	9.2%	
	2014	5.1%	
	2015	0.1%	
	2016	3.4%	
	2017	17.6%	27.5%
	Geometric Mean	2.8%	8.4%

2 Customer Class: **GS < 50 kW** Is the customer class billed on consumption (kWh) or demand (kW or kVA)? **kWh**

	Calendar Year (for 2017 Cost of Service)	Customers			Consumption (kWh) ⁽³⁾				Consumption (kWh) per Customer			
					Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized	
Historical	2011	Actual	771	Board-approved	Actual	20,088,297	20,013,177	Board-approved	Actual	26054.86	25957.428	Board-approved
Historical	2012	Actual	751		Actual	20,381,841	20,051,827		Actual	27139.602	26700.1691	
Historical	2013	Actual	748		Actual	20,406,290	20,051,827		Actual	27281.136	26807.2553	
Historical	2014	Actual	755		Actual	20,089,108	20,090,477		Actual	26608.09	26609.9033	
Historical	2015	Actual	785		Actual	19,602,981	20,051,827		Actual	24971.95	25543.7287	
Bridge Year	2016	Forecast	785		Forecast		20,013,177		Forecast	0	25494.493	
Test Year	2017	Forecast	784		Forecast		20,013,177		Forecast	0	25527.0115	

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board- approved
	2011			2011				2011			
	2012	-2.6%		2012	1.5%	0.2%		2012	4.2%	2.9%	
	2013	-0.4%		2013	0.1%	0.0%		2013	0.5%	0.4%	
	2014	0.9%		2014	-1.6%	0.2%		2014	-2.5%	-0.7%	
	2015	4.0%		2015	-2.4%	-0.2%		2015	-6.1%	-4.0%	
	2016	0.0%		2016		-0.2%		2016		-0.2%	
	2017	-0.1%		2.2%	2017		0.0%	0.6%	2017		0.1%
	Geometric Mean	#NUM!	0.7%	Geometric Mean	100.0%		0.2%	Geometric Mean	101.3%		-0.5%

	Calendar Year (for 2017 Cost of Service)	Revenues			
Historical	2011	Actual	\$ 476,997	Board-approved	\$ 493,678.00
Historical	2012	Actual	\$ 487,643		
Historical	2013	Actual	\$ 520,141		
Historical	2014	Actual	\$ 546,480		
Historical	2015	Actual	\$ 548,601		
Bridge Year (Forecast)	2016	Forecast	\$ 582,512		
Test Year (Forecast)	2017	Forecast	\$ 681,824		

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved
	2011		
	2012	2.2%	
	2013	6.7%	
	2014	5.1%	
	2015	0.4%	
	2016	6.2%	
	2017	17.0%	
	Geometric Mean	3.8%	11.4%

3 Customer Class: **GS > 50 kW** Is the customer class billed on consumption (kWh) or demand (kW or kVA)? **kW**

	Calendar Year (for 2017 Cost of Service)	Customers			Consumption (kWh) ⁽³⁾			Consumption (kWh) per Customer		
					Actual (Weather actual)	Weather- normalized	Weather- normalized	Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2011	Actual	70	Board-approved	Actual	51,199,910	51,199,910	Actual	731427.29	731427.286
Historical	2012	Actual	68		Actual	54,630,822	54,630,822	Actual	803394.44	803394.441
Historical	2013	Actual	68		Actual	61,406,393	61,406,393	Actual	903035.19	903035.191
Historical	2014	Actual	60		Actual	55,041,599	55,041,599	Actual	917359.98	917359.983
Historical	2015	Actual	71		Actual	59,289,165	59,289,165	Actual	835058.66	835058.662
Bridge Year	2016	Forecast	71	Board-approved	Forecast	57,165,382	57,165,382	Forecast	0	805146.225
Test Year	2017	Forecast	71		Forecast	57,165,382	57,165,382	Forecast	0	805146.225

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board- approved
	2011			2011			2011		
	2012	-2.9%		2012	6.7%	6.7%	2012	9.8%	9.8%
	2013	0.0%		2013	12.4%	12.4%	2013	12.4%	12.4%
	2014	-11.8%		2014	-10.4%	-10.4%	2014	1.6%	1.6%
	2015	18.3%		2015	7.7%	7.7%	2015	-9.0%	-9.0%
	2016	0.0%		2016	-3.6%	-3.6%	2016	-3.6%	-3.6%
	2017	0.0%	1.4%	2017	0.0%	0.0%	2017	0.0%	4.0%
	Geometric Mean	#NUM!	0.5%	Geometric Mean	91.6%	1.8%	Geometric Mean	92.6%	1.3%

	Calendar Year (for 2017 Cost of Service)	Revenues			Demand (kW)			Demand (kW) per Customer		
					Actual (Weather actual)	Weather- normalized	Weather- normalized	Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2011	Actual	\$ 262,659	Board-approved	Actual	167,396	167,396	Actual	0.637313	0.63731302
Historical	2012	Actual	\$ 272,698		Actual	167,376	167,376	Actual	0.6137779	0.61377788
Historical	2013	Actual	\$ 274,394		Actual	191,639	191,639	Actual	0.6984081	0.69840813
Historical	2014	Actual	\$ 224,978		Actual	165,499	165,499	Actual	0.735623	0.73562304
Historical	2015	Actual	\$ 265,937		Actual	171,931	171,931	Actual	0.6465103	0.64651026
Bridge Year (Forecast)	2016	Forecast	\$ 272,177	Board-approved	Forecast	168,829	168,829	Forecast	0	0.62029121
Test Year (Forecast)	2017	Forecast	\$ 318,652		Forecast	168,829	168,829	Forecast	0	0.5298225

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board- approved
	2011			2011			2011		
	2012	3.8%		2012	0.0%	0.0%	2012	-3.7%	-3.7%
	2013	0.6%		2013	14.5%	14.5%	2013	13.8%	13.8%
	2014	-18.0%		2014	-13.6%	-13.6%	2014	5.3%	5.3%
	2015	18.2%		2015	3.9%	3.9%	2015	-12.1%	-12.1%
	2016	2.3%		2016	-1.8%	-1.8%	2016	-4.1%	-4.1%
	2017	17.1%	-1.8%	2017	0.0%	-10.4%	2017	-14.6%	-8.8%
	Geometric Mean	#NUM!	-0.6%	Geometric Mean	#NUM!	-3.6%	Geometric Mean	115.9%	-3.0%

4 Customer Class: Streetlighting Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2017 Cost of Service)	Customers			Consumption (kWh) ⁽³⁾			Consumption (kWh) per Customer		
					Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized
Historical	2011	Actual	1,546	Board-approved	Actual	1,610,563	1,610,563	Board-approved	Actual	1041.7613
Historical	2012	Actual	1,580		Actual	1,543,417	1,543,417		Actual	976.8462
Historical	2013	Actual	1,593		Actual	1,531,779	1,531,779		Actual	961.56874
Historical	2014	Actual	1,600		Actual	1,400,857	1,400,857		Actual	875.53563
Historical	2015	Actual	1,650		Actual	745,147	745,147		Actual	451.60424
Bridge Year	2016	Forecast	1,650		Forecast	556,610	556,610		Forecast	0
Test Year	2017	Forecast	1,650		Forecast	556,610	556,610		Forecast	0

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board- approved
	2011			2011			2011		
	2012	2.2%		2012	-4.2%		2012	-6.2%	
	2013	0.8%		2013	-0.8%		2013	-1.6%	
	2014	0.4%		2014	-8.5%		2014	-8.9%	
	2015	3.1%		2015	-46.8%		2015	-48.4%	
	2016	0.0%		2016	-25.3%		2016	-25.3%	
	2017	0.0%	6.7%	2017	0.0%	-65.1%	2017	0.0%	-67.3%
	Geometric Mean	#NUM!	2.2%	Geometric Mean	234.0%	-29.6%	Geometric Mean	246.5%	-31.1%

	Calendar Year (for 2017 Cost of Service)	Revenues			Demand (kW)			Demand (kW) per Customer		
					Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized
Historical	2011	Actual	\$ 123,471	Board-approved	Actual	4,315	4,315	Board-approved	Actual	0.0349475
Historical	2012	Actual	\$ 125,392		Actual	4,403	4,403		Actual	0.0351139
Historical	2013	Actual	\$ 142,716		Actual	4,306	4,306		Actual	0.0301718
Historical	2014	Actual	\$ 155,831		Actual	4,034	4,034		Actual	0.025887
Historical	2015	Actual	\$ 135,458		Actual	1,986	1,986		Actual	0.0146614
Bridge Year (Forecast)	2016	Forecast	\$ 147,059		Forecast	1,576	1,576		Forecast	0
Test Year (Forecast)	2017	Forecast	\$ 173,525		Forecast	1,576	1,576		Forecast	0

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year	Test Year Versus Board- approved
	2011			2011			2011		
	2012	1.6%		2012	2.0%		2012	0.5%	
	2013	13.8%		2013	-2.2%		2013	-14.1%	
	2014	9.2%		2014	-6.3%		2014	-14.2%	
	2015	-13.1%		2015	-50.8%		2015	-43.4%	
	2016	8.6%		2016	-20.6%		2016	-26.9%	
	2017	18.0%	-22.8%	2017	0.0%	-63.1%	2017	-15.3%	-52.2%
	Geometric Mean	#NUM!	-8.3%	Geometric Mean	#NUM!	-28.3%	Geometric Mean	293.9%	-21.8%

5 Customer Class: **Unmetered Scattered Load** Is the customer class billed on consumption (kWh) or demand (kW or kVA)? **kWh**

	Calendar Year (for 2017 Cost of Service)	Customers			Consumption (kWh) ⁽³⁾				Consumption (kWh) per Customer			
					Actual (Weather actual)	Weather- normalized		Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2011	Actual	18		Actual	127,637	127,637		Actual	7090.9444	7090.9444	
Historical	2012	Actual	23		Actual	146,700	146,700		Actual	6378.2609	6378.26087	
Historical	2013	Actual	23	Board-approved	Actual	166,144	166,144	Board-approved	Actual	7223.6522	7223.65217	Board-approved 7017.277778
Historical	2014	Actual	23		Actual	161,162	161,162		Actual	7007.0435	7007.04348	
Historical	2015	Actual	23		Actual	168,348	165,218		Actual	7319.4783	7183.3913	
Bridge Year	2016	Forecast	23		Forecast		165,218		Forecast	0	7183.3913	
Test Year	2017	Forecast	23		Forecast		165,218		Forecast	0	7183.3913	

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board- approved
	2011			2011				2011			
	2012	27.8%		2012	14.9%	14.9%		2012	-10.1%	-10.1%	
	2013	0.0%		2013	13.3%	13.3%		2013	13.3%	13.3%	
	2014	0.0%		2014	-3.0%	-3.0%		2014	-3.0%	-3.0%	
	2015	0.0%		2015	4.5%	2.5%		2015	4.5%	2.5%	
	2016	0.0%		2016		0.0%		2016		0.0%	
	2017	0.0%	27.8%	2017		0.0%	30.8%	2017		0.0%	2.4%
	Geometric Mean	#NUM!	8.5%	Geometric Mean	81.3%		9.4%	Geometric Mean	99.0%		0.8%

	Calendar Year (for 2017 Cost of Service)	Revenues			
Historical	2011	Actual	\$ 4,379		
Historical	2012	Actual	\$ 4,821		
Historical	2013	Actual	\$ 5,931	Board-approved	\$ 5,244.00
Historical	2014	Actual	\$ 6,310		
Historical	2015	Actual	\$ 6,546		
Bridge Year (Forecast)	2016	Forecast	\$ 6,725		
Test Year (Forecast)	2017	Forecast	\$ 7,759		

Variance Analysis	Year	Year-over-year	Test Year Versus Board- approved
	2011		
	2012	10.1%	
	2013	23.0%	
	2014	6.4%	
	2015	3.7%	
	2016	2.7%	
	2017	15.4%	48.0%
	Geometric Mean	7.8%	14.0%

3-Staff-30

Ref: Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / pp. 4-7

Question(s):

- a) For each rate class, please provide rationale supporting the number of observations used in the regression analysis.
- b) For each rate class, please explain the purpose of each of the variables used in regression analysis.

Response:

- a) 96 Observations were used for each of the Residential and GS < 50 rate classes, representing the 8 calendar years from 2008-2015 inclusive. The regression approach found a better fit in terms of for these two classes using 8 calendar years than the 9 calendars years for which data is available. The regression approach for the GS > 50 rate class did not produce an acceptable model regardless of the number of years used, therefore regression was not used for GS > 50.
- b) For Residential, the following variables were used:
 - HDD (Heating Degree Days): To determine impact of heating requirements on energy use.
 - CDD (Cooling Degree Days): To determine the impact of cooling requirements on energy use.
 - Trend: A trend variable which increments by 1 each month, intended to capture an overall decreasing trend in energy consumption.
 - Spring: A dummy variable indicating the spring months of March, April, and May, where less heating and cooling is typically required regardless of the heating and cooling variables.
 - Fall: A dummy variable indicating the fall months of September, October, and November, where less heating and cooling is typically required regardless of the heating and cooling variables.
 - February: A dummy variable indicating the month of February – which exhibited a statistically significant lower consumption.
 - July: A dummy variable indicating the month of July – which exhibited a statistically significant higher consumption.

For GS < 50, the following variables were used:

HDD (Heating Degree Days): To determine impact of heating requirements on energy use.

CDD (Cooling Degree Days): To determine the impact of cooling requirements on energy use.

PeakDays: A count of the working days in the month – including the days Monday through Friday, which are not statutory holidays, when businesses would normally be open.

Shoulder: A dummy variable indicating the spring and fall months of March, April, May, September, October, and November where less heating and cooling is typically required regardless of the heating and cooling variables.

The remaining classes, GS > 50, Street Light, and USL were not forecasted by means of a statistical regression. Therefore, no explanatory variables were used.

3-Staff-31

Ref: Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / p. 8

Preamble:

Elenchus stated that Northern Ontario Wires adopted the most recent 10-year monthly degree day average as the definition of weather normal. Elenchus stated that this is consistent with many LDCs load forecast filings for cost of service applications.

Question(s):

- a) Please advise which other LDCs use the 10-year monthly degree day average as the definition for weather normal.
- b) Please provide further rationale supporting the use of a 10-year average for weather normal.
- c) Please advise whether using a 20-year monthly degree day average would result in material changes to the load forecast. If so, please provide the updated load forecast for each rate class.

Response:

- a) In addition to Northern Ontario Wires Inc, seven other LDCs have submitted weather normalized load forecasts for 2017 Cost of Service applications. Six of those, Brantford, Canadian Niagara Power, Lakefront, London Hydro, Renfrew Hydro, and Thunder Bay Hydro have adopted the 10-year average as the definition of weather normal. Welland Hydro has adopted a 14-year average as its definition of Weather normal. No utilities have selected a 20-year trend in their definition of weather normal as part of a 2017 Cost of Service application.
- b) The 10 year average methodology provides for a weather normal that is within the range of recent experience, and provides greater consistency with the time period used in the regression analysis. The other option, a 20-year trend has the potential to produce a result which is more extreme than any recent year.
- c) The Filing Requirements provide for the use of a 20-year monthly degree day trend, or a 10-year monthly degree day average. The use of a 20-year trend would result in the following load forecast. Note that only Residential and GS < 50 are found to be weather sensitive, so only these two are changed.

Normal Forecast					
kWh	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast
Residential	42,817,440	41,096,056	41,511,670	41,331,461	41,151,252
GS < 50	20,089,108	19,602,981	20,079,966	20,041,316	20,041,316
GS > 50	55,041,599	59,289,165	59,289,165	57,165,382	57,165,382
Street Light	1,400,857	745,147	745,147	556,610	556,610
USL	161,162	168,348	165,218	165,218	165,218
Total	119,510,166	120,901,697	121,791,167	119,259,988	119,079,779

CDM Adjusted			
kWh	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
Residential	41,151,252	362,099	40,789,153
GS < 50	20,041,316	272,636	19,768,680
GS > 50	57,165,382	777,660	56,387,722
Street Light	556,610	0	556,610
USL	165,218	0	165,218
Total	119,079,779	1,412,395	117,667,384

The impact to Residential is approximately 85,000 kWh or 0.2%, while the impact to GS < 50 is approximately 28,000 kWh, or 0.14%.

3-Staff-32

**Ref: Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / pp. 10-18
Exhibit 3 / Tab 2 / Schedule 1 / Attachment 1**

Question(s):

- a) Please confirm whether any economic variables were used in the calculation of residential consumption. If not, please explain the introductory sentence at Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / p. 10.
- b) Please provide rationale for using the geometric mean of the annual growth from 2009 to 2014 to forecast the residential customer growth rate for 2016 to 2017. Does the forecast customer count change materially if the period 2009-2015 (or 2016 - if information is available) is used?
- c) Please provide rationale for using the geometric mean of the annual growth from 2009 to 2014 to forecast the GS <50 customer growth rate for 2016 to 2017. Does the forecast customer count change materially if the period 2009-2015 (or 2016 - if information is available) is used?
- d) Please provide detailed rationale supporting Elenchus' proposal to forecast GS > 50 consumption based on an average of 2014 / 2015 actual usage.
- e) Please explain the significant increase in GS > 50 annual consumption and demand in 2015 (compared to 2014). Please explain why Elenchus does not believe that this level of consumption and demand will continue in the future.
- f) If available, please provide the actual 2016 consumption and demand for the GS > 50 rate class.
- g) If available, please provide the actual 2016 consumption for the USL and streetlight classes. Please also provide the actual demand for the streetlight class.
- h) Elenchus noted that the streetlight conversion was largely completed in 2015. In that context, please explain the large forecasted decrease in consumption and demand for 2016 for the streetlight class.

- i) There is a discrepancy between the 2013 actual consumption presented at Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 at p. 12 for the GS > 50 rate class (61,406,393) and the 2013 actual consumption presented at Exhibit 3 / Tab 2 / Schedule 1 / Attachment 1 (51,406,393). Please confirm which amount is correct and update the evidence as necessary.

Response:

- a) Economic Variables were tested for explanatory power in the derivation of the Residential consumption forecast, and found to not be statistically significant predictors of energy use. Therefore they were not used. The introductory sentence at Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 / p.10 is therefore not correct.
- b) The statement was not correct, the model correctly used 2009-2015 as 2015 was the last year for which there was available data at the time of filing. Customer counts have been relatively flat. Had the series been stopped at 2014, there would have been 3 additional customers forecasted.
- c) The statement was not correct, the model correctly used 2009-2015 as 2015 was the last year for which there was available data at the time of filing. Customer counts have been relatively flat. Had the series been stopped at 2014, there would have been 6 fewer customers forecasted.
- d) In November 2013, a major GS > 50 customer ceased production. That customer remained at the site until early 2015. It was an oversight that the new customer was not appropriately factored into the load forecast. Please see the following response in (e) for the corrected approach.
- e) The 2015 consumption and demand reflects the addition of a new customer in March 2015. In preparing the load forecast. Elenchus did not include the full year ongoing impact of this new customer. In preparing a revised forecast, Elenchus has derived an adjusted historical 2014 and 2015 as follows:
 - Historic Actual load (energy and demand) in 2014 and 2015 for the discontinued customer has been removed.
 - Historic Actual load (energy and demand) in 2015 for the new customer has been removed
 - Historic Actual load (energy and demand) for 2016 for the new customer has been added to both the historic 2014 and 2015.

Actual consumption for the new customer in 2016 was used as this reflects the going forward load. The resulting adjusted historical 2014 and 2015 were averaged to produce the proposed load forecast below. These values will be used in NOW Inc.'s updated rate impacts to be provided on February 17 2017:

GS > 50	2017 Weather	CDM	2017 CDM Adjusted
	Normal Forecast	Adjustment	Forecast
kWh	62,937,387	796,895	62,140,492
kW	184,009	2,330	181,679

- f) Please see 3-Staff-29 c) for the best available 2016 Actual information.
- g) Please see 3-Staff-29 c) for the best available 2016 Actual information.
- h) The streetlight conversion was completed June 2015. From July-December 2015, streetlight consumption averaged 36.2% of the same periods in 2012-2013 prior to the conversion project. Streetlight consumption for the full years 2016 and 2017 is therefore forecast to be 36.2% of the average full-year consumption of 2012 and 2013.
- i) Exhibit 3 / Tab 1 / Schedule 2 / Attachment 1 at p. 12 is correct, the GS > 50 rate class actual consumption for 2013 was 61,406,393 kWh. Please see the updated table for Exhibit 3, Tab 2, Schedule 1, Attachment 1, provided as Attachment 1.

Annual Consumption And Connection Variance

kWh Variances

Customer Class Name	Residential	General Service < 50 kW	General Service > 50 to 4999 kW	Unmetered Scattered Load	Street Lighting	TOTAL
2013 Approved	42,490,590	19,894,994	54,194,875	126,311	1,593,834	118,300,604
kWh change	826,660	511,296	7,211,518	39,833	(57,324)	8,531,983
% increase	1.95%	2.57%	13.31%	31.54%	-3.60%	7.21%
2013 Actual	43,317,250	20,406,290	61,406,393	166,144	1,536,510	126,832,587
kWh change	(499,810)	(317,182)	(6,364,794)	(4,982)	(99,258)	(7,286,026)
% increase	-1.15%	-1.55%	-10.37%	-3.00%	-6.46%	-5.74%
2014 Actual	42,817,440	20,089,108	55,041,599	161,162	1,437,252	119,546,561
kWh change	(1,721,384)	(486,127)	4,247,566	7,186	(692,105)	1,355,136
% increase	-4.02%	-2.42%	7.72%	4.46%	-48.15%	1.13%
2015 Actual	41,096,056	19,602,981	59,289,165	168,348	745,147	120,901,697
kWh change	331,262	448,846	-	(3,130)	-	776,978
% increase	0.81%	2.29%	0.00%	-1.86%	0.00%	0.64%
2015 Normalized	41,427,318	20,051,827	59,289,165	165,218	745,147	121,678,675
kWh change	(180,209)	(38,650)	(2,123,783)	-	(188,537)	(2,531,179)
% increase	-0.44%	-0.19%	-3.58%	0.00%	-25.30%	-2.08%
2016 Normalized	41,247,109	20,013,177	57,165,382	165,218	556,610	119,147,496
kWh change	-	-	-	-	-	-
% increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016 Estimated	41,247,109	20,013,177	57,165,382	165,218	556,610	119,147,496
kWh change	(542,308)	(272,353)	(777,944)	-	-	(1,592,605)
% increase	-1.31%	-1.36%	-1.36%	0.00%	0.00%	-1.34%
2017 Normalized	40,704,801	19,740,824	56,387,438	165,218	556,610	117,554,891

Northern Ontario Wires Inc.
Filed: 26 August, 2016
EB-2016-0096
Exhibit 3
Tab 2
Schedule 1
Attachement 1
Page 2 of 3

kW Variances

Customer Class Name	General Service > 50 to 4999 kW	Street Lighting	TOTAL
2013 Approved	188,386	4,270	192,656
kW change	3,253	36	3,289
% increase	1.73%	0.84%	1.71%
2013 Actual	191,639	4,306	195,945
kW change	(26,140)	(272)	(26,412)
% increase	-13.64%	-6.32%	-13.48%
2014 Actual	165,499	4,034	169,533
kW change	6,432	(2,048)	4,384
% increase	3.89%	-50.77%	2.59%
2015 Actual	171,931	1,986	173,917
kW change	-	-	-
% increase	0.00%	0.00%	0.00%
2015 Normalized	171,931	1,986	173,917
kW change	(3,102)	(410)	(3,512)
% increase	-1.80%	-20.64%	-2.02%
2016 Normalized	168,829	1,576	170,405
kW change	-	-	-
% increase	0.00%	0.00%	0.00%
2016 Estimated	168,829	1,576	170,405
kW change	(2,298)	-	(2,298)
% increase	-1.36%	0.00%	-1.35%
2017 Normalized	166,531	1,576	168,107

Customer Connections

Customer Class Name	Residential	General Service < 50 kW	General Service > 50 to 4999 kW	Unmetered Scattered Load	Street Lighting	TOTAL
2013 Approved	5255	767	70	18	1546	7656
Connection Additions	(6)	(19)	(2)	5	47	25
% increase	-0.11%	-2.48%	-2.86%	27.78%	3.04%	0.33%
2013 Actual	5249	748	68	23	1593	7681
Connection Additions	(12)	7	2	-	7	4
% increase	-0.23%	0.94%	2.94%	0.00%	0.44%	0.05%
2014 Actual	5237	755	70	23	1600	7685
Connection Additions	(18)	30	1	-	50	63
% increase	-0.34%	3.97%	1.43%	0.00%	3.13%	0.82%
2015 Actual	5219	785	71	23	1650	7748
Connection Additions	-	-	-	-	-	-
% increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2015 Normalized	5219	785	71	23	1650	7748
Connection Additions	(1)	-	-	-	-	(1)
% increase	-0.02%	0.00%	0.00%	0.00%	0.00%	-0.01%
2016 Normalized	5218	785	71	23	1650	7747
Connection Additions	-	-	-	-	-	-
% increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2016 Estimated	5218	785	71	23	1650	7747
Connection Additions	(2)	(1)	-	-	-	(3)
% increase	-0.04%	-0.13%	0.00%	0.00%	0.00%	-0.04%
2017 Normalized	5216	784	71	23	1650	7744

3-Staff-33

Ref: Exhibit 3 / Tab 1 / Schedule 4

Question(s):

- a) Please confirm that Northern Ontario Wires will update pass-through charges where applicable to reflect the OEB's latest approvals at the Draft Rate Order stage of the proceeding.

Response:

- a) Confirmed, pass-through charges will be updated to reflect the OEB's latest approvals at the Draft Rate Order stage of this proceeding.

3-Staff-34

Ref: Exhibit 3 / Tab 3 / Schedule 1

Question(s):

- a) Please provide a detailed calculation (including assumptions) for the forecast \$30,045 of specific service charge revenues. Please explain why a 2.1% increase of specific service charge revenue in the test year (as compared to 2015) is appropriate.
- b) If available, please provide the actual 2016 specific service charge revenue.
- c) Please provide a detailed calculation (including assumptions) for the forecast \$89,347 of late payment revenue. Please explain why a 1.4% increase of late payment revenue in the test year (as compared to 2015) is appropriate.
- d) If available, please provide the actual 2016 late payment revenue.
- e) Please provide a detailed calculation (including assumptions) for the forecast \$119,246 of other operating revenues. Please explain why a 5.7% increase of other operating revenue in the test year (as compared to 2015) is appropriate.
- f) If available, please provide the actual 2016 other operating revenue.
- g) Please provide a detailed calculation (including assumptions) for the forecast \$30,280 of other income and deductions.
- h) If available, please provide the actual 2016 other income and deductions.

Responses:

- a) Returned cheques 131 @ \$15 = \$1,975
Account set up/change of occupancy 781 @ \$30 = \$23,430
Meter dispute 3 @ \$30 = \$90
Disconnect/Reconnect: 70 @ \$65 = \$4,550

This was compared to historic values to determine reasonability. The projected trend is based on recent volumetric increases.

- b) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing of on February 17, 2017. Please note that this information will be unaudited.
- c) NOW analyzed past revenues from interest on late payments and collection charges to determine the \$89,347 test year forecast. This assumption is based on recent collection charges and is forecast to be the sum of \$60,751 in collection charges and \$28,596 in late payment charges based on recent trends. This revenue increasing is consistent with the assumption that the cost of power is increasing and current pattern of collections is maintained.
- d) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing of on February 17, 2017. Please note that this information will be unaudited.
- e) Rent from Electric property: \$88,735
Standard Supply Service: \$17,408
Retail Service Revenue: \$7,116
Other Utility Operating Income: \$5,766
STR: \$221

The increase is a result of the Other Utility operating income is in line with recent trends. This encompasses other miscellaneous revenues expected to be generated.

- f) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing of on February 17, 2017. Please note that this information will be unaudited.
- g) Revenue from Merchandising: \$27,020
Non-Utility Operating Revenue: \$860
Interest and Dividend Income: \$2,400

Assumptions: Non-utility income represents revenue from MicroFITs
Interest and dividend income under new banking agreement is more consistent with 2014 levels where a full year revenue was collected.

Revenue from merchandising decreasing as one time projects are coming to an end.

- h) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing of on February 17, 2017. Please note that this information will be unaudited.

3-SEC-20

Ref: Exhibit 2 / Tab 1 / Schedule 4 / p. 1

Question(s):

For each rate class, please provide a 2016 year-end:

- a) Customer / connections count
- b) Actual and normalized kWh and KW forecast (as applicable)

Response:

- a) Please see the response to 3-Staff-29
- b) Please see the response to 3-Staff-29

3-SEC-21

Ref: Exhibit 2 / Tab 1 / Schedule 4 / p. 1

Question(s):

- a) Please explain the increase in the GS>50 KW and KWh forecast between 2014 and 2015.

Response:

- a) Please see the response to 3-Staff-32 e).

3.0 –VECC -19

Reference: E3/T1/S2, pages 1-2 / E3/T1/S2, Attachement 1, pages 2-3

- a) It is noted (Table 1) that the consumption in 2015 (both actual and weather normalized) is higher than that in either of the preceding years, the subsequent year or the Board approved level. What accounted for this material increase in load for 2015 and why is assumed to not be sustained?
- b) Please explain reconcile the following differences between the values in Table 1 (E3/T1/S2) and Table 1 (Elenchus Report):
 - The 2015 actual total
 - The 2015 weather normalized total

Response:

- a) The increase in system load for 2015 is due to an increase in GS > 50 load. Residential, GS < 50, and Street Light all exhibited declines in usage. For an explanation of the increase in GS > 50 load in 2015, please see 3-Staff-32 e)
- b) There is a typo in the filed Appendix 2-IB, and this is the source for Table 1 (E3/T1/S2). Please see the response to 3-Staff-29 b) with the revised Appendix 2-IB which has the correction. Table 1 (Elenchus Report) can be taken as correct.

3.0 –VECC -20

Reference: E3/T1/S2, Attachment 1, pages 2-3

- a) Please confirm that the weather normalized Residential and GS<50 2015 consumption values were determined by using the regression equation and inputting the actual 2015 values for all of the explanatory variables except HDD and CDD, where the average 10-year values were used. If not, explain how the values were derived.

Response:

- a) Confirmed.

3.0 –VECC -21

Reference: E3/T1/S2, Attachment 1, pages 4-5

- a) Please confirm that the Trend variable is likely, in part, capturing the impact of Residential CDM programs implemented over the 2008-2015 period.
- b) Please complete the following schedule setting out the impact of Residential CDM programs over the 2008-2015 period based on IESO/OPA verified results reports.

Response:

- a) Confirmed
- b) Please see the completed table.

CDM Prog. Year	Verified Residential CDM Program Impacts Calendar Year							
	'08	'09	'10	'11	'12	'13	'14	'15
2008	181,651	181,117	181,117	181,117	162,610	162,574	143,338	128,968
2009	-	195,088	108,954	108,954	108,840	104,477	89,755	79,592
2010	-	-	518,462	367,161	366,612	366,610	359,073	333,652
2011	-	-	-	481,705	481,705	481,705	431,406	421,821
2012	-	-	-	22,450	468,565	468,565	468,565	382,382
2013	-	-	-	-	25,185	671,201	660,715	654,448
2014	-	-	-	-	3,416	26,409	1,052,502	1,020,730
2015	-	-	-	-	-	-	-	567,895
Total	181,651	376,205	808,534	1,161,388	1,616,933	2,281,542	3,205,355	3,589,488

3.0 –VECC –22

Reference: E3/T1/S2, Attachment 1, pages 8-9

- a) Please provide a schedule that compares the Residential and GS<50 Residential and GS<50 forecasts using: i) a 10-year definition of weather normal vs. ii) a 20-year definition of weather normal.

Response:

- a) Please see the table below.

Normal Forecast

kWh	Residential		GS < 50	
	10 year average	20 year trend	10 year average	20 year trend
2011 Actual	41,936,263	41,936,263	20,088,297	20,088,297
2012 Actual	41,580,385	41,580,385	20,381,841	20,381,841
2013 Actual	43,317,250	43,317,250	20,406,290	20,406,290
2014 Actual	42,817,440	42,817,440	20,089,108	20,089,108
2015 Actual	41,096,056	41,096,056	19,602,981	19,602,981
2015 Normalized	41,427,318	41,511,670	20,051,827	20,079,966
2016 Forecast	41,247,109	41,331,461	20,013,177	20,041,316
2017 Forecast	41,066,900	41,151,252	20,013,177	20,041,316

3.0 –VECC -23

Reference: E3/T1/S2, Attachment 1, pages 10-16

- a) Please provide a schedule that for each customer class sets out the customer/connection count as of June 30, 2015 and June 30, 2016.
- b) In what month of 2013 was the GS>50 customer “lost” and in what month of 2015 did the new GS>50 customer start operation (per E3/T1/S2, page 1)?
- c) Please confirm whether, for the Residential class, the geomean of the annual customer grow was calculated from 2009-2014 or 2009-2015. If the former (as stated on page 10), please explain why 2015 was omitted.

Response:

- a) Please see the table below, which sets out the customer/connection counts requested:

	JUNE 30,2015	JUNE 30,2016
RESIDENTIAL	5,223	5,215
GS<50KW	754	746
GS>50KW	70	59
UNMETERED	23	23
STREET LIGHTS	1,650	1,650

- b) The GS > 50 customer ceased production in November 2013, and greatly reduced consumption and demand at that time. They remained on as a customer until March, 2015. A new customer took over at the same facility March, 2015.
- c) The Geomean was calculated from 2009-2015.

3.0 –VECC -24

Reference: E3/T1/S2, Attachment 1, pages 12-14

- a) Please explain why the GS>50 forecast use is based on the average of 2014 and 2015 when 2014 is the year after the one GS>50 customer was lost and the year before the new one commenced operation.
- b) Please provide a schedule that sets out the 2016 year to date consumption of GS>50 class (up to the most recent month available) and compare the results with the GS>50 consumption over the same period in 2014 and 2015.
- c) Please confirm that, contrary to the statement on page 13, the GS>50 customer count geomean is based on the years 2009-2015.

Response:

- a) It was an oversight that the new customer was not appropriately factored into the load forecast. Please see 3-Staff-32 e) for a corrected approach to the forecast.
- b) Class consumption data is available for January 2016 to November 2016, and provided below. Please also see 3-Staff-32 where a representative year of energy billed in 2016 is provided.

	2014	2015	2016
kWh	49,354,650	53,761,923	55,221,869

GS > 50 January-November consumption.

- c) The Geomean was calculated from 2009-2015.

3.0 –VECC -25

Reference: E3/T1/S2, Attachment 1, pages 14-16

- a) Please indicate when the Street Light conversion program started.
- b) It is noted that the Street Light forecast for 2017 is based on 36.2% of the average use in 2012 and 2013 (per Load Forecast Model, kW Forecast Tab). What is the basis for the 36.2% factor?

Response:

- a) LED lights have been in service in 2010. However, LEDs started being installed in substantial numbers in 2014.
- b) The Street Light conversion program concluded in June, 2015. From July to December 2015, the Street Light class kW was 36.2% of the average kW of the same periods in 2012 and 2013. This reflects post-LED conversion, street light demand is 36.2% of the pre-conversion amount. As observed, the 36.2% was applied to the full-year 2012 and 2013 kW to arrive at a forecast for 2017 kW.

3.0 –VECC -26

Reference: E3/T1/S2, Attachment 1, pages 17-18 / E3/T1/S3, pages 1-2 and Appendix 2-I

- a) Please provide a copy of NOW's 2015-2020 CDM Plan as submitted to the IESO.
- b) Please provide a copy of the IESO report on verified savings from 2011-2014 CDM programs through to 2020 for NOW (per Attachment 1, page 17).
- c) Please provide a copy of the IESO's verified 2015 CDM saving report(s) for NOW which sets out the verified savings for 2015 programs and the associated annual persisting savings through to 2020 (per E3/T1?3, page 1).
- d) Why is it necessary (per E3/T1/S3, page 2) to include the 2015 results in the LRAMVA amount when this value as already been verified by the IESO?

Responses:

- a) NOW Inc. submitted a joint plan through CustomerFirst Inc., which was originally approved in 2015. Attachment 1 is the second submission, reflecting 2015 updated results and was approved by the IESO in August 2016 .

The plan is a joint plan that includes all LDCs of CustomerFirst Inc. Each LDCs target and budget in the plan is the same as what was originally prescribed to each LDC by the IESO.

- b) Please see Attachment 2. Please note that the IESO has recognized additional savings through an in-house initiative as indicated by Attachment 3.
- c) Please see Attachment 4.
- d) It was not necessary to include the 2015 results and they could have been excluded from the LRAMVA target given that they're verified. They were included for two reasons. First, to maintain symmetry with the CDM adjustment. CDM program delivery for 2015 would have been in effect for ½ year of 2015, on average. Therefore, the CDM adjustment needed to decrease consumption by ½ year. From the last year where only half a year of savings was captured in the regression. The other reason is that 2015

reflects a logical breaking point where all of the 2015-2020 program savings could be used in LRAMVA claims going forward.



1600 – 120 Adelaide Street West
Toronto, ON M5H 1T1

www.ieso.ca

August 19, 2016

Mr. Chris Barker
Executive Director, Conservation
Greater Sudbury Hydro Inc.
500 Regent St.
Sudbury ON P3E 3Y2

Dear Mr. Barker:

RE: Conditional Approval of CDM Plan

We refer to the joint CDM Plan submitted by Greater Sudbury Hydro Inc., Newmarket-Tay Power Distribution Ltd., North Bay Hydro Distribution Limited, Northern Ontario Wires Inc., PUC Distribution Ltd., St Thomas Energy Inc., and Espanola Regional Hydro Distribution Corporation on April 23, 2015 and conditionally approved by the IESO on July 17, 2015 (CDM Plan 201504230024). We acknowledge receipt of the joint CDM Plan submitted on July 27, 2016, updated on July 29, 2016 and August 18, 2016 (CDM Plan #: 201607280024) (the **“Proposed CDM Plan”**). The Proposed CDM Plan is submitted under section 2.4(a) of:

- a) the Energy Conservation Agreement between the Independent Electricity System Operator (**“IESO”**) and Greater Sudbury Hydro Inc. dated December 29, 2014, as amended as of May 1, 2016;
- b) the Energy Conservation Agreement between the IESO and Newmarket-Tay Power Distribution Ltd. dated December 22, 2014, as amended as of May 1, 2016;
- c) the Energy Conservation Agreement between the IESO and North Bay Hydro Distribution Limited dated December 22, 2014, as amended as of May 1, 2016;
- d) the Energy Conservation Agreement between the IESO and Northern Ontario Wires Inc. dated January 26, 2015, as amended as of May 1, 2016;

- e) the Energy Conservation Agreement between the IESO and PUC Distribution Inc. dated December 29, 2014, as amended as of May 1, 2016;
- f) the Energy Conservation Agreement between the IESO and St. Thomas Energy Inc. dated December 15, 2014, as amended as of May 1, 2016;
- g) the Energy Conservation Agreement between the IESO and Espanola Regional Hydro Distribution Corporation dated December 29, 2014, as amended as of May 1, 2016;

as applicable (each, the “**Energy Conservation Agreement**” or “**Agreement**”).

Terms used in this letter that are defined in the Energy Conservation Agreement will have the meanings given to them in the Energy Conservation Agreement.

Subject to the exceptions set out below and the following terms and conditions, the IESO approves the Proposed Amended CDM Plan (the “**CDM Plan**”), pursuant to section 2.1(b) of the Energy Conservation Agreement:

- 1) The CDM Plan comprises the updated version of the documents submitted by the LDC set out at Schedule “A” and includes, for certainty, any information requests and responses thereto;
- 2) The LDCs acknowledge and agree that no approval is being granted in respect of the assumptions made by the LDC in Section G of the “Overview of CDM Plan”;
- 3) The Program Rules that apply to each of the approved Programs are those in effect as of the Program Start Date set out in the CDM Plan;
- 4) Except as otherwise agreed to in writing with the IESO, the LDC will only accept applications under the Energy Conservation Agreement as of the applicable Program Start Dates set out in the CDM Plan;
- 5) The LDCs will not accept applications under a Registered Initiative (as defined in the 2011-2014 Master CDM Program Agreement dated January 1, 2011) on or after the applicable Program Start Date of its successor Program under the Energy Conservation Agreement;
- 6) The IESO does not approve any of the proposed Programs set out in the CDM Plan, including, without limitation, any proposed regional or local CDM Programs or pilot Program (each a “**Proposed Program**” and collectively, the “**Proposed Programs**”). For certainty, the LDC is not entitled to receive any funding under the Energy Conservation Agreement, including, without limitation, reimbursement for Eligible Expenses relating to a Proposed Program that are incurred before such Proposed Program is approved;
- 7) In respect of the Proposed Programs:

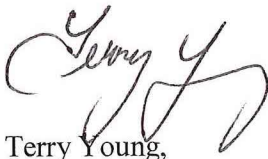
- a) the Program Start Dates for each respective Proposed Program are deleted. If the IESO approves a Proposed Program, the Program Start Date will be determined at the time of such approval;
 - b) in the case of a Proposed Program that is approved subsequent to the date of this letter, the LDC will submit a proposed amendment to the CDM Plan within 60 days of such approval reflecting the IESO's approval;
 - c) in the case of a Proposed Program that is rejected, the LDC will submit an amended CDM Plan within 60 days of such rejection indicating how that portion of the LDC's CDM Plan Target assigned to the Proposed Program will be achieved through approved Programs, proposed regional or local CDM Programs, or pilot Programs; and
- 8) Each LDC acknowledges that its implementation of the CDM Plan is based on its own assessment of its CDM Plan Target and CDM Plan Budget; and
- 9) Each LDC consents to the disclosure by the IESO of this letter and the LDC's CDM Plan in its entirety, including, without limitation, to the public, except for Anticipated Annual Budgets for Proposed Pilots or Programs.

Please confirm your agreement to the above noted terms and conditions of this CDM Plan approval by countersigning this letter and returning a copy to the IESO within 10 business days. For certainty, if each LDC does not countersign and return this letter to the IESO, the CDM Plan approval will not be effective.

This approval may be signed and delivered by original or by email transmission and executed in any number of counterparts, and each executed counterpart will be considered to be an original. All executed counterparts taken together will constitute one agreement.

Should you have any questions or concerns, please do not hesitate to contact your Business Development contact Rouselle Gratela at 416-969-6363.

Sincerely,



Terry Young,
Vice-President, Conservation & Corporate Relations

cc:
Frank Kallonen, President & CEO, Greater Sudbury Hydro Inc.
Paul Ferguson, President, Newmarket-Tay Power Distribution Ltd.
Todd Wilcox, CEO, North Bay Hydro Distribution

Dan Boucher, General Manager, Northern Ontario Wires Inc.
Dominic Parrella, President & CEO, PUC Distribution Inc. & Espanola Regional Hydro
Distribution Corporation.
Duane Orth, Conservation Officer, St. Thomas Energy Inc.

**The undersigned hereby acknowledges and
agrees to the terms and conditions set out
in this letter:**

GREATER SUDBURY HYDRO INC.

By: _____ Date: _____

Name:

Title:

**The undersigned hereby acknowledges and
agrees to the terms and conditions set out
in this letter:**

NEWMARKET-TAY POWER DISTRIBUTION LTD.

By: _____ Date: _____

Name:

Title:

**The undersigned hereby acknowledges and
agrees to the terms and conditions set out
in this letter:**

NORTH BAY HYDRO DISTRIBUTION

By: _____ Date: _____

Name:

Title:

The undersigned hereby acknowledges and agrees to the terms and conditions set out in this letter:

NORTHERN ONTARIO WIRES INC.

By: _____ Date: _____
Name:
Title:

The undersigned hereby acknowledges and agrees to the terms and conditions set out in this letter:

PUC DISTRIBUTION INC.

By: _____ Date: _____
Name:
Title:

The undersigned hereby acknowledges and agrees to the terms and conditions set out in this letter:

ST. THOMAS ENERGY INC.

By: _____ Date: _____
Name:
Title:

The undersigned hereby acknowledges and agrees to the terms and conditions set out in this letter:

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION

By: _____ Date: _____
Name:
Title:

SCHEDULE "A"

#	File	File Name	Date Submitted
<u>All LDC's</u>			
1	Updated CDM Plan	CDM-Plan CustomerFirst CDM Plan (Amendment No.2)-r4.xlsx	August 18, 2016
2	Cost Effectiveness Tool	CustomerFirst CDM Plan (Amendment No.2) Cost Effectiveness Test-JOINT.xlsm	July 27, 2016
4	Supporting Document- Cover Letter	CustomerFirst CDM Plan (Amendment No. 2) Cover Letter.pdf	July 27, 2016
5	Supporting Document- Addendum	Addendum to CustomerFirst CDM Plan- CDM Contact Information for Regional Planning.docx	July 27, 2016
6	Supporting Document- Addendum	Addendum to CustomerFirst CDM Plan- CDM Contribution to Regional Planning.docx	July 27, 2016
<u>Greater Sudbury Hydro Inc.</u>			
7	Cost Effectiveness Tool	CustomerFirst CDM Plan (Amendment No.2) Cost Effectiveness Test-GSH.xlsm	July 27, 2016
8	Authorization Form	LDC Declaration Greater Sudbury Hydro- signed.pdf	July 27, 2016
9	Achievable Potential Tool	Greater Sudbury Hydro Achievable Potential.xlsm	July 27, 2016
<u>Newmarket-Tay Power Distribution Ltd.</u>			
10	Cost Effectiveness Tool	CustomerFirst CDM Plan (Amendment No.2) Cost Effectiveness Test-Newmarket.xlsm	July 27, 2016
11	Authorization Form	LDC Declaration Newmarket Hydro- signed.pdf	July 27, 2016
12	Achievable Potential Tool	Newmarket-Tay PD Achievable Potential- ESSA.xlsm	July 27, 2016
13	Achievable Potential Tool	Newmarket-Tay PD Achievable Potential- TORONTO.xlsm	July 27, 2016
<u>North Bay Hydro Distribution</u>			
14	Cost Effectiveness Tool	CustomerFirst CDM Plan (Amendment No.2) Cost Effectiveness Test-North Bay.xlsm	July 27, 2016
15	Authorization Form	LDC Declaration North Bay Hydro- signed.pdf	July 27, 2016
16	Achievable Potential Tool	North Bay Hydro Achievable Potential.xlsm	July 27, 2016
<u>Northern Ontario Wires Inc.</u>			
	Cost Effectiveness Tool	CustomerFirst CDM Plan (Amendment No.2) Cost Effectiveness Test-NOW.xlsm	July 27, 2016
	Authorization Form	LDC Declarationb NOW- signed.pdf	July 27, 2016
	Achievable Potential Tool	Northern Ontario Wires Achievable Potential.xlsm	July 27, 2016
<u>PUC Distribution Inc.</u>			
	Cost Effectiveness Tool	CustomerFirst CDM Plan (Amendment No.2) Cost Effectiveness Test-PUC.xlsm	July 27, 2016
	Authorization Form	LDC Declaration PUC and ERHDC July 22, 2016-signed.pdf	July 27, 2016
	Achievable Potential Tool	PUC Achievable Potential.xlsm	July 27, 2016
<u>St. Thomas Energy Inc.</u>			
	Cost Effectiveness Tool	CustomerFirst CDM Plan (Amendment No.2) Cost Effectiveness Test-STE.xlsm	July 27, 2016

	Authorization Form	LDC Declaration St. Thomas Energy-signed.pdf	July 27, 2016
	Achievable Potential Tool	St. Thomas Energy Achievable Potential.xlsm	July 27, 2016
<u>Espanola Regional Hydro Distribution Corporation</u>			
	Cost Effectiveness Tool	CustomerFirst CDM Plan (Amendment No.2) Cost Effectiveness Test-ERD.xlsm	July 27, 2016
	Authorization Form	LDC Declaration PUC and ERHDC July 22, 2016-signed.pdf	July 27, 2016
	Achievable Potential Tool	Espanola RDC Achievable Potential.xlsm	July 27, 2016

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the IESO under the Energy Conservation Agreement between the LDC and the IESO. The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the IESO in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.	CDM Plan Submission Date: (DD-Mon-YYYY)	28-Jul-2016
	CDM Plan Version	Amendment No. 2

2.	LDC INFORMATION									
	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LDC 6	LDC 7	LDC 8	LDC 9	LDC 10
	LDC Name:	Greater Sudbury Hydro Inc.	Newmarket-Tay Power Distribution Ltd.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	PUC Distribution Inc.	St. Thomas Energy Inc.	Espanola Regional Hydro Distribution Corporation		
	Company Representative:									
	Name:	Frank Kallonen	Paul Ferguson	Todd Wilcox	Dan Boucher	Dominic Parrella	Duane Orth	Dominic Parrella		
	Title:	President & CEO	President	Chief Operating Officer	General Manager	President & CEO	Conservation Officer	President & CEO		
	Email Address:	frankk@gsuinc.com	pferguson@nmhydro.ca	TWilcox@northbayhydro.com	danb@nowinc.ca	dominic.parrella@ssmpuc.com	dorth@sttenergy.com	dominic.parrella@ssmpuc.com		
	Phone Number (XXX-XXX-XXXX):	705-675-0520	905-953-8548	705-474-8100	705-272-2451	705-759-6552	519-631-5550	705-759-6552		

3.	Primary Contact for CDM Plan	
	Name:	Chris Barker
	LDC Name:	Greater Sudbury Hydro Inc.
	Title:	Executive Director, Conservation
	Email Address:	chris.barker@customerfirstinc.com
	Phone Number (XXX-XXX-XXXX):	647 255-8845

Estimated Start Date of CDM Plan: (DD-Mon-YYYY)	28-Jul-2016

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	Yes
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	Yes
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	Yes
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	Yes
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	Yes
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	Yes
Frequency of LDC Invoicing to IESO (subsequent changes to the frequency should be notified to us by email).	Quarterly

COMPLETE FOR CDM PLAN AMENDMENTS ONLY	
Select the reason(s) for CDM Plan amendment, as per ECA.	
One time each calendar year of the term	Yes
LDC wishes to request an adjustment to the CDM Plan Budget	
The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan	
LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term	
Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [Reallocation not subject to IESO approval]	
IESO has triggered remedies under Article 5 of the ECA	
LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]	
Other (Please specify reason)	

B. LDC Authorization

LDC DECLARATION	
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.	

LDC	
<i>I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.</i>	
LDC's Legal Name:	See attached signed declarations from each LDC in this plan.
Company Representative:	
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET												
		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7	LCD 8	LCD 9	LCD 10
a.	Allocated LDC CDM Plan Target (MWh) <i>Indicate total CDM Plan Target allocated to LDC(s)</i>	141,877	34,740.0	36,240.0	20,260.0	4,310.0	26,410.0	17,510.0	2,406.8			
b.	CDM Plan MWh Savings <i>Calculated as part of CDM Plan</i>	141,877	30,945	35,142	32,115	3,508	23,527	14,139	2,501	0	0	0
c.	Allocated LDC CDM Plan Budget (\$) <i>Indicate total budget allocated to LDC</i>	\$38,811,539	\$9,672,498.00	\$9,649,555.00	\$5,545,424.00	\$1,174,934.00	\$7,440,107.00	\$4,643,532.00	\$685,489.16			
d.	Total CDM Plan Budget (\$) <i>Calculated as part of CDM Plan</i>	\$38,811,539	\$9,229,844	10,044,416	5,765,892	1,145,685	7,276,494	4,584,129	765,078	0	0	0
f.	CDM Plan Cost Effectiveness <i>Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool</i>	Program Year 2015 2016 2017 2018 2019 2020 CDM Plan Total	Total Resource Cost (TRC)			Program Administrator Cost (PAC)			Levelized Cost (\$/kWh)	#DIV/0!		
	Benefits (\$)		Costs (\$)	Ratio	Benefits (\$)	Costs (\$)	Ratio					
	\$0.00		\$0.00	#DIV/0!	\$0.00	\$0.00	#DIV/0!					
	\$11,733,756.63		\$6,999,738.81	1.7	\$9,824,949.75	\$6,948,589.41	1.4	\$0.050				
	\$14,046,498.33		\$7,217,573.58	1.9	\$11,763,092.37	\$7,231,848.04	1.6	\$0.047				
	\$17,695,995.20		\$7,324,862.88	2.4	\$15,009,505.03	\$7,643,533.67	2.0	\$0.034				
	\$15,283,251.99		\$6,973,372.89	2.2	\$12,911,467.46	\$7,105,484.46	1.8	\$0.040				
	\$18,038,455.23		\$7,040,429.52	2.6	\$15,307,296.36	\$7,346,725.94	2.1	\$0.034				
			\$76,797,957	\$35,555,978	2.2	\$64,816,311	\$36,276,182	1.8	\$0.040			
g.	Plan Cost Effectiveness-Exceptions Rationale <i>Complete this section if proposed plan <u>does not</u> meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.</i>											

#DIV/0!

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES																										
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.																									
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.																									
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.																									
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.																									
LDC 1:	Greater Sudbury Hydro Inc.																									
TABLE 2. PROGRAM AND MILESTONE SCHEDULE																										
Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program								Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
													2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Total CDM Plan Budget (\$)	Total Persisting Energy Savings in 2020 (MWh)						
Full Cost Recovery Programs	Heating and Cooling Program			1-Dec-2015	Yes	Yes	Yes						\$16,680	56.0	\$228,230	99.3	\$228,230	99.3	\$228,230	99.3	\$228,230	99.3	\$228,230	99.3	\$1,157,830	552.2
	Coupon Program			1-Dec-2015	Yes	Yes							\$66,650	633.0	\$371,343	1,095.8	\$371,343	1,095.8	\$371,343	1,095.8	\$371,343	1,095.8	\$371,343	1,095.8	\$1,923,364	6,109.2
				1-Jun-2017	Yes	Yes									\$140,905	0.0	\$310,953	307.7	\$310,953	307.7	\$310,953	307.7	\$310,953	307.7	\$1,384,716	1,230.9
		Pilot - HEAR		1-Dec-2015	Yes	Yes									\$126,016	307.7	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$126,016	307.7
				1-Jun-2017	Yes	Yes									\$0	0.0	\$2,530	20.5	\$0	0.0	\$0	0.0	\$0	0.0	\$2,530	20.5
	Retrofit			1-Dec-2015			Yes	Yes	Yes	Yes	Yes		\$27,140		\$370,143	2,284.7	\$370,143	2,284.7	\$370,143	2,284.7	\$370,143	2,284.7	\$370,143	2,284.7	\$1,877,853	11,423.7
	Small Business Lighting			1-Sep-2016				Yes	Yes						\$100,155	49.8	\$100,155	49.8	\$100,155	49.8	\$100,155	49.8	\$100,155	49.8	\$500,773	249.1
	High Performance New Construction			1-Dec-2015			Yes	Yes	Yes	Yes	Yes		\$500		\$89,868	54.7	\$89,868	54.7	\$89,868	54.7	\$89,868	54.7	\$89,868	54.7	\$449,841	273.6
	Audit Funding Program			1-Dec-2015					Yes	Yes	Yes	Yes	\$1,045		\$91,901	54.6	\$91,901	54.6	\$91,901	54.6	\$91,901	54.6	\$91,901	54.6	\$460,550	218.5
	Process and Systems Upgrades Program			1-Dec-2015					Yes	Yes	Yes	Yes	\$370		\$88,065	0.0	\$88,065	0.0	\$188,907	946.1	\$188,907	946.1	\$289,749	1,892.2	\$844,064	3,784.3
	Energy Manager			1-Sep-2016					Yes	Yes	Yes	Yes	\$94,390	51.2	\$94,390	51.2	\$94,390	51.2	\$94,390	51.2	\$94,390	51.2	\$94,390	51.2	\$471,950	256.1
			Pilot - Channel Partners	1-Jan-2017				Yes	Yes	Yes	Yes	Yes			\$0	0.0	\$30,358	245.9	\$0	0.0	\$0	0.0	\$0	0.0	\$30,358	245.9

CDM PLAN TOTAL	\$112,385	7,711.0	\$1,701,015	3,997.9	\$1,777,935	4,264.3	\$1,845,889	4,944.0	\$1,845,889	4,944.0	\$1,946,731	5,890.1	\$9,229,844	30,945.3
MINIMUM ANNUAL SAVINGS CHECK	True		True		True		True		True		True			

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES																									
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.																								
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.																								
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.																								
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.																								
LDC 2:	Newmarket-Tay Power Distribution Ltd.																								
TABLE 2. PROGRAM AND MILESTONE SCHEDULE																									
Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program								Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)												
													2015		2016		2017		2018		2019		2020		Total 2015 - 2020
					Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Total CDM Plan Budget (\$)	Total Persisting Energy Savings in 2020 (MWh)					
Full Cost Recovery Programs	Heating and Cooling Program			1-Dec-2015	Yes	Yes	Yes						\$25,318	53.5	\$247,249	107.5	\$247,249	107.5	\$247,249	107.5	\$247,249	107.5	\$1,261,563	591.1	
	Coupon Program			1-Dec-2015	Yes	Yes							\$25,900	155.9	\$402,288	1,187.1	\$402,288	1,187.1	\$402,288	1,187.1	\$402,288	1,187.1	\$2,097,341	6,090.1	
		Local - HEAR		1-Jun-2017	Yes	Yes									\$152,647	0.0	\$336,866	333.4	\$336,866	333.4	\$336,866	333.4	\$1,500,109	1,333.4	
		Pilot - Financing		1-Jan-2017	Yes	Yes	Yes								\$0	0.0	\$115,951	939.2	\$0	0.0	\$0	0.0	\$115,951	939.2	
		Pilot - HEAR		1-Dec-2015	Yes	Yes									\$136,517	333.4	\$0	0.0	\$0	0.0	\$0	0.0	\$136,517	333.4	
		Pilot - Home Solar		1-Jun-2017	Yes	Yes									\$0	0.0	\$2,741	22.2	\$0	0.0	\$0	0.0	\$2,741	22.2	
	Retrofit			1-Dec-2015			Yes	Yes	Yes	Yes	Yes				\$400,988	2,475.1	\$400,988	2,475.1	\$400,988	2,475.1	\$400,988	2,475.1	\$2,004,939	12,375.7	
	Small Business Lighting			1-Sep-2016			Yes	Yes							\$108,501	54.0	\$108,501	54.0	\$108,501	54.0	\$108,501	54.0	\$542,504	269.8	
	High Performance New Construction			1-Dec-2015			Yes	Yes	Yes	Yes	Yes				\$97,357	59.3	\$97,357	59.3	\$97,357	59.3	\$97,357	59.3	\$486,786	296.4	
	Audit Funding Program			1-Dec-2015			Yes	Yes	Yes	Yes	Yes				\$99,559	59.2	\$99,559	59.2	\$99,559	59.2	\$99,559	59.2	\$497,797	236.7	
	Process and Systems Upgrades Program			1-Dec-2015				Yes	Yes	Yes	Yes				\$95,404	0.0	\$95,404	0.0	\$204,649	1,024.9	\$204,649	1,024.9	\$313,895	2,049.8	
	Energy Manager			1-Sep-2016			Yes	Yes	Yes	Yes	Yes				\$102,256	55.5	\$102,256	55.5	\$102,256	55.5	\$102,256	55.5	\$511,279	277.5	
		Pilot - Channel Partners		1-Jan-2017			Yes	Yes	Yes	Yes	Yes				\$0	0.0	\$32,888	266.4	\$0	0.0	\$0	0.0	\$32,888	266.4	

MINIMUM ANNUAL SAVINGS CHECK

True

True

True

True

True

True

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES																									
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.																								
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.																								
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.																								
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.																								
LDC 3:	North Bay Hydro Distribution Limited																								
TABLE 2. PROGRAM AND MILESTONE SCHEDULE																									
Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program								Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)												
					Residential	Low-income	Small business	Commercial (inc. Multi-Fam)	Agricultural	Institutional	Industrial	2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
												Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Total CDM Plan Budget (\$)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Heating and Cooling Program			1-Dec-2015	Yes	Yes	Yes					\$4,200	16.5	\$133,134	57.9	\$133,134	57.9	\$133,134	57.9	\$133,134	57.9	\$133,134	57.9	\$669,871	306.0
	Coupon Program			1-Dec-2015	Yes	Yes						\$23,000	148.1	\$216,617	639.2	\$216,617	639.2	\$216,617	639.2	\$216,617	639.2	\$216,617	639.2	\$1,106,083	3,342.9
		Pilot - HEAR		1-Jun-2017	Yes	Yes								\$82,194	0.0	\$181,389	179.5	\$181,389	179.5	\$181,389	179.5	\$181,389	179.5	\$807,751	718.0
				1-Dec-2015	Yes	Yes								\$23,509	179.5	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$73,509	179.5
			Pilot - Home Solar	1-Jun-2017	Yes	Yes								\$0	0.0	\$1,476	12.0	\$0	0.0	\$0	0.0	\$0	0.0	\$1,476	12.0
	Retrofit			1-Dec-2015			Yes	Yes	Yes	Yes	Yes			\$215,916	1,332.8	\$215,916	1,332.8	\$215,916	1,332.8	\$215,916	1,332.8	\$215,916	1,332.8	\$1,079,582	6,663.8
	Small Business Lighting			1-Sep-2016			Yes	Yes						\$58,424	29.1	\$58,424	29.1	\$58,424	29.1	\$58,424	29.1	\$58,424	29.1	\$292,118	145.3
	High Performance New Construction			1-Dec-2015			Yes	Yes	Yes	Yes	Yes			\$52,423	31.9	\$52,423	31.9	\$52,423	31.9	\$52,423	31.9	\$52,423	31.9	\$262,116	159.6
	Audit Funding Program			1-Dec-2015				Yes	Yes	Yes	Yes			\$53,609	31.9	\$53,609	31.9	\$53,609	31.9	\$53,609	31.9	\$53,609	31.9	\$268,045	127.4
	Process and Systems Upgrades Program			1-Dec-2015					Yes	Yes	Yes	Yes	9,936.0	\$51,371	0.0	\$51,371	0.0	\$110,196	551.9	\$110,196	551.9	\$169,020	1,103.8	\$492,155	12,143.5
	Energy Manager			1-Sep-2016				Yes	Yes	Yes	Yes			\$55,061	29.9	\$55,061	29.9	\$55,061	29.9	\$55,061	29.9	\$55,061	29.9	\$275,304	149.4
			Pilot - Channel Partners	1-Jan-2017				Yes	Yes	Yes	Yes			\$0	0.0	\$17,709	143.4	\$0	0.0	\$0	0.0	\$0	0.0	\$17,709	143.4
			Pilot - CEP	1-Jan-2017				Yes						\$0	0.0	\$0	0.0	\$420,174	3,942.0	\$0	0.0	\$0	0.0	\$420,174	3,942.0

CDM PLAN TOTAL	\$27,200	15,138.5	\$992,259	2,332.1	\$1,037,129	2,487.5	\$1,496,943	6,826.0	\$1,076,769	2,884.0	\$1,135,593	3,435.9	\$5,765,892	32,115.3
MINIMUM ANNUAL SAVINGS CHECK		True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 4: Northern Ontario Wires Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE																										
Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program								Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
													2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Total CDM Plan Budget (\$)	Total Persisting Energy Savings in 2020 (MWh)								
																			Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	
Full Cost Recovery Programs	Heating and Cooling Program Coupon Program			1-Dec-2015	Yes	Yes	Yes						\$780	3.1	\$28,529	12.4	\$28,529	12.4	\$28,529	12.4	\$28,529	12.4	\$143,424	65.1		
			Local - HEAR	1-Dec-2015	Yes	Yes							\$4,100	23.7	\$46,418	137.0	\$46,418	137.0	\$46,418	137.0	\$46,418	137.0	\$236,189	708.3		
			Pilot - HEAR	1-Jun-2017	Yes	Yes									\$17,613	0.0	\$38,869	38.5	\$38,869	38.5	\$38,869	38.5	\$173,090	153.9		
			Pilot - Home Solar	1-Dec-2015	Yes	Yes									\$15,752	38.5	\$0	0.0	\$0	0.0	\$0	0.0	\$15,752	38.5		
				1-Jun-2017	Yes	Yes									\$0	0.0	\$316	2.6	\$0	0.0	\$0	0.0	\$316	2.6		
	Retrofit Small Business Lighting			1-Dec-2015			Yes	Yes	Yes	Yes	Yes	\$900		\$46,268	285.6	\$46,268	285.6	\$46,268	285.6	\$46,268	285.6	\$46,268	285.6	\$232,339	1,428.0	
	High Performance New Construction			1-Sep-2016				Yes	Yes					\$12,519	6.2	\$12,519	6.2	\$12,519	6.2	\$12,519	6.2	\$12,519	6.2	\$62,597	31.1	
	Audit Funding Program			1-Dec-2015				Yes	Yes	Yes	Yes			\$11,234	6.8	\$11,234	6.8	\$11,234	6.8	\$11,234	6.8	\$11,234	6.8	\$56,168	34.2	
	Process and Systems Upgrades Program			1-Dec-2015				Yes	Yes	Yes	Yes			\$11,488	6.8	\$11,488	6.8	\$11,488	6.8	\$11,488	6.8	\$11,488	6.8	\$57,438	27.3	
	Energy Manager			1-Dec-2015				Yes	Yes	Yes	Yes	\$223		\$11,008	0.0	\$11,008	0.0	\$23,613	118.3	\$23,613	118.3	\$36,219	236.5	\$105,685	473.0	
				1-Sep-2016				Yes	Yes	Yes	Yes			\$11,799	6.4	\$11,799	6.4	\$11,799	6.4	\$11,799	6.4	\$11,799	6.4	\$58,994	32.0	
				Pilot - Channel Partners	1-Jan-2017				Yes	Yes	Yes	Yes	Yes		\$0	0.0	\$3,795	30.7	\$0	0.0	\$0	0.0	\$0	0.0	\$3,795	30.7

MINIMUM ANNUAL SAVINGS CHECK

True

True

True

True

True

True

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDCs:	PUC Distribution Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE																												
Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program								Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)															
													2015		2016		2017		2018		2019		2020		Total 2015 - 2020			
					Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Total CDM Plan Budget (\$)	Total Persisting Energy Savings in 2020 (MWh)								
Full Cost Recovery Programs	Heating and Cooling Program			1-Dec-2015	Yes	Yes	Yes							\$14,275	49.7	\$180,682	78.6	\$180,682	78.6	\$180,682	78.6	\$180,682	78.6	\$180,682	78.6	\$917,685	442.5	
	Coupon Program		Local - HEAR	1-Dec-2015	Yes	Yes								\$34,190	194.2	\$293,980	867.5	\$293,980	867.5	\$293,980	867.5	\$293,980	867.5	\$293,980	867.5	\$1,504,089	4,530.0	
			Pilot - HEAR	1-Dec-2015	Yes	Yes										\$99,762	243.6	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$99,762	243.6	
			Pilot - Home Solar	1-Jun-2017	Yes	Yes										\$0	0.0	\$2,003	16.2	\$0	0.0	\$0	0.0	\$0	0.0	\$2,003	16.2	
	Retrofit			1-Dec-2015			Yes	Yes	Yes	Yes	Yes		\$10,040		\$293,029	1,808.8	\$293,029	1,808.8	\$293,029	1,808.8	\$293,029	1,808.8	\$293,029	1,808.8	\$1,475,187	9,043.8		
	Small Business Lighting			1-Sep-2016			Yes	Yes								\$79,289	39.4	\$79,289	39.4	\$79,289	39.4	\$79,289	39.4	\$79,289	39.4	\$396,445	197.2	
	High Performance New Construction			1-Dec-2015			Yes	Yes	Yes	Yes	Yes					\$71,146	43.3	\$71,146	43.3	\$71,146	43.3	\$71,146	43.3	\$71,146	43.3	\$355,728	216.6	
	Audit Funding Program			1-Dec-2015				Yes	Yes	Yes	Yes					\$72,755	43.2	\$72,755	43.2	\$72,755	43.2	\$72,755	43.2	\$72,755	43.2	\$363,775	172.9	
	Process and Systems Upgrades Program			1-Dec-2015				Yes	Yes	Yes	Yes					\$69,718	0.0	\$69,718	0.0	\$149,552	749.0	\$149,552	749.0	\$229,385	1,498.0	\$667,924	2,095.9	
	Energy Manager			1-Sep-2016				Yes	Yes	Yes	Yes					\$74,725	40.6	\$74,725	40.6	\$74,725	40.6	\$74,725	40.6	\$74,725	40.6	\$373,627	202.8	
			Pilot - Channel Partners	1-Jan-2017			Yes	Yes	Yes	Yes	Yes					\$0	0.0	\$24,033	194.7	\$0	0.0	\$0	0.0	\$0	0.0	\$24,033	194.7	
	FCR TOTAL													\$58,505	243.9	\$1,346,637	3,165.0	\$1,407,532	3,375.9	\$1,461,329	3,914.0	\$1,461,329	3,914.0	\$1,541,162	4,663.0	\$7,276,494	19,230.7	
	Pay for Performance Programs																											
P4P TOTAL													\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0		
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) (Not funded through 2015-2020 CDM Framework)	Conservation Instant Coupon Booklet															272.9											270.4	
	Bi-Annual Retailer Event															775.4											761.5	
	Other															24.5											0.0	
	Heating and Cooling Initiative															438.0											438.0	
	Retrofit Initiative																2,758.2											2,734.8
	Direct Install Lighting																											
2011-2014 CDM Framework (and 2015 extension) TOTAL													\$0	4,406.4													0.0	4,296.1
TARGET GAP TOTAL																											0.0	
CDM PLAN TOTAL													\$58,505	4,650.3	\$1,346,637	3,165.0	\$1,407,532	3,375.9	\$1,461,329	3,914.0	\$1,461,329	3,914.0	\$1,541,162	4,663.0	\$7,276,494	23,526.8		

MINIMUM ANNUAL SAVINGS CHECK

True

True

True

True

True

True

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 6:	St. Thomas Energy Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE																									
Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program								Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)												
													2015		2016		2017		2018		2019		2020		Total 2015 - 2020
					Residential	Low-Income	Small Business	Commercial (Ex. Multi-Fam)	Agricultural	Institutional	Industrial	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Total CDM Plan Budget (\$)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Heating and Cooling Program			1-Dec-2015	Yes	Yes	Yes						\$9,910	14.6	\$114,115	49.6	\$114,115	49.6	\$114,115	49.6	\$114,115	49.6	\$580,485	262.7	
	Coupon Program		Local - HEAR	1-Dec-2015	Yes	Yes							\$11,699	66.8	\$185,671	547.9	\$185,671	547.9	\$185,671	547.9	\$185,671	547.9	\$940,056	2,895.7	
		Pilot - HEAR		1-Jun-2017	Yes	Yes									\$70,452	0.0	\$155,476	153.9	\$155,476	153.9	\$155,476	153.9	\$692,358	613.4	
			Pilot - Home Solar	1-Dec-2015	Yes	Yes									\$63,008	153.9	\$0	0.0	\$0	0.0	\$0	0.0	\$63,008	153.9	
				1-Jun-2017	Yes	Yes									\$0	0.0	\$1,265	10.2	\$0	0.0	\$0	0.0	\$1,265	10.2	
	Retrofit			1-Dec-2015			Yes	Yes	Yes	Yes	Yes		\$3,420		\$185,071	1,142.4	\$185,071	1,142.4	\$185,071	1,142.4	\$185,071	1,142.4	\$928,776	5,711.9	
	Small Business Lighting			1-Sep-2016			Yes	Yes							\$50,077	24.9	\$50,077	24.9	\$50,077	24.9	\$50,077	24.9	\$250,387	124.5	
	High Performance New Construction			1-Dec-2015			Yes	Yes	Yes	Yes	Yes				\$44,934	27.4	\$44,934	27.4	\$44,934	27.4	\$44,934	27.4	\$224,671	136.8	
	Audit Funding Program			1-Dec-2015				Yes	Yes	Yes	Yes				\$110		\$45,950	27.3	\$45,950	27.3	\$45,950	27.3	\$229,862	109.2	
	Process and Systems Upgrades Program			1-Dec-2015				Yes	Yes	Yes	Yes				\$260		\$44,033	0.0	\$44,033	0.0	\$94,454	473.0	\$144,874	946.1	
	Energy Manager			1-Sep-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes				\$47,195	25.6	\$47,195	25.6	\$47,195	25.6	\$47,195	25.6	\$235,975	128.1	
			Pilot - Channel Partners	1-Jan-2017			Yes	Yes	Yes	Yes	Yes					\$0	0.0	\$15,179	122.9	\$0	0.0	\$0	0.0	\$15,179	122.9
	FCR TOTAL												\$25,399	81.4	\$850,507	1,999.0	\$888,968	2,132.1	\$922,945	2,472.0	\$922,945	2,472.0	\$973,366	2,945.0	\$4,584,129
Pay for Performance Programs																									
P4P TOTAL												\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) (Not funded through 2015-2020 CDM Framework)	Conservation Instant Coupon Booklet														94.2									93.3	
	Bi-Annual Retailer Event														261.2									256.5	
	Other														10.2									0.0	
	Heating and Cooling Initiative														187.3									187.3	
	Residential New Construction														20.2									20.2	
	Audit Funding														71.4									0.0	
	Retrofit Initiative														1,484.3									1,467.4	
	Direct Install Lighting														45.2										24.8
	High Performance New Construction																								
															131.6									3.4	
	Energy Manager (PSUI)														17.7									12.9	
	Low Income Home Assistance Program																								
2011-2014 CDM Framework (and 2015 extension) TOTAL												\$0	2,323.4											0.0	2,065.8
TARGET GAP TOTAL																								0.0	

CDM PLAN TOTAL	\$25,399	2,404.8	\$850,507	1,999.0	\$888,968	2,132.1	\$922,945	2,472.0	\$922,945	2,472.0	\$973,366	2,945.0	\$4,584,129	14,139.4
MINIMUM ANNUAL SAVINGS CHECK		True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 7:	Espanola Regional Hydro Distribution Corporation

TABLE 2. PROGRAM AND MILESTONE SCHEDULE																												
Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program								Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)															
													2015		2016		2017		2018		2019		2020		Total 2015 - 2020			
					Residential	Low-income	Small business	Commercial (excl. Multi-Fam)	Agricultural	Institutional	Industrial	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Anticipated Annual Budget (\$)	Energy Savings (MWh)	Total CDM Plan Budget (\$)	Total Persisting Energy Savings in 2020 (MWh)			
Full Cost Recovery Programs	Heating and Cooling Program			1-Dec-2015	Yes	Yes	Yes						\$260	1.0	\$19,019	8.3	\$19,019	8.3	\$19,019	8.3	\$19,019	8.3	\$19,019	8.3	\$95,356	42.4		
	Coupon Program		Local - HEAR	1-Dec-2015	Yes	Yes							\$3,230	18.3	\$30,945	91.3	\$30,945	91.3	\$30,945	91.3	\$30,945	91.3	\$30,945	91.3	\$157,356	474.7		
			Pilot - HEAR	1-Jun-2017	Yes	Yes							\$11,742	0.0	\$25,913	25.6	\$25,913	25.6	\$25,913	25.6	\$25,913	25.6	\$25,913	25.6	\$115,393	102.6		
				1-Dec-2015	Yes	Yes							\$10,501	25.6	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$10,501	25.6		
				1-Jun-2017	Yes	Yes							\$0	0.0	\$211	1.7	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$211	1.7		
	Retrofit			1-Dec-2015			Yes	Yes	Yes	Yes	Yes	\$1,800		\$30,845	190.4	\$30,845	190.4	\$30,845	190.4	\$30,845	190.4	\$30,845	190.4	\$30,845	190.4	\$156,026	952.0	
	Small Business Lighting			1-Sep-2016			Yes	Yes						\$8,346	4.2	\$8,346	4.2	\$8,346	4.2	\$8,346	4.2	\$8,346	4.2	\$8,346	4.2	\$41,731	20.8	
	High Performance New Construction			1-Dec-2015			Yes	Yes	Yes	Yes	Yes			\$7,489	4.6	\$7,489	4.6	\$7,489	4.6	\$7,489	4.6	\$7,489	4.6	\$7,489	4.6	\$37,445	22.8	
	Audit Funding Program			1-Dec-2015				Yes	Yes	Yes	Yes			\$7,658	4.6	\$7,658	4.6	\$7,658	4.6	\$7,658	4.6	\$7,658	4.6	\$7,658	4.6	\$38,292	18.2	
	Process and Systems Upgrades Program			1-Dec-2015				Yes	Yes	Yes	Yes			\$7,339	0.0	\$7,339	0.0	\$15,742	78.8	\$15,742	78.8	\$24,146	157.7	\$70,308	315.4			
	Energy Manager			1-Sep-2016			Yes	Yes	Yes	Yes	Yes			\$7,866	4.3	\$7,866	4.3	\$7,866	4.3	\$7,866	4.3	\$7,866	4.3	\$7,866	4.3	\$39,329	21.3	
			Pilot - Channel Partners	1-Jan-2017				Yes	Yes	Yes	Yes	Yes			\$0	0.0	\$2,530	20.5	\$0	0.0	\$0	0.0	\$0	0.0	\$0	0.0	\$2,530	20.5

CDM PLAN TOTAL	\$5,290	506.2	\$141,751	333.2	\$148,161	355.4	\$153,824	412.0	\$153,824	412.0	\$162,228	490.8	\$765,078	2,500.8
MINIMUM ANNUAL SAVINGS CHECK		True		True		True		True		True		True		

E. Proposed Local and Regional Pilot CDM Programs

Notes			
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.			

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	Program Name	Local - HEAR	Use same "Program name" included in other worksheets	
b.	Program Type	Proposed Local Program		
b.	Estimated Business Case Submission Date (DD-Mon-YYYY)	1-Mar-2017		
c.	Customer Segment(s) Served by Programs	Residential	Low Income	
d.	Participating LDCs (If applicable)	Greater Sudbury Hydro Inc.	Newmarket-Tay Power Distribution Ltd.	North Bay Hydro Distribution Limited
		Northern Ontario Wires Inc.	PUC Distribution Inc.	St. Thomas Energy Inc.
e.	Overview of Proposed Program or Pilot	Following successful completion of approved pilot program.		
	Provide overview of key objectives and elements of proposed program or pilot.			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	Program Name	Pilot - Financing	Use same "Program name" included in other worksheets	
b.	Program Type	Proposed Pilot		
b.	Estimated Business Case Submission Date (DD-Mon-YYYY)	1-Oct-2016		
c.	Customer Segment(s) Served by Programs	Residential	Low Income	Small Business
d.	Participating LDCs (if applicable)	Newmarket-Tay Power Distribution Ltd.		
e.	Overview of Proposed Program or Pilot	A conservation project financing program for customers.		
	Provide overview of key objectives and elements of proposed program or pilot.			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS			
a.	Program Name	Pilot - CEP	Use same "Program name" included in other worksheets
b.	Program Type	Proposed Pilot	
b.	Estimated Business Case Submission Date (DD-Mon-YYYY)	1-Oct-2016	
c.	Customer Segment(s) Served by Programs	Commercial (inc. Multi-Family)	
d.	Participating LDCs (if applicable)	North Bay Hydro Distribution Limited	
e.	Overview of Proposed Program or Pilot	A pilot to develop a Community Energy Park in North Bay.	
	Provide overview of key objectives and elements of proposed program or pilot.		

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS			
a.	Program Name	Pilot - Home Solar	Use same "Program name" included in other worksheets
b.	Program Type	Proposed Pilot	
b.	Estimated Business Case Submission Date (DD-Mon-YYYY)	1-Jan-2017	
c.	Customer Segment(s) Served by Programs	Residential	Low Income Small Business
d.	Participating LDCs (if applicable)	Greater Sudbury Hydro Inc.	Newmarket-Tay Power Distribution Ltd. North Bay Hydro Distribution Limited
		Northern Ontario Wires Inc.	PUC Distribution Inc. St. Thomas Energy Inc.
e.	Overview of Proposed Program or Pilot Provide overview of key objectives and elements of proposed program or pilot.	A rebate offered to customers to install solar and net-metering. Financing will also be offered. Potential to expand to include small commercial.	

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	Program Name	Pilot - Channel Partners	Use same "Program name" included in other worksheets	
	Program Type	Proposed Pilot		
b.	Estimated Business Case Submission Date (DD-Mon-YYYY)	1-Oct-2017		
c.	Customer Segment(s) Served by Programs	Residential	Low Income	Small Business
d.	Participating LDCs (if applicable)	Greater Sudbury Hydro Inc.	Newmarket-Tay Power Distribution Ltd.	North Bay Hydro Distribution Limited
		Northern Ontario Wires Inc.	PUC Distribution Inc.	St. Thomas Energy Inc.
e.	Overview of Proposed Program or Pilot	A program to engage channel partners to increase customer participation in conservation programs.		
	Provide overview of key objectives and elements of proposed program or pilot.			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	Program Name	Pilot - Home Solar	Use same "Program name" included in other worksheets	
b.	Program Type	Proposed Pilot		
b.	Estimated Business Case Submission Date (DD-Mon-YYYY)	1-Jan-2017		
c.	Customer Segment(s) Served by Programs	Residential		
d.	Participating LDCs (if applicable)	Espanola Regional Hydro Distribution Corporation		
e.	Overview of Proposed Program or Pilot	A rebate offered to customers to install solar and net-metering. Financing will also be offered. Potential to expand to include small commercial.		
	Provide overview of key objectives and elements of proposed program or pilot.			

E. Proposed Local and Regional Pilot CDM Programs

Notes			
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.			

TABLE 3g. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS			
a. Program Name	Local - HEAR	Use same "Program name" included in other worksheets	
b. Program Type	Proposed Local Program		
b. Estimated Business Case Submission Date (DD-Mon-YYYY)	1-Mar-2017		
c. Customer Segment(s) Served by Programs	Residential		
d. Participating LDCs (if applicable)	Espanola Regional Hydro Distribution Corporation		
e. Overview of Proposed Program or Pilot	Following successful completion of approved pilot program.		
Provide overview of key objectives and elements of proposed program or pilot.			

TABLE 3i. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS			
a. Program Name		Use same "Program name" included in other worksheets	
b. Program Type			
b. Estimated Business Case Submission Date (DD-Mon-YYYY)			
c. Customer Segment(s) Served by Programs			
d. Participating LDCs (if applicable)			
e. Overview of Proposed Program or Pilot			
Provide overview of key objectives and elements of proposed program or pilot.			

TABLE 3h. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS			
a. Program Name	Pilot - Channel Partners	Use same "Program name" included in other worksheets	
b. Program Type	Proposed Pilot		
b. Estimated Business Case Submission Date (DD-Mon-YYYY)	1-Oct-2017		
c. Customer Segment(s) Served by Programs	Residential		
d. Participating LDCs (if applicable)	Espanola Regional Hydro Distribution Corporation		
e. Overview of Proposed Program or Pilot	A program to engage channel partners to increase customer participation in conservation programs.		
Provide overview of key objectives and elements of proposed program or pilot.			

TABLE 3j. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS			
a. Program Name		Use same "Program name" included in other worksheets	
b. Program Type			
b. Estimated Business Case Submission Date (DD-Mon-YYYY)			
c. Customer Segment(s) Served by Programs			
d. Participating LDCs (if applicable)			
e. Overview of Proposed Program or Pilot			
Provide overview of key objectives and elements of proposed program or pilot.			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC(s) Collaboration <i>Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.</i>	CustomerFirst LDCs will collaborate with eachother in all facets of conservation and this plan. CustomerFirst is a member of multiple working groups and CFIC and will continue to look for collaboration opportunities through these groups and others. Active discussions with other LDCs on collaboration are taking place and it is expected that collaboration activities will expand.
Gas Collaboration <i>Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.</i>	CustomerFirst has had discussions with Union Gas and Enbridge (Newmarket-Tay) for potential collaboration opportunites in all areas of conservation. Initial focus will be on those sectors and customers where the gas utilities are already active with conservation programs in CustomerFirst communities. Discussions for additional potential areas of collaboration will take place regarding the pilot programs. Union Gas will be collaborating with the Pilot - CEP program.
CDM Contribution to Regional Planning <i>Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.</i>	CustomerFirst supports the IRRP process and its objectives to develop long-term electricity plans that thoughtfully integrate all relevant resource options, such as conservation and demand management, distributed generation, large-scale generation, transmission and distribution. The LDCs of the CustomerFirst joint CDM Plan will continue to contribute to the ongoing development of IRRP's and system distribution plans and will continue to play an active role with the development of Community Energy Plans in the communities we serve. All of the LDC's in this plan are committed to support the implementation of IRRP's through the delivery of this CDM plan and will ensure that committments in the CDM plan are aligned with the IRRP's. The LDCs of CustomerFirst are working with the IESO, OEB and other LDCs according to the regional planning cycle. PUC is part of the East Lake Superior region, St. Thomas is part of the London area plan and Greater Sudbury Hydro and Espanola Regional Hydro Distribution Corp. are part of the North/East of Sudbury region and all are scheduled to be included in the next planning cycle. North Bay Hydro and Northern Ontario Wires are part of the North/East of Sudbury region that is scheduled for a future planning cycle. Newmarket-Tay Hydro was included in the first planning cycle under the York Region area and the community of Tay is part of the South Georgian Bay/Muskoka and will be included in the next planning cycle. The York Region IRRP was developed by a working group composed of Newmarket-Tay Hydro, IESO, PowerStream and Hydro One Networks Inc..

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs <i>Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs</i>	IESO provided archetypes were used in the Cost Effectiveness Tool wherever available. Where archetypes were not available, a close proxy was used and this includes cost effectiveness for pilot and local programs. CustomerFirst strived for consistency in all aspects of the joint plan. As such, the same IESO archetypes were used for all LDCs when using the cost effectiveness tool and the budget and target for each LDC in the plan are the same amounts that were allocated under the new framework. Additionally, each LDCs percentage share of the program budgets and savings, as well as the program participants, are equal to their share of the overall (combined) budget and target. This approach ensured that program cost effectiveness is consistent across all LDCs and that each LDCs portion of the plan is also cost effective.
Approved Local and/or Regional Programs and Pilot Programs <i>Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs</i>	See above.
Proposed Local and/or Regional Programs and Pilot Programs <i>Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs</i>	See 'Programs' above.
Programs from 2011-2014/2015 CDM Framework <i>Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs</i>	Not applicable.
Programs funded through Pay-for-Performance <i>Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs</i>	Not applicable.
Other <i>Additional assumptions used in the CDM Plan</i>	Providing low-income customers with access to conservation programs is important to CustomerFirst. As outlined in the plan, CustomerFirst will be offering no less than five programs including two pilot programs to low income customers. The proposed Home Energy Assessment & Retrofit (HEAR) pilot program will be targeting low income customers in addition to those with electric heat. Information on HEAR and how it will assist low income customers can be found on Tab E. Proposed Programs&Pilots.



saveONenergy™

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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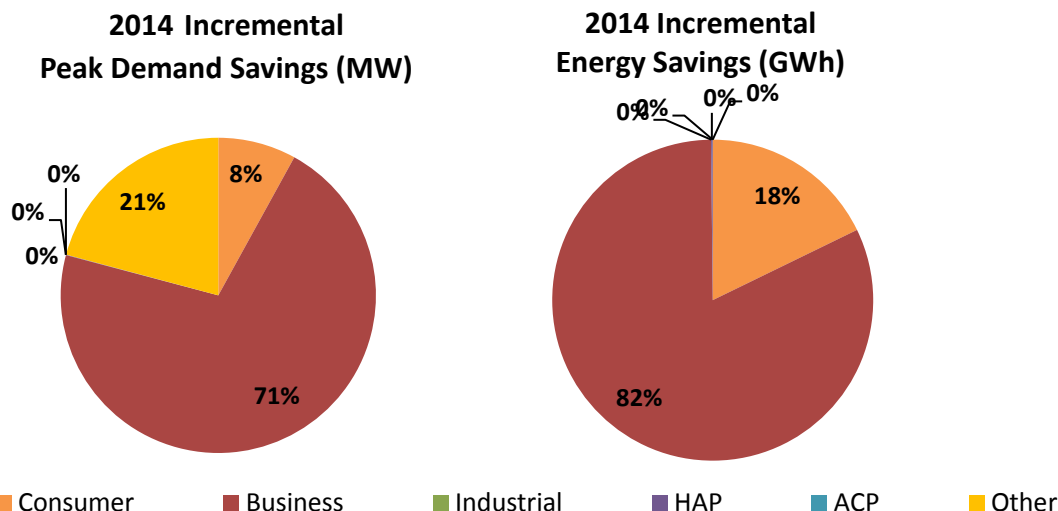
IESO-Contracted Province-Wide CDM Programs: 2011-2014 Final Results Report

LDC: Northern Ontario Wires Inc.

Final 2014 Achievement Against Targets	2014 Incremental	2011-2014	
		Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	0.2	0.6	52.7%
Net Energy Savings (GWh)	1.1	5.7	97.7%

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)

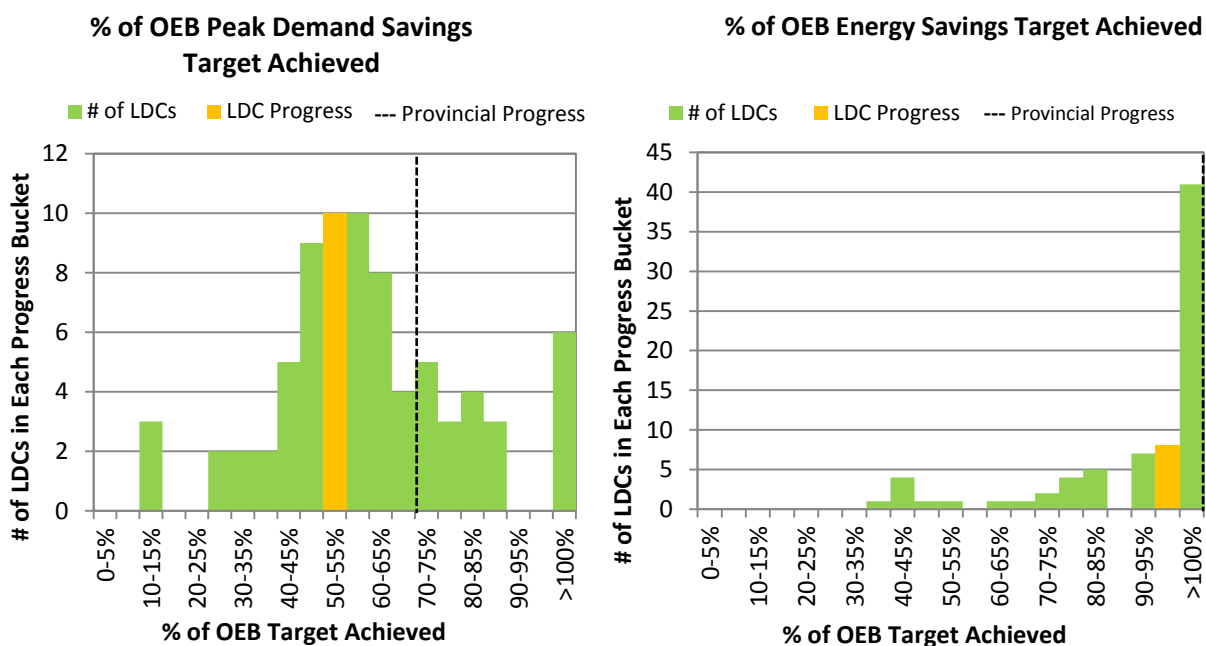


Table 1: Northern Ontario Wires Inc. Initiative and Program Level Net Savings by Year

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)
Consumer Program															
Appliance Retirement	Appliances	66	38	27	34	4	2	2	2	28,618	15,585	11,769	14,542	10	199,206
Appliance Exchange	Appliances	5	9	1	2	1	1	0	0	824	2,298	369	739	2	11,434
HVAC Incentives	Equipment	1	1	3	13	0	0	1	3	819	374	1,532	6,491	5	13,950
Conservation Instant Coupon Booklet	Items	550	33	369	1,113	1	0	1	2	20,258	1,484	8,181	30,294	4	132,141
Bi-Annual Retailer Event	Items	1,011	1,126	1,003	5,121	2	2	1	9	31,192	28,426	18,235	130,450	13	376,967
Retailer Co-op	Items	0	0	0	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	0	0	0
Residential Demand Response (IHD)	Devices	0	0	0	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	0	0	0
Consumer Program Total						8	5	4	17	81,712	48,166	40,085	182,515	34	733,698
Business Program															
Retrofit	Projects	3	1	6	5	46	10	19	18	278,297	6,484	69,149	359,113	93	1,630,051
Direct Install Lighting	Projects	36	97	63	122	47	85	87	131	121,356	315,820	310,069	482,772	333	2,485,832
Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Audit	Audits	0	4	2	0	0	16	18	0	0	75,529	96,902	0	33	420,389
Small Commercial Demand Response	Devices	0	0	0	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	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Business Program Total						93	110	124	149	399,653	397,833	476,120	841,885	459	4,536,273
Industrial Program															
Process & System Upgrades	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit	Projects	0	0	0	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	0	0	0
Industrial Program Total						0	0	0	0	0	0	0	0	0	0
Home Assistance Program															
Home Assistance Program	Homes	0	0	131	1	0	0	11	0	0	0	129,810	1,693	10	250,827
Home Assistance Program Total						0	0	11	0	0	0	129,810	1,693	10	250,827
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	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Performance New Construction	Projects	0	0	0	0	0	0	0	0	340	116	0	0	0	1,709
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						0	0	0	0	340	116	0	0	0	1,709
Other															
Program Enabled Savings	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	44	0	0	0	0	44	0
LDC Pilots	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Total						0	0	0	44	0	0	0	0	44	0
Adjustments to 2011 Verified Results							5	0	0		22,450	0	0	5	89,799
Adjustments to 2012 Verified Results								5	1			25,185	3,416	6	85,804
Adjustments to 2013 Verified Results									0				22,993	0	45,986
Energy Efficiency Total						101	116	139	210	481,705	446,115	646,016	1,026,093	548	5,522,508
Demand Response Total (Scenario 1)						0	0	0	0	0	0	0	0	0	0
Adjustments to Previous Years' Verified Results Total						0	5	5	1	0	22,450	25,185	26,409	11	221,588
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						101	121	144	210	481,705	468,565	671,201	1,052,502	559	5,744,096
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).														Full OEB Target:	
														1,060	
														5,880,000	
% of Full OEB Target Achieved to Date (Scenario 1):														52.7%	
														97.7%	

Interrogatory Responses

Table 2: Adjustments to Northern Ontario Wires 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	0	0	0		0	0	0		-184	9	0		0	-710
Conservation Instant Coupon Booklet	Items	9	0	1		0	0	0		293	0	25		0	1,220
Bi-Annual Retailer Event	Items	87	0	0		0	0	0		2,317	0	0		0	9,270
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						0	0	0		2,426	9	25		0	9,780
Business Program															
Retrofit	Projects	1	0	1		5	0	0		20,024	0	22,904		5	125,902
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	0	0		0	0	0		0	0	0		0	0
Energy Audit	Audits	0	1	0		0	6	0		0	28,592	64		6	85,906
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	6	0		20,024	28,592	22,968		11	211,808
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	0	0		0	0	0		0	0	0		0	0
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	0	0		0	0	0		0	0
Home Assistance Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Home Assistance Program Total						0	0	0		0	0	0		0	0
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	0	0	0		0	0	0		0	0	0		0	0
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						0	0	0		0	0	0		0	0
Other															
Program Enabled Savings	Projects	0	0	0		0	0	0		0	0	0		0	0
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						0	0	0		0	0	0		0	0
Adjustments to 2011 Verified Results						5				22,450				5	89,799
Adjustments to 2012 Verified Results							6				28,601			6	85,804
Adjustments to 2013 Verified Results								0				22,993		0	45,986
Total Adjustments to Previous Years' Verified Results						5	6	0		22,450	28,601	22,993		11	221,588

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. Adjustments in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 3: Northern Ontario Wires 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	0.52	0.47	0.42	0.42	1.00	1.00	n/a	n/a	0.52	0.47	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	1.71	1.00	1.00	1.00	1.00	1.11	1.05	1.13	1.75
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	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
Business Program																
Retrofit	0.93	0.99	1.02	0.90	0.75	0.68	0.72	0.72	1.35	0.98	1.16	1.00	0.76	0.67	0.73	0.72
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	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 Audit	n/a	n/a	1.02	n/a	n/a	n/a	0.66	n/a	n/a	n/a	0.97	n/a	n/a	n/a	0.66	n/a
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	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
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	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
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	n/a	1.03	0.89	n/a	n/a	1.00	1.00	n/a	n/a	0.92	0.80	n/a	n/a	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	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
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	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
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	0.1	0.1	0.1	0.1
2012 - Verified†	0.0	0.1	0.1	0.1
2013 - Verified†	0.0	0.0	0.1	0.1
2014 - Verified†	0.0	0.0	0.0	0.2
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.6
Northern Ontario Wires Inc. 2014 Annual CDM Capacity Target:				1.1
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				52.7%

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.5	0.5	0.5	0.4	1.9
2012 - Verified†	0.0	0.5	0.5	0.5	1.4
2013 - Verified†	0.0	0.0	0.7	0.7	1.4
2014 - Verified†	0.0	0.0	0.03	1.1	1.1
Verified Net Cumulative Energy Savings 2011-2014:					5.7
Northern Ontario Wires Inc. 2011-2014 Annual CDM Energy Target:					5.9
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					97.7%

†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 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	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
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).										Full OEB Target:				1,330,000	6,000,000,000
*Includes adjustments after Final Reports were issued Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year.										% of Full OEB Target Achieved to Date (Scenario 1):				70%	109%

Interrogatory Responses

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)	
		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	-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. Adjustments 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.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program			
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.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
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 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).
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.	
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.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
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: Northern Ontario Wires 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	8	2	4	5	54,787	15,585	24,851	30,867
Appliance Exchange**	Appliances	1	1	0	1	1,600	2,298	702	1,404
HVAC Incentives	Equipment	1	0	2	7	1,370	762	3,269	13,695
Conservation Instant Coupon Booklet	Items	1	0	0	1	18,411	1,407	7,262	17,546
Bi-Annual Retailer Event	Items	2	2	1	5	28,551	31,017	17,451	74,569
Retailer Co-op	Items	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	0	0	0	0	0	0	0	0
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0
Consumer Program Total		12	6	7	19	104,719	51,068	53,534	138,080
Business Program									
Retrofit	Projects	62	14	26	24	364,205	9,822	94,546	531,257
Direct Install Lighting	Projects	44	114	92	138	130,696	379,566	328,509	511,481
Building Commissioning	Buildings	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	0	0	0	0	0	0
Energy Audit	Audits	0	16	27	0	0	75,529	146,621	0
Small Commercial Demand Response	Devices	0	0	0	0	0	0	0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Business Program Total		106	144	145	162	494,901	464,917	569,676	1,042,738
Industrial Program									
Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	0	0	0	0	0	0	0
Retrofit	Projects	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Industrial Program Total		0	0	0	0	0	0	0	0
Home Assistance Program									
Home Assistance Program	Homes	0	0	11	0	0	0	129,810	1,693
Home Assistance Program Total		0	0	11	0	0	0	129,810	1,693
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	0	0	0	0	0	0	0	0
High Performance New Construction	Projects	0	0	0	0	680	232	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		0	0	0	0	680	232	0	0
Other									
Program Enabled Savings	Projects	0	0	0	0	0	0	0	0
Time-of-Use Savings	Homes	0	0	0	44	0	0	0	0
LDC Pilots	Projects	0	0	0	0	0	0	0	0
Other Total		0	0	0	44	0	0	0	0
Adjustments to 2011 Verified Results			7	0	0		28,812	0	0
Adjustments to 2012 Verified Results				5	1			25,194	5,034
Adjustments to 2013 Verified Results					0				32,214
Energy Efficiency Total		118	150	163	225	600,301	516,217	753,020	1,182,511
Demand Response Total		0	0	0	0	0	0	0	0
Adjustments to Previous Years' Verified Results Total		0	7	5	1	0	28,812	25,194	37,248
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		118	157	169	226	600,301	545,029	778,215	1,219,759

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 Northern Ontario Wires 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	0	0	0		-308	18	0	
Conservation Instant Coupon Booklet	Items	0	0	0		272	0	22	
Bi-Annual Retailer Event	Items	0	0	0		2,519	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		0	0	0		2,483	18	22	
Business Program									
Retrofit	Projects	7	0	0		26,329	0	32,094	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	0	0		0	0	0	
Energy Audit	Audits	0	5	0		0	30,210	97	
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		7	5	0		26,329	30,210	32,192	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	0	0		0	0	0	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		0	0	0		0	0	0	
Home Assistance Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Home Assistance Program Total		0	0	0		0	0	0	
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	0	0	0		0	0	0	
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		0	0	0		0	0	0	
Other									
Program Enabled Savings	Projects	0	0	0		0	0	0	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		0	0	0		0	0	0	
Adjustments to 2011 Verified Results		7				28,812			
Adjustments to 2012 Verified Results			5				30,228		
Adjustments to 2013 Verified Results				0				32,214	
Total Adjustments to Previous Years' Verified Results		7	5	0		28,812	30,228	32,214	

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

1600 – 120 Adelaide Street West
Toronto, ON M5H 1T1

www.ieso.ca

Date: September 30, 2015

To: Northern Ontario Wires Inc.

From: Independent Electricity System Operator (the “**IESO**”)

Re: Request for adjustments to Northern Ontario Wires 2011-2014 Final Results Report pursuant to Section 8.2 of the Master CDM Program Agreement (“**Master Agreement**”) dated as of January 1, 2011 between the IESO and the LDC, as amended.

We have received your 2011-2014 Final Results Report adjustments request dated September 23, 2015 to adjust Northern Ontario Wires 2011-2014 Final Results Report pursuant to Section 8.2 of the Master Agreement.

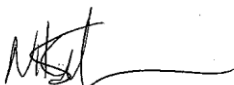
The IESO and Northern Ontario Wires agree that the following projects qualify for additional energy savings and peak demand savings arising from registered initiatives delivered by Northern Ontario Wires:

Initiative	Unit	Incremental Activity	Net Incremental Peak Demand Savings (kW)	Net Incremental Energy Savings (kWh)
Program Enabled Savings	Projects	1	17.5	167,300.0

The IESO estimates an additional 1.7% of peak demand and 2.8% of energy savings to Northern Ontario Wires’ achievement against target as a result of the abovementioned projects. This is further detailed in Appendix A, as updates to Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1) and Table 5: Net Energy Savings at the End User Level (GWh) of your 2011-2014 Final Results Report.

While the IESO will not reissue a 2011-2014 Final Results Report, Northern Ontario Wires may include these additional energy savings and peak demand savings at your discretion in your Annual Report to the Ontario Energy Board.

Regards,



Nik Schruder
Manager, Program Delivery & Partner Services, Conservation

Cc: Josh Wasylyk, Ontario Energy Board

Appendix A

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.1	0.1	0.1	0.1
2012 - Verified†	0.0	0.1	0.1	0.1
2013 - Verified†	0.0	0.0	0.1	0.1
2014 - Verified†	0.0	0.0	0.0	0.2
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.6
Northern Ontario Wires Inc. 2014 Annual CDM Capacity Target:				1.1
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				54.4%

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.5	0.5	0.5	0.4	1.9
2012 - Verified†	0.0	0.5	0.5	0.5	1.4
2013 - Verified†	0.0	0.0	0.7	0.7	1.4
2014 - Verified†	0.0	0.0	0.03	1.2	1.2
Verified Net Cumulative Energy Savings 2011-2014:					5.9
Northern Ontario Wires Inc. 2011-2014 Annual CDM Energy Target:					5.9
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					100.5%

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Final 2015 Annual Verified Results Report

Letter from the Vice-President, Conservation & Corporate Relations

June 30, 2016

The IESO is pleased to provide the Final 2015 Annual Verified Results Report including final 2015 Project Lists and EM&V Key Findings & FAQs. Collectively LDCs achieved 1.1 TWh of energy savings persisting to 2020 – representing 16% of the 7 TWh target. These results were achieved through both Legacy Framework and Conservation First Framework (CFF) programs. The results indicate a smooth transition between frameworks and demonstrate the continued collaboration between LDCs and the IESO in promoting a culture of conservation across the province.

The IESO remains committed to supporting LDCs in the delivery of conservation programs and 2015 marked some significant milestones, including the completion and approval of over 40 CDM plans and the implementation of 14 pilot programs and 5 local programs. Other highlights include:

- Business sector accounted for 79% of the net energy savings persisting to 2020 with the remainder 21% through the Residential sector.
- The Coupons program shifted toward ENERGY STAR® rated LED lighting, accounting for roughly 90% of coupons redeemed.
- The Retrofit program participation increased nearly 20%, and net energy savings increased by over 50% over 2014 results. Net-to-gross adjustments are trending higher than previous years, minimum of a 75% net-to-gross in all regions.
- The Process & Systems Upgrades program achieved a 20% increase in Capital Incentive projects totalling 12 in all, including 4 Behind-the-Meter Generation, and a broad spectrum of industrial processes and end-uses.

2015 also marks the first year that regional and local net-to-gross values have been employed where possible in certain programs, providing LDCs with a more granular analysis on their individual results.

CFF provides many opportunities to support LDCs in achieving their energy targets and delivering value to customers. Through increased flexibility for LDCs to design and deliver programs based on local needs and fostering collaboration and innovation through enhanced program funding opportunities we are well positioned to achieve success in delivering effective conservation programs to all customers.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process and as we look ahead to the remainder of 2016, the IESO will be focusing on improving its communication and support services to further enhance the participation in conservation programs for both LDCs and customers.

Please continue to monitor Save on Energy E-blasts for future updates and should you have any other questions or comments please contact LDC.Support@ieso.ca.

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 2015 Annual Verified 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 2015 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 Progress	A comprehensive report of 2015 conservation results including: 1) activity; 2) savings including: a) energy and demand; b) net and gross; c) CDM Plan forecasts, verified actuals and relative progress; d) Allocated Target and Target achievement; and 3) spending, including participant incentives and administrative expenses. Data is grouped by category and summarized at the LDC level.
4	Province-Wide Progress	A comprehensive report of 2015 conservation results including: 1) activity; 2) savings including: a) energy and demand; b) net and gross; c) CDM Plan forecasts, verified actuals and relative progress; d) Allocated Target and Target achievement; and 3) spending, including participant incentives and administrative expenses. Data is grouped by category and summarized at the province-wide level.
5	IESO Value Added Services Costs	Provision of the LDCs and the Province-Wide aggregated IESO Value Added Services activity and costs for each year.
6	Methodology	Description of the methods used to calculate energy savings, financial results and cost-effectiveness.
7	Reference Tables	Consumer Program Province-Wide results allocation to specific LDCs.
8	Glossary	Definitions for the terms used throughout this report.

Final 2015 Annual Verified Results Report

How to use this 2015 Annual Verified Results Report

The IESO is pleased to provide you with the 2015 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 savings;
 - b) allocated target, target achievement and progress towards target;
 - c) incremental net first year energy savings;
 - d) incremental net first year demand savings;
 - e) annual net-to-gross and realization rate adjustments;
 - f) incremental gross first year energy savings; and
 - g) incremental gross first year 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 for each cost: i) forecasts; ii) 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 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.

11213	A	E	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY	BZ	CA	CB	CC	CD	CE	CF	CG	CH	CI	CJ	CK	CL	CM	CN	CO	CP	CQ	CR	CS	CT	CU	CV	CW	CX	CY	CZ	DA	DB	DC	DD	DE	DF	DG	DH	DI	DJ	DK	DL	DM	DN	DO	DP	DQ	DR	DS	DT	DU	DV	DW	DX	DY	DZ	EA	EB	EC	ED	EE	EF	EG	EH	EI	EJ	EK	EL	EM	EN	EO	EP	EQ	ER	ES	ET	EU	EV	EW	EX	EY	EZ	FA	FB	FC	FD	FE	FF	FG	FH	FI	FJ	FK	FL	FM	FN	FO	FP	FQ	FR	FS	FT	FU	FV	FW	FX	FY	FZ	GA	GB	GC	GD	GE	GF	GG	GH	GI	GJ	GK	GL	GM	GN	GO	GP	GQ	GR	GS	GT	GU	GV	GW	GX	GY	GZ	HA	HB	HC	HD	HE	HF	HG	HH	HI	HJ	HK	HL	HM	HN	HO	HP	HQ	HR	HS	HT	HU	HV	HW	HX	HY	HZ	IA	IB	IC	ID	IE	IF	IG	IH	II	IJ	IK	IL	IM	IN	IO	IP	IQ	IR	IS	IT	IU	IV	IW	IX	IY	IZ	JA	JB	JC	JD	JE	JF	JG	JH	JI	JJ	JK	JL	JM	JN	JO	JP	JQ	JR	JS	JT	JU	JV	JW	JX	JY	JZ	KA	KB	KC	KD	KE	KF	KG	KH	KI	KJ	KL	KM	KN	KO	KP	KQ	KR	KS	KT	KU	KV	KW	KX	KY	KZ	LA	LB	LC	LD	LE	LF	LG	LH	LI	LJ	LK	LM	LN	LO	LP	LQ	LR	LS	LT	LU	LV	LW	LX	LY	LZ	MA	MB	MC	MD	ME	MF	MG	MH	MI	MJ	MK	ML	MM	MN	MO	MP	MQ	MR	MS	MT	MU	MV	MW	MX	MY	MZ	NA	NB	NC	ND	NE	NF	NG	NH	NI	NJ	NK	NL	NM	NO	NP	NQ	NR	NS	NT	NU	NV	NW	NX	NY	NZ	OA	OB	OC	OD	OE	OF	OG	OH	OI	OJ	OK	OL	OM	ON	OO	OP	OQ	OR	OS	OT	OU	OV	OW	OX	OY	OZ	PA	PB	PC	PD	PE	PF	PG	PH	PI	PJ	PK	PL	PM	PN	PO	PP	PQ	PR	PS	PT	PU	PV	PW	PX	PY	PZ	QA	QB	QC	QD	QE	QF	QG	QH	QI	QJ	QK	QL	QM	QN	QO	QP	QQ	QR	QS	QT	QU	QV	QW	QX	QY	QZ	RA	RB	RC	RD	RE	RF	RG	RH	RI	RJ	RK	RL	RM	RN	RO	RP	RQ	RR	RS	RT	RU	RV	RW	RX	RY	RZ	SA	SB	SC	SD	SE	SF	SG	SH	SI	SJ	SK	SL	SM	SN	SO	SP	SQ	SR	SS	ST	SU	SV	SW	SX	SY	SZ	TA	TB	TC	TD	TE	TF	TG	TH	TI	TJ	TK	TL	TM	TN	TO	TP	TQ	TR	TS	TU	TV	TW	TX	TY	TZ	UA	UB	UC	UD	UE	UF	UG	UH	UI	UJ	UK	UL	UM	UN	UO	UP	UQ	UR	US	UT	UU	UV	UW	UX	UY	UZ	VA	VB	VC	VD	VE	VF	VG	VH	VI	VJ	VK	VL	VM	VN	VO	VP	VQ	VR	VS	VT	VU	VV	VW	VX	VY	VZ	WA	WB	WC	WD	WE	WF	WG	WH	WI	WJ	WK	WL	WM	WN	WO	WP	WQ	WR	WS	WT	WU	WV	WW	WX	WY	WZ	XA	XB	XC	XD	XE	XF	YG	YH	YI	YJ	YK	YL	YM	YN	YO	YP	YQ	YR	YS	YT	YU	YV	
	Province-Wide Progress																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		

Please note:

- 2) 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;
will not be available for the 2015 program year in this report but will be provided to LDCs in August 2016.
- 2) forecasts of: a) activity; b) savings; and c) spending; included in this report are based on LDC submitted and IESO received CDM Plan - Cost Effectiveness Tools as of May 16, 2016 (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 Annual Verified Results Report provides results for the LDC and province only. No aggregated

Final 2015 Annual Verified Results Report
Summary

For: Northern Ontario Wires Inc.

Target Achievement

#	Metric	2015 Verified Results	2015-2020 Total CDM Plan Forecast	2015 Verified Results versus CDM Plan (%)	2015-2020 Total Allocated Target / Budget	2015 Verified Results versus Allocated Target / Budget (%)	LDC Ranking in the Province out of 75 (2015 Verified Results versus Allocated Target / Budget (%))
1	Net Verified Annual Energy Savings Persisting to 2020 (MWh)	509,732	4,309,997	12	4,310,000	12	55
2	Total Spending (\$)	6,212	1,174,934	1	1,174,934	1	23

Annual Results

#	Metric	2015	2016	2017	2018	2019	2020	Total
1	Net Verified Annual Energy Savings Persisting to 2020 (MWh)	509,732						509,732
2	Net Verified Incremental First Year Energy Savings (MWh)	567,895						567,895
3	Total Spending (\$)	6,212						6,212
4	Total Resource Cost Test (Ratio)	n/a						n/a
5	Program Administrator Cost Test (Ratio)	n/a						n/a
6	Levelized Unit Energy Cost Result (\$/kWh)	n/a						n/a

Annual Full Cost Recovery Progress

#	Metric	Result
1	Net Verified 2015 Annual Energy Savings from Full Cost Recovery Programs (MWh)	567,895
2	Net 2015 Annual Energy Savings from Full Cost Recovery Program per CDM Plan Forecast (MWh)	359,852
3	Annual Full Cost Recovery Progress (%)	158

Budget Progress

#	Metric	Result
1	2015 Spending (\$)	6,212
2	2015 CDM Plan Budget (\$)	9,082
3	CDM Plan Budget Progress (%)	68

Net Verified 2020 Annual Energy Savings by Program

2015 Spending by Sector

Net Verified Annual Energy Savings Persisting to 2020 by Program Year

Allocated Target Achievement relative to LDC Community

Allocated Budget Spending Progress relative LDC Community

Northern Ontario Wires Inc. Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Participation ^

Northern Ontario Wires Inc. Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Progress Towards 2020 Net Annual Energy Savings Target >

Northern Ontario Wires Inc. Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
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46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Net Incremental First Year Energy Savings ^

Northern Ontario Wires Inc. Progress

#	Programs

2011-2014+2015 Extension Legacy Framework Programs

Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	

Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	

Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	

Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	

Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	

Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	

Sub-total - 2011-2014+2015 Extension Legacy Framework	

2015-2020 Conservation First Framework Programs

Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	

Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	

Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	

Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
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50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	

Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	

Sub-total - 2015-2020 Conservation First Framework	

Total	

Net Incremental First Year Peak Demand Savings >

Northern Ontario Wires Inc. Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
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39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
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49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Net-to-Gross and Realization Rate Adjustments - Actual >

Northern Ontario Wires Inc. Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Willmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Gross Incremental First Year Energy Savings ^

Gross Incremental First Year Peak Demand Savings ^

Savings Group ^

Northern Ontario Wires Inc. Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Participant Incentive Spending >

Northern Ontario Wires Inc. Progress

#	Programs

2011-2014+2015 Extension Legacy Framework Programs

Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	

Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	

Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	

Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	

Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	

Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	

Sub-total - 2011-2014+2015 Extension Legacy Framework

2015-2020 Conservation First Framework Programs

Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	

Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	

Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	

Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
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42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
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47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	

Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	

Sub-total - 2015-2020 Conservation First Framework

Total

Administrative Expense Spending ^

Northern Ontario Wires Inc. Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
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49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Total Spending ^

Spending Group ^

Northern Ontario Wires Inc. Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Willmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Total Resource Cost - Cost Effectiveness Test - Actual	^
Program Administrator Cost - Cost Effectiveness Test - Actual	^
Levelized Unit Energy Cost - Cost Effectiveness Test - Actual	^
Cost Effectiveness Tests Group	^

Province-Wide Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
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43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
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45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
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49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Participation ^

Province-Wide Progress

#	Programs

2011-2014+2015 Extension Legacy Framework Programs

Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	

Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	

Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	

Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	

Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	

Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	

Sub-total - 2011-2014+2015 Extension Legacy Framework	

2015-2020 Conservation First Framework Programs

Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	

Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	

Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	

Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
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49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	

Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	

Sub-total - 2015-2020 Conservation First Framework	

Total	

Progress Towards 2020 Net Annual Energy Savings Target >

Province-Wide Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
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40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
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48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Net Incremental First Year Energy Savings ^

Province-Wide Progress

#	Programs

2011-2014+2015 Extension Legacy Framework Programs

Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	

Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	

Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	

Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	

Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	

Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	

Sub-total - 2011-2014+2015 Extension Legacy Framework	

2015-2020 Conservation First Framework Programs

Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	

Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	

Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	

Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Willmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	

Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	

Sub-total - 2015-2020 Conservation First Framework	

Total	

Net Incremental First Year Peak Demand Savings >

Province-Wide Progress

#	Programs

2011-2014+2015 Extension Legacy Framework Programs

Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	

Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	

Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	

Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	

Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	

Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	

Sub-total - 2011-2014+2015 Extension Legacy Framework

2015-2020 Conservation First Framework Programs

Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	

Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	

Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	

Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Wilmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	

Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	

Sub-total - 2015-2020 Conservation First Framework

Total

Net-to-Gross and Realization Rate Adjustments - Actual >

Province-Wide Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Willmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Gross Incremental First Year Energy Savings ^

Gross Incremental First Year Peak Demand Savings ^

Savings Group ^

Province-Wide Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
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48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Participant Incentive Spending >

Province-Wide Progress

#	Programs

2011-2014+2015 Extension Legacy Framework Programs

Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	

Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	

Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	

Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	

Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	

Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	

Sub-total - 2011-2014+2015 Extension Legacy Framework	

2015-2020 Conservation First Framework Programs

Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	

Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	

Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	

Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Willmot Hydro Inc. - Pilot - DCKV
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47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	

Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	

Sub-total - 2015-2020 Conservation First Framework	

Total	

Administrative Expense Spending ^

Province-Wide Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Willmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
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47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Total Spending ^

Spending Group ^

Province-Wide Progress

#	Programs
2011-2014+2015 Extension Legacy Framework Programs	
Residential Program	
1	Coupon Initiative
2	Bi-Annual Retailer Event Initiative
3	Appliance Retirement Initiative
4	HVAC Incentives Initiative
5	Residential New Construction and Major Renovation Initiative
Sub-total - Residential Program	
Commercial & Institutional Program	
6	Energy Audit Initiative
7	Efficiency- Equipment Replacement Incentive Initiative
8	Direct Install Lighting and Water Heating Initiative
9	New Construction and Major Renovation Initiative
10	Existing Building Commissioning Incentive Initiative
Sub-total - Commercial & Institutional Program	
Industrial Program	
11	Process and Systems Upgrades Initiatives - Project Incentive Initiative
12	Process and Systems Upgrades Initiatives - Monitoring and Targeting Initiative
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative
Sub-total - Industrial Program	
Low Income Program	
14	Low Income Initiative
Sub-total - Low-Income Program	
Pilot Program	
15	Loblaws Pilot
16	Social Benchmarking Pilot
17	Conservation Fund Pilot - SEG
18	Conservation Fund Pilot - EnerNOC
Sub-total - Pilot Program	
Other	
19	Aboriginal Conservation Program
20	Program Enabled Savings
21	Adjustments to 2015 Legacy Framework Verified Results
Sub-total - Other	
Sub-total - 2011-2014+2015 Extension Legacy Framework	
2015-2020 Conservation First Framework Programs	
Residential Province-Wide Program	
22	Save on Energy Coupon Program
23	Save on Energy Heating and Cooling Program
24	Save on Energy New Construction Program
25	Save on Energy Home Assistance Program
Sub-total - Residential Province-Wide Program	
Business Province-Wide Program	
26	Save on Energy Audit Funding Program
27	Save on Energy Retrofit Program
28	Save on Energy Small Business Lighting Program
29	Save on Energy High Performance New Construction Program
30	Save on Energy Existing Building Commissioning Program
31	Save on Energy Process & Systems Upgrades Program
32	Save on Energy Monitoring & Targeting Program
33	Save on Energy Energy Manager Program
Sub-total - Business Province-Wide Program	
Local & Regional Program	
34	Business Refrigeration Local Program
35	First Nation Conservation Local Program
36	Social Benchmarking Local Program
Sub-total - Local & Regional Program	
Pilot Program	
37	Enersource Hydro Mississauga Inc. - Performance-Based Conservation Pilot Program - C
38	EnWin Utilities Ltd. - Building Optimization Pilot
39	EnWin Utilities Ltd. - Re-Invest Pilot
40	Horizon Utilities Corporation - ECM Furnace Motor Pilot
41	Horizon Utilities Corporation - Social Benchmarking Pilot
42	Hydro Ottawa Limited - Conservation Voltage Regulation (CVR) Leveraging AMI Data Pil
43	Hydro Ottawa Limited - Residential Demand Response Wi-Fi Thermostat Pilot
44	Kitchener-Willmot Hydro Inc. - Pilot - DCKV
45	Niagara-on-the-Lake Hydro Inc. - Direct Install Energy Efficiency Measures for the Agric
46	Oakville Hydro Electricity Distribution Inc. - Direct Install - Hydronic
47	Oakville Hydro Electricity Distribution Inc. - Direct Install - RTU Controls
48	Toronto Hydro-Electric System Limited - Direct Install - Hydronic (Pilot Savings)
49	Toronto Hydro-Electric System Limited - Direct Install - RTU Controls (Pilot Savings)
50	Toronto Hydro-Electric System Limited - PFP - Large (Pilot Savings)
Sub-total - Pilot Program	
Other	
51	Adjustments to 2015 CFF Verified Results
52	Adjustments to 2016 CFF Verified Results
53	Adjustments to 2017 CFF Verified Results
54	Adjustments to 2018 CFF Verified Results
55	Adjustments to 2019 CFF Verified Results
Sub-total - Other	
Sub-total - 2015-2020 Conservation First Framework	
Total	

Total Resource Cost - Cost Effectiveness Test - Actual	^
Program Administrator Cost - Cost Effectiveness Test - Actual	^
Levelized Unit Energy Cost - Cost Effectiveness Test - Actual	^
Cost Effectiveness Tests Group	^

Final 2015 Annual Verified Results Report

IESO Value Added Services Costs (as of March 31, 2016)

# Reporting Level		Program	Unit of Measure	Units (#)							Administrative Expenses (\$)						
				2015	2016	2017	2018	2019	2020	Total	2015	2016	2017	2018	2019	2020	Total
1	Northern Ontario Wires Inc.	Save on Energy Coupon Program	Coupons	627	0	0	0	0	0	627	1,098	0	0	0	0	0	1,098
2		Save on Energy Heating and Cooling Program	Applications	3	0	0	0	0	0	3	39	0	0	0	0	0	39
Total				630	0	0	0	0	0	630	1,137	0	0	0	0	0	1,137
3	Province Wide	Save on Energy Coupon Program	Coupons	785,625	0	0	0	0	0	785,625	1,374,844	0	0	0	0	0	1,374,844
4		Save on Energy Heating and Cooling Program	Applications	20,446	0	0	0	0	0	20,446	265,798	0	0	0	0	0	265,798
Total				806,071	0	0	0	0	0	806,071	1,640,642	0	0	0	0	0	1,640,642

Final 2015 Annual Verified Results Report Methodology

General

All results are at the end-user level (not including transmission and distribution losses) and are based on activity completed on or after January 1, 2015 and on or before December 31, 2015 and reported to IESO by March 31, 2016.

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	Project List Date	Savings 'start' Date	Calculating Resource Savings
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.	March 31, 2016	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	saveONenergy Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016		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	Results are directly attributed to LDC based on LDC identified in application.	March 31, 2016	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 Process & System Upgrades		March 31, 2016		
13	saveONenergy Monitoring & Targeting		March 31, 2016		
14	saveONenergy Energy Manager		March 31, 2016		
14	saveONenergy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	March 31, 2016	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		March 31, 2016		

2015-2020 Conservation First Framework Programs

#	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 average of 2008 & 2009 residential throughput.	March 31, 2016	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 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	March 31, 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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016		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		March 31, 2016		
10	Save on Energy Process and Systems Upgrades Program	Results are directly attributed to LDC based on LDC identified in application.	March 31, 2016	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.	March 31, 2016	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.	March 31, 2016	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	Business Refrigeration Incentive Program		March 31, 2016	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).
14	Social Benchmarking Program	Results are directly attributed to LDC based on LDC identified in the application.	March 31, 2016	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		March 31, 2016	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.

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Consumer Program Allocation Methodology

#	Local Distribution Company	Allocation
1	Algoma Power Inc.	0.2207%
2	Atikokan Hydro Inc.	0.0265%
3	Attawapiskat Power Corporation	0.0255%
4	Bluewater Power Distribution Corporation	0.6460%
5	Brant County Power Inc.	0.1979%
6	Brantford Power Inc.	0.7255%
7	Burlington Hydro Inc.	1.3757%
8	Cambridge and North Dumfries Hydro Inc.	0.9578%
9	Canadian Niagara Power Inc.	0.5110%
10	Centre Wellington Hydro Ltd.	0.1129%
11	Chapleau Public Utilities Corporation	0.0379%
12	COLLUS PowerStream Corp.	0.2858%
13	Cooperative Hydro Embrun Inc.	0.0494%
14	E.L.K. Energy Inc.	0.2270%
15	Enersource Hydro Mississauga Inc.	3.9265%
16	Entegrus Powerlines Inc.	0.7226%
17	EnWin Utilities Ltd.	1.5542%
18	Erie Thames Powerlines Corporation	0.3535%
19	Espanola Regional Hydro Distribution Corporation	0.0821%
20	Essex Powerlines Corporation	0.6539%
21	Festival Hydro Inc.	0.3498%
22	Fort Albany Power Corporation	0.0212%

23	Fort Frances Power Corporation	0.0995%
24	Greater Sudbury Hydro Inc.	1.0276%
25	Grimsby Power Incorporated	0.2279%
26	Guelph Hydro Electric Systems Inc.	0.8983%
27	Haldimand County Hydro Inc.	0.4244%
28	Halton Hills Hydro Inc.	0.5475%
29	Hearst Power Distribution Company Limited	0.0667%
30	Horizon Utilities Corporation	4.0429%
31	Hydro 2000 Inc.	0.0390%
32	Hydro Hawkesbury Inc.	0.1394%
33	Hydro One Brampton Networks Inc.	2.8180%
34	Hydro One Networks Inc.	29.9788%
35	Hydro Ottawa Limited	5.5954%
36	InnPower Corporation	0.3951%
37	Kashechewan Power Corporation	0.0286%
38	Kenora Hydro Electric Corporation Ltd.	0.0989%
39	Kingston Hydro Corporation	0.5014%
40	Kitchener-Wilmot Hydro Inc.	1.6310%
41	Lakefront Utilities Inc.	0.1907%
42	Lakeland Power Distribution Ltd.	0.2906%
43	London Hydro Inc.	2.7308%
44	Midland Power Utility Corporation	0.1196%
45	Milton Hydro Distribution Inc.	0.5695%
46	Newmarket-Tay Power Distribution Ltd.	0.6607%
47	Niagara Peninsula Energy Inc.	0.9945%
48	Niagara-on-the-Lake Hydro Inc.	0.1586%
49	Norfolk Power Distribution Inc.	0.3495%
50	North Bay Hydro Distribution Limited	0.5333%

51	Northern Ontario Wires Inc.	0.1061%
52	Oakville Hydro Electricity Distribution Inc.	1.4632%
53	Orangeville Hydro Limited	0.2120%
54	Orillia Power Distribution Corporation	0.2722%
55	Oshawa PUC Networks Inc.	1.2283%
56	Ottawa River Power Corporation	0.1974%
57	Peterborough Distribution Incorporated	0.7132%
58	PowerStream Inc.	6.6383%
59	PUC Distribution Inc.	0.8687%
60	Renfrew Hydro Inc.	0.0775%
61	Rideau St. Lawrence Distribution Inc.	0.1120%
62	Sioux Lookout Hydro Inc.	0.0841%
63	St. Thomas Energy Inc.	0.2939%
64	Thunder Bay Hydro Electricity Distribution Inc.	0.8738%
65	Tillsonburg Hydro Inc.	0.1280%
66	Toronto Hydro-Electric System Limited	12.7979%
67	Veridian Connections Inc.	2.3525%
68	Wasaga Distribution Inc.	0.1799%
69	Waterloo North Hydro Inc.	1.0019%
70	Welland Hydro-Electric System Corp.	0.3879%
71	Wellington North Power Inc.	0.0632%
72	West Coast Huron Energy Inc.	0.0653%
73	Westario Power Inc.	0.5411%
74	Whitby Hydro Electric Corporation	0.8651%
75	Woodstock Hydro Services Inc.	0.2548%
Total		100.0000 %

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

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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 perscentage 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.

3.0 –VECC -27

Reference: E3/T1/S4

- a) Please update the Pass-Through Charges to reflect the OEB's October 14, 2016 RPP Report.

Response:

- a) Please see the updated Pass-Through charge information below:

Customer Class Name			2015 ACTUAL kWh's				
	Total	non-RPP	Class A (High Five)	TOU Off-Peak	TOU Mid-Peak	TOU On-Peak	RPP
Residential	41,096,056	1,383,728		25,851,701	6,770,575	7,079,372	10,680
General Service < 50 kW	19,602,981	2,854,717		8,846,696	3,204,967	3,318,183	1,378,418
General Service > 50 to 4999 kW	59,289,165	59,289,165					
Unmetered Scattered Load	168,348	23,806					144,542
Street Lighting	745,147	745,147					
TOTAL	120,901,697	64,296,563		34,698,397	9,975,542	10,397,555	1,533,640
%	100.00%	53.18%		28.70%	8.25%	8.60%	1.27%
Forecast Price							
HOEP (\$/MWh)		\$ 22.59	\$ 22.59				
Global Adjustment (\$/MWh)		\$ 84.50	\$ 84.50				
TOTAL (\$/MWh)		\$107.09	\$107.09	\$ 87.00	\$ 132.00	\$ 180.00	\$ 112.39
\$/kWh		\$0.10709	\$0.10709	\$0.08700	\$0.13200	\$0.18000	\$0.11239
%		53.18%		28.70%	8.25%	8.60%	1.27%
WEIGHTED AVERAGE PRICE	\$0.1097	\$0.0570		\$0.0250	\$0.0109	\$0.0155	\$0.0014

Electricity (Commodity)	Customer Class Name	Revenue USA #	Expense USA #	2016 rate (\$/kWh):		2017 rate (\$/kWh):	
				Volume	Amount	Volume	Amount
kWh	Residential	4006	4705	44,110,846	4,839,712	43,530,886	4,776,080
kWh	General Service < 50 kW	4010	4705	21,402,668	2,348,237	21,111,406	2,316,281
kWh	General Service > 50 to 4999 kW	4035	4705	61,134,306	6,707,475	60,302,350	6,616,196
kWh	Unmetered Scattered Load	4035	4705	176,689	19,386	176,689	19,386
kWh	Street Lighting	4025	4705	595,255	65,310	595,255	65,310
	TOTAL			127,419,763	13,980,120	125,716,585	13,793,252

3.0 –VECC –28

Reference: E3/T3/S1, Appendix 2-H

- a) Please explain the forecast increase in Revenue from Merchandising (Account 4325) in 2016 and the subsequent material decrease in 2017.

Responses:

- a) The increase in the forecast for Revenue from Merchandising in 2016 is a result of the carryover of sundry work from 2015 related to third party requests for pole changes and service upgrades. The subsequent decrease in 2017 is a result of the projects from 2015 and 2016 coming to an end with no significant opportunities in 2017. The 2017 balance still represents a 37% increase over 2013 Actual which is aggressive given that there are no major sundry projects expected in the region.

Exhibit 4 – Operating Costs

4-Staff-35

Ref: Exhibit 4 / Tab 1 / Schedule 1 / p. 7

Question(s):

- a) Please explain the difference between the figures presented in Table 4 at Exhibit 4 / Tab 1 / Schedule 1 / p. 7 and Exhibit 4 / Tab 2 / Schedule 1 / Attachment 4. Specifically, please discuss why different FTEs are presented in each table.

Responses:

- a) In the E4/T1/S1 Table 4 exhibit, the FTE values are for staff directly employed by and on the payroll of NOW Inc. (3.5 FTE's in 2017). This is consistent with the Reporting and Recordkeeping methodology for calculating FTE's. In addition to these FTE's NOW Inc. also receives support through shared services from its Cochrane Telecom Services (CTS) affiliate. Shared services are 13.2 FTE's in 2017 and this combined with the NOW Inc. FTE's results in a total staff level of 16.7 FTE's in 2017 – which is the FTE count in E4/T2/S1 Attachment 4. Further detail on the derivation of FTE by organization group and position can be found at E4/T3/S2 pg. 3 of 18.

4-Staff-36

**Ref: Exhibit 4 / Tab 3 / Schedule 1
Chapter 2 Appendices / 2-JA**

Question(s):

- a) Does Northern Ontario Wires agree that given the significant amount of one-off OM&A expenses incurred in 2013 (disposition of smart meters, cost of service related regulatory expenses, bad debt related to a large customer, etc.), comparing historical year, bridge year and test year OM&A to 2013 actuals is not appropriate.
- b) Please provide an estimate of 2013 OM&A with the one-time expenses removed from the total. Please provide this information in the same format as shown in Table 2 (Exhibit 4 / Tab 3/ Schedule 1).
- c) Please recalculate the: (i) simple average of % variance for all years; and (ii) compound annual growth rate as shown in Chapter 2 Appendices / 2-JA excluding 2013 actuals.
- d) If available, please provide actual 2016 OM&A expenses by sub-category of spending. Please provide this information at the same level of detail as is provided for historical years in Exhibit 4 / Tab 3 / Schedule 1.
- e) For each category of OM&A spending (Table 1 at Exhibit 4 / Tab 3 / Schedule 1), please provide the amount that is related to employee salaries and benefits.
- f) Please confirm whether the amount cited at Exhibit 4 / Tab 3 / Schedule 1 / p. 4 noting that “operations costs in the 2017 test year are \$248,903 (44%) higher than 2013 actual costs” is correct. Please explain the discrepancy between that amount and the amount set out in Table 3 (Exhibit 4 / Tab 3 / Schedule 1 / p. 4).
- g) Northern Ontario Wires noted that with the introduction of the outage management system, it expects additional controls and predictive measures being applied (Exhibit 4 / Tab 3 / Schedule 1 / p. 5). Please describe what measures Northern Ontario Wires is referring to in the above cited statement. Please explain whether the OM&A budget includes spending on these measures.

- h) If available, please provide the total number of 2016 customer locates (Exhibit 4 / Tab 3 / Schedule 1 / p. 8).
- i) If available, please provide the number of animal guards installed in 2016. Please provide the average cost of an animal guard installation.
- j) Please confirm that the forecasted 100 animal guard installations per year will continue throughout the entire expected IRM period (Exhibit 4 / Tab 3 / Schedule 1 / p. 8).
- k) Please provide a detailed breakdown of the \$73,276 increase in engineering and operations expenses between 2017 and 2015 (Exhibit 4 / Tab 3 / Schedule 1 / p. 9).
- l) Please provide evidence supporting the relatively large increase in meter spending in 2017 (as compared to 2015 and 2013 OEB approved) (Exhibit 4 / Tab 3 / Schedule 1 / p. 9).
- m) Please explain why overhead line work is being prioritized over other maintenance work (Exhibit 4 / Tab 3 / Schedule 1 / p. 11).
- n) Please advise which third-party project Northern Ontario Wires is referring to that is concluding in 2016, which will allow it to focus more spending on overhead line work (Exhibit 4 / Tab 3 / Schedule 1 / p. 11).
- o) Northern Ontario Wires noted that the municipality of Cochrane has ceased its activities to maintain laneways where the majority of Northern Ontario Wires' assets are located. Northern Ontario Wires noted that this change will result in additional costs incurred. (Exhibit 4 / Tab 3 / Schedule 1 / p. 14).
 - i. Please advise whether there was a formal agreement with the municipality in place in the past regarding the maintenance of laneways.
 - ii. Please provide an estimate of these incremental costs for 2017.
 - iii. Please advise whether Northern Ontario Wires has approached the municipality about sharing these incremental costs.
- p) Northern Ontario Wires noted that it plans to have some vegetation control in each service area every year with more significant work every three years

(Exhibit 4 / Tab 3 / Schedule 1 / p. 14). Please provide a detailed schedule for vegetation control by year (starting with the test year and extending into the expected IRM period).

- q) Please explain why billing and collection expenses were significantly lower in 2014 and 2015 (as compared to 2013 OEB approved and the test year forecast) (Exhibit 4 / Tab 3 / Schedule 1 / p. 16).
- r) Please provide an estimate of the incremental cost for 2017 associated with additional customers electing to make electronic payments (Exhibit 4 / Tab 3 / Schedule 1 / p. 18). Please also provide the total electronic payment fees incurred by Northern Ontario Wires during the 2013-2016 period.
- s) Please provide the manual meter read costs for the historical period and the bridge and test years (Exhibit 4 / Tab 3 / Schedule 1 / p. 19).
- t) Please provide a breakdown of the third-party costs associated with meter reading for the historical period and the bridge and test years (Exhibit 4 / Tab 3 / Schedule 1 / p. 19).
- u) Please provide a detailed breakdown of the training costs incurred during the historical period and forecast for the bridge and test years (Exhibit 4 / Tab 3 / Schedule 1 / pp. 22-24). Please explain the types of training that is provided to Northern Ontario Wires' staff and to its Board of Directors.
- v) Please provide a detailed breakdown of the travel costs incurred during the historical period and forecast for the bridge and test years (Exhibit 4 / Tab 3 / Schedule 1 / pp. 22-24).
- w) Northern Ontario Wires noted that the billing system is provided by a third-party that provides software and support. Northern Ontario Wires stated that this cost increased in the past and is anticipated to increase as more regulation requires greater customization and effort on the part of the provider. Please provide a detailed breakdown of the billing system costs incurred during the historical period and forecast for the bridge and test years (Exhibit 4 / Tab 3 / Schedule 1 / p. 24).
- x) Please confirm that the regulatory expenses set out at Exhibit 4 / Tab 3 / Schedule 1 / p. 24 of \$107,305 is made up of \$66,605 (20% of the COS related

costs – Exhibit 4 / Tab 3 / Schedule 5) and \$40,700 of ongoing regulatory costs (Exhibit 4 / Tab 3 / Schedule 6 / Attachment 1).

- y) Please provide a detailed breakdown of the outside service expenditures (including the EDA fees) for the historical period and the bridge and test years (Exhibit 4 / Tab 3 / Schedule 1 / p. 26).
- z) Please provide a detailed breakdown of the property expenditures for the historical period and the bridge and test years (Exhibit 4 / Tab 3 / Schedule 1 / p. 27).
- aa) Please describe how the property insurance was selected. Please advise whether the decision arose from a competitive bidding process. Please provide rationale for the property insurance purchased by Northern Ontario Wires.

Responses:

- a) Northern Ontario Wires agrees that in circumstances where there has been a significant “one-off” expenditure, such expenditure should be removed in order to enable a meaningful “apples to apples” comparison for variance analysis purposes. It is noted that the 2013 “one-off” adjustments while significant, were limited to three specific work programs. Comparing historic, bridge and test year expenditures to 2013 actual results is a meaningful exercise for the many work programs where there was not a significant “one-off” adjustment.
- b) The three significant 2013 “one-off” adjustments totalled \$966,151 and are summarized as follows:
 - Administration:** \$492,497 lower due to removal of disposition of smart meter OM&A
 - Bad Debt Work Program:** \$381,363 lower due to removing bad debt expense resulting from large customer bankruptcy
 - Regulatory Expenses Work Program:** \$92,291 lower due to regulatory costs, which will not be incurred until the next COS cycle (2016/2017).

Please see the table below for the updated table 2 reflecting the above adjustments.

		Historical	Variance	
	2013 APPROVED	2013	2013 vs 2013 APPROVED	
TRANSFORMER/SUBSTATION	31,052	43,998	12,946	42%
CUSTOMER PREMISES	157,980	231,360	73,380	46%
LOAD DISPATCHING	189,909	193,028	3,119	2%
ENGINEERING & OPERATIONS	103,960	123,276	19,316	19%
METER EXPENSES	17,278	9,179	-8,099	-47%
Total OPERATIONS EXPENSES	500,179	600,841	100,662	20%
MAINTENANCE O/H LINES				
MAINTENANCE O/H LINES	279,357	342,134	62,777	22%
MAINTENANCE OF LINE TRANSFORMERS	34,967	48,374	13,407	38%
MAINTENANCE U/G CONDUCTORS	131,085	117,747	-13,338	-10%
TREE TRIMMING AND VEGETATION CONT	157,157	123,193	-33,964	-22%
Total MAINTENACE EXPENSES	602,566	631,448	28,882	5%
BILLING/FINALS/COLLECTIONS				
BILLING AND COLLECTING	539,292	472,521	-66,771	-12%
METER READING	196,520	202,578	6,058	3%
BAD DEBT	21,052	16,246	-4,806	-23%
Total CUSTOMER SERVICE EXPENSES	756,864	691,345	-65,519	-9%
ADMINISTRATION	457,672	537,996	80,324	18%
REGULATORY EXPENSES	23,464	23,464	-0	0%
OUTSIDE SERVICES	63,687	66,876	3,189	5%
PROPERTY EXPENSE	36,048	39,399	3,351	9%
Total ADMINISTRATION EXPENSES	580,871	667,735	86,864	15%
	2,440,480	2,591,368	150,888	6%

c) In order to calculate the %'s in i) and ii) above it is necessary to establish a Base Year. The interrogatory says "excluding 2013 actuals" but it does not specify what Base Year to replace it with. For the purpose of this response, Northern Ontario Wires has assumed that the "one off" expenses as discussed in a) and b) should be excluded, this results in 2013 actual OM&A of \$2,591,368, which has been used as the Base Year for the following calculations:

- i) Simple average of % variance for all years: 12.2%
- ii) Compound Annual Growth rate for all years: 2.3%

- d) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This unaudited information will be provided in a supplementary filing on February 17, 2017.
- e) The amount relating to employee salaries and benefits per OM&A category is included in the table below.

		Historical			Bridge Year	Test Year
	2013 APPROVED	2013	2014	2015	2016	2017
OPERATIONS	360,583	370,383	412,228	416,061	371,299	416,055
MAINTENANCE	328,814	349,520	275,647	275,640	393,035	487,534
CUSTOMER SERVICE	368,931	361,855	289,900	306,481	299,804	318,822
ADMINISTRATION	328,595	358,828	384,712	253,115	261,293	270,789
Total	1,386,923	1,440,586	1,362,487	1,251,297	1,325,431	1,493,200

- f) The amount cited at E4/T3/S1 p. 4 is not correct and should read “operations costs in the 2017 test year are \$214,824 (36%) higher than 2013 actual costs”. With this correction there is no discrepancy with the amount set out in Table 3.
- g) The measures and controls cited in the application include response time on issue identification through real-time meter information, loading specification control, at risk assets identification, and voltage fluctuation information. The OM&A budget includes spending on the identified items through the maintenance programs
- h) A preliminary calculation of 2016 locates is 669.
- i) NOW Inc. installed approximately 50 animal guards in 2016. The cost per installation, including labour, truck time and material is about \$250 per installation.
- j) NOW Inc. confirms that 100 animal guard installations are projected per year throughout the forecasted period.
- k) The increase in engineering and operations is a result of new programs being undertaken in addition to inflation costs.

New costs of \$68,631 result from the ongoing operating costs of the third party Outage Management System (\$30,000) and the updating of the DSP (\$39,000). The remaining \$4,276 represents inflation for the 2016 and 2017 year.

- l) NOW Inc. will be re-verifying smart meters that were installed in 2009, namely testing the accuracy of the identified meters. There were 6130 meters installed in 2009 which will be due for re-verification in 2021. Therefore to alleviate a large cost and having to hire a contractor NOW Inc. will be re-verifying 500 meters per community per year for the next four (4) years and will do so with in- house staff, as this is a manageable number versus the total of approximately 2000 per community in one year.
- m) Overhead line work is being prioritized over other maintenance work due in part to a significant portion of assets that are spread out over the service territories. The other maintenance programs are less urgent and somewhat cyclical such as tree trimming cycles and NOW Inc.'s approach to vegetation control. Overhead lines have more potential to cause outages and prioritizing of this work area helps the reliability of the system.
- n) A telecommunications company has recently expanded into the Cochrane area, which required extensive pole work. The bulk of the project was completed in 2016.
- o)
 - i) There were no formal agreements with the municipalities in the past.
 - ii) The estimated incremental costs in 2017 for NOW Inc. is \$15,000. The full incremental cost is estimated to be \$25,000, of which \$10,000 is assumed by the municipalities.
 - iii) NOW Inc. and the municipalities have an unwritten agreement/ understanding that they will work collaboratively with regard to tree trimming and vegetation control. NOW Inc. is responsible for the trimming and the municipalities are responsible for cleanup. This arrangement has reduced the incremental cost by approximately \$10,000.
- p) Trimming in all three communities will be done in early summer as the public works staff will be assisting with cleanup which will alleviate NOW Inc.'s time and labour in order to concentrate more effort on additional trimming. Furthermore, all municipally-owned trees will be removed and replanted on the opposite side of

the road where feasible, thus eliminating future problems. All other trees that cannot be removed (example: customer-owned trees) will be trimmed back as required in order to mitigate the stress on the tree when it becomes too large.

- q) The billing and collecting expenses were lower in 2014 and 2015 versus 2013 Approved as a result of an unexpected vacancy created by a departing employee. This position was not replaced in an effort to maximize efficiencies and maintain a viable financial position. Costs for 2017 are higher in part due to increasing work demands due to customer engagement, customer education and administration of initiatives. The 2017 Test year remains lower than 2013 Approved as NOW Inc. has been able to continue to benefit from earned efficiencies.
- r) The electronic payment fees incurred by NOW Inc. from 2013 – 2016 are provided in the following table.

The estimated incremental cost for 2017 associated with additional customers making electronic payments is \$1,000.

	2013	2014	2015	2016
Electronic Payment Fees	\$ 3,036	\$ 3,123	\$ 3,157	\$ 5,223

- s) The manual meter read cost including labour and materials such as vehicle and telecommunication costs for interval meters are as follows:

	Historical			Bridge Year	Test Year
	2013	2014	2015	2016	2017
Manual Meter Reading Costs	\$ 62,684	\$ 49,038	\$ 43,427	\$ 48,007	\$ 50,350

- t) The third-party meter reading cost are as follows:

	Historical			Bridge Year	Test Year
	2013	2014	2015	2016	2017
Third-Party Meter Reading Costs	\$ 139,894	\$ 122,976	\$ 138,967	\$ 143,469	\$ 147,773

- u) Board Members are offered training opportunities tailored to the industry that relate to the corporate governance. Board Members who attend are encouraged to share the materials and learning with other Board Members. The training opportunities include educational courses and industry conferences.

For staff members, training varies depending on the position. For operational employees, training may involve cross training to expand their understanding e.g. accounting for non-accountants, pole top rescue and lineman training. For financial staff, updates to filing requirements, regulatory group meetings, and industry conferences are used to educate. Training and education conferences may also include attending workshops or presentations from suppliers to enhance understanding and product updates.

As many of these training costs take place away from NOW Inc service territory, training costs are closely associated with travel costs and it is useful to evaluate them together. Costs for training include travel costs which are a significant portion of the costs.

The following table contains the breakdown of both travel and training costs:

				Forecast	Forecast
	2013	2014	2015	2016	2017
BoD	\$ 8,788	\$ 6,300	\$ 2,894	\$ 8,489	\$ 8,744
Staff	\$ 44,475	\$ 20,790	\$ 9,527	\$ 21,728	\$ 22,380
	\$ 53,263	\$ 27,090	\$ 12,421	\$ 30,217	\$ 31,124

v) Please refer to the response for 4-Staff-36 u). Travel costs are combined with training costs as both are interrelated for NOW Inc.

w) The third-party billing system costs are as follows:

	Historical			Bridge Year	Test Year
	2013	2014	2015	2016	2017
Billing System Costs	\$ 45,733	\$ 49,077	\$ 54,262	\$ 57,945	\$ 61,653

x) NOW Inc. confirms that the \$107,305 Regulatory Expenses for 2017 is made up of \$66,605 (1/5 if COS related one-time costs) and \$40,700 of ongoing regulatory costs.

y) Please see the following breakdown:

	Historical			Bridge Year	Test Year
Outside Services	2013	2014	2015	2016	2017
Auditor	\$ 27,624	\$ 22,794	\$ 22,632	\$ 22,575	\$ 24,000
EDA	\$ 15,300	\$ 16,000	\$ 16,500	\$ 16,700	\$ 16,900
Mearie	\$ 1,400	\$ 1,500	\$ 1,600	\$ 1,700	\$ 1,800
Legal/Consulting	\$ 13,276	\$ 13,026	\$ 1,769	\$ 920	\$ 2,000
CGIS and other billing costs	\$ 9,276	\$ 12,112	\$ 9,044	\$ 9,690	\$ 8,433
	\$ 66,876	\$ 65,432	\$ 51,545	\$ 51,585	\$ 53,133

z) Please see the following breakdown

	Historical			Bridge Year	Test Year
Property Expenditures	2013	2014	2015	2016	2017
Insurance	\$ 37,507	\$ 34,787	\$ 34,418	\$ 38,536	\$ 39,692
Taxes other than Income Tax	\$ 1,892	\$ 1,823	\$ 1,948	\$ 408	\$ 420
	\$ 39,399	\$ 36,610	\$ 36,366	\$ 38,944	\$ 40,112

aa) NOW Inc. requested quotations from providers in the past. The current insurance company has been providing NOW Inc. with property coverage for the last six years, with a total increase of \$1,107 for the entire period. Insurance for 2017 was a rollover contract agreement based on a minimal increase of \$189 from the preceding year. In the fall of 2017 NOW Inc. will be entering a tendering process, thus inviting commercial property insurance providers to submit bids.

4-Staff-37

Ref: Exhibit 4 / Tab 3 / Schedule 2

Question(s):

- a) Please advise whether any staff are paid incentives for performance (Exhibit 4 / Tab 3 / Schedule 2 / p. 1).
- b) Please provide the management salary grid referenced at Exhibit 4 / Tab 3 / Schedule 2 / p. 2.
- c) Please provide the net impact on the compensation budget of the non-replacement of the CEO position for 2015, 2016 and 2017. The net impact calculation should include both the savings related to removing the CEO position and incremental salary paid to other staff that took over the responsibilities (Exhibit 4 / Tab 3 / Schedule 2 / p. 2).
- d) Please confirm that the “outside employees” that are shared with Cochrane Telecom Services (CTS) actually work entirely for Northern Ontario Wires (Exhibit 4 / Tab 3 / Schedule 2 / p. 3).
- e) Typically when an employee is shared, that employee actually splits their work with two companies. In the case of the “outside employees” that does not seem to be true (as OEB staff asked Northern Ontario Wires to confirm in the above question). Please explain why the “outside employees” do not work directly for Northern Ontario Wires (Exhibit 4 / Tab 3 / Schedule 2 / p. 3).
- f) Please explain the efficiencies that are gained by sharing the “outside employees” with CTS (Exhibit 4 / Tab 3 / Schedule 2 / p. 3). Please provide this response in the context of the substantial management fee that is paid to CTS (Exhibit 4 / Tab 3 / Schedule 3).
- g) Please provide an estimated comparison for 2017 of the total costs of continuing to share the “outside employees” with CTS and hiring these employees in-house.
- h) Please advise whether Northern Ontario Wires has a formal succession plan. If so, please file that plan (Exhibit 4 / Tab 3 / Schedule 2 / p. 7). If not, please provide a summary succession plan for the next 5 years (Exhibit 4 / Tab 3 / Schedule 2 / p. 7).

- i) Please explain Northern Ontario Wires' competitive bid process for acquiring a health benefit provider. Please advise as to when the last time Northern Ontario Wires sought bids for its health benefit portfolio. Please explain how the provider was selected. Please advise as to when Northern Ontario Wires will next tender its benefits portfolio (Exhibit 4 / Tab 3 / Schedule 2 / p. 10).
- j) Please provide the average impact (on a percentage basis) to a unionized employee of the 2017 salary escalation of \$0.80 + 2% (Exhibit 4 / Tab 3 / Schedule 2 / p. 11).
- k) Please provide the total cost of overtime expenses during the historical period, the bridge year and the budgeted amount for the test year (Exhibit 4 / Tab 3 / Schedule 2 / p. 11).
- l) In regard to the lineman position that will be replaced in 2017, please advise when it was vacated. Please advise whether Northern Ontario Wires has hired for this position yet. If not, please explain when the hiring will occur (Exhibit 4 / Tab 3 / Schedule 2 / p. 17).

Responses:

- a) NOW Inc does not provide staff with incentives for performance.
- b) This information will be provided under the OEB's Practise Direction on Confidential Filings as it contains personal identifying information.
- c) This information will be provided under the OEB's Practise Direction on Confidential Filings as it contains personal identifying information.

The only position with a compensation adjustment resulting from the change was the General Manager/Operations Supervisor. The workload increase as a result of the vacancy was undertaken as a team effort and has left remaining personnel busy with multiple responsibilities. The net compensation change resulted in significant savings.

- d) NOW Inc. confirms that the “Outside Employees” identified on Table 1 (E4/T3/S2) are fully dedicated to the NOW Inc. work and do not provide services to CTS.
- e) NOW understands this question to relate to why NOW Inc. does not have the outside staff on NOW Inc. payroll as opposed to CTS.

NOW was incorporated as part of deregulation to create the LDC separate from the affiliate utilities. The management staff was employed by NOW Inc., while the remaining staff, all of whom are unionized remained within CTS. Keeping all unionized employees with the affiliate has proved valuable to NOW Inc. Unionized staff are on the CTS payroll which reduces the workload of NOW Inc. staff.

Maintaining the outside employees in the affiliate reduces duplication of work that would be required to maintain two separate payroll systems. This would create inefficiency and result in higher costs. Additionally, more legal and consultant costs would be required in order to facilitate having unionized employees in NOW Inc. The arrangement also reduces WSIB and statutory requirements to NOW Inc. as these are already being done and managed by the affiliate. The systems are already in place at the affiliate which would have to be recreated and managed in NOW Inc.

- f) As indicated in Exhibit 4/ Tab 3/ Schedule 3 page 4, “The Management Fee includes CTS costs associated with management and supervision of support staff, labour relations, human resources and other costs directly charged to NOW Inc.”.

Further to the response to (d) above, “outside employees” work entirely for NOW Inc. as a legacy circumstance from the formation of NOW Inc. and as a cost efficiency as these staff receive infrastructure support from CTS that would otherwise have to be resourced from within NOW Inc. on an incremental basis. As these “outside staff”, reside in CTS they form part of the same collective bargaining group as other CTS staff. The benefit of these staff residing in CTS and having a Management Fee applied is that CTS is responsible for management of the full range of human resource issues such collective bargaining, legal advice, health and safety compliance, negotiating/managing health and benefit contract, post-retirement benefits and actuarial evaluation, safety services, general administration and governance, grievances; employer/employee concerns and relationships; training; development and

compliance of Human Resources and Health and Safety policies; and supervision of payroll system upgrades and training.

In addition to the above services, the support from CTS that is charged to NOW Inc. through the Management Fee applied to “outside staff” includes general support such as:

- engineering support services on work planning issues
- CGIS mapping and system upgrade, data updates and annual support fee
- management of financial systems, system support and upgrade
- facilities support such as maintenance and equipment

If CTS were to stop providing all support services, NOW Inc. would need to hire staff or retain other expertise to provide the full scope of support services currently received. It is expected that the resulting cost would be in excess of the current management fee that is paid to CTS. Accordingly, NOW Inc. believes that the current services agreement is reasonable.

- g) The following table provides the estimated comparison for 2017 of total costs for hiring outside staff in house rather than sharing with CTS. The estimated incremental cost indicates that it is beneficial to remain with the current arrangement of having the outside staff remain with CTS.

	Cost of Employees with CTS	Cost if Hired by NOW	Incremental Cost of Hiring Outside Staff into NOW
Outside Staff Costs	\$ 972,589	\$ 1,100,396	\$ 127,807

- h) NOW Inc. does not have a formal succession plan. The expectation is that a new lineman will be hired in 2017 to replace the outgoing lineman in 2017, with no further staff turnover currently foreseen in the next five years.
- i) In December 2012, and in conjunction with Cochrane Telecom Services and the Corporation of the Town of Cochrane, a Request for Expression of Interest and Statement of Qualifications for Group Benefits (RFEI & SOQ) was issued. This RFEI & SOQ closed in mid-January of 2013 and four of the six respondents were selected to continue to the quotation/cost comparison phase and were provided until the end of February to submit their costing proposals. An evaluation committee was formed with representatives from each company, wherein a decision was reached with regard to the current provider. Services with the current provider began in June 2013. There are no plans to tender this in the near future.

- j) The average impact for lineman positions for the escalation of \$0.80 + 2% is 4.2% which aligns these positions with other utilities. The average impact for all other unionized staff is 2%.
- k) The total cost of Overtime during the historic, bridge and test year are presented in the following table.

	Historic			Bridge	Test
	2013	2014	2015	2016	2017
Overtime Cost	\$ 88,633	\$ 74,705	\$ 87,844	\$ 74,368	\$ 72,000
* Includes paid and banked time					

- l) This position is forecast for vacancy August 2017. The replacement will occur prior to the resulting vacancy.

4-Staff-38

**Ref: Exhibit 4 / Tab 3 / Schedule 3
Chapter 2 Appendices / 2-N**

Question(s):

- a) Please provide the percentage of Northern Ontario Wires staff vs. CTS staff that work in the administrative building (Exhibit 4 / Tab 3 / Schedule 3 / p. 2).
- b) Please provide a detailed explanation of the allocation of the time spent by the GM and CFO on work for Northern Ontario Energy Inc. (NOE) (Exhibit 4 / Tab 3 / Schedule 3 / p. 3).
- c) Please provide rationale supporting a management fee of 12% charged by CTS to Northern Ontario Wires for direct labour and facility costs. Please provide management fees paid by other LDCs to affiliates for similar services (Exhibit 4 / Tab 3 / Schedule 3 / p. 4).
- d) For the final three lines in Appendix 2-N, please explain whether the amounts are payments to or from Northern Ontario Wires (in other words, are these credits or debits from Northern Ontario Wires' perspective).

Responses:

- a) In total, 13 staff work in the administrative building. Of these 13 staff, 6.7 FTE's (51.5%) provide support to NOW Inc.. E4/T3/S2 pg. 3 provides a breakdown of the specific positions included in the 6.7 FTE's. Please note that the GM & President works out of the service centre, not the administrative building.
- b) The costs charged in 2017 are associated with the CFO and are a result of time spent on accounting functions and preparing the year end activities. In 2017, no time is allocated to NOE for the General Manager as no direct time is expected to be attributable as only general oversight is provided.
- c) With respect to shared services, most costs are directly charged from CTS to NOW Inc. through time sheets. The Management Fee is designed to recover other costs that are incurred to support the services provided to Northern Ontario Wires by Cochrane Telecom Services (CTS). These support costs are not directly charged and are for services such as such human resources, information

technology and other support services as discussed in 4-Staff-37(f).

NOW Inc. is aware that other LDCs do charge management related fees. Those other LDC's receive similar costs and there are a variety of ways that they are charged to the LDC from the service provider. In some cases they are directly charged (e.g. Brantford Power Inc. EB-2016-0058 Exhibit 4, Tab 5, Schedule 1, pg. 8 of 10), in other cases there is a cost allocation resulting from a shared services study (e.g. Hydro One Distribution EB-2013-0416, Exhibit C1, Tab 5, Schedule 1, page 3 of 6), and in still other cases there is a Management Fee (e.g. Milton Hydro Distribution Inc. EB-2015-0089, Exhibit 4, pgs. 46, 48). The Milton Hydro Distribution Management Fee is calculated using a different methodology from NOW Inc. and is comprised of different costs and a different applicable rate. NOW Inc. does not know whether there are any other LDCs that have a management fee that is calculated in precisely the same way that NOW Inc.'s management fee operates.

- d) These amounts are payments to Northern Ontario Wires and are recorded as credits.

4-Staff-39

Ref: Exhibit 4 / Tab 3 / Schedule 3 / Attachment 2

Question(s):

- a) Please better explain article 7.1 / part (d) of the Services Agreement (Exhibit 4 / Tab 3 / Schedule 3 / Attachment 2 / p. 8). Please advise whether a bonus to CTS has ever been paid (and provide the amount of the bonus).

Responses:

- a) Article 7.1 (d) was included to provide an incentive for CTS to pursue cost savings that would be passed on to NOW Inc. As there were no negotiations regarding this clause within the allocated six month period following the execution of this agreement, this clause became null and void. NOW Inc. confirms that this section was not triggered and no bonus has been paid to CTS with regard to part (d) of the Services Agreement.

4-Staff-40

Ref: Exhibit 4 / Tab 3 / Schedule 4 / Attachment 1

Question(s):

- a) Please describe what was included in the payments for each the third-party vendors listed in the table.
- b) If available, please provide a similar table with descriptions of the spending for 2016.

Responses:

- a) Please see the following summary:
 - HS Supply Power Solutions is NOW Inc.'s primary inventory supplier such as wire, bolts, brackets, ground rods, transformers, etc.
 - Sensus Metering Systems provides a monthly smart meter monitoring service.
 - Burman Energy provided CDM services, such as program administration and development.
 - Harris Computer Systems provides annual maintenance and support for NOW Inc.'s billing software as well as meter maintenance.
 - OMERS is the retirement savings provider for Northern Ontario Wires Inc.
 - MEARIE provides vehicle insurance for NOW Inc.'s fleet.
 - PowerTel Utilities is a contractor that provided services for capital projects in Iroquois Falls.

b) Purchases from Vendors Exceeding \$50k including HST – 2016 (preliminary)

Vendor Code	Vendor Name	Total	Description
1003	Anixter Power Solutions	\$115,830	Anixter purchased HD Supply Power Solutions, who supplies NOW Inc.'s inventory.
1028	Harris Computer Systems	\$78,818	Harris provides annual maintenance and support for NOW Inc.'s billing software
12017	Elenchus	\$126,908	Consultant fees for Cost of Service Application
15008	OMERS	\$76,696	Retirement savings provider
18009	Ray's Diesel	\$73,135	Vehicle repairs

4-Staff-41

Ref: Exhibit 4 / Tab 3 / Schedule 5 / p. 1

Preamble:

At the reference, Northern Ontario Wires indicated that it retained a strategic consulting firm that provided guidance on customer engagement requirements and to assist the DSP.

Question(s):

- a) Were any consultants utilized to develop and produce Northern Ontario Wires' DSP? If so, please provide a list of consultants utilized and their role in the DSP's development.

Responses:

- a) Northern Ontario Wires Inc. retained the services of Metsco in Mississauga, Ontario to assist with the core development of its Distribution System Plan.

IndEco assisted with the customer engagement survey, of which the results are reflected within the DSP.

4-Staff-42

Ref: Exhibit 4 / Tab 3 / Schedule 5

Question(s):

- a) Please provide a breakdown of the Cost of Service-related costs by task and service provider (consultant, legal, etc.) (Exhibit 4 / Tab 3 / Schedule 5 / p. 1).

Responses:

- a) Provided in the table below is a breakdown of the Cost of Service related costs by task and provider.

		2016	2017	Total
Consultant costs				
	Elenchus			
	COS Application Support	\$ 138,529		
	COS Interrogatories, Settlement, Support		\$ 55,000	
		\$ 138,529	\$ 55,000	\$ 193,529
Legal Costs				
	M. Buonaguro			
	COS Application support and advice	\$ 20,000		
	COS Interrogatory support and advice, settlement, hearings		\$ 33,000	
		\$ 20,000	\$ 33,000	\$ 53,000
Special Studies				
	Metsco - DSP	\$ 30,000		
	INDECO - Customer Survey Support	\$ 1,590		
		\$ 31,590	\$ -	\$ 31,590
Incremental Operating Costs				
	Travel for CoS proceedings	\$ -	\$ 10,000	\$ 10,000
Intervenor Costs			\$ 44,906	\$ 44,906
		\$ 190,119	\$ 142,906	\$ 333,025

Elenchus is providing support for the Application in during all stages of the proceeding from planning, and project management through, assisting with the application, interrogatories, settlement, and any other tasks that arise that NOW Inc. needs assistance with. NOW Inc. does not have any dedicated regulatory personnel, and as such assistance is required to make up for the lack of internal resources.

4-Staff-43

**Ref: Exhibit 4 / Tab 4 / Schedule 1 UPDATED
Chapter 2 Appendices / Appendix 2-CH
Exhibit 4 / Tab 1 / Schedule 1**

Question(s):

- a) Please link each of the asset categories listed in Table 1 at Exhibit 4 / Tab 4 / Schedule 1 UPDATED / p. 4 to the asset categories in Appendix 2-CH. Please confirm that the depreciation rates used are consistent in both sections of the evidence.
- b) Northern Ontario Wires noted that the useful lives for Distribution Building & Infrastructure, Overhead Conductor and Devices, and Buildings (owned by Northern Ontario Wires) are below the minimum range set out by Kinectrics at Exhibit 4 / Tab 4 / Schedule 1 UPDATED / pp. 4-5. Please recalculate the depreciation expense in the test year for each of these asset categories using the lower end of the Kinectrics range. Please provide the response in respect of each asset category and on a total basis.
- c) Please confirm that Northern Ontario Wires applied the half-year rule when calculating its depreciation expenses.
- d) Please explain the difference between the depreciation expenses for each year set out in Chapter 2 Appendices / Appendix 2-CH and the depreciation expenses for each year set out in the table at Exhibit 4 / Tab 1 / Schedule 1 / p. 1. For 2017, please confirm the depreciation expense amount for which Northern Ontario Wires is seeking approval. Please advise where that amount can be found in the pre-filed evidence.

Response:

- a) The letter coding in the first column establishes the link between the two following tables:

		Current		Proposed		Kinectrics	
	Asset Class	Years	Rate	Years	Rate	Low	High
A	Distribution Stations - Buildings and Infrastructure	30	3%	30	3%	50	75
B	Poles, Towers, Fixtures	45	2%	45	2%	35	75
C	Overhead Conductors and Devices	45	2%	45	2%	50	75
D	Underground Conduit	45	2%	45	2%	30	85
E	Underground Conductor and Devices	35	3%	35	3%	35	60
F	Transformers	45	2%	45	2%	30	60
G	Overhead Services	35	3%	35	3%	50	75
H	Office Equipment	7	14%	7	14%	5	15
I	Vehicles - Trucks & Buckets	8	13%	8	13%	5	15
	Vehicles - Trailers	8	13%	8	13%	5	20
	Vehicles - Vans	5	20%	5	20%	5	10
J	Buildings	30	3%	30	3%	50	75
K	Computer - Hardware	5	20%	5	20%	3	5
L	Computer - Software	7	14%	7	14%	2	5
M	Stores Equipment	10	10%	10	10%	5	10
N	Tools & Equipments	5	20%	5	20%	5	10
O	Residential Energy Meters	25	4%	25	4%	25	35
	Industrial/Commercial Meters	25	4%	25	4%	25	35
	Wholesale Energy Meters	25	4%	25	4%	15	30
P	Smart Meters	15	7%	15	7%	5	15
	Data Collectors - Smart Metering	15	7%	15	7%	15	20

Appendix 2-CH ¹											
Depreciation and Amortization Expense											
Revised CGAAP or MIFRS											
Assumes the applicant changed capitalization and depreciation policies and reflected these changes in a prior rebasing application											
			Accounting Standard		MIFRS						
			Year		2017						
Account	Description	Opening Regulatory Gross PP&E as at Jan. 1	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation ²	Years	Depreciation Rate	Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (I)	Variance ³
		(a)	(b)	(c)	(d)	(e) = (c) + ½ x (d)	(f)	(g) = 1 / (f)	(h) = (e) / (f)		(m) = (h) - (I)
L	1611 Computer Software (Formally known as Account 1925)	\$ 578,738	\$ 42,433	\$ 536,305	\$115,000	\$ 593,805	7.00	14.29%	\$ 84,829	\$ 86,293	\$ 1,464
	1612 Land Rights (Formally known as Account 1906)	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1805 Land	\$ 87,700	\$ -	\$ 87,700	\$ -	\$ 87,700		0.00%	\$ -	\$ -	\$ -
A, J	1808 Buildings	\$ 530,753	\$ 40,127	\$ 490,626	\$ -	\$ 490,626	30.00	3.33%	\$ 16,354	\$ 19,373	\$ 3,019
	1810 Leasehold Improvements	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1815 Transformer Station Equipment >50 kV	\$ 3,644	\$ -	\$ 3,644	\$ -	\$ 3,644	30.00	3.33%	\$ 121	\$ -	\$ 121
	1820 Distribution Station Equipment <50 kV	\$ 638,136	\$ 39,467	\$ 598,669	\$ 50,000	\$ 623,669	28.00	3.57%	\$ 22,274	\$ 21,977	\$ 297
	1825 Storage Battery Equipment	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
B	1830 Poles, Towers & Fixtures	\$ 3,418,614	\$ -	\$ 3,418,614	\$417,500	\$ 3,627,364	25.00	4.00%	\$ 145,095	\$ 142,035	\$ 3,060
C	1835 Overhead Conductors & Devices	\$ 2,121,158	\$ 68,286	\$ 2,052,872	\$101,250	\$ 2,103,497	45.00	2.22%	\$ 46,744	\$ 39,231	\$ 7,513
D	1840 Underground Conduit	\$ 112,571	\$ 101,659	\$ 10,912	\$ -	\$ 10,912	8.00	12.50%	\$ 1,364	\$ 1,364	\$ -
E	1845 Underground Conductors & Devices	\$ 3,690	\$ 1,278	\$ 2,412	\$ -	\$ 2,412	8.00	12.50%	\$ 302	\$ 301	\$ 1
F	1850 Line Transformers	\$ 1,007,655	\$ 352,643	\$ 655,012	\$101,250	\$ 705,637	30.00	3.33%	\$ 23,521	\$ 24,692	\$ 1,171
G	1855 Services (Overhead & Underground)	\$ 422,321	\$ 173,049	\$ 249,272	\$ -	\$ 249,272	23.00	4.35%	\$ 10,838	\$ 12,625	\$ 1,787
O	1860 Meters	\$ 31,277	\$ 4,379	\$ 26,898	\$ -	\$ 26,898	25.00	4.00%	\$ 1,076	\$ 1,936	\$ 860
P	1860 Meters (Smart Meters)	\$ 914,510	\$ -	\$ 914,510	\$ 15,000	\$ 922,010	15.00	6.67%	\$ 61,467	\$ 61,467	\$ 0
	1905 Land	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1908 Buildings & Fixtures	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1910 Leasehold Improvements	\$ 4,692	\$ 470	\$ 4,222	\$ -	\$ 4,222	5.00	20.00%	\$ 844	\$ -	\$ 844
H	1915 Office Furniture & Equipment (10 years)	\$ 17,607	\$ 15,261	\$ 2,346	\$ -	\$ 2,346	10.00	10.00%	\$ 235	\$ 60	\$ 175
	1915 Office Furniture & Equipment (5 years)	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
K	1920 Computer Equipment - Hardware	\$ 114,309	\$ 76,520	\$ 37,789	\$ 10,000	\$ 42,789	7.00	14.29%	\$ 6,113	\$ 6,300	\$ 187
	1920 Computer Equip.-Hardware(Post Mar. 22/04)	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
K	1920 Computer Equip.-Hardware(Post Mar. 19/07)	\$ 501,882	\$ -	\$ 501,882	\$ -	\$ 501,882	15.00	6.67%	\$ 33,459	\$ 32,885	\$ 574
I	1930 Transportation Equipment	\$ 2,075,767	\$ 556,289	\$ 1,519,478	\$ -	\$ 1,519,478	8.00	12.50%	\$ 189,935	\$ 188,694	\$ 1,241
M	1935 Stores Equipment	\$ 2,181	\$ -	\$ 2,181	\$ -	\$ 2,181	7.00	14.29%	\$ 312	\$ 68	\$ 244
N	1940 Tools, Shop & Garage Equipment	\$ 219,889	\$ 90,479	\$ 129,410	\$ 17,500	\$ 138,160	8.00	12.50%	\$ 17,270	\$ 12,216	\$ 5,054
	1945 Measurement & Testing Equipment	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1950 Power Operated Equipment	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1955 Communications Equipment	\$ 4,638	\$ -	\$ 4,638	\$ -	\$ 4,638	5.00	20.00%	\$ 928	\$ -	\$ 928
	1955 Communication Equipment (Smart Meters)	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1960 Miscellaneous Equipment	\$ 6,603	\$ 6,603	\$ -	\$ -	\$ -	5.00	20.00%	\$ -	\$ -	\$ -
	1970 Load Management Controls - Customer Premises	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1975 Load Management Controls Utility Premises	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1980 System Supervisor Equipment	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1985 Miscellaneous Fixed Assets	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1990 Other Tangible Property	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	1995 Contributions & Grants	\$ -	\$ -	\$ -	\$ -	\$ -		0.00%	\$ -	\$ -	\$ -
	Total	\$12,818,335	\$ 1,568,943	\$11,249,392	\$827,500	\$11,663,142			\$ 663,080	\$ 651,517	\$ 11,563

NOW Inc. confirms that the depreciation rates are consistent in both sections of the evidence. Appendix 2-CH rates incorporate the age of existing assets which lowers the weighting of the depreciation rate. All new assets are based on appropriate rates shown in Table 1 at Exhibit 4 / Tab 4 / Schedule 1 UPDATED / p. 4.

- b) The following table contains the depreciation expense by asset category at the low end of the Kinectrics range.

Asset Category	Low End Kinectrics Range
	2017
Distribution Buildings & Infrastructure	\$ 18,872
Overhead Conductors and Devices	\$ 32,310
Buildings	\$ 10,130
	\$ 61,312

As noted in E4/T4/S1, the reasons for the deviation from the Kinectrics range is due to the assets being used assets when acquired. As such, a portion of the assets useful service life had elapsed prior to acquisition which is the reason for the deviation. The service lives used were chosen to match the depreciation period with the condition of the assets. Also, as discussed in the application, certain Distribution Stations will be removed from service in the coming years. As such the depreciation rate utilizes the remaining years in service, as per proper accounting treatment. Please refer to 4-SEC-31 b) for more discussion on the distribution station building and infrastructure depreciation rate. New assets additions are depreciated using the Kinectrics ranges.

- c) NOW Inc. confirms that the half-year rule was applied when calculating depreciation expenses.
- d) The difference between depreciation expenses for each year in Appendix 2-CH column K (" Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (I)") and depreciation expense in Table 1 reconciles as shown in the table below.

Reference				2013	2014	2015	2016	2017
E1/T1/S1/p1	Table 1	Depreciation		\$ 655,388	\$ 357,653	\$ 366,475	\$ 390,396	\$ 439,680
E4/T4/S1/Att1	Per 2-BA	Depreciation		\$ 580,753	\$ 606,207	\$ 616,708	\$ 613,872	\$ 651,517
		Variance per interrogatory		\$ 74,635	-\$ 248,554	-\$ 250,233	-\$ 223,476	-\$ 211,837
E2/T1/S1/Att1	Fully Allocated Depreciation			\$ 218,088	\$ 248,505	\$ 250,234	\$ 220,626	\$ 208,987
E2/T1/S1/Att1	Deferred Revenue						\$ 2,850	\$ 2,850
	Smart Meter Disposition			-\$ 319,884				
	Balance adjustments			\$ 27,161				
	Variance in the application			\$ 0	-\$ 49	\$ 1	\$ -	\$ -

As per Appendix 2-BA as seen in Exhibit 2, Tab 1, Schedule 1, Attachment 1, The total depreciation per Appendix 2-CH is also included in the total depreciation cell, below which the Fully Allocated Depreciation is removed to arrive at the Net Depreciation. Fully Allocated Depreciation primarily relates to depreciation on Transportation and Work Equipment which is charged to work as part of charge out rate based on usage. The net depreciation is included in Table 1 in Exhibit 4 / Tab 1 / Schedule 1 / p. 1. There is also a small amount of deferred revenue as per the table below. The 2013 year also included the smart meter disposition which resulted in opening amortization being adjusted rather than current depreciation expense along with other balance adjustments as noted below.

The 2017 depreciation expense amount is \$648,667 which includes the offset 2440 account Deferred Revenues. The Net Depreciation being requested for approval is \$439,680 (Table 1 figure) which is found in NOW Inc.'s revenue requirement in Exhibit 6, Tab, 1 Schedule 1, and Exhibit 6, Tab, 1 Schedule 1, Att 1.

4-Staff-44

Ref: Exhibit 4 / Tab 5 / Schedule 1, PILs model

Preamble:

In the PILs model at the tab titled, "Taxable Income – Test Year," Northern Ontario Wires is using all of the \$156,220 losses carried forward from 2016 in calculating its Regulatory Taxable Income in 2017 of \$92,538.

Question(s):

- a) Is Northern Ontario Wires projecting similar magnitude of losses in each year of the rate-setting term? Please discuss and explain.
- b) If Northern Ontario Wires is not projecting any further losses, please file an updated PILs model using 1/5th of losses for the test year in line 331 "Non-capital losses for preceding taxation years from Schedule 7-1" and update its PILs proxy amount in rates.

Response:

- a) NOW Inc. is not projecting a similar magnitude of losses in each year of the rate setting term. This loss is anticipated only for the 2016 year and with the adjustment of NOW rates, the losses are not anticipated to continue.
- b) An updated PILS model will be filed on February 17, 2017.

4-Staff-45

Ref: Exhibit 4 / Tab 6 / Schedule 1

Preamble:

Northern Ontario Wires noted that it is including the disposition of a residual balance of (\$2,091) in its LRAMVA claim.

Question(s):

- a) Please provide a better explanation of the residual balance referenced at Exhibit 4 / Tab 6 / Schedule 1 / p. 2.
- b) Please file a copy of the IESO report referenced at Exhibit 4 / Tab 6 / Schedule 1 / p. 3.

Response:

- a) The residual balance relates to the remaining balance of the LRAMVA which was approved in the previous LRAMVA disposition. The residual amount is a balance that was over collected through the approved rate rider and is now owing to customers. As this amount is a refund due to customers, it is included in this application.
- b) 2011-2014 and 2015 Final Verified CDM results are provided in response 3-VECC-26 Attachments 2, 3 and 4 respectively.

4-SEC-22

[Ex.4-4-1, p.4-5) Please provide an explanation of the variances between 'current year depreciation expense' (Column H) and 'deprecation expenses per Appendix 2 BA fixed assets' (column J)

Response:

The variance between the 'Current Year Depreciation Expense' and 'Depreciation Expense per Appendix 2-BA' is a result of the formulas in the 'current year depreciation expense' in relation to opening accumulated amortization, and the various stages of amortizations. The spreadsheet does not account for some assets that have been depreciated for a number of years and those that are new additions. These assets would have different remaining useful lives, this creates an imprecision in the calculation. The Years column (f) attempts to align for this issue by using a more approximate value rather than the actual depreciation term, but it is not as precise in calculating the variance for reasonability. The depreciation is more accurate in the Fixed Assets Continuity Schedule as the Board model does not fully reflect the more detailed calculation done in the NOW Inc. fixed asset system, which is more accurate.

The variance in each of the years is not material and the resulting depreciation expense used in the application is less than the calculation in Appendix 2-CH. NOW Inc. notes that this results in a smaller Bill impact for customers.

4-SEC-23

[Ex.4-2-1, Attachment 2] Please revise the Appendix 2-JB table to show the cost drivers by incremental activities or cost drivers, and not by programs.

Response:

Please see the table below showing Appendix 2-JB by cost drivers.

**Appendix 2-JB
Recoverable OM&A Cost Driver Table**

OM&A	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
<i>Reporting Basis</i>	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Opening Balance	\$ 2,440,480	\$ 3,557,520	\$ 2,468,516	\$ 2,395,215	\$ 2,675,683
Labour Escalation and Allocation		\$ 21,858	\$ 43,829	\$ 63,534	\$ 55,388
Staffing changes	\$ 34,336	-\$ 54,145	-\$ 216,625		\$ 94,772
Smart Meter Disposition	\$ 492,497	-\$ 492,497			
Vehicle /Fuel Repairs		\$ 7,587	-\$ 44,048	\$ 2,270	\$ 1,900
Bad Debt	\$ 376,557	-\$ 384,931	\$ 138,836	-\$ 86,640	\$ 10,126
Meter Reading	\$ 6,058	-\$ 30,562	\$ 10,378	\$ 9,082	\$ 6,647
Regulatory Costs	\$ 92,291	-\$ 88,692	\$ 965	\$ 201,616	-\$ 122,339
Work Program Changes	\$ 115,301	-\$ 67,621	-\$ 6,636	\$ 90,606	\$ 185,726
Closing Balance	\$ 3,557,520	\$ 2,468,516	\$ 2,395,215	\$ 2,675,683	\$ 2,907,903

4-SEC-24

[Ex.4-3-1, p.14] With respect to 'tree trimming and vegetation control expenditures:

- a) Please explain the reduction in expenses between 2013 and 2014.
- b) Please explain the increase in expenses between 2016 and 2017.

Response:

- a) In 2014 all three municipalities began collaborating with tree trimming and vegetation control wherein if the tree is municipally-owned, they are responsible for clean-up procedures, which in turn reduced NOW Inc.'s expenses. Where possible, the communities will adjust tree planting areas away from the NOW system which will reduce future costs.
- b) The increase in 2016 and 2017 is primarily due to outside assistance, namely equipment and machinery, in order to cut down brush and trees near feeders in targeted areas.

4-SEC-25

[Ex.4-3-1, p.21] Please explain the basis for the 2017 test year forecast of bad debt expenses.

Response:

- a) Please see response to 4-VECC-30 (a)

4-SEC-26

[Ex.4-3-3] With respect to the shared service agreement between the Applicant and Cochrane Telecom Services (“CTS”):

- a) Please provide a summary of all changes made to service agreement in January 2016. Please provide a copy of the agreement in place before the revisions were made.
- b) [Attach 2, p.8] Please explain the basis of the 12% mark-up on certain costs.
- c) [Attach 2, p.8] The agreement contemplates that the affiliates (which includes the Applicant) and CTS will negotiate a bonus to be paid to CTS and as an incentive for cost savings. Has such an agreement been reached? If so, please provide a copy.

Responses:

- a) A copy of the previous services agreement is provided.

A summary of changes are:

- 1. Addition of parts E and F in introduction
- 2. Change of wording from PUC to CTS throughout the entire document
- 3. Amendments to Section 5 to reflect current services
- 4. Amendments to Section 8 to reflect current practice
- 5. Amendments to Schedule B to reflect current services

- b) Please see response to 4-Staff-38(c)
- c) NOW Inc. confirms that no bonus has ever been paid to CTS with regard to part (d) of the Services Agreement. As there were no negotiations that occurred within the allocated six month period following the execution of this agreement, this clause becomes null and void.

SERVICES AGREEMENT

THIS AGREEMENT made as of the 1st day of November, 2000.

BETWEEN:

NORTHERN ONTARIO WIRES INC.,
a business corporation governed by
the laws of the Province of Ontario

("NOW")

OF THE FIRST PART

-and-

NORTHERN ONTARIO ENERGY INC.,
a business corporation governed by
the laws of the Province of Ontario

("NOE")

OF THE SECOND PART

-and-

THE COCHRANE PUBLIC UTILITIES COMMISSION,
a public utilities commission governed by
the laws of the Province of Ontario

("PUC")

OF THE THIRD PART

RECITALS:

- A. The Corporation of the Town of Cochrane and the Corporation of the Town of Iroquois Falls entered into a Merger Agreement dated October 27, 2000, pursuant to which they established the terms and conditions upon which each Town would merge the businesses of the electricity portion of the Cochrane Public Utilities Commission and the Iroquois Falls Hydro-Electric Commission.
- B. The Town of Cochrane and the Town of Iroquois Falls created NOW and NOE (collectively the "Corporations") and transferred to the Corporations pursuant to transfer by-laws substantially all of the assets and liabilities of each Town, the Iroquois Falls Hydro-Electric Commission and the electricity portion of the Cochrane Public Utilities

Commission associated with the generation, distribution, transmission and retailing of electricity and associated businesses.

- C. Section 6 of the said Merger Agreement provides that NOW and NOE will enter into a services agreement with the Cochrane Public Utilities Commission, pursuant to which the Cochrane Public Utilities Commission will agree to carry out substantially all of the day-to-day activities of NOW and NOE, including the operations, administration and operational support of NOW and NOE.
- D. NOW and NOE require the services of a contractor to provide certain management services to NOW and NOE;
- E. NOW and NOE wish to appoint PUC to provide certain management services to NOW and NOE, and PUC wishes to accept such appointment, upon and subject to the terms and conditions set forth in this Agreement;

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the fees, other payments and mutual covenants provided for in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which is acknowledged by each of the Parties, the Parties covenant and agree as follows:

1. INTERPRETATION

Words or phrases defined in Schedule "A" to this Agreement shall have the meaning ascribed to them in that Schedule unless the context expressly or by necessary implication otherwise requires. In this Agreement, where the context so admits, words importing the singular include the plural and vice-versa and words importing gender include all genders.

2. APPOINTMENT OF PUC

2.1 Appointment by NOW and NOE

NOW and NOE appoint PUC to provide certain management services to NOW and NOE upon and subject to the terms and conditions of this Agreement.

2.2 Acceptance by PUC

PUC accepts its appointment to provide certain management services to NOW and NOE upon and subject to the terms and conditions of this Agreement.

2.3 PUC and Independent Contractor

Nothing in this Agreement shall be construed as or shall constitute a partnership or joint venture between PUC and the Corporations and each Party expressly disclaims any intention to create a partnership or joint venture. Except as otherwise expressly provided in this Agreement, the duties to be performed and the obligations assumed by PUC under this Agreement shall be performed and assumed by PUC as an independent contractor and not as the agent or otherwise as the representative of the Corporations. The Corporations

acknowledge and agree that the business of PUC includes the management of the business affairs of PUC and that this Agreement shall not be construed as in any way restricting the business of PUC.

3. REPRESENTATION AND WARRANTY BY PUC

PUC represents and warrants that it has, and throughout the Term will continue to have, the required expertise, skill, personnel and experience to fulfill its obligations and duties under this Agreement. PUC acknowledges and agrees that the Corporations are relying on the truthfulness and accuracy of this representation and warranty in entering into this Agreement.

4. TERM

4.1 Initial Term

This Agreement, and the appointment of PUC, shall commence on the 1st day of November, 2000 and, subject to early termination in accordance with the provisions of Article 9, shall continue for a term of ten (10) years until the 31st day of October, 2010 (the "Term").

4.2 Renewal

This Agreement may be renewed by NOW and/or NOE after the initial ten (10) year term for successive renewal terms of ten (10) years upon NOW and NOE giving written notice to PUC to that effect at least 1 year prior to the termination of the initial term or renewal term, as the case may be. The Management Fees payable hereunder for any renewal term shall be negotiated and agreed to by the Corporations and PUC prior to the commencement of such renewal term, failing which the matter shall be referred to arbitration in accordance with the provisions of section 10 hereof.

5. DUTIES OF PUC

5.1 Standard of Performance of PUC

PUC shall perform and carry out all its obligations and duties under this Agreement honestly, in good faith, competently, efficiently, with due care and attention and in a business-like manner. PUC shall make appropriate employees of PUC available to the Corporations from time to time as is necessary to discharge PUC's management and administration responsibilities under this Agreement. The services may be performed at or from such locations as PUC considers best suited for their effective discharge, provided, however, that there shall be no change in the existing locations in Cochrane or Iroquois Falls without the prior written approval of NOW or NOE, as applicable. PUC shall select those of its employees it is satisfied are suitable to perform the acts or provide the services for which they are appointed or retained by PUC and PUC shall properly supervise all such employees, provided that NOW or NOE shall have the right to notify PUC that any such employee selected by PUC and providing senior management services is not acceptable to NOW or NOE, in which case PUC shall not utilize such employee in providing services to NOW or NOE pursuant to this Agreement and shall provide alternate personnel to perform such services.

5.2 General Duties and Obligations of PUC

5.2.1 Management and Administration

Upon and subject to the terms of this Agreement and, in particular, but without limitation, Section 5.1 and Article 6, PUC shall administer and manage all aspects of the day-to-day operations of NOW and NOE.

5.2.2 Value Enhancement Strategies

PUC shall develop for review and consideration by the Corporations and advise the Corporations with respect to strategies, opportunities, policies and programs for the development and improvement of the operations of the Corporations. Such advice will be submitted by PUC to the Boards of Directors of NOW and NOE, as applicable.

5.3 Specific Duties and Obligations of PUC

The specific duties and obligations of PUC, under this Agreement shall include, without limiting Section 5.2, the following:

5.3.1 Administrative Services

Provide budgetary, accounting, billing, collecting, payroll and financial services, including assisting the Corporations in their financial planning by preparing and submitting to the Corporations for their approval capital budgets and monthly financial reports;

5.3.2 Management Services

Prepare and submit to the Corporations for their approval an annual business and operating plan; carry out invoicing and collection of accounts for customers of the Corporations; respond to customer concerns and complaints; conduct electricity meter reading for the customers of NOW; provide such marketing services, as are deemed advantageous by the Corporations; provide management of the human resources activities of the Corporations; provide information systems and system analysis services; ensure that payments in lieu of taxes are properly calculated and paid on time. A detailed description of these services is set forth in Schedule "B" hereto.

5.3.3 Partial Collections

It is agreed that, to the extent the PUC receives partial payments on customer accounts of NOW, NOW directs the PUC and the PUC agrees to apply such partial payments first to the PUC and NOW portions of such customer accounts, pro rata to the amounts noted in the applicable accounts, prior to payment of any third party portions of such customer accounts.

5.4 Personnel

5.4.1 Required Personnel

PUC shall engage as employees and properly instruct all personnel as may be required for the satisfactory performance of PUC's responsibilities under this Agreement.

5.4.2 Responsibility for Personnel

All of the personnel required to provide management services hereunder shall be employees of PUC. The remuneration of all of PUC's personnel shall be solely for the account of PUC.

5.4.3 Compliance With Laws

PUC shall at all times comply with all applicable collective agreements and other applicable employment standards, occupational health and safety, Highway Traffic Act, workers' compensation and human rights legislation relating to employees and personnel working at the Corporations.

5.4.4 Disclosure

At the request of NOW or NOE, PUC shall provide the Corporations with any and all information and documentation relating to the employees of PUC working at NOW or NOE.

5.4.5 Utilization of Others

For greater certainty, the parties hereby expressly agree that in providing the Management services hereunder PUC may utilize the advice and assistance and may engage the services of such other firms, professionals, persons or third parties, as it may reasonably determine necessary or appropriate and the costs and expenses of such services shall, without duplication, be recoverable from the Corporations in accordance with the provisions of this Agreement, provided, however, that PUC shall be liable for the acts and omissions of such third parties.

5.4.6 Identification

PUC shall ensure that all personnel providing services to NOW or NOE hereunder shall carry appropriate NOW or NOE identification, as applicable, when providing services to NOW or NOE, as applicable.

5.5 Conduct of Work

5.5.1 PUC agrees that when performing its services in connection with this Agreement, that it shall ensure:

- (a) that its services to the Corporations are in compliance with all of the applicable requirements of the Energy Competition Act, 1998, the Independent Market Operator ("IMO") and of the OEB, including the Affiliate

Relationship Code for Electricity Distributors and Transmitters issued by the OEB and any amendments or additions thereto;

- (b) that sharing personnel and information between NOW and NOE will not disadvantage potential or actual competitors of NOW, thereby placing NOW at risk of violation of the OEB's Affiliate Relationship Code for Electricity Distributors and Transmitters.
- (c) that its employees, contractors and subcontractors are Qualified;
- (d) that safe working practices are used in carrying out the services; and
- (e) that any and all of its employees, workers, agents, contractors and subcontractors and servants, at all times, comply with Applicable Laws including applicable rules of the Electric Utilities Safety Association (EUSA), the Workplace Safety and Insurance Act, 1997 and the Occupational Health and Safety Act and any amendments or additions thereto.

5.5.2 All services shall comply with Applicable Law and be in accordance with Good Utility Practice.

5.6 Changes

NOW or NOE may from time to time request changes in the scope of the services to be performed hereunder by PUC, and such requests are subject to the following procedure:

- 5.6.1 NOW or NOE shall advise PUC in writing of the desired change or modification;
- 5.6.2 PUC will assess the impact of the desired changes or modifications on the total cost of the services, the time frame for completion and any further areas which, in the opinion of PUC, is likely to be affected by the desired changes;
- 5.6.3 PUC shall notify NOW or NOE, as applicable, in writing of its estimates and shall await instructions from NOW or NOE on whether or not to proceed with the changes or modifications;
- 5.6.4 any changes or modifications which increase the fee to be charged to NOW or NOE hereunder shall be implemented only with the prior written approval of the Board of Directors of NOW or NOE;
- 5.6.5 any increased fee caused by the desired changes or modifications shall be billed to NOW or NOE, as applicable, and are recoverable outside any limit of maximum fees under this Agreement.

6. CONTROL BY THE CORPORATIONS

6.1 General Control by the Corporations

PUC shall not take any action unless that action:

6.1.1 is authorized by the terms of this Agreement; or

6.1.2 has been approved by NOW or NOE, as applicable,

provided that in the event of an emergency, where NOW or NOE, as applicable, or their duly authorized representatives cannot be reasonably located for the purpose of giving its approval, PUC may take such actions as it reasonably determines if in PUC's opinion the failure to act could:

- (a) result in a hazardous situation which could cause personal injury or damage to property, or
- (b) impair the value of NOW or NOE's investment, as applicable, or
- (c) expose any of PUC, NOW or NOE, as applicable, to the imposition of penalties, fines, imprisonment or any other liability,

and shall notify the Corporations in writing of any such actions as soon as practicable thereafter.

6.2 The Corporations' Right to Issue Directives

NOW or NOE may, from time to time, at PUC's request or at NOW or NOE's own initiative, issue written directives and instructions and establish written policies and procedures governing the duties and obligations of PUC and the performance by PUC of its duties and obligations under this Agreement and shall provide those directives, instructions, policies and procedures to PUC. PUC shall at all times act in accordance with such directives, instructions, policies and procedures provided that such directives, instructions and policies shall not oblige PUC to perform any duty or obligation not provided for in this Agreement and shall not have the effect of putting PUC into default under this Agreement.

6.3 Approval of the Corporations

Notwithstanding, and without limiting, any other provisions in this Agreement, PUC in its capacity as manager shall not undertake any of the following matters without the prior approval of NOW or NOE:

6.3.1 any financing or borrowing with respect to the Corporations;

6.3.2 those matters specifically identified in this Agreement as requiring the approval of either of the Corporations.

6.3.3 those matters requiring the approval of the IMO or the OEB.

6.4 Approval and Response Time

In the event that approval of NOW or NOE is required pursuant to this Agreement, PUC shall deliver written notice in the manner set forth in section 11.6 setting forth particulars of the matter and requesting approval of NOW or NOE. NOW or NOE shall endeavour to respond to any request by PUC for the approval of NOW or NOE or for the directions or instructions of NOW or NOE within five (5) Business Days, or such other period as is expressly provided for in this Agreement.

7. MANAGEMENT FEES

7.1 Level of Management Fees

- (a) It is acknowledged that NOW is regulated by the OEB and that the management fees payable by NOW will be calculated and paid in accordance with the OEB's regulatory requirements in force from time to time. Currently, such fees must be calculated, at the PUC's long run incremental cost, plus a reasonable mark-up for fixed common costs (the "Mark-up"). The fees that NOE pays the PUC for its services are unregulated, but, because NOE must also make payments in lieu of taxes, management fees must be reasonable for such tax purposes.
- (b) NOW and NOE, as applicable, will pay PUC the cost of the services (as hereinafter defined) and a fee of 20% on items (i), (iv) and (v) of the cost of the services, being a reasonable Mark-up for fixed common costs.
- (c) The cost of the services shall include cost recoveries for:
 - (i) expenditures for wages and for salaries and a reasonable portion of employee future liabilities of outdoor workers, clerks and other personnel of the PUC while engaged in providing services to the Corporations;
 - (ii) expenditures for material used in or required in connection with the performance of the services hereunder;
 - (iii) the cost of all the expendable materials, supplies and tools;
 - (iv) the cost of office and other commercial space utilized in the operations of NOW and NOE; and
 - (v) such other expenditures in connection with the services hereunder as may be approved by NOW or NOE as applicable.
- (d) It is acknowledged by the parties hereto that the reduction of costs by the PUC is a direct benefit to the Corporations because these reductions will be passed through to NOW and NOE. Accordingly, the Corporations and the PUC agree to negotiate in good faith within the six month period after the execution of this Agreement to agree upon a bonus to be earned by PUC as an incentive to the PUC, out of the cost savings passed through to NOW and NOE, for reducing the cost of the services.

7.2 Payment

7.2.1 Estimate

Prior to the commencement of each Fiscal Year, the Corporations and PUC shall discuss the anticipated services required by the Corporations from PUC for the next Fiscal Year. Each annual budget of the Corporations shall contain an estimate of the Management Fees payable to PUC for the ensuing Fiscal Year based upon the anticipated time to be expended by the PUC's personnel in rendering the services hereunder. The Management Fees for any Fiscal Year (or portion thereof, if such is the case) shall be paid to PUC monthly, in advance, in equal monthly installments, on the basis of the estimate referred to above.

7.2.2 Time Sheets or Estimates

PUC shall cause its personnel providing services to NOW to maintain daily time sheets or estimates describing the time expended by such personnel of the PUC in rendering the management services and detailing the actual services provided.

7.2.3 Actual Fees

The actual Management Fees for any Fiscal Year shall be calculated by the PUC utilizing the time sheets maintained pursuant to Section 7.2.2. PUC time charges shall not exceed by more than 10% in any Fiscal Year the Management Fees payable under Section 7.1.1 estimated in the applicable annual budget of the Corporations, without obtaining the prior written approval of the Corporations. Within thirty (30) days after the completion of each Fiscal Year, PUC shall submit a final statement to the Corporations which shall present the management services provided during the prior Fiscal Year, a summary of the time expended by the personnel of PUC, the other items forming part of the cost of the services, the Mark-up charged on the cost of the services and applicable taxes, and state the actual Management Fee payable.

7.2.4 Adjustment

If the amount which has been paid on account of the estimated Management Fees for any Fiscal Year differs from the actual Management Fees, the necessary adjusting payment shall be made by the Corporations or PUC, as the case may be, within thirty (30) days after the actual Management Fees payable have been determined in accordance with Section 7.2.3.

7.2.5 Records and Audit

- (a) The PUC shall keep complete and accurate documentation supporting the final annual statements sent to the Corporations. The Corporation, through their representatives, employees, auditors and authorized persons, shall have the right, at the Corporations' expense, to inspect and audit the documentation at any time during the Term and for one (1) year thereafter

during reasonable business hours, for the purpose of determining the sufficiency and accuracy thereof and the final annual statements.

- (b) The PUC shall maintain NOW's books in conformity with the OEB's Uniform System of Accounts. These accounts will be summarized and reported to the OEB in accordance with the OEB's requirements, and to NOW for use for its planning activities. If the OEB's requirements for NOW also requires the PUC to keep its books in accordance with the OEB's Uniform System of Accounts, the PUC will comply.

7.2.6 Determination by Auditors

If required, the auditors of the Corporations shall determine the amount paid on account of Management Fees and the actual Management Fees payable by the Corporations. If the Corporations and PUC do not agree with the determination of the auditors of the Corporations, the issue shall be submitted to final and binding arbitration as provided for in the last paragraph of section 10 hereof.

7.3 Expenses

7.3.1 General

Except as otherwise expressly approved by NOW or NOE, PUC shall pay all of its own costs and expenses incurred in fulfilling its obligations under this Agreement.

7.3.2 Travel and Lodging

PUC shall be entitled to be reimbursed, in accordance with its policy, for the travel and lodging expenses it has incurred in the course of providing services under this Agreement.

7.3.3 Invoices for Permitted Expenses

PUC shall provide invoices for all out-of-pocket costs and expenses in respect of which PUC is entitled to be reimbursed together with such supporting materials as may be appropriate.

7.4 Hardship

If, during the Term of this Agreement, a situation arises which is beyond the reasonable anticipation or control of either party and which results in a material disadvantage to one party, the Parties will endeavour in good faith to renegotiate the terms of this Agreement to the end that this Agreement shall operate between the Parties with fairness. The party disadvantaged shall make a request for revision within a reasonable time from the moment it becomes aware of the event and of its effect on the economy of this Agreement. The request shall indicate the grounds on which it is based. The Parties shall then consult one another with a view to revising this Agreement on an equitable basis in order to ensure that neither party suffers excessive prejudice. The request for revision does not of itself suspend performance of this Agreement. If

the Parties are unable to agree on the revision to this Agreement within sixty (60) days of the request, the matter shall be referred to binding arbitration pursuant to Section 10.3 of this Agreement.

8. REPORTS BY PUC

8.1 In furtherance of its obligation to provide management services to the Corporations, PUC shall do the following:

8.1.1 assist the Corporations in their financial planning, prepare and submit to the Corporations for the approval of the Corporations not less than sixty (60) days prior to the commencement of each Fiscal Year an annual business, capital and operating plan for the Corporations for such Fiscal Year and an annual budget;

8.1.2 prepare and present quarterly reports on payments in lieu of taxes and on service quality and reliability in comparison with other municipal utilities of comparable number of customers and geographic area, and with OEB benchmarking standards prepare and present quarterly reports to the Board of Directors of NOW or NOE on PUC's activities under this Agreement;

8.1.3 maintain appropriate books of account and records to be maintained at the offices of NOW, with respect to all activities undertaken by PUC in performance of this Agreement.

8.2 Availability of Personnel

PUC agrees to cause its personnel to be available for meetings with the Board of Directors of NOW or NOE from time to time as may reasonably be required by NOW or NOE and to provide such information with respect to this Agreement as may be reasonably requested by NOW or NOE.

9. TERMINATION OF PUC'S APPOINTMENT

9.1 Event of Default

9.1.1 Notice of Default

If an Event of Default occurs, NOW or NOE, as applicable, may provide a notice to PUC (the "Default Notice") of such Event of Default which shall specify in reasonable detail the Event of Default.

9.1.2 Return Notice

Within five (5) Business Days after delivery by NOW or NOE of the Default Notice, PUC shall provide notice to NOW or NOE which shall specify whether or not PUC believes that it will be reasonably able to cure the Event of Default within thirty (30) days and a proposed timetable and course of action for curing the Event of Default.

9.1.3 Right of Termination

NOW or NOE, as applicable, shall have the right to terminate this Agreement by notice to PUC stating that this Agreement is terminated and the reason for termination if PUC fails to:

- (a) commence diligent efforts to rectify the Event of Default within ten (10) days after the date of receipt by PUC of the Default Notice; or
- (b) either,
 - (i) rectify the Event of Default within thirty (30) days after the date of receipt by PUC of the Default Notice; or
 - (ii) if PUC is not able to rectify the Event of Default within such thirty (30) day period, notwithstanding its diligent efforts to do so, and PUC requests by notice in writing to NOW or NOE, as applicable prior to the expiry of the thirty (30) day period a longer period to rectify the Event of Default, such longer period to which NOW or NOE may consent in writing prior to the end of the thirty (30) day period, such consent not be unreasonably or arbitrarily withheld.

Such termination shall be effective as of the last day of the month following the month in which the notice of termination is delivered by NOW or NOE to PUC.

9.1.4 Liquidated Damages

If NOW terminates this Agreement pursuant to this section 9.1.1, upon the effective date of such termination, PUC shall pay to NOW or NOE, as applicable, as liquidated damages and not as a penalty an amount equal to the management fees payable by NOW to PUC pursuant to this Agreement for the previous six completed calendar months. The parties acknowledge that in terminating this Agreement by virtue of an Event of Default, NOW or NOE will suffer significant business losses and costs and expenses in searching for and retaining new management services for its business operations. The parties accordingly acknowledge that the amount of the liquidated damages set forth above is a bona fide and reasonable estimate of the damages, costs and expenses which would be incurred by NOW or NOE upon such a termination.

9.2 Termination for Insolvency

PUC shall forthwith provide written notice to NOW or NOE, as applicable, in the event that an Event of Insolvency occurs, whereupon NOW or NOE, as applicable, may elect, in its sole and unfettered discretion, to terminate this Agreement by notice to PUC stating that this Agreement is terminated. In the event that PUC receives a notice of a petition in bankruptcy, it shall forthwith deliver a copy thereof to NOW or NOE and provide such information with respect thereto as may be required by NOW or NOE, so that NOW or NOE may decide if an Event of Insolvency has occurred.

9.3 Termination by PUC

If NOW or NOE fails to:

9.3.1 Payments

Make any payment which it is obliged to make or provide under this Agreement; or

9.3.2 Directions

give such directions as were properly requested by PUC for the performance of its obligations under this Agreement in the time provided to give such directions,

PUC may give written notice to NOW or NOE, as applicable, specifying in reasonable detail the matter complained of. If, in the case of a monetary default, within ten (10) days after receipt of such notice NOW fails to cure the matter complained of, or, in the case of a non-monetary default, if NOW fails to begin to cure such failure within thirty (30) days after receipt of such notice PUC may terminate this Agreement upon providing written notice to NOW and NOE and the termination of this Agreement shall be effective as of the date which is thirty (30) days after the date on which the notice of termination is given by PUC.

9.4 Obligations on Termination

9.4.1 If this Agreement is terminated, by expiration or otherwise, PUC shall, upon the termination becoming effective:

(a) Deliver Books and Records

deliver to NOW and NOE all records and documents relating to NOW and NOE which are then in the possession or control of PUC;

(b) Vacate

peacefully leave and cause its personnel to peacefully leave any sites of the Corporations and return and cause its personnel to return all keys to the Corporations;

(c) Computer Records

deliver to NOW and NOE a hard copy and an electronic copy of all files and records maintained by PUC with respect to NOW and NOE and that are stored electronically and return to NOW and NOE all records, books, papers, data, notes, memoranda, reports, proposals, software, discs and other electronic or computer data, improvements, drawings, storage, media, manuals, lists, correspondence, specifications, materials or any other documents properly belonging to NOW and NOE, together with any copies or reproductions which have come into PUC's possession prior to or during the term of this Agreement (collectively, the "Computer Records"). PUC shall use

its reasonable best efforts to provide the electronic copy in a format which is compatible with NOW's and NOE's electronic data maintenance system. PUC shall ensure that it does not give NOE any information that is the property of NOW and that is not also available to actual or potential competitors of NOW.

(d) Otherwise Assist

otherwise instruct its personnel to promptly provide all reasonable assistance and information requested by NOW and NOE, in order to settle all matters outstanding under this Agreement, and to enable the smooth transition of management of NOW and NOE from PUC to the Corporations or any other PUC appointed by NOW.

9.4.2 If this Agreement is terminated by expiration or otherwise, NOW shall, unless otherwise agreed to by PUC, upon the termination becoming effective:

- (a) offer employment to those employees of PUC who have provided substantial services hereunder to NOW (the "Employees") as determined by PUC acting reasonable on substantially the same terms of employment as enjoyed by the Employees on the effective date of termination of this Agreement; or
- (b) designate to PUC those Employees which NOW does not wish to employ, whereupon PUC shall terminate the employment of such designated Employees and NOW shall be responsible for and immediately pay to PUC all termination and other severance costs incurred by PUC in relation to any such terminations of employment.

9.5 Rights on Termination

Any termination of this Agreement shall terminate all rights and obligations of the Parties to this Agreement except:

- 9.5.1 rights and obligations with respect to amounts owing or to remedies, if either PUC or the Corporations shall be entitled to an accounting as to the fees or other monies payable to PUC or by PUC;
- 9.5.2 rights and obligations with respect to any event which occurred prior to the effective date of the termination of this Agreement;
- 9.5.3 Sections 9.4, 9.5, 9.6, 9.7, 11.1 and 11.2 of this Agreement,

which shall survive any termination of this Agreement and shall remain in full force and effect thereafter.

9.6 Confidentiality

- 9.6.1 PUC acknowledges that it has and will have access to confidential and proprietary information relating to each of the Corporations and their operations

and agrees that such confidential and proprietary information shall not be used by it for any purpose other than the purposes of this Agreement and shall not be disclosed by PUC to any third party without the prior written consent of NOW or NOE, as applicable, except to employees or the Commissioners of PUC who have entered into an agreement with PUC to ensure the confidentiality and security of the Confidential Information. PUC agrees that it will not provide any confidential and proprietary information of NOW to NOE without NOW's prior written consent. PUC further acknowledges that it is aware of the provisions of the Shareholders Agreement relating to the Corporations and agrees to be bound by the confidential provisions of such Shareholders Agreement. All confidential and proprietary information that PUC has access to or acquires in the course of providing the services hereunder shall be used by PUC only for the benefit of the Corporations. PUC will promptly notify the Corporations in the event any unauthorized person obtains access to the Confidential Information. If any of the provisions of this Section 9.6 are violated in any material respect by PUC or its agents or employees, the Corporations shall have the right, in addition to any other right hereunder, to terminate this Agreement immediately upon notice thereof to PUC. The parties agree that injunctive relief in addition to any other right or remedy is an appropriate remedy to enforce the provisions of this Section 9.6 and the Corporations' proprietary rights, should the need arise.

9.6.2 Upon termination of this Agreement, PUC will deliver to the Corporations the Computer Records referred to in Section 9.4.3 of this Agreement.

9.6.3 PUC's obligations under this Section 9.6 shall survive the termination of the Agreement.

9.7 Non Solicitation

During the term of this Agreement and for a period of one (1) year from the date of termination of this Agreement, PUC agrees that it will not, without the prior written consent of the Corporations, which consent may be unreasonably or arbitrarily withheld, directly or indirectly through any of its affiliates or associates (as such terms are defined in the Business Corporations Act, Ontario), solicit, offer employment to or employ any of the employees of the Corporations.

10. DISPUTE RESOLUTION

Except as otherwise provided in this Agreement, the Corporations and PUC will act reasonably in exercising their rights and discharging their duties pursuant to this Agreement. At any time while this Agreement and any of its provisions are in force, should any dispute, difference of opinion, computation, or question arise between any of the parties hereto (the "Disputing Parties") touching this Agreement or any part thereof (other than the provisions of sections 9.6 and 9.7 hereof) which cannot be resolved by the provisions hereof or by the agreement of the parties, then such dispute, difference of opinion, computation, or question (collectively a "Dispute") shall be arrived at and settled as herein provided:

- 10.1 within two (2) Business Days of written notice by any party hereto of a Dispute, each party shall designate in writing to the other a Representative. The Representatives shall meet as often as necessary during a twenty (20) Business Day period following notice of the Dispute (or such other time period as the Representatives may agree) to gather and furnish to the other all information with respect to the Dispute which is appropriate and germane to its resolution. The Representatives shall negotiate in good faith in an effort to resolve the Dispute without the necessity of any proceedings. The specific format for such discussions will be left to the discretion of the Representatives;
- 10.2 if the Representatives cannot resolve the Dispute within that twenty (20) Business Day period, the dispute will be immediately referred by the Representatives to the following individuals (or their designated representatives) for a period of ten (10) Business Days for further good faith efforts to resolve the Dispute: for NOW or NOE, the Chairman of the Board and, for PUC, a member of senior management of PUC (who is not on the Board of either NOW or NOE);
- 10.3 if the Dispute is not resolved by those individuals within a ten (10) Business Day period, then either of the parties may initiate proceedings as set forth below; provided, however, that such proceedings for resolution of any Dispute may not be commenced until the earlier of thirty (30) Business Days after the initial notice of the Dispute or thirty (30) Business Days before the statute of limitations governing any cause of action or relating to the dispute would expire, unless preliminary or temporary relief of an emergency nature is sought by one of the parties.

If the parties are not successful in resolving the Dispute informally, they agree to submit the matter to final and binding arbitration in accordance with the provisions of the Arbitration Act, 1991 (Ontario), as amended. Arbitration hereunder shall be held in Cochrane, Ontario or such other place in Ontario as the parties may agree. The substantive and procedural law of the Province of Ontario shall apply to the proceedings. Equitable remedies shall be available in any arbitration. Neither punitive damages nor trebled or otherwise escalated damages shall be awarded. Judgement upon the award rendered in any arbitration may be entered in any court having jurisdiction thereof, or application may be to such court for a judicial acceptance of the award and enforcement thereof, as the law of such jurisdiction may require or allow. Nothing contained herein shall prejudice the right of any party to apply to any court of appropriate jurisdiction for temporary or preliminary injunctive or other equitable relief. The costs of the arbitration will be determined by the arbitrator in his sole discretion.

11. GENERAL

11.1 Indemnity by NOW and NOE

Both during and after the termination of this Agreement, NOW and NOE shall indemnify and save PUC and its employees, officers and directors harmless from any action, cause of action, suit, debt, cost, expense, liability, claim or demand whatsoever at law or in equity, in connection with the performance by PUC of any and all of its obligations under this Agreement or pursuant to the policies, instructions and procedures of NOW and NOE including, without limitation, any damage or injury whatsoever to any employee or other Person or property arising out of the administration of NOW and NOE, or any assets of NOW and NOE during the

Term of this Agreement, provided the indemnity provided under this Section 11.1 shall not extend to any negligence or malfeasance of PUC or its employees, officers, directors, agents or any other Person for whom it is responsible at law other than those caused by a peril or event against which NOW and NOE is liable to insure, in which event the indemnity is limited to the portion of the cost, damage or loss not recovered pursuant to insurance.

11.2 Indemnity by PUC

Both during and after the termination of this Agreement, PUC shall indemnify and save NOW and NOE and their employees, officers and directors harmless in respect of any action, cause of action, suit, debt, cost, expense, liability, claim or demand whatsoever, at law or in equity, arising by reason of any,

- 11.2.1 negligence or malfeasance of PUC or its employees, officers, directors, agents or any other Person for whom it is responsible at law; or
- 11.2.2 breach by PUC of any provision under this Agreement.

other than those caused by a peril or event against which NOW and NOE is liable to insure, in which event the indemnity is limited to the portion of the cost, damage or loss not recovered pursuant to insurance.

11.3 Insurance

NOW and NOE will maintain, at their expense, insurance on its real and personal property and public liability insurance and carry PUC as an additional insured. The insurance policy shall contain a waiver of any subrogation rights which the Corporations' insurers may have against PUC whether any such damage is caused by the act, omission or negligence of PUC.

PUC will maintain, at its expense, fidelity bond insurance covering its employees who handle or are responsible for handling the Corporations' funds, insuring against loss, theft, embezzlement, or other fraudulent acts on the part of employees. PUC will carry the Corporations as an additional insured and loss payee on such policy. PUC shall provide the Corporations with copies of all such insurance policies. PUC will also maintain at all times throughout the term of this Agreement, public liability and property damage insurance with respect to PUC's operations at the sites of the Corporations in such reasonable amounts and with such reasonable deductibles as determined from time to time by the Corporations. The insurance policy shall contain a waiver of any subrogation rights which PUC's insurers may have against the Corporations, whether any such damage is caused by the act, omission or negligence of the Corporations.

11.4 Environment

- 11.4.1 The Corporations shall in respect of the assets and operations which are the subject of this Agreement be responsible for all environmental liability which results from:
 - (a) the operations of the Corporations;

- (b) any products, goods or materials brought onto property or used by the Corporations.

11.4.2 PUC shall in respect of the assets and operations which are the subject of this Agreement be responsible for all environmental liability which results from:

- (a) PUC's operations; or
- (b) any products, goods or materials brought onto property or used by PUC or by a person with the express or implied consent of PUC.

11.5 Regulatory Matters

11.5.1 Nothing in this Agreement shall derogate from, restrict or limit the rights and obligations of the parties under applicable law including, without limitation, the Electricity Act, 1998 (Ontario) and the Telecommunications Act (Canada) and any conflict or inconsistency shall be resolved in favour of applicable law.

11.5.2 The parties acknowledge that the subject matter of this Agreement may be subject to ruling of one or more governmental bodies including the OEB, the IMO and CRTC from time to time. The parties agree to consult and negotiate in good faith, in the event that any term of this Agreement is affected by such ruling.

11.6 Notice

Any notice or other communication required or permitted to be given under or for the purposes of this Agreement shall be in writing and shall be sufficiently given if delivered personally to the Party to whom the notice or other communication is to be given, or if transmitted by telecopier or other form of recorded communication during the transmission of which no indication of failure of receipt is communicated to the sender;

11.6.1 in the case of a notice to the Corporations:

153 Sixth Avenue
P.O. Box 640
COCHRANE, ON P0L 1C0

11.6.2 in the case of a notice to PUC at:

Cochrane Public Utilities Commission
153 Sixth Avenue
P.O. Box 640
COCHRANE, ON P0L 1C0

or at such other address as the Party to whom such notice is to be given shall have last notified to the Party giving the same in the manner provided in this Section. Any notice delivered to a Party in accordance with this Section shall be deemed to have been given and received on the day it is so delivered at such address, provided that if such day is not a Business Day, then the notice shall be deemed to have been given and received on the Business Day next following such day. Any notice transmitted by telecopier or other form of recorded communication to a Party in accordance with this Section shall be deemed to be given and received on the day of its transmission if such day is a Business Day and the transmission is completed before 6:00 p.m. and, if not, on the next following Business Day.

11.7 Further Assurances

Each of the Parties hereto shall promptly do, make, execute and deliver, or cause to be done, made, executed and delivered, all such further acts, documents and things as the other Party hereto may reasonably require from time to time for the purpose of giving effect to this Agreement and shall use reasonable efforts and take all such steps as may be reasonably within its power to implement to its full extent the provisions of this Agreement.

11.8 Assignment

11.8.1 By PUC

This Agreement and all rights, entitlements, duties and obligations arising from it shall not be assigned in whole or in part by PUC unless the assignment is approved by NOW and NOE, which approval may be arbitrarily withheld.

11.8.2 By the Corporations

This Agreement and all rights, entitlements, duties and obligations arising from it shall not be assigned in whole or in part by NOW or NOE without the prior written consent of PUC, which consent shall not be arbitrarily or unreasonably withheld.

11.8.3 Transfer of Utility or Dissolution of PUC

Without the prior written consent of NOW, which consent shall not be arbitrarily or unreasonably withheld, there shall be no transfer of any utility from PUC to the Corporation of the Town of Cochrane, and no dissolution of PUC.

11.8.4 Change of Control of NOW or NOE

Without the prior written consent of PUC, which consent shall not be arbitrarily or unreasonably withheld, there shall be no effective change in the voting control of NOW or NOE.

11.9 Extended Meanings

Words importing persons shall include individuals, partnerships, associations, trusts, unincorporated organizations and corporations.

11.10 Time of Essence

Time is of the essence in this Agreement.

11.11 Severability

Any provision of this Agreement which is illegal, prohibited or unenforceable in any jurisdiction shall as to such jurisdiction, be ineffective to the extent of such illegality, prohibition or unenforceability without invalidating the remaining provisions hereof or affecting the validity or enforceability of such provision in any jurisdiction.

11.12 Force Majeure

Notwithstanding anything to the contrary contained herein, if any Party hereto is bona fide delayed or hindered in or prevented from the performance of any work, term, covenant or act required hereunder by reason of strikes, labour disputes, lock outs, power failures, riots, insurrections, sabotage, rebellions, war, acts of God, or any other cause beyond the reasonable control of the Party delayed in the performance of any work, term, covenant or act required hereunder, then performance of the same is excused for the period of the delay and the Party so delayed shall be entitled to perform such work, term, covenant or act within a reasonable time period after the expiration of the period of such delay; provided however that the Party so delayed is acting and continues at all times to act in good faith and in a reasonable manner with respect to such condition or cause and provided that, if the delay exceeds thirty (30) days and the cause of the delay is personal to PUC then at any time after the expiry of such period, the Party in whose favour the work, term, covenant or act was to be performed may terminate this Agreement forthwith by notice in writing.

The Party delayed will notify the other Party as soon as practicable after becoming aware of an event giving rise to a delay under this Section and will, from time to time, notify the other Party of the expected duration of the period of the delay.

The financial condition of a Party or any lack of funds on the part of a Party shall be deemed not to be a condition or cause beyond the reasonable control of that Party unless the lack of funds is on the part of PUC and is caused by the failure of NOW or NOE to pay PUC any sums to be provided by NOW or NOE hereunder.

11.13 Change in Laws

The rights and obligations of the Parties hereto under this Agreement shall be subject to all Applicable Law having jurisdiction over the Parties hereto. In the event, however, that any Applicable Law shall change and, in the judgement of either party hereto such change substantially alters the relationship between the Parties under this Agreement, or the advantage derived from such relationship, either party may request the other party hereto to modify this Agreement, and if, within thirty (30) days subsequent to making such requests, the Parties hereto are unable to agree upon a mutually satisfactory modification hereof, then the adversely affected party may either refer the matter to binding arbitration pursuant to Section 10.3 hereof or terminate this Agreement on 30 days prior written notice to the other party.

11.14 No Waiver

No consent or waiver, express or implied, by a Party to or of any breach or default by the other Party in the performance of such other Party of its obligations hereunder shall be deemed or construed to be a consent or waiver to or of any other breach or default in the performance by such other Party hereunder. Failure on the part of a Party to complain of any act or failure to act by the other or to declare the other Party in default, irrespective of how long such failure continues, shall not constitute a waiver by such first mentioned Party of its rights hereunder.

11.15 Governing Law

This Agreement is made pursuant to and shall be governed and interpreted in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

11.16 Entire Agreement

This Agreement constitutes the entire agreement between the Parties respecting the subject matter herein and supersedes all prior agreements, undertakings, negotiations and discussions between the Parties, whether oral or written, and there are no warranties, representations or other agreements between the Parties in connection with the subject matter hereof except as specifically set forth herein. All amendments to this Agreement shall be made in writing and executed by the Parties hereto.

11.17 Accounting Principles

All accounting terms not specifically defined herein shall be construed in accordance with generally accepted accounting principles in Canada.

11.18 Enurement

This Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and permitted assigns.

IN WITNESS WHEREOF the Parties have duly executed this Agreement as of the day, month and year first above written.

NORTHERN ONTARIO WIRES INC.

Per: _____
Name:
Title:

Per: _____
Name:
Title:

NORTHERN ONTARIO ENERGY INC.

Per: _____
Name:
Title:

Per: _____
Name:
Title:

COCHRANE PUBLIC UTILITIES COMMISSION

Per: _____
Name:
Title:

Per: _____
Name:
Title:

SCHEDULE "A"

DEFINITIONS

In this Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the respective meanings ascribed to them as follows:

1. **"Affiliate"** of any party hereto means any corporation which is an affiliate of the applicable party within the meaning of the Business Corporations Act, R.S.O. 1990, c. B.16.
2. **"Agreement", "this Agreement", "the Agreement", "hereto", "hereof", "herein", "hereby", "hereunder"** and similar expressions means or refer to this Agreement, as amended or supplemented from time to time in writing by the Parties.
3. **"Applicable Law"** means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws (of general application), orders, injunctions, rulings, awards, judgements, or decrees or any requirements or decision or agreement with or by any government or governmental department, commission board, court authority or agency and includes the standards of the Town and codes, licenses and rulings issued by the OEB, the IMO and the CRTC.
4. **"Business Day"** means any day which is not a Saturday, Sunday or statutory holiday under the laws of the Province of Ontario or the laws of Canada applicable therein.
5. **"Corporations"** means NOW and NOE collectively.
6. **"Event of Default"** means any default under this Agreement including, without limitation, either of the following:
 - 6.1 any failure by PUC to perform or comply with its duties and obligations under this Agreement; and
 - 6.2 a situation in which the personnel of PUC who are providing services hereunder do not have the requisite skills or experience to provide management services to the Corporations.
7. **"Event of Insolvency"** means the occurrence of any one of the following events:
 - 7.1 if any Party:
 - 7.1.1 other than in connection with a bona fide corporate reorganization which does not otherwise contravene this Agreement, is wound up, dissolved, liquidated or has its existence terminated or has any resolution passed therefore or makes a general assignment for the benefit of its creditors or

a proposal under the Bankruptcy and Insolvency Act, as amended or re-enacted from time to time;

7.1.2 makes an application to the applicable court for a compromise or arrangement under the Companies' Creditors Arrangement Act (Canada), as amended or re-enacted from time to time; or

7.1.3 files any written request, application, answer or other document seeking or consenting to any re-organization, arrangement, composition, re-adjustment, liquidation or similar relief for itself under any present or future law relating to bankruptcy, insolvency or other relief for or against debtors generally including, without limitation, any notice of intention to make a proposal pursuant to the Bankruptcy and Insolvency Act;

7.1.4 if a court of competent jurisdiction enters an order, judgement or decree against such Party which approves or provides for any reorganization, arrangement, composition, re-adjustment, liquidation, dissolution, winding-up, termination of existence, declaration of bankruptcy or insolvency or similar relief with respect to such Party, under any present or future law relating to bankruptcy, insolvency or other relief for or against debtors generally and such order, judgement or decree remains unvacated and unstayed for an aggregate period of thirty (30) days (whether or not consecutive) from the date it is made;

7.1.5 if any trustee in bankruptcy, receiver, receiver and manager, liquidator or any other officer with similar powers is appointed for or with respect to such Party and that appointment remains in effect for an aggregate period of thirty (30) days (whether or not consecutive) from the date of the appointment; or

7.1.6 if an encumbrancer or anyone acting on behalf of an encumbrancer takes possession of all or substantially all of the property of PUC and remains in possession for an aggregate period of thirty (30) days (whether or not consecutive) from the first date of the taking of possession.

8. **"Fiscal Year"** means a period of twelve (12) consecutive months ending on December 31, or such other date as designated in writing by the Corporations, or such other period as may be designated in writing from time to time by the Corporations, provided that any such other period shall not be effective unless PUC receives written notice of such period at least ninety (days) prior to the first day of such period; provided that the initial Fiscal Year shall be the period commencing on the date of this Agreement and ending on December 31, 2001.

9. **"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utilities of comparable numbers of customers and geographic area in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to

accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to optimum practices or methods, or act to the exclusion of all others, but rather to include all practices, methods, or acts generally accepted in North America.

10. **"IMO"** has the same meaning as in subsection 2 (1) of the Electricity Act, 1998.
11. **"Management Fees"** means the aggregate of all net fees payable to PUC pursuant to Sections 7.1.1 and 7.1.2.
12. **"OEB"** means the Ontario Energy Board and any successor or other governmental regulatory authority in respect of the electricity industry in Ontario.
13. **"Parties"** means PUC, NOW and NOE and their respective permitted successors and assigns.
14. **"Person"** means an individual, partnership, corporation, government or any department or agency thereof, trustee, or unincorporated organization and the heirs, executors, administrators or legal representatives or an individual.
15. **"Qualified"** means the worker or workers in question are duly qualified under Applicable Law (including the requirements of the Occupational Health and Safety Act, with respect to working near electrical hazards) or the entity uses only such qualified workers, to carry on the work in question, as applicable.
16. **"Term"** has the meaning ascribed to it in Section 4.

SCHEDULE "B"

Description of Services. The Management Services provided by PUC to the Corporations pursuant to Section 5.3.2 shall consist of the following categories:

- (a) **General Corporate.** PUC shall provide to the Corporations general office, corporate and other management services including, without limitation, the following services (collectively, the "General Corporate Services"):
 - (i) Corporate accounting, including, without limitation, review, preparation and consolidation of budgets, fixed asset accounting, maintenance of accounting books and records, review, preparation and consolidation of corporate financial information, including financial information of all subsidiaries and preparation of monthly, quarterly and annual financial reports and the review, analysis, consultation and recommendation concerning special projects;
 - (ii) Finance, including, without limitation, treasury and cash management services (including reconciliation of bank accounts and administration of loans and debt and sale-lease back arrangements), monitoring and preparation for payment of accounts payable, maintenance of bank relationships and debt availability reporting, general cash flow reporting and negotiation of banking facilities;
 - (iii) Transportation, including, without limitation, fleet maintenance, fleet replacement management, analysis of inbound and outbound freight costs, verification of payment of freight and warehousing charges, damage prevention activities, monitoring of warehousing / distribution operations;
 - (iv) Taxation, including, without limitation, tax planning advice, minimization of tax costs, assistance in negotiations with government auditors, compliance with federal and provincial tax requirements, computations of tax payments and filings of required declarations and vouchers, preparation and filing of any applicable federal and provincial tax or payment in lieu of tax returns, preparation of monthly sales tax returns, advising purchasing department personnel regarding proper sales tax procedures, auditing of accounts payable, listing invoices to ensure proper tax liability, monitoring progress on outstanding tax audits, preparation and filing of any compliance reporting to regulators, and monitoring of evolving regulatory requirements to ensure continuing compliance;
 - (v) Management information systems services such as implementation, maintenance and servicing of various information systems and programs related to payroll matters, human resources, management reporting, roll outs, ordering and shipping, statistical quality control, statistic process control, order fulfillment system, and periodic review of the effectiveness of the information systems;

- (vi) Internal audit services, including without limitation, evaluation of the adequacy, application and effectiveness of internal financial controls, internal controls relating to computer operations, systems and security, monitoring and preservation of corporate assets, monitoring of compliance with corporate policies, guidelines and procedures, co-ordination with external auditors, and reporting of audit findings and follow-up;
 - (vii) Risk management and insurance, including, without limitation, ensuring the adequacy of, provision and maintenance of insurance coverage for property, business interruption, automobile, general liability, employee fidelity, bonds and other types of exposures as are required and/ or standard in the industry, assistance in the filing and negotiations of claims and their follow-up, and administrative services in relation to the foregoing;
 - (viii) Legal services including, without limitation, advice and assistance relating to litigation matters, regulatory and legal compliance issues and negotiation and review of transactions, bank or other commercial financing arrangements, review of contracts and other such legal matters as may involve or affect the Corporations;
 - (ix) Administrative services, including, without limitation, communications and public relations, commercial property leases, filing, records and archive services, management of the Corporations' real and immovable property, wherever situated, whether such real and immovable property is owned or leased.
 - (x) Such other general management services as are ancillary to the provision of any of the above or upon which the Parties may from time to time agree.
- (b) **Human Resources.** PUC shall provide to the Corporations general human resources services, including, without limitation, the following (collectively, the "Human Resources Services"): corporate employee relations, labour relations services including negotiation and management of collective agreements and grievances and co-ordination of related legal matters, management of employee/ pension and benefits plans, including payroll services for non-unionized employees and coordination of employee health and safety plans and the PUC shall report on a regular basis to the Operations, Health, Safety and Environmental Committee in connection with such services.
- (c) **Distribution Facilities Operations.** PUC shall provide to the Corporations general services required to ensure the continued operations of the Corporations' facilities (the "**Facilities**"), at levels of service quality and reliability that are the higher of OEB prescribed levels and Good Utility Practice, such operations to include, without limitation, the following (collectively the "**Facilities Operation Services**"); general management and maintenance of the Facilities, purchasing and procurement services including supply chain management, the negotiation of supply contracts and management of computerized purchasing, inventory and

invoice matching systems, technical support and testing services, general administration and personnel services including the use and operation of computer programs, including monitoring of information systems, system engineering and planning services and technical services.

- (d) **Environmental.** PUC shall provide to the Corporations environmental management services, including, without limitation, the following (the “**Environmental Services**”): consultation and planning regarding environmental matters and monitoring of compliance with environmental regulations, and process control and planning at the Facilities, maintain a licensed PCB site and dispose of PCB waste, environmental auditing, and liaison and negotiations with regulatory bodies and agencies.

4-SEC-27

[Ex.4-3-5, p.1] Please provide a breakdown of 'Consultant Costs.'

Responses:

- a) Please refer to the response to Board Staff interrogatory 4-Staff-42.

4-SEC-28

[Ex.4-3-2, p.11] Has the Applicant, or its Board of Directors, considered an incentive compensation program. If so, please provide details. If not, please explain why it has not.

Response:

As mentioned in E4/T3/S2, NOW Inc. does not have any form of incentive compensation. NOW Inc. recognizes that this may be a tool to help drive performance and intends to investigate and potentially develop such a program for positions where it would be beneficial.

4-SEC-29

[Ex.4-3-2, p.12] Please provide a row to the Appendix 2-K table that shows the amount of total compensation allocated to OM&A for each year.

Response:

The following table contains the approximate amount of total compensation allocated to OM&A.

Appendix 2-K						
Employee Costs						
	Last Rebas ing Year - 2013- Board Approved	Last Rebas ing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Number of Employees (FTEs including Part-Time)¹						
Management (including executive)	4.2	4.5	4.5	3.5	3.5	3.5
Non-Management (union and non-union)	14.6	14.0	13.6	12.6	12.2	13.2
Total	18.8	18.5	18.1	16.1	15.7	16.7
Total Salary and Wages including overtime and incentive pay						
Management (including executive)	\$ 343,682	\$ 409,460	\$ 459,366	\$ 328,853	\$ 337,749	\$ 345,411
Non-Management (union and non-union)	\$ 922,279	\$ 920,392	\$ 939,014	\$ 933,605	\$ 900,235	\$ 1,001,414
Total	\$ 1,265,961	\$ 1,329,852	\$ 1,398,380	\$ 1,262,458	\$ 1,237,984	\$ 1,346,825
Total Benefits (Current + Accrued)²						
Management (including executive)	\$ 114,208	\$ 117,493	\$ 141,048	\$ 87,864	\$ 94,404	\$ 95,772
Non-Management (union and non-union)	\$ 280,334	\$ 136,557	\$ 211,500	\$ 231,702	\$ 276,084	\$ 301,776
Total	\$ 394,542	\$ 254,050	\$ 352,549	\$ 319,565	\$ 370,488	\$ 397,548
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	\$ 457,890	\$ 526,953	\$ 600,414	\$ 416,717	\$ 432,153	\$ 441,183
Non-Management (union and non-union)	\$ 1,202,613	\$ 1,056,949	\$ 1,150,514	\$ 1,165,307	\$ 1,176,319	\$ 1,303,190
Total	\$ 1,660,503	\$ 1,583,902	\$ 1,750,928	\$ 1,582,024	\$ 1,608,472	\$ 1,744,373
Total Compensation in OM&A	\$ 1,386,923	\$ 1,440,586	\$ 1,362,487	\$ 1,251,297	\$ 1,325,431	\$ 1,493,200

4-SEC-30

[Ex.4-3-2, p.17] With respect to the additional lineman position being added in 2017:

- a) When does the Applicant next forecast a retirement of a lineman to take place?
What is the basis for the forecast?
- b) Please confirm that reference to filling a position vacated previously is that of the
Lead Hand position vacated in 2014.
- c) Is the Applicant planning on hiring a journeyman or an apprentice?

Response:

- a) NOW Inc. has been advised that a lineman from Cochrane will be retiring in
August of 2017.
- b) NOW Inc. confirms that this position was a Lead Hand position.
- c) NOW Inc. confirms that it is seeking a journeyman, however if not available we
will consider an apprentice.

4-SEC-31

[4-4-1, p.4] With respect to the asset service lives used for depreciation purposes:

- a) Please provide a copy of the report or other final work product of the consultant used to review the Applicant's asset service lives.
- b) The Applicant states that "distribution station building and infrastructure is below the Kinetrics range due to the fact that Now Inc. is working to eliminate the distribution stations." Please explain this statement more fully. Would the asset service lives be any different if the Applicant was not working to eliminate these distributions stations?

Response:

- a) Please see Attachment 1 for documentation on the BDO review of asset service lives on IFRS adoption. Additionally the following table outlines the impact of the revised useful lives that resulted from the BDO work.

Northern Ontario Wires Depreciation Analysis						
	Asset Class	Depreciation Expense Per 2012 Statements	Revised Useful Lives	Depreciation Expense Per MIFRS Analysis	Difference	Variance
1820	Distribution Stations	\$20,564	Various	\$19,581	(\$983)	
1830	Poles, Towers, Fixtures	\$106,343	45 Years	\$117,876	\$11,533	
1835	Overhead Conductor & Devices	\$62,726	45 Years	\$27,662	(\$35,064)	
1840	Underground Conduit	\$4,739	45 Years	\$1,364	(\$3,375)	
1845	Underground Conductor & Devices	\$148	45 Years	\$301	\$154	
1850	Transformers	\$27,241	45 Years	\$17,747	(\$9,494)	
1855	Overhead Services	\$9,186	35 Years	\$9,295	\$109	
1855	Underground Services	\$4,832	35 Years	\$808	(\$4,023)	
		\$235,778		\$194,634	-\$41,143	-17%

- b) As per consultation with BDO, as NOW Inc. is working to eliminate the distribution stations, the remaining useful life is decreased based on an estimate of when they will be out of service. This allocates the remaining cost over the period that it will be in service in accordance with proper accounting treatment. If the stations were not being removed from service, then the useful life may be different and would be evaluated based on its condition and service life adjusted accordingly.



SUBJECT: PROPERTY, PLANT, & EQUIPMENT - IFRS POSITION PAPER

DATE: JANUARY 2012

BACKGROUND AND SCOPE

This memorandum documents the significant Property, Plant & Equipment issues dealt with by the management of Northern Ontario Wires Inc. ("NOW" or "the Company") for the purpose of preparing the Company's financial statements for the conversion to International Financial Reporting Standards ("IFRS").

NOW is a hydro distribution company operating in Ontario and is licensed by the Ontario Energy Board ("OEB"). NOW prepares its Financial Statements in accordance with CGAAP and the company's accounting policies are mandated by the OEB. These are listed in the Accounting Procedures handbook.

The regulation and monitoring of the sector is performed through the application of codes, rules and guidelines, the licensing of market participants, assisting firms with the management of regulatory requirements, monitoring and enforcing compliance and adjudication.

For both financial reporting and rate setting purposes, if an item of PP&E is made up of significant separable component parts, it must be allocated to the component parts when practicable and when estimates can be made of the lives of the separate components. Depreciation is then calculated for each component separately. Separable components are defined in the APH as "readily identifiable assets" i.e. assets of a material unit cost which are tracked separately. In accordance with the APH, if such assets are retired or disposed, a gain/loss should be recognized in income in the period the transaction occurs.

It is recognized, however, that in this industry there are a large number of capital assets that are individually insignificant. It is common practice, therefore, to group such assets for general purpose financial reporting and rate setting. These asset groups are amortized such that the combined cost of the assets is amortized over their estimated useful life. This position paper will analyze the different components of capital assets identified under Canadian GAAP and determine whether this is appropriate under IFRS.

This paper addresses the following issues:

- ☛ Summary of Current Accounting
- ☛ Analysis
 - A. IFRS 1 Election – Deemed Cost
 - B. Cost vs. Revaluation
 - C. Initial Recognition of PP&E
 - D. Componentization / Depreciation
- ☛ Summary of IFRS Issues Deemed Not Applicable

MANAGEMENT'S RESPONSIBILITIES & CONCLUSIONS:

BDO worked with management to outline the requirements under IFRS and help determine the implications for the Company. Management then made all applicable judgments and policy choices regarding the adoption of IFRS. Management also undertook any required quantification.

Management reviewed this memorandum in detail and accepted any and all management choices/decisions. In addition, management acknowledged their overall responsibilities for all conclusions related to compliance with CGAAP and/or IFRS.

In February 2012 the following members of management reviewed and acknowledged agreement with management's responsibilities:

☛ CFO

This memorandum documents the implications of adoption of IFRS on the Company as the date of transition to IFRS being January 1, 2011. Management will consider the implications of transactions which occur during the year of transition and the comparative period separately.

SUMMARY OF CURRENT ACCOUNTING

NOW's financial statements for the year ended December 31, 2010 state the following:

PROPERTY PLANT AND EQUIPMENT

Property plant and equipment are recorded at cost. The company provides for amortization using the straight-line method at rates designed to amortize the cost of the property plant and equipment over their estimated useful lives. The annual amortization rates are as follows:

Land, buildings and leasehold improvements	5 - 50 years
Vehicles	5 - 8 years
Distribution system	25 years
Office equipment	5 - 10 years
Substation	30 years
Tools and equipment	5 - 10 years

PROPERTY AND EQUIPMENT

	Cost	Accumulated Amortization	2010 Net	2009 Net
Land, buildings and leasehold improvements	\$ 124,158	\$ 62,585	\$ 61,573	\$ 65,727
Vehicles	743,821	234,184	509,637	401,001
Distribution system	4,697,258	2,322,202	2,375,056	2,582,643
Office equipment	262,290	129,915	132,375	161,454
Substation	556,681	291,540	265,141	286,046
Tools and equipment	153,261	78,870	74,391	66,240
Capital work in progress	65,934	-	65,934	43,747
	<u>\$ 6,603,403</u>	<u>\$ 3,119,296</u>	<u>\$ 3,484,107</u>	<u>\$ 3,606,858</u>

ANALYSIS

A. IFRS 1 ELECTION - DEEMED COST

Description of Issue / Standard

As noted above, the International Accounting Standards Board (“IASB”) acknowledged that restatement of PP&E can be onerous. Thus, first-time adoption voluntary exemptions from the requirements of IFRS are offered.

To apply IAS 16 retrospectively, NOW must have the ability to reconstruct from historical records the support for key PP&E balances. The detailed fixed asset register must be able to support the correct capitalization of assets and potential changes to separate certain PP&E assets into components for amortization purposes (see below for more details).

For PP&E, the company has the following options available if management cannot or does not desire to apply IFRS retrospectively. Management should assess the following options of determining the deemed cost of PP&E assets, as of the date of transition to IFRS:

- ✦ NOW may elect at the date of transition, on an individual asset basis, to measure an item of PP&E at its fair value and use that fair value as its deemed cost going forward, as at the transition date.
- ✦ NOW could also elect to use the previous CGAAP fair value of an item of PP&E at, or before, the date of transition to IFRS as deemed cost if, at the date of revaluation, the value assigned was broadly comparable to fair value or depreciated cost under IFRS. An example of a CGAAP revaluation would include the values determined as part of a business combination or an impairment analysis.

The fact that IFRS 1 offers different bases for valuation means that management can influence its future reported performance by carefully selecting a first-time adoption policy for the valuation of its assets.

For the purpose of IFRS 1, operations are subject to rate regulation if they provide goods or services to customers at prices (ie rates) established by an authorized body empowered to establish rates that bind the customers and that are designed to recover the specific costs the entity incurs in providing the regulated goods or services and to earn a specified return. The specified return could be a minimum or range and need not be a fixed or guaranteed return.

The carrying amount of such items of property, plant and equipment or intangible assets might include amounts that were determined under previous GAAP but may not qualify for capitalization in accordance with IFRSs. If this is the case, a first-time adopter may elect to use the previous GAAP carrying amount of such an item at the date of transition to IFRSs as deemed cost. This exemption is available on an item by item basis.

This exemption is a recent amendment to IFRS. The amendment is to be applied for annual periods beginning on or after January, 1 2011. Earlier application is permitted.

Entities that adopted IFRSs in periods before the effective date of IFRS 1 or applied IFRS 1 in a previous period are permitted to apply the amendment retrospectively in the first annual period after the amendment is effective.

Implications for NOW:

Management should be aware of the following when considering their ability and desire to adopt an election under IFRS 1:

- ✦ The IFRS 1 elections should be considered if management are struggling to support their PP&E balances with a detailed fixed asset register.
- ✦ The elections above essentially offer the opportunity to increase PP&E asset values on an item-by-item basis rather than to an entire asset class; this election is independent of the option to elect to carry PP&E assets at fair value on a go forward basis (essentially it is a ‘one time bump’).

- ✦ The elections above can prevent management from having to look at the differences between CGAAP and IFRS since inception of the company and retrospectively apply IAS 16.
- ✦ Based on international experience to date, other than for certain types of assets such as land and buildings, this option does not appear to possess a significant cost/benefit advantage to IFRS adopters.
- ✦ If a first-time adopter's depreciation methods under previous CGAAP are unacceptable under IFRS, a previous CGAAP fair value less accumulated depreciation cannot be brought forward. In such situations, NOW would have to adjust the accumulated depreciation recognized on the assets as if IFRS was applied since their original acquisition.

Management's Conclusions:

As per the rate regulation election, management has elected to use the previous PP&E CGAAP carrying amounts, at the date of Transition to IFRS, as deemed cost.

B. COST VS. REVALUATION

Description of Issue / Standard

This is a fundamental difference between CGAAP and IFRS.

For PP&E assets, IAS 16 allows one of two alternatives to be chosen as the accounting policy for measurement after initial recognition. Management's policy choice must be applied to an entire class of PP&E, however, not all classes require the same policy.

- ✦ Cost Model: NOW may elect to treat PP&E assets the traditional way under CGAAP, whereby the PP&E assets are carried at cost less accumulated depreciation less any impairment losses.
- ✦ Revaluation Model: NOW may elect PP&E assets to be carried at fair value less subsequent accumulated depreciation or impairment losses. IAS 16 defines fair value as being the amount at which an asset could be exchanged between knowledgeable, willing parties in an arm's length transaction. Management is to perform revaluations with sufficient regularity to ensure that the carrying amount does not differ materially from the fair value at the end of the reporting period.

The adoption of the revaluation policy by an entity when it has previously used the cost model is a change in accounting policy, however IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* ("IAS 8") treats this change as a revaluation during the year. As a result, no prior year adjustments to the financial statements are required.

Implications for NOW:

Management should consider the implications of applying either accounting policy in regards to the future value PP&E assets, including:

- ✦ Varying depreciation and impairment charges in future reporting periods decreasing net income;
- ✦ Ability to affect total assets;
- ✦ Selecting the revaluation model will require as much lead time as possible to ensure systems and controls can be developed, as these valuations will need to be collected on a regular and timely basis;
- ✦ PP&E costs represented on the Balance Sheet may fluctuate from period to period;
- ✦ The cost of developing and/or obtaining the valuations with regularity may weigh against the financial reporting benefits; and
- ✦ Based on international experience to date, the cost model is predominately used for subsequent measurement purposes.

Management's Conclusions:

Management has indicated that they will continue using the cost model for all PP&E assets. As a result, NOW elects to treat PP&E assets the traditional way under CGAAP, whereby the PP&E assets are carried at cost less accumulated depreciation less any impairment losses.

No differences upon Transition to IFRS.

C. INITIAL RECOGNITION OF PP&E

For PP&E, there are a number of differences between CGAAP and IFRS that companies need to assess in regards to initial recognition of an asset. Both IFRS and CGAAP require that items of PP&E be recognized at cost; however, IAS 16 has more detailed guidance than CGAAP regarding the expenditures that should be included or excluded from the cost of PP&E that can be capitalized.

IAS 16 states that, where the cost model is applied, an item of PP&E is carried at cost less any accumulated depreciation and any accumulated impairment losses.

Management should review the initial recognition under IAS 16 for the following categories – costs capitalized, cessation of capitalization, incidental income, borrowing costs and other differences.

A. Costs Capitalized

Description of Issue / Standard

IAS 16 contains more detail than CGAAP for an item of PP&E that is recognized as an asset and how its cost is determined.

Items of property, plant and equipment recognized as assets are measured initially at cost. The cost of an item of property plant and equipment is comprised of:

- ✦ its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;
- ✦ any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management; and
- ✦ the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories.

Examples of directly attributable costs (which are eligible for capitalization):

- ✦ costs of employee benefits arising directly from the construction or acquisition of the item of PP&E;
- ✦ costs of site preparation;
- ✦ initial delivery and handling costs;
- ✦ installation and assembly costs;
- ✦ costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition; and
- ✦ professional fees.

Examples of costs that are not costs of an item of PP&E:

- ✦ costs of opening a new facility;

- ↖ costs of introducing a new product or service (including costs of advertising and promotional activities);
- ↖ costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
- ↖ administration and other general overhead costs.

B. Cessation of Capitalization

Description of Issue / Standard

CGAAP allows more flexibility than IAS 16 in determining when recognition of the initial costs of an item of PP&E should cease.

Under IFRS, recognition of costs in the carrying amount of an item of PP&E ceases when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management. Therefore, costs incurred in using or redeploying an item are not included in its carrying amount.

For example, the following costs are not included in the carrying amount of an item of PP&E:

- ↖ costs incurred while an item capable of operating in the manner intended by management has yet to be brought into use or is operated at less than full capacity;
- ↖ initial operating losses, such as those incurred while demand for the item's output builds up; and
- ↖ costs of relocating or reorganizing part or all of an entity's operations.

C. Incidental Income

Description of Issue / Standard

IAS 16 requires income generated wholly and necessarily as a result of the process of bringing the asset into the location and condition for its intended use by management to be credited to the initial cost of the asset.

Incidental income from testing or operating a new asset is part of the directly attributable cost of the asset. Income and expenses from other incidental operations, which are not necessary to bring an item to the location or condition necessary for it to be capable of operating as intended, should be recognized in profit or loss. This differs from CGAAP, where incidental income or expense derived from PP&E prior to its substantial completion and readiness for use is always recognized as part of the cost of the asset.

D. Borrowing Costs

Description of Issue / Standard

IFRS requires borrowing costs related to qualifying assets to be capitalized if certain conditions are met. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. IAS 23 defines borrowing costs as "interest and other cost that an entity incurs in connection with the borrowing of funds." IAS 23R requires that all borrowing costs be capitalized if they are directly attributable to the acquisition, construction or production of a qualifying asset. This requirement to capitalize borrowing costs is permitted under CGAAP in certain situations but is not required.

Summary of Implications for NOW and Management's Conclusions:

	Application to NOW	Management's Conclusion
Costs capitalized	Cost includes mainly purchase price and costs relating to the assembly or construction on-site.	NOW measures items of PP&E at cost, which is comprised of the purchase price plus any incremental costs required to bring the asset into use. No difference will arise on transition. Initial cost per CGAAP remains appropriate under IFRS.
Cessation of capitalization	As above, capitalization ceases when the asset is available for use.	No difference on transition.
Incidental income	NOW does not earn incidental income.	No difference on transition.
Borrowing costs	NOW has not incurred borrowing costs applicable to qualifying assets.	No difference on transition.

D. COMPONENTIZATION / DEPRECIATION:

Issue

In both CGAAP and IFRS, the requirements for charging depreciation on PP&E are similar. However, when the detail is examined there are a few key differences. The differences are addressed below:

A. Componentization:

Description of Issue / Standard

IFRS requires a componentization approach, whereby significant individual components of assets which have different useful lives (or depreciation methods), are separately identified and measured. These components are then required to be depreciated separately. Although the concept does not differ greatly, between the two standards, CGAAP appears to be less prescriptive. CGAAP refers to componentizing where the component is separable and practicable. The concept of practicability is not specifically mentioned in IFRS hence a difference in practice arises. The requirement for componentization, under IFRS, may result in the requirement to maintain additional detail in the PP&E sub-ledger. However, significant parts of an asset that have the same useful economic life and depreciation method can be grouped together when determining the depreciation charge. A typical example would be an aircraft being split into its airframe and engines.

B. Residual Value:

Description of Issue / Standard

Under IAS 16, depreciation is based on allocating the cost of an asset, less its residual value, over its useful life. CGAAP requires that annual depreciation be based instead, if greater, on an allocation of cost less salvage value over the asset's entire life.

IAS 16 defines more specifically the calculation of residual value as the estimated amount that an entity would currently obtain from disposal of the asset, after deducting estimated disposal costs, if the asset were already of the age and in the condition expected at the end of its useful life.

CGAAP states that residual value is the estimated net realizable value of an item of PP&E at the end of its useful life. It is not explicit on whether this concept reflects current or future prices.

Management must assess residual value at least at each financial year-end, with any change in the calculation being treated as a change in accounting estimate under IAS 8.

C. Depreciation Method:

Description of Issue / Standard

IFRS is more explicit in requiring the depreciation method used to reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. Each part of an asset with a cost that is significant in relation to the total cost of the item must be depreciated separately, which means the initial cost must be allocated between the significant parts by the entity. The standard allows parts identified that have the same useful lives and depreciation method to be grouped for depreciation purposes.

The depreciation method adopted by NOW must reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. The decisions taken by management should be decided on an asset per asset basis.

Under both CGAAP and IFRS, Property, Plant & Equipment is depreciated over its useful life. This can be defined as either:

- a) the period over which an asset is expected to be available for use by an entity; or
- b) the number of production or similar units expected to be obtained from the asset by an entity.

IFRS states that estimates of useful life must be reviewed at each annual reporting date at minimum. Any changes are accounted for prospectively as changes in estimates. This is different to CGAAP where the useful life is reviewed "regularly".

The following factors should be considered in determining the useful life of an asset:

- a) expected usage of the asset. Usage is assessed by reference to the asset's expected capacity or physical output.
- b) expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance program, and the care and maintenance of the asset while idle.
- c) technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset.
- d) legal or similar limits on the use of the asset, such as the expiry dates of related leases.

The useful life of an asset is defined in terms of the asset's expected utility to the entity. The asset management policy of the entity may involve the disposal of assets after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset.

Therefore, the useful life of an asset may be shorter than its economic life. The estimation of the useful life of the asset is a matter of judgment based on the experience of the entity with similar assets.

The analysis performed on the PPE components including poles, conduit and distribution station includes suggested revised useful lives as stated in the OEB depreciation study report . The study suggests the minimum, maximum and typical useful life for the components. When performing the analysis of component costing, the typical useful life was used. Management may revise the useful life of the components if conditions specific to the utility suggest an alternate depreciation period.

D. Overhauls:

Description of Issue / Standard

IFRS requires the cost of major periodic overhauls to be capitalized and segregated as a separate component from all other components. The estimated useful life of the overhaul should equate the period between the current overhaul and the following overhaul.

Summary of Implications for NOW and Management's Conclusions:

	Application to NOW	Management's Conclusions
Componentization	NOW does not currently depreciate its existing components separately. Componentization will have a major impact on transition to IFRS. By their nature, distribution assets will contain components that will have different economic useful lives, and these components can be separately identified and measured.	Management has performed an analysis of all material items of PP&E to determine whether any significant components exist with a different useful life to the overall asset. Please see the PP&E Worksheets and Schedules for details of this analysis and proposed adjustment. Management has identified major components for the different distribution assets. Distribution assets have been separated into their major components as of Transition Date.
Residual value	Residual value is assumed to be nil. There is no policy in place to review residual values on an annual basis.	The depreciation methodology remains appropriate under IFRS. There are no differences on transition. A policy must be created to review the basis for having no residual values on an annual basis.
Depreciation method	NOW currently depreciates all of its PP&E assets using the straight-line method. Management should update procedures and controls to ensure that the depreciation method, useful life and residual value are reviewed at least annually and more so if expectations differ.	Management believes the current straight line depreciation policy remains appropriate on transition to IFRS. At Transition Date, management has reassessed the economic useful lives of the major components of distribution assets. All other depreciation rates were deemed appropriate. A policy will be created to review the depreciation and useful lives of PP&E on an annual basis.
Overhauls	Under IFRS the cost of major overhauls will be capitalized if the major overhaul will lead to future economic benefits.	Management to implement a policy to capitalize major overhauls as separate components and depreciate them over their estimated economic useful lives.

4.0 -VECC -29

Reference: E1/T5/S5/pg.1 & E4/T1/S1/pg.2-

- a) Please explain the rationale for including depreciation expense in OM&A.
- b) Please show the amount of “fully allocated depreciation” that is included in 2017 OM&A.

Responses:

- a) The portion of depreciation included in OM&A relates primarily to the depreciation associated with Transportation and Work Equipment (T&WE). In order to charge use of T&WE (e.g. a bucket truck) to an OM&A or capital work order, a “charge out” rate is used. This “charge out” rate is determined based on the overall annual operating costs of the truck and dividing that amount by the number of annual hours to be utilized in order to arrive at a “charge out” rate per hour. Included in the overall operating costs of the truck are vehicle maintenance and repairs, fuel and depreciation. A piece of equipment can be charged to a number of different capital and OM&A work orders depending on what it was used for (e.g. installing a new pole would be capital, responding to a line trouble call would be OM&A). As the cost of depreciation is embedded in a charge out rate it provides an accurate representation of the actual cost of undertaking a specific work project/program. To remove the depreciation component, would understate the true cost of performing a task.

If T&WE were to be rented from an external provider for a specific OM&A or Capital project, the rental charge from the vendor would include a depreciation component, it would not be appropriate to remove this depreciation component from the work order cost as it would understate the true cost of the work and from an accounting perspective could not be legitimately categorized as depreciation expense.

In addition to the above rationale, removing depreciation expense at a work program level would be cumbersome as the standard equipment charge out rate (which includes depreciation) is part of the work order costing process.

It is also noted that OEB Chapter 2 Appendix 2-BA specifies the removal of Fully Allocated Depreciation from the Depreciation Expense that is to be recovered in the calculation of Revenue Requirement.

- b) In 2017 the total amount "Fully Allocated Depreciation" is \$208,987 (T&WE: \$188,695 + Stores Equipment: \$20,292). Of this amount, \$167,190 is allocated to OM&A work and the remainder to Capital work.

4.0 -VECC -30

Reference: E4/T1/S1

- a) Please explain how the bad debt forecast for 2017 is estimated.
- b) Please provide the actual bad debt for 2016.
- c) What measures has NOW taken to reduce bad debt?

Response:

- a) The 2017 test year forecast of bad debt expense is based on a calculation of historic results comparing bad debt expense and Gross revenues including cost of electricity. The historic rate of bad debt expense to service revenue was averaged and compared for outliers (which were removed) and the resulting average was used to determine the \$75,000 bad debt expense forecast for 2017. The increase is consistent with the increasing cost of electricity which is included as part of NOW's bad debt expense.
- b) The Bad Debt Expense for 2016 is currently \$70,000 (subject to confirmation and adjustment pending closure of 2016 year-end and audit).
- c) NOW Inc. follows its internal procedures and the disconnection and payment arrangement regulations as provided in the Distribution System Code. NOW Inc. monitors overdue payment status on an ongoing basis and identifies accounts that require reminder notices and other communication regarding the overdue account. NOW Inc. works with customers to structure payment arrangements in a manner that seeks to avoid undue hardship. That being said, NOW Inc. has proceeded with the use of collection agencies and small claims courts when necessary and warranted.

Additionally, NOW Inc. is investigating whether certain riskier major consumers could provide an irrevocable letter of credit or guarantee from their bank to help mitigate the risk to NOW Inc. in the event of a bankruptcy of financial difficulty.

A significant portion of all bad debt expense is the Cost of Power which is a pass through cost which LDC's are prohibited from making a profit or loss on. NOW Inc, would like to see the industry proceed with an evaluation as to whether the uncollectible Cost of Power should be passed back to suppliers or passed back

to customers in the form of a deferral and variance account as this would help to alleviate the impact of bad debt risk on LDCs.

4.0 -VECC -31

Reference: E4/T3/S1

- a) Please update Table 5 to show the actual 2016 customer premise costs.
- b) Please explain who the 2017 customer premise costs were estimated.

Responses:

- a) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.
- b) Customer Premises costs for 2017 were forecasted based by looking at historic trends and volumes for work done at customer premises. Items that are considered include number of locates which are increasing. The number of locates forecast for 2017 is 800 which is slightly less than the 2014 number (824). The costs associated are slightly less than 2014 figures. NOW Inc. expects an active construction season and with the implementation of the outage management system, more customer premises visits will occur.

All these factors taking into account when determining the costs for the 2017 customer premise work program.

4.0 -VECC -32

Reference: E4/T3/S1

- a) Please provide a table listing for the period 2016 to 2021 any incremental OM&A costs related to the new outage management system;

Response:

- a) The following table forecasts the incremental OM&A costs related to the new outage management system from 2016-2021. NOW Inc. expects the costs to increase steadily, and in 2019 require an increase for a data refresh to ensure that the system is being optimized.

The costs included in the table relate to third party costs associated with the outage management system.

	2016	2017	2018	2019	2020	2021
OMS Costs	\$ -	\$ 30,000	\$ 31,500	\$ 35,000	\$ 33,075	\$ 34,729

4.0 -VECC -33

Reference: E4/T3/S1/ Table 14

- a) Please explain the reduction in tree trimming and vegetation control in 2014 and 2015 as compared to prior and subsequent years.
- b) Please provide the actual 2016 tree trimming OM&A.

Response:

- a) Please see response to 4-SEC-24.
- b) NOW Inc. is in the process of completing year-end financial activities and Actual results for 2016 are not yet available. This information will be provided in a supplementary filing on February 17, 2017. Please note that this information will be unaudited.

4.0 -VECC -34

Reference: E4/T3/S1/Table 18

- a) Please provide the actual 2016 bad debt expense.
- b) Please show the derivation of the 2017 bad debt expense forecast.
- c) Please explain how the collection of customer deposits might be detrimental to objective of reducing bad debt expenses.

Response:

- a) Please refer to 4-VECC-30 b).
- b) Please refer to 4-VECC-30 a).
- c) Currently NOW Inc. collects a deposit and it has to be applied to the account if the customer is being disconnected. Applying the deposit to the account prior to disconnection may not cover the full arrears, but the disconnection has to be deferred as a partial payment is deemed to have been made. In many cases this extends the length of time until a future disconnection occurs. The disconnection process does not occur until 30 days or more after the due date, resulting in further consumption and another bill being processed. Additionally, since the billing is a month behind, two months of electricity has been used and not paid for.

NOW Inc. could reduce bad debt expenses if it collected a deposit from each customer and didn't return it until the customer moved out of the residence. At that time the deposit would go towards the Final Bill and the customer would get back any monies left or pay the remaining amount.

4.0-VECC- 35

Reference: E4/T3/S1/pg.27

- a) If NOW receives any insurance products through MEARIE please provide the annual costs of these premiums for the same period.

Responses:

- a) NOW Inc. receives automobile and liability insurance through MEARIE as follows:

MEARIE Insurance		
Year	Automobile Cost	Liability Cost
2013	\$11,065	\$19,968
2014	\$11,452	\$18,440
2015	\$10,556	\$17,290
2016	\$11,566	\$20,854
2017	\$12,607	\$22,006

4.0-VECC-36

Reference: E4/T2/Attachment 1 Appendix 2-k

- a) Please amend Appendix 2-K to show the total compensation capitalized in each year.

Response:

- a) Please see the following amended Appendix 2-K which identifies total compensation capitalized each year:

Appendix 2-K						
Employee Costs						
	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Number of Employees (FTEs including Part-Time)¹						
Management (including executive)	4.2	4.5	4.5	3.5	3.5	3.5
Non-Management (union and non-union)	14.6	14.0	13.6	12.6	12.2	13.2
Total	18.8	18.5	18.1	16.1	15.7	16.7
Total Salary and Wages including overtime and incentive pay						
Management (including executive)	\$ 343,682	\$ 409,460	\$ 459,366	\$ 328,853	\$ 337,749	\$ 345,411
Non-Management (union and non-union)	\$ 922,279	\$ 920,392	\$ 939,014	\$ 933,605	\$ 900,235	\$ 1,001,414
Total	\$ 1,265,961	\$ 1,329,852	\$ 1,398,380	\$ 1,262,458	\$ 1,237,984	\$ 1,346,825
Total Benefits (Current + Accrued)²						
Management (including executive)	\$ 114,208	\$ 117,493	\$ 141,048	\$ 87,864	\$ 94,404	\$ 95,772
Non-Management (union and non-union)	\$ 280,334	\$ 136,557	\$ 211,500	\$ 231,702	\$ 276,084	\$ 301,776
Total	\$ 394,542	\$ 254,050	\$ 352,549	\$ 319,565	\$ 370,488	\$ 397,548
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	\$ 457,890	\$ 526,953	\$ 600,414	\$ 416,717	\$ 432,153	\$ 441,183
Non-Management (union and non-union)	\$ 1,202,613	\$ 1,056,949	\$ 1,150,514	\$ 1,165,307	\$ 1,176,319	\$ 1,303,190
Total	\$ 1,660,503	\$ 1,583,902	\$ 1,750,928	\$ 1,582,024	\$ 1,608,472	\$ 1,744,373
Total Compensation Capitalized	\$ 273,580	\$ 143,316	\$ 388,441	\$ 330,727	\$ 283,041	\$ 251,173

4.0-VECC-37

Reference: E4/T3/S3/pg.4 & Appendix 2-N

- a) What adjustments were made to the Management fee as a result of the elimination of the shared CEO position in 2014?
- b) What is the reason for the large reduction in the Credit for services provided by NOW management in 2013 (\$102,283) as compared to subsequent years (69k-51.7k)?
- c) The Service Agreement indicates a revision as of January 1, 2016. Please explain any revisions to the agreement previously reviewed in the last cost of service filing.

Responses:

- a) The Management fee percentage remained at 12% as this position was paid directly by Northern Ontario Wires Inc. The Management fees were higher by \$4,190 in 2014 $((\$102,283 - \$67,375) \times .12)$ as the credit for the CEO salary was reduced.
- b) The reduction in credit relates to CTS no longer needing the services of NOW Inc.'s CEO.
- c) The revisions are primarily housekeeping items and changes to reflect current practices and services.

A summary of changes is as follows:

- 1. Addition of parts E and F in introduction
- 2. Change of wording from PUC to CTS throughout the entire document
- 3. Amendments to Section 5 to reflect current services
- 4. Amendments to Section 8 to reflect current practice
- 5. Amendments to Schedule B to reflect current services

4.0-VECC-38

Reference: E4/T3/S5

- a) Who prepared the application filing for NOW?
- b) What are the actual application costs as of year-end 2016?
- c) Please explain what the incremental costs of 10k are for.

Responses:

- a) The application filing was prepared by Northern Ontario Wires staff, primarily by Mr. Geoff Sutton (CFO) with contributions from other staff. In addition, consultant support was provided by Elenchus Research Associates and Metsco.
- b) Application costs of Northern Ontario Wires staff have not been recorded. External costs incurred as of year-end 2016 are unaudited and are currently approximately \$153k.
- c) Incremental costs of \$10K in 2017 relate to expected costs associated with travel and accommodation for Northern Ontario Wires staff to attend in Toronto the following events related to this proceeding: Technical Conference, Settlement Conference, Presentation Day, Oral Hearing, and other incremental expenses related to this proceeding.

4.0-VECC-39

Reference: E4/T4/S1/pg.4

- a) Were the adjusted asset service lives shown in Table 1 at the above reference reviewed as part of the 2013 cost of service applications, or is 2017 the first year for the adjustments to be implemented?
- b) If not, please file the consultant study which supports the deviations in asset lives from the Kinectric ranges.

Responses:

- a) The adjusted asset service lives in Table 1 at the above reference were reviewed and implemented as a part of the 2013 cost of service application.
- b) Not applicable.

4.0 -VECC -40

Reference: E4/T6/S1

- a) Please indicate any previous applications NOW has made for LRAMVA refund/recovery (i.e., what years' of program activity and for which calendar years) and the approvals obtained.
- b) Please confirm that the current application is for the refund/recovery of LRAMVA balances associated with the impact of 2011-2014 CDM programs in the calendar years 2012-2014.

Responses:

- a) The last application that NOW Inc. has made for LRAMVA was the 2013 Cost of Service Application (EB-2012-0153). The Program activity was for the 2011 to 2013. This included some persistence into 2014.
- b) The current application is for the recovery of the impact of 2011 through 2014 CDM program results as it has an effect on the 2012 through 2014 calendar years.

4.0 -VECC -41

Reference: E4/T6/S1, page 2 and Attachment 1 (Burman Report)

EB-2012-0153, Settlement Agreement, page 20 of 41

- a) Please explain the basis of the 1,233,666 kWh LRAMVA baseline when the Board approved (as part of NOW's 2013 COS Rate Decision) a baseline of 1,816,198 kWh.
- b) Please explain why the LRAMVA baseline was used in the calculation of the LRAMVA amount for the 2012 calendar year.
- c) If not provided in response to previous interrogatories, please provide a copy of the IESO report regarding NOW's verified CDM savings for the period 2011-2014.
- d) Please provide a completed copy of the Board's LRAMVA Work Form (as updated August 4, 2016). Alternatively, please provide a working excel version of the LRAMVA calculations from the Burman Report (page 12).

Responses:

- a) The figures used by Burman Energy came from the document EB-2012-0153, section 3.3 Settlement Table #7: CDM Adjusted Forecast kWh & Settlement Table #8: CDM Adjusted Forecast kW. In the case of Settlement Table #7 the values of the residential rate class (445,995kWh), GS<50 rate class (208,824), and GS>50 rate class (568,847) added together result in the basis of 1,223,666 kWh. These figures were selected in error by Burman Energy as typically when receiving the CDM portion of the load forecast from a distributor the wording matches the title used in these tables (CDM Adjusted Forecast). It was brought to Burman Energy's attention on January 26th, 2017 that the proper figures to use should have come from Settlement Table #10: LRAMVA Allocation per Customer Class – kWh and Settlement Table #11: LRAMVA Allocation per Customer Class – kW. Each table is provided below for context, the impact of this correction will be included in the update of rate impacts to be provided on February 17, 2017:

Settlement Table #7: CDM Adjusted Forecast kWh

	Weather Normalized 2013F (Elenchus)	CDM Load Forecast Adjustment	2013 CDM Adjusted Load Forecast
kWh			
Residential (kWh)	42,936,585	36%	445,995
GS<50 (kWh)	20,103,818	17%	208,824
GS>50 (kW)	54,763,722	46%	568,847
USL (kWh)	127,637	0%	1,326
Street Lights (kW)	1,610,563	1%	16,729
Total Customer (kWh)	119,542,325	100%	1,241,722

Settlement Table #8: CDM Adjusted Forecast kW

	Weather Normalized 2013F (Elenchus)	CDM Load Forecast Adjustment	2013 CDM Adjusted Load Forecast
kW			
Residential (kWh)	-	0%	-
GS<50 (kWh)	-	0%	-
GS>50 (kW)	190,364	98%	1,977
USL (kWh)	-	0%	-
Street Lights (kW)	4,315	2%	45
Total Customer (kWh)	194,679	100%	2,022

Settlement Table #10: LRAMVA Allocation per Customer Class - kWh

	Weather Normalized 2013F (Elenchus)	CDM Load Forecast Adjustment	2013 CDM Adjusted Load Forecast
kWh			
Residential (kWh)	42,936,585	36%	658,968
GS<50 (kWh)	20,103,818	17%	308,543
GS>50 (kW)	53,559,928	45%	822,010
Street Lights (kW)	1,610,563	1%	24,718
USL (kWh)	127,637	0%	1,959
Total Customer (kWh)	118,338,531	100%	1,816,198

Settlement Table #11: LRAMVA Allocation per Customer Class - kW

	Weather Normalized 2013F (Elenchus)	CDM Load Forecast Adjustment	2013 CDM Adjusted Load Forecast
kW			
Residential (kWh)	-	0%	-
GS<50 (kWh)	-	0%	-
GS>50 (kW)	190,364	98%	1,037
Street Lights (kW)	4,315	2%	23
USL (kWh)	-	0%	-
Total Customer (kWh)	194,679	100%	1,060

- b) The original figures as outlined in response “a” were incorrectly attributed to the 2012 calendar year. As the 2009 forecast did not include a CDM component the 2012 calendar year should not have a baseline at all. A new report dated 2017-01-26 has been included which will replace the original document from 2016-08-25 (EB-2016-0096 – Exhibit 4 – Tab 6 – Schedule 1 – Attachment 1). The overall results of the updated forecast figures as specified in response “a” and removing the forecast allocation from the 2012 calendar year is reflected in the following tables:

Table 1: Original (2016-08-25) LRAMVA Summary

Results	Lost Revenue Adjustment Mechanism Year					
Year	2012	2013	2014			
2014	\$ -	\$ -	\$ 14,786			
2013	\$ -	\$ 8,750	\$ 9,140			
2012	\$ 6,352	\$ 6,814	\$ 7,235			
2011	\$ 3,186	\$ 3,460	\$ 2,937			
Total	\$ 9,538	\$ 19,024	\$ 34,099			
Forecast	\$ 10,173	\$ 11,078	\$ 11,871			
Net	\$ (634)	\$ 7,946	\$ 22,228			
Variance				\$ 29,540		

Table 2: Updated (2017-01-26) LRAMVA Summary

Results Year	Lost Revenue Adjustment Mechanism Year					
	2012	2013	2014			
2014	\$ -	\$ -	\$ 14,786			
2013	\$ -	\$ 8,750	\$ 9,140			
2012	\$ 6,352	\$ 6,814	\$ 7,235			
2011	\$ 3,186	\$ 3,460	\$ 2,937			
Total	\$ 9,538	\$ 19,024	\$ 34,099			
Forecast	\$ -	\$ 14,872	\$ 15,882			
Net	\$ 9,538	\$ 4,152	\$ 18,217			
Variance				\$ 31,907		

Table 3: CDM Forecast Adjustments by Calendar Year

	Original (2016-08-25)	Updated (2017-01-26)	Net Change
2012	\$ 10,172.67	\$ 0.00	\$ -10,172.67
2013	\$ 11,078.22	\$ 14,872.30	\$ 3,794.08
2014	\$ 11,870.75	\$ 15,881.97	\$ 4,011.22
Total	\$ 33,121.64	\$ 30,754.27	\$ -2,367.37

Table 4: Overall Eligible LRAMVA Claim Comparison

	Original (2016-08-25)	Updated (2017-01-26)	Net Change
2012	\$ -634.32	\$ 9,538.35	\$ 10,172.67
2013	\$ 7,945.66	\$ 4,151.58	\$ -3,794.08
2014	\$ 22,228.28	\$ 18,217.06	\$ -4,011.22
Total	\$ 29,539.62	\$ 31,906.99	\$ 2,367.37

The overall resulting change increased the originally indicated LRAMVA of \$29,539.62 to \$31,906.99 an overall increase of \$2,367.37.

- c) 2011-2014 and 2015 Final Verified CDM results are provided in response 3-VECC-26 Attachments 1, 2 and 3 respectively.
- d) Working excel version of calculations included as attachment "NOW-IR-VECC-41-d.xlsx". This document shows source figures for persistence and rate classes as retrieved from the IESO or OEB respectively.

NORTHERN ONTARIO WIRES INC.

LRAMVA SUPPORT

January 26, 2017

PREPARED BY: JARRETT URECH, CET

REVIEWED BY: BART BURMAN, MBA BA.SC. P.ENG

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Executive Summary

Burman Energy Consultants group has calculated Northern Ontario Wires's LRAMVA value for the period of 2012 through 2014 to be a total of \$31,906.99 . This number was derived by calculating the total LRAM value of \$62,661.26 and subtracting the forecasted lost revenue already collected of \$30,754.27 .

Introduction

Since the completion of Third Tranche CDM programs and reporting, LDCs across Ontario have sought to recover revenues lost to successful CDM programming. The mechanism that enables this recovery is the Lost Revenue Adjustment Mechanism (LRAM).

On April 26, 2012, new Board-issued CDM Guidelines were enacted that provide updated LRAM details. For CDM programs delivered within the 2011 to 2014 term, the Board established the Lost Revenue Adjustment Variance Account (LRAMVA). This account captures the variance between the Board-approved CDM forecast and the actual CDM results.

The variance calculated from this comparison must be recorded in separate sub-accounts per the applicable customer rate classes.

LDCs must apply for the disposition of the balance in the LRAMVA as part of their cost of service (COS) applications or on an annual basis, as part of their IRM rate applications.

The LRAM mechanism determines persistent CDM impacts realized after 2010, for those distributors whose load forecast has not been updated.

Terms

Term	Description
Persistence	CDM savings during the subsequent years after the first year savings.
Extension Framework	The conservation period between 2011 and 2015
Conservation First Framework	The conservation period between 2015 and 2020.
CDM	Conservation and Demand Management
LRAM	Lost Revenue Adjustment Mechanism
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
COS	Cost of Service
IRM	Incentive Regulation Model

Scope of Work

Specifically, Burman Energy will perform the following in its work undertaking:

- 1) Collect and outline savings for the following data sets:
 - i. CDM Results for programs as applicable for the LRAMVA period.
 - ii. Forecasted savings for Conservation and Demand Management programs (Last Approved).
- 2) Collect additional data as outlined:
 - i. LDC volumetric distribution rates for LRAMVA years.
 - ii. Completed Retrofit projects for years for which retrofit savings are reported.
- 3) Calculate by initiative and year the lost revenue values.
- 4) Calculate the currently recovered lost revenue from the load forecast.
- 5) Outline the net LRAMVA values by year and overall.
- 6) Provide summary report with supporting information.

About Burman Energy Consultants Group Inc.

Burman Energy is a vibrant, growing company, and has provided energy conservation program planning, administration and delivery services since the inception of IESO programs in 2007. Serving 39 CDM client LDCs in Ontario, we currently have over 30 staff with specialized expertise in CDM planning and program administration, marketing, technical review and support, quality control, and contractor management. In 2013, Bart Burman, President of Burman Energy, was inducted into Worldwide Who's Who for Excellence in Energy Consulting, and in 2014/15, Bart sits as chair of the EDA's Commercial Steering Committee.

Burman Energy has adopted a new structured approach to fulfilling its contracted obligations with our numerous and diverse LDC CDM clients. Recognizing, in practice, the significant peaks and valleys associated with sustaining a consistent high standard of service on time delivery, our organizational focus continues to be to ensure adequate and flexible staff resources. Cross training in several different aspects of program execution has historically enabled us to make this approach extremely effective in meeting our clients' timeliness criteria.

As a process centric organization, our starting point is to use stock, off the shelf, proven process designs, and adjust collaboratively, in discussion with you, our client, for your specific LDC protocols as required. From this common basis for understanding, identification of roles and associated accountabilities can be easily determined. In addition, this work, up front, provides for a more solid basis upon which to convey pricing options.

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Lost Revenue Adjustment Mechanism History

From 2005 to the end of 2010, distributors delivered CDM programs either through approved distribution rate funding by way of the third installment of their incremental market adjusted revenue requirement ("MARR"), or through contracts with the IESO. Some distributors received incremental distribution rate funding separate from MARR. To promote the participation in and the delivery of CDM programs by distributors, the Board made available an LRAM regardless of whether the CDM programs were funded by the IESO or through distribution rates.

Lost Revenue Adjustment Mechanism Outline

In preparation of this document, Burman Energy performed this analysis in compliance with Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003 with specific reference to the following:

13.6 LRAM & Shared Savings Mechanism for Pre-CDM Code Activities

The Board notes that the Filing Requirements for Transmission and Distribution Applications state the following:

Distributors intending to file an LRAM or SSM application for CDM Programs funded through distribution rates, or an LRAM application for CDM Programs funded by the IESO between 2005 and 2010, shall do so as part of their 2012 rate application filings, either cost-of-service or IRM. If a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for this legacy period of CDM activity.

The 2008 CDM Guidelines state as follows: "lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the CDM savings would be assumed to be incorporated in the load forecast at that time". The intent of the LRAM in the 2008 CDM Guidelines was to keep electricity distributors revenue neutral for CDM activities implemented by the distributor during the years in which its rates were set using the incentive regulation mechanism, and that future LRAM claims should be unnecessary once a distributor rebases and updates its load forecast.

The Board therefore expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:

http://www.ontarioenergyboard.ca/oeb/Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Lost Revenue Adjustment Mechanism Variance Account Outline

With specific reference to the following:

13.2 LRAM Mechanism for 2011- 2014

The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account ("LRAMVA") to capture, at the customer rate-class level, the difference between the following:

- i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and IESO-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and
- ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third party for each year of the CDM program (i.e., 2011 to 2014) in accordance with the IESO's EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor's Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Summary Of Lost Revenue Adjustments

LRAMVA Summary

Burman Energy Consultants Group Inc. (Burman Energy) has prepared the following LRAMVA tables, representing the variance amount to be recorded in the LRAM Variance Account. The amount is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by Northern Ontario Wires's Board-approved variable distribution changes applicable to the customer rate class in which the volumetric variance occurred. The calculations provided by Burman Energy do not include carrying charges or adjustments based on CDM reductions as included in any CDM Load reduction forecast.

Results Year	Lost Revenue Adjustment Mechanism Year					
	2012	2013	2014			
2014	\$ -	\$ -	\$ 14,786			
2013	\$ -	\$ 8,750	\$ 9,140			
2012	\$ 6,352	\$ 6,814	\$ 7,235			
2011	\$ 3,186	\$ 3,460	\$ 2,937			
Total	\$ 9,538	\$ 19,024	\$ 34,099			
Forecast	\$ -	\$ 14,872	\$ 15,882			
Net	\$ 9,538	\$ 4,152	\$ 18,217			
Variance				\$ 31,907		

Results Year	Lost Revenue Adjustment Mechanism Summary By Rate Class					
	Residential	GS <= 50 kW	GS > 50 kW			Total
2014	\$ 7,420	\$ 25,700	\$ 980			\$ 34,099
2013	\$ 4,415	\$ 13,887	\$ 722			\$ 19,024
2012	\$ 1,785	\$ 7,249	\$ 504			\$ 9,538
Total	\$ 13,620	\$ 46,835	\$ 2,206			\$ 62,661
Forecast	\$ 19,906	\$ 9,112	\$ 1,736			\$ 30,754
Net	\$ (6,286)	\$ 37,723	\$ 470			\$ 31,907



Reference Material

The following IESO documents were used to prepare the LRAMVA calculations:

- i. [2006-2014]_RATES_DATABASE_FROM TARIFFS.xls
- ii. 2011-2014 Northern Ontario Wires Results with Persistence.xls
- iii. Northern Ontario Wires [2012-2014] Retrofit Project Lists

Methodology

Burman Energy would like to present a summary of the methodology used to calculate the LRAMVA figures in this report for the purposes of auditing.

Burman Energy collects the following information as the sources for the values calculated in this report:

- Rate Database documents from the Ontario Energy Board (OEB) website for all years that are being calculated.
- Final CDM results and their persistence into future years received directly from the IESO or from the Local Distributor.
- Retrofit & High Performance New Construction (HPNC) project data with kW, kWh and Rate Class information for each project.
- The forecasted CDM results from the distributors most recently approved Cost of Service application (COS).

Burman Energy takes the results of each initiative where the savings for the LRAMVA report period are not equal to zero and enters the figures into the report. The values entered into the report are organized by results year, rate class, and then initiative. The rate classes outlined here are examples and may not be actual customer classes for this local distribution company.

Results from 2014
Residential
HVAC Incentives
RESIDENTIAL TOTAL
GS Less Than 50 kW
Retrofit
GS LESS THAN 50 KW TOTAL
GS Greater Than 50 kW
Retrofit
GS GREATER THAN 50 KW TOTAL
Large Use
Retrofit
LARGE USE TOTAL
RESULTS FROM 2014 TOTAL

The results for Retrofit and HPNC items are initially collected for all rate classes then using verified project

savings the result savings are divided into the appropriate rate classes.

Year	Application Type	LDC	Demand Savings	Energy Savings	Rate Class	Sector
2014	Retrofit	northern Ontario Wires	24.39	103,433	GS>50	Industrial
2014	Retrofit	northern Ontario Wires	1.80	427,112	GS<50	Business

kW	GS>50	93.13%	GS<50	6.87%	Large Use	0.00%
kWh		19.50%		80.50%		0.00%

Volumetric distribution rates are derived by using the rate database provided on the OEB website directly as they appear. These volumetric distribution rates are collected for each rate class for the years during the LRAMVA reporting period and one year prior are entered into the report along with their effective date. Burman Energy uses the effective date to create a weighted volumetric rate for each of the calendar years (Jan1st through Dec 31st) years in the reporting period. A summary of the calculation is presented below:

$$\text{Weighted Rate} = \left(\text{Rate}_{\text{old}} * \left(\frac{\text{Months at Old}}{12} \right) \right) + \left(\text{Rate}_{\text{new}} * \left(\frac{\text{Months at New}}{12} \right) \right)$$

The weighted volumetric rate is multiplied by the savings metric selected by rate class (the Residential and GS<50 metric is kWh and the GS>50 and Large Use metric is kW). The resulting figure is then subject to global modifiers based on initiative (eg. Demand Response 3 is taken at a factor of 0% due to the type of savings it provides).

$$\text{LRAM}(kW) = \text{Weighted Rate} * \text{Modifier}\%_{\text{If Applicable}} * ((kW_{\text{Per Month}} * \text{Months at old Rate}) + (kW_{\text{Per Month}} * \text{Months at New Rate}))$$

$$\text{LRAM}(kWh) = \text{Weighted Rate} * \text{Modifier}\%_{\text{If Applicable}} * kWh_{\text{Annual}}$$

The totals are outlined at the bottom of each section with a summary by rate class presented near the bottom of the table for comparison to the forecasted figures.

If the distributor had forecasted CDM savings Burman Energy takes the values and applies same methods outlined for the savings results to calculate the total lost revenue that has already been recovered for the reporting period.

The recovered lost revenue is subtracted from the calculated LRAM resulting in the net figures or Variance. These figures are outlined by reporting period year and as an overall.

Supporting Attachments

Northern Ontario Wires Inc. LRAMVA CALCULATIONS
OPA Conservation & Demand Management Programs
Initiative Results at End-User Level

	2011	2012				2013				2014			
Initiative Name	Volumetric Rate	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: Feb 1)	2012 LRAMVA	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: Jun 1)	2013 LRAMVA	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: May 1)	2014 LRAMVA
LRAM CDM Results and Persistence													
Results from 2014													
Residential													
Appliance Exchange	0.0134			0.0135				0.0154		0.41	738.88	0.0157	\$ 11.53
Appliance Retirement	0.0134			0.0135				0.0154		2.19	14,541.74	0.0157	\$ 226.85
Bi-Annual Retailer Event	0.0134			0.0135				0.0154		8.54	130,450.00	0.0157	\$ 2,035.02
Conservation Instant Coupon Booklet	0.0134			0.0135				0.0154		2.26	30,293.81	0.0157	\$ 472.58
Home Assistance Program	0.0134			0.0135				0.0154		0.10	1,692.70	0.0157	\$ 26.41
HVAC Incentives	0.0134			0.0135				0.0154		3.38	6,490.77	0.0157	\$ 101.26
RESIDENTIAL TOTAL		0.00	0		\$ -	0.00	0		\$ -	16.89	184,208		\$ 2,873.64
GS Less Than 50 kW													
Direct Install Lighting	0.0133			0.0134				0.015		130.71	482,772.06	0.0153	\$ 7,338.14
Retrofit	0.0133			0.0134				0.015		1.26	289,101.91	0.0153	\$ 4,394.35
Time-of-Use Savings	0.0133			0.0134				0.015		43.67	0.00	0.0153	\$ -
GS LESS THAN 50 KW TOTAL		0.00	0		\$ -	0.00	0		\$ -	175.64	771,874		\$ 11,732.48
GS Greater Than 50 kW													
Retrofit	0.6806			0.688				0.8698		17.06	70,011.42	0.8846	\$ 180.07
GS GREATER THAN 50 KW TOTAL		0.00	0		\$ -	0.00	0		\$ -	17.06	70,011		\$ 180.07
RESULTS FROM 2014 TOTAL		0.00	0		\$ -	0.00	0		\$ -	209.58	1,026,093		\$ 14,786.20
Results from 2013													
Residential													
Annual Coupons	0.0134			0.0135		0.55	8,180.88	0.0154	\$ 119.51	0.55	8,180.88	0.0157	\$ 127.62
Appliance Exchange	0.0134			0.0135		0.21	369.44	0.0154	\$ 5.40	0.21	369.44	0.0157	\$ 5.76
Appliance Retirement	0.0134			0.0135		1.68	11,768.69	0.0154	\$ 171.92	1.68	11,768.69	0.0157	\$ 183.59
Bi-Annual Retailer Events	0.0134			0.0135		1.26	18,234.82	0.0154	\$ 266.38	1.26	18,234.82	0.0157	\$ 284.46
Conservation Instant Coupon Booklet	0.0134			0.0135		0.00	25.00	0.0154	\$ 0.37	0.00	25.00	0.0157	\$ 0.39
Home Assistance Program	0.0134			0.0135		10.88	129,810.28	0.0154	\$ 1,896.31	10.33	119,324.25	0.0157	\$ 1,861.46
HVAC	0.0134			0.0135		0.79	1,531.66	0.0154	\$ 22.37	0.79	1,531.66	0.0157	\$ 23.89
RESIDENTIAL TOTAL		0.00	0		\$ -	15.37	169,921		\$ 2,482.26	14.82	159,435		\$ 2,487.18
GS Less Than 50 kW													
Energy Audit	0.0133			0.0134		0.01	64.27	0.015	\$ 0.92	0.01	64.27	0.0153	\$ 0.98
Energy Audit Funding	0.0133			0.0134		17.63	96,901.54	0.015	\$ 1,388.92	17.63	96,901.54	0.0153	\$ 1,472.90
Retrofit	0.0133			0.0134		4.27	20,517.91	0.015	\$ 294.09	4.27	20,517.91	0.0153	\$ 311.87
Small Business Lighting	0.0133			0.0134		87.11	310,069.49	0.015	\$ 4,444.33	87.11	310,069.49	0.0153	\$ 4,713.06
GS LESS THAN 50 KW TOTAL		0.00	0		\$ -	109.02	427,553		\$ 6,128.26	109.02	427,553		\$ 6,498.81
GS Greater Than 50 kW													
Retrofit	0.6806			0.688		14.62	71,535.09	0.8698	\$ 139.28	14.62	71,535.09	0.8846	\$ 154.30
GS GREATER THAN 50 KW TOTAL		0.00	0		\$ -	14.62	71,535		\$ 139.28	14.62	71,535		\$ 154.30
RESULTS FROM 2013 TOTAL		0.00	0		\$ -	139.01	669,009		\$ 8,749.80	138.46	658,523		\$ 9,140.29
Results from 2012													
Residential													
Appliance Exchange	0.0134	1.33	2,297.79	0.0135	\$ 31.00	1.33	2,297.79	0.0154	\$ 33.57	1.33	2,297.79	0.0157	\$ 35.85
Appliance Retirement	0.0134	2.07	15,584.64	0.0135	\$ 210.26	2.07	15,584.64	0.0154	\$ 227.67	2.07	15,584.64	0.0157	\$ 243.12
Bi-Annual Retailer Event	0.0134	1.57	28,426.29	0.0135	\$ 383.52	1.57	28,426.29	0.0154	\$ 415.26	1.57	28,426.29	0.0157	\$ 443.45
Conservation Instant Coupon Booklet	0.0134	0.24	1,484.06	0.0135	\$ 20.02	0.24	1,484.06	0.0154	\$ 21.68	0.24	1,484.06	0.0157	\$ 23.15
HVAC	0.0134	0.00	8.81	0.0135	\$ 0.12	0.00	8.81	0.0154	\$ 0.13	0.00	8.81	0.0157	\$ 0.14
HVAC Incentives	0.0134	0.22	373.65	0.0135	\$ 5.04	0.22	373.65	0.0154	\$ 5.46	0.22	373.65	0.0157	\$ 5.83
RESIDENTIAL TOTAL		5.44	48,175		\$ 649.96	5.44	48,175		\$ 703.76	5.44	48,175		\$ 751.53
GS Less Than 50 kW													
Direct Install Lighting	0.0133	85.28	315,820.16	0.0134	\$ 4,229.36	85.28	315,820.16	0.015	\$ 4,526.76	85.28	315,820.16	0.0153	\$ 4,800.47
Energy Audit	0.0133	16.22	78,945.00	0.0134	\$ 1,057.21	16.22	78,945.00	0.015	\$ 1,131.55	16.22	78,945.00	0.0153	\$ 1,199.96
Energy Audit Funding	0.0133	5.18	25,176.25	0.0134	\$ 337.15	5.18	25,176.25	0.015	\$ 360.86	5.18	25,176.25	0.0153	\$ 382.68
GS LESS THAN 50 KW TOTAL		106.68	419,941		\$ 5,623.72	106.68	419,941		\$ 6,019.16	106.68	419,941		\$ 6,383.11
GS Greater Than 50 kW													
Retrofit	0.6806	9.55	6,483.83	0.688	\$ 78.80	9.55	6,483.83	0.8698	\$ 91.03	9.55	6,483.83	0.8846	\$ 100.84
GS GREATER THAN 50 KW TOTAL		9.55	6,484		\$ 78.80	9.55	6,484		\$ 91.03	9.55	6,484		\$ 100.84
RESULTS FROM 2012 TOTAL		121.67	474,600		\$ 6,352.48	121.67	474,600		\$ 6,813.95	121.67	474,600		\$ 7,235.49
Results from 2011													
Residential													
Appliance Exchange	0.0134	0.59	824.40	0.0135	\$ 11.12	0.59	824.40	0.0154	\$ 12.04	0.33	590.14	0.0157	\$ 9.21
Appliance Retirement	0.0134	3.88	28,618.46	0.0135	\$ 386.11	3.88	28,618.46	0.0154	\$ 418.07	3.77	28,517.37	0.0157	\$ 444.87
Bi-Annual Retailer Event	0.0134	1.90	33,509.57	0.0135	\$ 452.10	1.90	33,509.57	0.0154	\$ 489.52	1.90	33,509.57	0.0157	\$ 522.75
Conservation Instant Coupon Booklet	0.0134	1.26	20,550.91	0.0135	\$ 277.27	1.26	20,550.91	0.0154	\$ 300.21	1.26	20,550.91	0.0157	\$ 320.59
HVAC Incentives	0.0134	0.34	634.63	0.0135	\$ 8.56	0.34	634.63	0.0154	\$ 9.27	0.34	634.63	0.0157	\$ 9.90
RESIDENTIAL TOTAL		7.97	84,138		\$ 1,135.16	7.97	84,138		\$ 1,229.12	7.60	83,803		\$ 1,307.32
GS Less Than 50 kW													
Direct Install Lighting	0.0133	46.60	121,356.33	0.0134	\$ 1,625.16	46.60	121,356.33	0.015	\$ 1,739.44	29.96	71,391.86	0.0153	\$ 1,085.16
GS LESS THAN 50 KW TOTAL		46.60	121,356		\$ 1,625.16	46.60	121,356		\$ 1,739.44	29.96	71,392		\$ 1,085.16
GS Greater Than 50 kW													
Retrofit	0.6806	51.59	298,320.55	0.688	\$ 425.55	51.59	298,320.55	0.8698	\$ 491.58	51.59	298,320.55	0.8846	\$ 544.58
GS GREATER THAN 50 KW TOTAL		51.59	298,321		\$ 425.55	51.59	298,321		\$ 491.58	51.59	298,321		\$ 544.58
RESULTS FROM 2011 TOTAL		106.16	503,815		\$ 3,185.87	106.16	503,815		\$ 3,460.14	89.15	453,515		\$ 2,937.06
Summary By Rate Class													
Residential	0.0134	13.41	132,313.20	0.0135	\$ 1,785.13	28.78	302,233.98	0.0154	\$ 4,415.13	44.75	475,620.50	0.0157	\$ 7,419.68
General Service Less Than 50 kW	0.0133	153.28	541,297.75	0.0134	\$ 7,248.88	262.30	968,850.95	0.015	\$ 13,886.86	421.30	1,690,760.46	0.0153	\$ 25,699.56
General Service Greater Than 50 kW	0.6806	61.14	304,804.38	0.688	\$ 504.35	75.76	376,339.47	0.8698	\$ 721.89	92.82	446,350.89	0.8846	\$ 979.79
SUMMARY BY RATE CLASS TOTAL		227.83	978,415		\$ 9,538.35	366.84	1,647,424		\$ 19,023.88	558.87	2,612,732		\$ 34,099.03
LRAM CDM RESULTS AND PERSISTENCE TOTAL													
		227.83	978,415.33		\$ 9,538.35	366.84	1,647,424.40		\$ 19,023.88	558.87	2,612,731.85		\$ 34,099.03
Load Forecast CDM Component													
Residential	0.0134	0.00	0.00	0.0135	\$ -	0.00	658,968.00	0.0154	\$ 9,626.42	0.00	658,968.00	0.0157	\$ 10,279.90
General Service Less Than 50 kW	0.0133	0.00	0.00	0.0134	\$ -	0.00	308,543.00	0.015	\$ 4,422.45	0.00	308,543.00	0.0153	\$ 4,689.85
General Service Greater Than 50 kW	0.6806	0.00	0.00	0.688	\$ -	1,037.00	822,010.00	0.8698	\$ 823.43	1,037.00	822,010.00	0.8846	\$ 912.21
LOAD FORECAST CDM COMPONENT TOTAL		0.00	0.00		\$ -	1,037.00	1,789,521.00		\$ 14,872.30	1,037.00	1,789,521.00		\$ 15,881.97
NORTHERN ONTARIO WIRES INC. NET LRAMVA TOTAL (LRAM MINUS FORECAST)													
		227.83	978,415.33		\$ 9,538.35	-670.16	-142,096.60		\$ 4,151.58	-478.13	823,210.85		\$ 18,217.06
Lost Revenue Adjustment Mechanism Variance													\$31,906.99

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/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/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)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 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.
2	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 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 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. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	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 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. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA 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
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; 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 a 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				
9	Efficiency: Equipment Replacement	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).
10	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).
11	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).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions.	Savings are considered to begin in the year of the actual project completion date.	
13	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
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA 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.
15	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 of the relevant year, 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				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system.	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).
17	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).
18	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
19	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).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, 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				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; reported results are presented with forecast assumptions as per the business case.	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.
Legacy Programs Completed in Current Year				
22	Electricity Retrofit 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 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 (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from the gas utility.	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application	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 (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory		

4-AMPCO-24

Ref: Ex 4, T1, S1, Page 3, Table 3

- a) Please provide the costs attributed to corrective maintenance compared to preventive maintenance.

Response:

- a) The costs attributed to corrective maintenance compared to preventative maintenance is provided in the following tables.

Corrective Maintenance						
Programs	Last Rebasement Year (2013 Board-Approved)	Last Rebasement Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Maintenance						
Maintenance of O/H Lines	41,904	51,320	39,717	51,902	62,281	73,635
Maintenance of Line Transformers	8,742	12,094	4,122	4,106	5,086	7,260
Maintenance of U/G Conductors	52,434	47,099	50,453	23,446	21,093	22,796
Tree Trimming and Vegetation Control	7,858	6,160	4,021	4,438	5,199	6,033
Total	110,937	116,672	98,313	83,892	93,658	109,724

Preventative Maintenance						
Programs	Last Rebasement Year (2013 Board-Approved)	Last Rebasement Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Maintenance						
Maintenance of O/H Lines	237,453	290,814	225,061	294,114	352,924	417,267
Maintenance of Line Transformers	26,225	36,281	12,365	12,317	15,259	21,781
Maintenance of U/G Conductors	78,651	70,648	75,679	35,169	31,639	34,193
Tree Trimming and Vegetation Control	149,299	117,033	76,405	84,320	98,772	114,625
Total	491,629	514,776	389,510	425,919	498,595	587,866

4-AMPCO-25

Ref: Ex 4, T1, S1, Page 4

- a) Please provide the number of Trouble Calls for the years 2012 to 2016 and the forecast for 2017.

Response:

- a) Please see the following table:

Year	Trouble Calls
2012	337
2013	262
2014	307
2015	245
2016	228
2017	276

4-AMPCO-26

Ref: Ex 4, T1, S1, Page 5

- a) Please provide the vacancy savings for the years 2013 to 2016 and forecast for 2017.

Response:

- a) The approximate vacancy savings for 2013 to 2016 and forecast for 2017 is provided in the following table.

	2013	2014	2015	2016	2017
Vacancy Savings	\$ 17,200	\$ 51,090	\$ 233,672	\$ 257,806	\$ 177,297

4-AMPCO-27

Ref: Ex 4, T3, S1, Page 1, Table 1

- a) Please provide a summary of the number of assets replaced for the years 2013 to 2016 under each of the Operations and Maintenance work programs.

Response:

- a) The types of assets that are replaced in the Operations and Maintenance work programs include insulators, secondary service wire, lightening arrestors, fuses and switches. Unfortunately NOW Inc. cannot readily identify the number of assets replaced under each of these work programs. It is estimated that from 2013 to 2016, NOW Inc. has over 1,000 work orders related to these work programs and it would be an onerous task to search/review each of these work orders to identify the line items that relate to replacement assets. Furthermore, this information would then need to be cross checked with accounts payable invoices to confirm the actual asset type in the work order. It is not possible to do an electronic search for this information and much of the information gathering would require manual effort.

4-AMPCO-28

Ref: Ex 4, T3, S1, Page 4

Preamble: The evidence indicates the work program under Transformer/Substation also includes vegetation control at substations.

- a) Please confirm the additional amount for vegetation control in 2017 and confirm this amount is in addition to the expenditures under the Maintenance budget related to Tree Trimming and Vegetation Control.

Response:

- a) Of the \$36,327 in 2017, approximately \$11,000 is related to vegetation control at substations. This is a similar level as previous years. NOW Inc. confirms that this is in addition to the \$120,658 that is in the tree trimming and vegetation control budget in 2017.

4-AMPCO-29

Ref: Ex 4, T3, S1, Page 5

- a) Please provide NOWI's expenditures, budget versus actuals, for reactive/emergency work for the years 2013 to 2016 and planned for 2017.

Response:

- a) NOW Inc. does not have a separate budget for reactive/emergency work. The cost of such work is included within the work program budgets.

4-AMPCO-30

Ref: Ex 4, T3, S1, Page 5

- a) Please identify the third party providing the outage management system at an annual cost of \$30,000.

Response:

- a) The party that NOW Inc. will be working with is Utilismart.

4-AMPCO-31

Ref: Ex 4, T3, S1, Page 10, Table 10

- a) Please provide the scheduled maintenance spending for the years 2013 to 2016 and forecast for 2017.
- b) Please provide the reactive maintenance spending for the years 2013 to 2016 and the forecast for 2017.

Response:

- a) The following table provides the approximate scheduled maintenance spending.

Scheduled Maintenance					
Programs	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
<i>Reporting Basis</i>	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Maintenance					
Maintenance of O/H Lines	239,494	185,345	242,211	290,644	343,631
Maintenance of Line Transformers	33,862	11,541	11,495	14,242	20,329
Maintenance of U/G Conductors	82,423	88,292	41,031	36,912	39,892
Tree Trimming and Vegetation Control	117,033	76,405	84,320	98,772	114,625
Total	472,812	361,583	379,057	440,570	518,478

- b) The following table provides the approximate reactive maintenance spending.

Reactive Maintenance					
Programs	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
<i>Reporting Basis</i>	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Maintenance					
Maintenance of O/H Lines	102,640	79,433	103,805	124,562	147,271
Maintenance of Line Transformers	14,512	4,946	4,927	6,104	8,712
Maintenance of U/G Conductors	35,324	37,840	17,585	15,820	17,097
Tree Trimming and Vegetation Control	6,160	4,021	4,438	5,199	6,033
Total	158,636	126,240	130,754	151,683	179,113

4-AMPCO-32

Ref: Ex 4, T3, S1, Page 14

- a) Please provide a breakdown of the budgeted and actual costs for the work activities under Tree Trimming and Vegetation Control for the years 2013 to 2016 and forecast for 2017.
- b) Please provide the planned and actual unit accomplishments for 2012 to 2016.
- c) Please provide NOWI's budgeted compared to actual storm budget for the years 2012 to 2016 and forecast for 2017, and indicate where in the budget these amounts are included.

Response:

- a) NOW Inc. did not historically prepare its operating budget on the work program basis. As such, direct payroll burden e.g. vacation, benefits, and other costs were not specifically allocated to the work program budget, while actual costs were restated for the purpose of this application and include all direct costs associated with the work program.

	Budget	Actual	Budget	Actual	Budget	Actual	Forecast	Forecast
	2013		2014		2015		2016	2017
Tree Trimming and Vegetation Control	\$ 75,887	\$ 114,042	\$ 48,581	\$ 74,385	\$ 38,200	\$ 81,752	\$ 103,971	\$ 120,658

- b) NOW Inc. plans on approximately 24km of line clearing per year. Noting that some segments are more difficult than others and priority locations are addressed in the year. All planned work was completed.
- c) NOW Inc. does not have a separate storm budget, but rather includes such occurrences within existing work programs such as tree trimming and maintenance of overhead line.

4-AMPCO-33

Ref: Ex 4, T3, S1

- a) Please provide the total savings related to each of the productivity descriptions in Schedule 1.

Response:

- a) The following summarizes the productivity descriptions in E4/T3/S1 and an effort has been made to quantify savings where possible. Please note that it is difficult to fully quantify savings for some initiatives as they represent a) avoided costs that were not tracked in the accounting system, b) better decisions being made, or c) work which did not lead to cost reduction but more work being accomplished. The savings achieved through productivity initiatives have been used to fund other work programs.

Customer Premises (pg. 7)

PRODUCTIVITY – cost increases are partially offset by increased productivity due to reduction in trouble calls and flickering as a result of the preventive maintenance replacing connectors which reduce the costs on an ongoing basis. Additionally, resources are scheduled to tackle programs in a systematic practice to reduce roll out costs and efficiency of the workforce. This reduces the amount of required overtime hours while taking into account customer impact regarding outages and scheduling them at the least intrusive time.

It is estimated that savings from this initiative are in the order of \$7,500/year.

Load Dispatching (pg.8):

PRODUCTIVITY – Cost increases are partially offset by increased productivity related to the installation of animal guards which reduces the amount of no power call outs and saves vehicle and labour costs associated with afterhours call outs. The guards are being installed in key locations by targeting risk areas. The installations are done in a systematic manner in order to attain efficiencies in the installation which reduces time required to complete the tasks.

It is estimated that savings from this initiative are in the order of \$10,000/year.

Maintenance of Overhead Lines (pg. 11)

PRODUCTIVITY – Cost increases are partially offset by increased productivity related to planning more preventative maintenance during business hours in order to minimize trouble calls that require after hours call outs.

It is estimated that savings from this initiative are in the order of \$3,000/year

Maintenance of Line Transformers (pg. 12)

PRODUCTIVITY – Cost increases are partially offset by increased productivity related to the low failure rate of transformers.

It is difficult to quantify the savings associated with this initiative as the benefit relates to the impact of avoiding transformer failures. The purchase of thermal imaging equipment in 2014 has enabled preventive maintenance to be conducted on transformers or replacement of equipment prior to failure. The avoided cost of equipment failure includes equipment replacement as well as potential safety and reliability impacts depending on the nature of the failure avoided. Productivity initiatives and cost control have enabled Northern Ontario Wires to continue to be ranked in Cohort 1 which identifies the most efficient utilities as per the PEG benchmarking report.

Maintenance of Underground Conductors (pg. 13)

PRODUCTIVITY – Productivity in this work program relates to the strategy that NOW Inc. has taken to work to eliminate underground feeds and reroute them to an overhead system which is less costly to maintain and replace.

It is estimated that savings from this initiative are in the order of \$5,000/year

Tree Trimming and Vegetation Control (pg. 15)

PRODUCTIVITY – Cost decreases are partially due to increased productivity related to initiatives such as having public works remove trees and plant trees on the opposite side of the road where they will grow and not interfere with NOW Inc.'s distribution system.

It is estimated that savings from this in initiative are in the order of \$3,000/year.

4-AMPCO-34

Ref: Ex 4, T3, S2, Page 11

- a) Please provide the total number of overtime hours and costs for the years 2013 to 2016 and the forecasts for 2017.
- b) Please provide the % of overtime costs paid at double time for the years 2013 to 2016.

Response:

- a) Please see the following table with regard to overtime hours and costs:

		Overtime Hours	Overtime Costs
	2013	2,206	\$ 88,633
	2014	1,740	\$ 74,705
	2015	1,955	\$ 87,844
	2016	1,758	\$ 74,368
Forecast	2017	1,674	\$ 72,000
* Includes paid and banked time			

- b) Please see the following table for the percentage of overtime costs paid at double time:

Year	% Paid at double time
2013	25%
2014	13%
2015	13%
2016	29%

4-AMPCO-35

Ref: Ex 4, T3, S2, Page 12, table 2

- a) Please provide the percentage of compensation costs allocated to OM&A and Capital for the years 2013 to 2017.

Response:

- a) The following table provides the percentage of compensation costs allocated to OM&A and Capital for the years 2013 to 2017.

	Actual			Forecast	Forecast
	2013	2014	2015	2016	2017
OM&A	85%	87%	86%	87%	88%
Capital	15%	13%	14%	13%	12%
Total	100%	100%	100%	100%	100%

4-AMPCO-36

Ref: Ex 4, T 3, S4, Attachment #1

Preamble: The Table provided shows purchases from vendors exceeding \$50 k for 2015.

- a) Please provide a description of the services provided under each vendor.
- b) Please provide a similar table for 2016.
- c) Please provide the forecast vendor costs for 2017.

Responses:

- a) Please see response to 4-Staff-40
- b) Please see response to 4-Staff-40
- c) NOW Inc. does not forecast purchases from specific vendors. However, costs for recurring vendors such as OMERS, Sensus Metering Systems and Harris Customer Systems are expected to be of a similar order of magnitude with an increase related to inflation/escalation.

4-AMPCO-37

Ref: Ex 4, T 3, S5, Page 1

Preamble: Table 1 provided One-Time Costs in 2017 related to the preparation of the 2017 Cost of Service Application.

- a) Please provide a cost breakdown and description of the Consultant Costs and identify each consultant.
- b) Please provide the costs separately for the DSP and Customer Engagement and identify the companies used.

Responses:

- a) Please refer to the response to 4-Staff-42.
- b) Please refer to the response to 4-Staff-42.

Exhibit 5 – Cost of Capital and Capital Structure

5-Staff-46

Ref: Exhibit 5 / Tab 1 / Schedule 1

Preamble:

Northern Ontario Wires noted that its largest loan (\$3,680,980) is scheduled to be renewed on July 31, 2017. For the purposes of the application, Northern Ontario Wires assumed the approved loan interest rate of 3.75% will apply until the end of the term and the loan will then be renewed at an assumed rate of 4.54% reflecting the current OEB deemed long-term debt rate.

Northern Ontario Wires noted that it will also secure additional financing in the amount of \$381,705 at an assumed interest rate of 4.54%.

Question(s):

- a) Please provide rationale supporting the use of a 4.54% debt rate for this loan after July 31, 2017 (Exhibit 5 / Tab 1 / Schedule 1 / p. 2).
- b) Does Northern Ontario Wires have any better information as to what the actual debt rate for this loan will be? If not, please inquire with the lender as to the likely renewal rate (Exhibit 5 / Tab 1 / Schedule 1 / p. 2).
- c) In the absence of specific information from the lender, does Northern Ontario Wires agree that the existing rate of 3.75% is likely a better assumption for the rate that it will receive from its lender (Exhibit 5 / Tab 1 / Schedule 1 / p. 2).
- d) Please explain why Northern Ontario Wires requires additional financing in the amount of \$381,705 (Exhibit 5 / Tab 1 / Schedule 1 / p. 3).

Responses:

- a) Northern Ontario Wires assumed a rate of 4.54% for Long Term Debt, consistent with the approved Cost of Capital parameter long term debt rate in place at the time of the August 26, 2016 filing date. In Exhibit 5/Tab 1/Schedule 1, page 3 lines 28-28 stated that this rate will be updated to reflect the OEB's most current long-term debt rate available at the time of preparing the draft rate order for this proceeding". Subsequent to filing the application, the OEB on October 27, 2016 released the Cost of Capital Parameter Updates for 2017 which specified a

deemed long term debt rate 3.72% which would be used instead of the 4.54% rate in the filing. Should Northern Ontario Wires manage to secure third party long term debt at a commercial rate in sufficient time to be reflected in the draft rate order, it is the intention that such a rate be used rather than the deemed rate of 3.72%.

- b) Northern Ontario Wires inquired with its current lender (Caisse Populaire) regarding a long term rate that would be applicable for a July 31, 2017 loan renewal. Caisse Populaire stated that the current rate for such long term debt is 4.35%, however they are not able to commit to a fixed rate for July 31, 2017 renewal until 30 days prior to renewal and a review of 2016 audited financial statements. NOW Inc. will do its best to negotiate the quoted rate downward.
- c) Based on the preliminary debt rate quoted by Caisse Populaire, Northern Ontario wires is concerned that it will not be able to re-new its loan at a rate consistent with the current OEB's long term debt rate of 3.72%. If a rate of 3.75% or 3.72% is used to determine NOW Inc.'s cost of debt, and the actual renewal is at a higher rate, this would result in un-recovered costs for 5 years.
- d) Northern Ontario Wires requires additional financing of \$381,705 in order to achieve the target deemed capital structure debt ratio of 56% long term debt and to use this financing to support operations and capital expenditures.

5-Staff-47

**Ref: Exhibit 5 / Tab 1 / Schedule 1 / Attachment 1
Exhibit 5 / Tab 1 / Schedule 1 / Attachment 2**

Questions(s):

- a) Please confirm that there is an error in the total amount set out at the bottom of Exhibit 5 / Tab 1 / Schedule 1 / Attachment 2 / p. 5. Please confirm that the total principle should be \$4,349,122 and the average long-term debt rate should be 4.09%.
- b) Please confirm that Northern Ontario Wires has calculated the two new 2017 loans (principle amounts of \$3,680,980 and \$381,705) based on the OEB's deemed long-term debt rate (Exhibit 5 / Tab 1 / Schedule 1 / Attachment 2 / p. 5).
- c) Please recalculate the interest charges for the two new 2017 loans based on an interest rate of: (i) 3.75%; and (ii) using a debt rate acquired from the lender as OEB staff asked for previously (Exhibit 5 / Tab 1 / Schedule 1 / Attachment 2 / p. 5).
- d) Please recalculate Chapter 2 Appendices / Appendix 2-0A / p. 2 using the average long-term debt rates arising from the calculations requested by OEB staff in the above question (Exhibit 5 / Tab 1 / Schedule 1 / Attachment 1 / p. 2).

Responses:

- a) Northern Ontario Wires confirms that the 2017 Long Term Debt principal balance is \$4,349,122 and the Long Term Debt Rate is 4.09% as per Appendix 2-OA (Attachment 1). Regarding the values that appear in Appendix 2-OB (Attachment 2), the principal balance of \$8,030,102 and rate of 2.22% is not an error but is a presentation issue, and Northern Ontario Wires acknowledges that the way in which the numbers are presented could be confusing. Northern Ontario Wires chose to identify the full amount of the principal balance being renewed on July 31, 2017 and the formula in the total line adds this amount even though it is only outstanding from July 31st onward and is a renewal of debt outstanding from January 1, 2017 to July 31, 2017 (not incremental new debt). The same presentation challenge applies in the Rate (%) column where the forecast rate of interest on the new debt is identified, but the formula in the total line is not designed to factor in the partial year weighting of the interest cost.

Northern Ontario Wires attempted to explain this in the Additional Comments section by indicating that the interest is calculated on a prorated basis for the duration of the outstanding bond principal. However, perhaps clearer approach would have been to override the formula in the Total line and exclude the “renewed debt” from the total.

- b) Northern Ontario Wires confirms that the interest cost on the two new loans in 2017 is calculated using the OEB’s deemed long term debt rate that was in place when the application was filed (4.54%). This rate will be updated to reflect the OEB’s current long term debt rate of 3.72% or if available, third party debt at a commercially negotiated rate.
- c)
 - i) The interest charge for the two new loans in 2017 at 3.75% is:
 - Loan 1 (\$381,705): \$14,314 - interest expense is for 365 days
 - Loan 2 (\$3,680,980): \$58,240 - interest expense is for 154 days
 - ii) The interest charge for the two new loans in 2017 at an expected commercial debt rate of 4.35% is:
 - Loan 1 (\$381,705): \$16,604 - interest expense is for 365 days
 - Loan 2 (\$3,680,980): \$67,559 - interest expense is for 154 days
- d) Please see the updated Appendix 2-OB in:
 - i. Attachment 1 (long term debt at 3.75%)
 - ii. Attachment 2 (long term debt at 4.35%)

Appendix 2-OB Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal (\$)	Rate (%) ²	Interest (\$) ¹	Additional Comments, if any
1	0	Caisse Populaire	Third-Party	Fixed Rate	0-Jan-00	20	\$ 3,680,980	3.75%	\$ 79,796.59	Due in 2017, interest pro-rated (211/365)
2	0	Caisse Populaire	Third-Party	Fixed Rate	0-Jan-00	5	\$ 158,459	3.75%	\$ 5,942.21	
3	0	Caisse Populaire	Third-Party	Fixed Rate	0-Jan-00	5	\$ 127,978	3.42%	\$ 4,376.85	
4	Loan 8-B	Caisse Populaire	Third-Party	Fixed Rate	31-Jul-17	20	\$ 3,680,980	3.75%	\$ 58,240.16	Renewed in 2017, interest pro-rated (154/365)
5		Caisse Populaire	Third-Party	Fixed Rate	1-Jan-17	5	\$ 381,705	3.75%	\$ 14,313.94	
6									\$ -	
Total							\$ 8,030,102	2.03%	\$ 162,669.75	

Notes

- 1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
- 2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with
- 3 Add more lines above row 12 if necessary.

Appendix 2-OB Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal (\$)	Rate (%) ²	Interest (\$) ¹	Additional Comments, if any
1	0	Caisse Populaire	Third-Party	Fixed Rate	0-Jan-00	20	\$ 3,680,980	3.75%	\$ 79,796.59	Due in 2017, interest pro-rated (211/365)
2	0	Caisse Populaire	Third-Party	Fixed Rate	0-Jan-00	5	\$ 158,459	3.75%	\$ 5,942.21	
3	0	Caisse Populaire	Third-Party	Fixed Rate	0-Jan-00	5	\$ 127,978	3.42%	\$ 4,376.85	
4	Loan 8-B	Caisse Populaire	Third-Party	Fixed Rate	31-Jul-17	20	\$ 3,680,980	4.35%	\$ 67,558.59	Renewed in 2017, interest pro-rated (154/365)
5		Caisse Populaire	Third-Party	Fixed Rate	1-Jan-17	5	\$ 381,705	4.35%	\$ 16,604.17	
6									\$ -	
Total							\$ 8,030,102	2.17%	\$ 174,278.40	

Notes

- 1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
- 2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with
- 3 Add more lines above row 12 if necessary.

5-SEC-32

- a) [Ex.5-1-1, p.2] Has the Applicant inquired with Caisse Populaire regarding the rate it may be able to get to renew the loan whose term end on July 31st 2017? If so, please provide details. If not, please do and so provide copies of the request and Caisse Populaire's response.

Response:

- a) Please refer to the response to 5-Staff-46 b).

5-VECC-42

Reference: E5/T1/S1/Attachment 2

- a) Please update Appendix 2-OB (2017) using the current Board cost of capital/debt figures.
- b) Please update to the negotiated rate for Caisse Populaire note of \$381,705 which has an expected date of January 1, 2017.

Responses:

- a) Please refer to Attachment 1 for the updated Appendix 2-OB (2017).
- b) The planned January 2017 debt issue of \$381,705 has not yet taken place. The rate currently quoted for this debt by Caisse Populaire is 5.15%, however NOW Inc. is hoping to negotiate a lower rate.

File Number: EB-2016-0096
Exhibit: 5
Tab: 1
Schedule: 1
Attachment: 2
Page: 1 of 5
Date: 31-Jan-17

Appendix 2-OB Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal (\$)	Rate (%) ²	Interest (\$) ¹	Additional Comments, if any
1	Loan 8	Caisse Populaire	Third-Party	Fixed Rate	27-Jul-12	20	\$ 4,324,895	3.75%	\$ 162,183.56	
2	Loan 1	Caisse Populaire	Third-Party	Fixed Rate	19-Sep-13	5	\$ 424,082	3.75%	\$ 4,487.72	Interest for partial year (103/365)
3									\$ -	
Total							\$ 4,748,977	3.51%	\$ 166,671.28	

Notes

- 1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
- 2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with any subsequent update issued by the Board.
- 3 Add more lines above row 12 if necessary.

File Number: EB-2016-0096
Exhibit: 5
Tab: 1
Schedule: 1
Attachment: 2
Page: 2 of 5
Date: 31-Jan-17

Appendix 2-OB Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal (\$)	Rate (%) ²	Interest (\$) ¹	Additional Comments, if any
1	Loan 8	Caisse Populaire	Third-Party	Fixed Rate	27-Jul-12	20	\$ 4,172,370	3.75%	\$ 156,463.88	
2	Loan 1	Caisse Populaire	Third-Party	Fixed Rate	19-Sep-13	5	\$ 404,741	3.75%	\$ 15,177.77	
3	Loan 4	Caisse Populaire	Third-Party	Fixed Rate	28-Apr-14	5	\$ 261,375	3.42%	\$ 6,049.15	Interest for partial year (247/365)
4									\$ -	
Total							\$ 4,838,486	3.67%	\$ 177,690.80	

Notes

- 1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
- 2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with
- 3 Add more lines above row 12 if necessary.

File Number: EB-2016-0096
Exhibit: 5
Tab: 1
Schedule: 1
Attachment: 2
Page: 3 of 5
Date: 31-Jan-17

Appendix 2-OB Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal (\$)	Rate (%) ²	Interest (\$) ¹	Additional Comments, if any
1	Loan 8	Caisse Populaire	Third-Party	Fixed Rate	27-Jul-12	20	\$ 4,014,026	3.75%	\$ 150,525.98	
2	Loan 1	Caisse Populaire	Third-Party	Fixed Rate	19-Sep-13	5	\$ 325,404	3.75%	\$ 12,202.65	
3	Loan 4	Caisse Populaire	Third-Party	Fixed Rate	28-Apr-14	5	\$ 229,049	3.42%	\$ 7,833.48	
4									\$ -	
5									\$ -	
6									\$ -	
7									\$ -	
8									\$ -	
9									\$ -	
10									\$ -	
11									\$ -	
12									\$ -	
Total							\$ 4,568,479	3.73%	\$ 170,562.10	

Notes

- 1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
- 2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with
- 3 Add more lines above row 12 if necessary.

File Number: EB-2016-0096
Exhibit: 5
Tab: 1
Schedule: 1
Attachment: 2
Page: 4 of 5
Date: 31-Jan-17

Appendix 2-OB Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal (\$)	Rate (%) ²	Interest (\$) ¹	Additional Comments, if any
1	Loan 8	Caisse Populaire	Third-Party	Fixed Rate	27-Jul-12	20	\$ 3,849,642	3.75%	\$ 144,361.58	
2	Loan 1	Caisse Populaire	Third-Party	Fixed Rate	19-Sep-13	5	\$ 243,043	3.75%	\$ 9,114.11	
3	Loan 4	Caisse Populaire	Third-Party	Fixed Rate	28-Apr-14	5	\$ 179,159	3.42%	\$ 6,127.24	
4	Short Term Deb	Town of Cochrane	Affiliated	Fixed Rate	17-Feb-16	1	\$ 546,000	2.00%	\$ 9,487.87	Interest for partial year (318/366)
5									\$ -	
6									\$ -	
7									\$ -	
8									\$ -	
9									\$ -	
10									\$ -	
11									\$ -	
12									\$ -	
Total							\$ 4,817,844	3.51%	\$ 169,090.80	

Notes

- 1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
- 2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with
- 3 Add more lines above row 12 if necessary.

File Number: EB-2016-0096
Exhibit: 5
Tab: 1
Schedule: 1
Attachment: 2
Page: 5 of 5
Date: 31-Jan-17

Appendix 2-OB Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.
Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal (\$)	Rate (%) ²	Interest (\$) ¹	Additional Comments, if any
1	Loan 8	Caisse Populaire	Third-Party	Fixed Rate	27-Jul-12	20	\$ 3,680,980	3.75%	\$ 79,796.59	Due in 2017, interest pro-rated (211/365)
2	Loan 1	Caisse Populaire	Third-Party	Fixed Rate	19-Sep-13	5	\$ 158,459	3.75%	\$ 5,942.21	
3	Loan 4	Caisse Populaire	Third-Party	Fixed Rate	28-Apr-14	5	\$ 127,978	3.42%	\$ 4,376.85	
4	Loan 8-B	Caisse Populaire	Third-Party	Fixed Rate	31-Jul-17	20	\$ 3,680,980	3.72%	\$ 57,774.24	Renewed in 2017, interest pro-rated (154/365)
5		Caisse Populaire	Third-Party	Fixed Rate	1-Jan-17	5	\$ 381,705	3.72%	\$ 14,199.43	
6									\$ -	
Total							\$ 8,030,102	2.02%	\$ 162,089.31	

Notes

- 1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
- 2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with
- 3 Add more lines above row 12 if necessary.

Exhibit 6 – Revenue Deficiency or Sufficiency

6-Staff-48

Ref: Exhibit 6 / Tab 1 / Schedule 1 / Attachment 1

Question(s):

- a) If necessary, upon responding to all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the previous version of the RRWF filed as part of the initial application. Entries for changes and adjustments should be included in the middle column on Sheet 3 - Data Input Sheet. Please include documentation of the corrections and adjustments in the final sheet of the model, such as a reference to an interrogatory response or an explanatory note.

Also upon completing all interrogatories from OEB staff and intervenors, please provide any updates to the following Microsoft Excel documents in working format: PILS, any Appendix 2 changes (e.g. cost allocation, rate design, and bill impacts, and so on as required), EDDVAR spreadsheet, and the updated cost allocation model reflecting the revised revenue requirement in the updated RRWF.

Response:

- a) Significant effort is required to update the requested information. For efficiency purposes, Northern Ontario Wires Inc. will provide this requested information on February 17, 2017. This will provide an opportunity to include the best information available for 2016 Actual year-end results as well as incorporate updates resulting from interrogatory responses.

6-SEC-33

Ref: Exhibit 6

Question(s):

Please revise the revenue requirement request and result bill impact model to include the Board's update cost of capital parameters for 2017 issued on October 27, 2016.

Response:

- a) The Board's update to cost of capital parameters reduces the revenue requirement as follows:

	As Filed	Updated Cost of Capital	Difference
Service Revenue Requirement	3,832,485	3,801,977	(30,508)
Revenue Offsets	268,918	268,918	-
Base Revenue Requirement	3,563,567	3,533,059	(30,508)

Please see 6-Staff-48, Northern Ontario Wires Inc. will perform one full update to all models, encompassing the bill impacts.

Exhibit 7 – Cost Allocation

7-Staff-49

Ref: Exhibit 7 / Tab 1 / Schedule 1

Preamble:

Northern Ontario Wires noted that it examined identifiable costs incurred in preparing and issuing bills, recording payment, and collecting in order to arrive at a cost per bill for each rate class. This was used to develop weighting factors for billing and collecting.

Northern Ontario Wires also noted that the services weighting factor was developed using engineering estimates of the average cost to install a service connection to each rate class.

Question(s):

- a) Please file a summary table showing the weighting factors applied to each rate class and provide detailed rationale supporting the weightings.

Response:

- a) Please see the table below:

Customers, 2017 Forecast										
Res	GS<50	GS>50	Strt Lgt	Sent Lgt						
5,216	784	71	3	27						
					6,101					

	2016 Budget	Relative Cost (weight) Per Customer					Total Weighted Customers	Allocated Cost				
		Res	GS<50	GS>50	Strt Lgt	Sent Lgt		Res	GS<50	GS>50	Strt Lgt	Sent Lgt
Canada Post Corp	58,570	1.0	1.0	1.0	1.0	1.0	6,101	9.60	9.60	9.60	9.60	9.60
Credit Bureau	4,145	1.0	1.0	-	-	-	6,000	0.69	0.69	-	-	-
Sensus	114,000	1.0	1.0	1.0	-	-	6,071	18.78	18.78	18.78	-	-
ERTH	2,400	1.0	1.0	1.0	-	-	6,071	0.40	0.40	0.40	-	-
Harris	10,800	1.0	1.0	1.0	1.0	1.0	6,101	1.77	1.77	1.77	1.77	1.77
A&B Digital - invoice	3,796	1.0	1.0	1.0	1.0	1.0	6,101	0.62	0.62	0.62	0.62	0.62
A&B Digital - envelopes	5,996	1.0	1.0	1.0	1.0	1.0	6,101	0.98	0.98	0.98	0.98	0.98
Purolator	200	1.0	1.0	1.0	1.0	1.0	6,101	0.03	0.03	0.03	0.03	0.03
CIBC EDI	3,600	1.0	1.0	1.0	0.3	-	6,072	0.59	0.59	0.59	0.18	-
CLEO	1,071	1.0	1.0	1.0	1.0	1.0	6,101	0.18	0.18	0.18	0.18	0.18
Utilismart	33,600	1.0	1.0	1.0	1.0	-	6,074	5.53	5.53	5.53	5.53	-
Peterborough Utilities	9,600	1.0	1.0	1.0	1.0	1.0	6,101	1.57	1.57	1.57	1.57	1.57
Supervision	88,460	1.0	1.0	1.0	1.0	1.0	6,101	14.50	14.50	14.50	14.50	14.50
Billing Department	102,831	1.0	1.0	1.0	1.0	1.0	6,101	16.85	16.85	16.85	16.85	16.85
Collections Department	133,747	1.0	1.0	1.0			6,071	22.03	22.03	22.03	-	-
Totals	572,816						Identified Cost per Customer	94.13	94.13	93.44	51.82	46.11

WEIGHTING FACTORS	1.00	1.00	0.99	0.55	0.49

The total Billing and Collecting budget reflects costs which are functionalized and classified above as well as costs which are more general in nature. These more general costs will be allocated in the Cost Allocation model using the weighting factor set out here.

The budgets here reflect the best available information, not the test year.

7-Staff-50

Ref: Exhibit 7 / Tab 1 / Schedule 1 / Attachment 1

Question(s):

- a) Please explain why Northern Ontario Wires was unable to obtain the data necessary for developing updated hourly load profiles in advance of filing its 2017 rates application (Exhibit 7 / Tab 1 / Schedule 1 / Attachment 1 / p. 5).

Response:

- a) Two components are necessary in order to produce updated load profiles. First, hourly data is required for either all, or a representative sample of customers from each rate class being updated. Second, the weather actual historic profiles must be weather normalized.

The communication regarding updated hourly load profiles was received late in the filing process. At the time the filing requirements came out, July 14, 2016, Northern Ontario Wires had not been collecting or retaining hourly load information. There was insufficient time prior to August 26, 2016 filing, to gather data, and perform the required analysis to prepare updated weather normal load profiles. Further, to do so, would have required a considerable amount of re-work of the application.

The filing requirements anticipated that it may not be possible to update load profiles as part of this rate application. At 2.7.1, in the 4th paragraph, it states:
If a distributor is not able to update its load profiles at this time, an explanation should be provided and the distributor should confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed.

Northern Ontario Wires confirms it plans to update its load profiles at its next rebasing, tentatively for rates effective 2022. To do this, it plans to start collecting and aggregating the required interval meter and smart meter data when resources are available, following this proceeding.

7-Staff-51

Ref: Exhibit 7 / Tab 1 / Schedule 1 / Attachment 2

Question(s):

- a) Please explain why the revenue deficiency entered at the top of Sheet I6.1 does not match the referenced cell in the RRWF nor does it reflect the amount set out in the written pre-filed evidence. Please update the evidence if necessary.

Response:

- a) The deficiency entered in Sheet I6.1 is correct. Cost Allocation contains a deficiency of \$543,318, calculated as a difference between the revenue requirement, and the revenue at existing rates.

As calculated in the RRWF, the deficiency is the difference in after tax revenue at approved rates and proposed rates. This resulted in a deficiency of \$526,990. The difference between the two is the additional \$16,330 required to recover the difference in income taxes, resulting in a total deficiency of \$543,320. The remaining \$2 difference is due to rounding.

7.0 – VECC –43

Reference: E7/T1/S1, page 1

- a) Please provide the analysis supporting the proposed Billing & Collecting weighting factors. In particular, the analysis supporting a weighting factor of 1.0 for the GS>50 class.

Response:

- a) Please see the response to 7-Staff-49 which contains the derivation of the Billing and Collecting weighting factors.

7.0 – VECC –44

Reference: E7/T1/S1, Attachment 1, page 6
E7/T2/S1, Attachment 1, page 3

- a) The Status Quo Revenue to Cost ratios set out in Table 7 of the Elenchus Report for Street Light and USL do not match those in the RRWF, Tab 11. Please reconcile.

Response:

- a) The Status Quo Ratios set out in Table 7 of the Elenchus report for Street Light and USL are transposed. The Street Light revenue to cost ratio is 83.35%, while the USL revenue to cost ratio is 122.71%. The RRWF, Tab 11 is correct.

7.0 – VECC –45

Reference: E7/T2/S1, page 1

- a) Please explain more fully how the shortfall due to the reduction in the USL Revenue to Cost ratio was apportioned between the Residential and Street Lighting classes.

Response:

- a) Residential and Street Lighting both have revenue to cost ratios below 100%, and therefore both received the same percentage rate increase of 17.998%. General Service < 50 and General Service > 50 both have revenue to cost ratios within the target range, but above 100%, and both received the status quo rate increase of 17.989%. These percentage increases can be verified on the RRWF, sheet 11, table b) by dividing the values in column 7D by the values in column 7B.

Exhibit 8 – Rate Design

8-Staff-52

Ref: Exhibit 8 / Tab 1 / Schedule 1

Question(s):

- a) Please explain why the fixed charge for the GS > 50 rate class is significantly higher than the ceiling developed in the cost allocation process (Exhibit 8 / Tab 1 / Schedule / p.2).
- b) Please provide the GS > 50 fixed charge that would be in place if the fixed / variable split was not adjusted to maintain the existing fixed charge (Exhibit 8 / Tab 1 / Schedule / p.2).

Response:

- a) The existing fixed charge is \$191.60, and has historically been above the ceiling developed in the cost allocation model. Northern Ontario Wires proposes to maintain this charge. This is the expected approach as per the Chapter 2 filing requirements dated July 14, 2016, section 2.8.1 on page 56.

If a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling for any non-residential class.

- b) If Northern Ontario Wires were to maintain the existing fixed / variable split, the resulting fixed charge would be \$226.07.

8-Staff-53

Ref: Exhibit 8 / Tab 3 / Schedule 3

Question(s):

- a) Please confirm that the rates set out at Exhibit 8 / Tab 3 / Schedule 3 / p. 1 (WMS, OESP, RRRP) will be updated at the draft rate order stage of the proceeding to reflect any OEB approved changes.

Response:

- a) Confirmed.

8-Staff-54

Ref: Exhibit 8 / Tab 3 / Schedule 5 / Attachment 1

Question(s):

- a) Please advise whether the 2017 low voltage costs are allocated to rate classes on the same basis as transmission connection rate revenues.

Response:

- a) No, low voltage charges have not been allocated to rate classes on the same basis as transmission connection rate revenue. They are allocated to rate classes in the same proportion as the approved low voltage rates. Therefore, changes to low voltage rates are implemented as an across the board rate increase.

8-Staff-55

Ref: Exhibit 8 / Tab 5 / Schedule 1 / Attachment 1

Question(s):

- a) Please advise whether Northern Ontario Wires has any WMP customers.
- b) Please explain why there are two separate rate riders listed in the proposed tariff sheets for the disposition of deferral and variance accounts ("Rate Rider for Disposition of Deferral/ Variance Accounts (2017)" and "Rate Rider for Disposition of Deferral/Variance Accounts – Non_WMP (2017)". Please advise whether these riders can be combined into a single line for simplicity.

Responses:

- a) Northern Ontario Wires does not have any WMP customers.
- b) There are two separate rate riders as NOW Inc. followed the methodology of the Deferral and Variance Account Workform to determine riders for the subject accounts. As there are no WMP customers and the allocators are the same, it is possible to combine these two riders into a single rider.

8-Staff-56

Ref: Exhibit 8 / Tab 5 / Schedule 1 / Attachment 2

Question(s):

- a) If necessary, upon responding to all interrogatories from OEB staff and intervenors, please provide updated bill impacts for all classes at the typical consumption / demand levels (e.g. 750 kWh for residential, 2,000 kWh for GS<50, etc.), reflecting any changes made during the interrogatory process. Please also provide updated bill impacts for the 10th consumption percentile residential customers.

Response:

- a) Please see response to 6-Staff-48.

8.0 –VECC - 46

Reference: E8/T3/S5, page 1

- a) Please confirm that the 2013-2015 values shown for “Low Voltage Payments” are the amounts that were paid to HONI each year.

Response:

- a) NOW Inc. confirms that the 2013-2015 values shown are for Low Voltage Payments were paid to HONI each year. Additional amounts paid to HONI each year that are not included in the referenced table are the Transmission Network Charge and the Transmission Connection Charge.

8.0 – VECC – 47

- a) Please explain why it is appropriate to use anticipated savings from commodity changes to justify not providing rate mitigation when changes in commodity charges for other customer classes are not included/considered in the rate/bill impact calculations.

Response:

- a) As the bill impact for Street Lighting customers was calculated to be 10.16%, which is over the threshold of 10.0 %, Northern Ontario Wires did not propose mitigation as the impact was only just slightly over the threshold and anecdotally mentioned that the customer impact would be mitigated by savings in consumption. Northern Ontario Wires does not suggest that this is an appropriate basis for all customer bill mitigation analysis and should have been clearer in its submission. It is noted that with using the updated cost of capital parameters issued on October 27, 2016 the bill impact for Street Lighting customers is expected to be less than 10%, hence no bill mitigation is required. The specific Street Lighting bill impact will be provided as part of the supplementary filing on February 17, 2017.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-57

**Ref: Exhibit 9 / Tab 1 / Schedule 3 / p. 1 / Account 1508: Other Regulatory Assets
– Sub-Account – Deferred IFRS Transition Costs**

Preamble:

Northern Ontario Wires is requesting to continue to use this account after its disposition in this proceeding.

Question(s):

- a) Given that Northern Ontario Wires adopted IFRS on January 1, 2015, and the work related to IFRS transition should have been substantially completed:
 - i. Why does Northern Ontario Wires need to keep this account open?
 - ii. Is Northern Ontario Wires expecting further material costs related to IFRS transition? If so, please provide a description of such expenditures, justification of why costs are recoverable, and the amounts forecast to be spent in the test year and beyond.

Response:

- a)
 - i. Although NOW Inc. adopted IFRS on January 1, 2015, NOW incurred costs in the amount of \$11,500 in 2016 for incremental audit fees in relation to the IFRS transition. These costs were not audited as a part of the 2015 year end. As the costs are not yet audited, they will continue to be in account 1508 until a subsequent disposition opportunity. More details can be found in the application at E9/T2/S1.

Should the unaudited costs be allowed for disposition in this application, NOW Inc. would then close the 1508 IFRS transition account.
 - ii. As discussed in E9/T2/S1 (lines 10-13) of the application, the transition costs of \$11,500 relating to incremental audit fees as a

result of the IFRS transition incurred in 2016. These costs would not have been incurred if NOW Inc. had not transitioned to IFRS. Beyond this, NOW is not anticipating further costs relating to transition.

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Reference: E9/T2/S1

- a) When are the 1508 transition costs for 2016 expected to be finalized?

Responses:

- a) The costs incurred are final but are unaudited. NOW Inc. expects the 1508 transition costs for 2016 to be finalized as part of the 2016 Audit which will be completed by April 30, 2017.

Please refer to the response to 9-Staff-57 for further information in regards to this account.