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483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

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frank.dandrea@HydroOne.com

Frank D'Andrea
Vice President
Regulatory Affairs & Chief Risk Officer

BY COURIER

January 26, 2018

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2017-0051 - Hydro One Remote Communities Inc. 2018 Revenue Requirement and Rates Application – Responses to Interrogatory Questions

Please find attached an electronic copy of responses provided by Hydro One Remote Communities Inc. to interrogatory questions. Two (2) hard copies will be sent to the Board shortly.

The interrogatory responses have been filed by the following Intervenors:

Tab 1	Board Staff
Tab 2	Energy Probe
Tab 3	Vulnerable Energy Consumers Coalition (VECC)
Tab 4	Opiikapawiin Servies LP (OSLP)

An electronic copy of the interrogatories has been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Attach.

c Intervenors (electronic)

OEB Staff - Interrogatory # 1

Reference:

Exhibit A / Tab 3 / Schedule 1 / Page 9

Interrogatory:

In the list of Specific Approvals Requested, Hydro One Remote Communities Inc. (Remotes) is seeking approval for specific service charges.

Please confirm that there are no changes to the specific service charges requested and Remotes is seeking approval to continue the existing service charges.

Response:

So confirmed.

OEB Staff - Interrogatory # 2

Reference:

Exhibit A / Tab 3 / Schedule 1 / Page 7 and Schedule 2 / Page 4

Interrogatory:

The application notes that at the time of Remotes' last cost of service application in 2012, eight communities were in connection restrictions. Remotes has worked with Indigenous and Northern Affairs Canada (INAC) and First Nation communities to address the need for community growth. Only one community is currently facing restrictions and a project is planned starting in 2018, to remove the connection restriction in that community. However, in another section of the application (Schedule 2, page 4, lines 14-15), Remotes has indicated that at this time, only two communities remain in connection restrictions.

Please reconcile the discrepancy in the evidence and clarify the number of communities that face connection restrictions.

Response:

At the time of the filing, two communities were in connection restrictions, so the reference to one community in Exhibit A, Tab 3, Schedule 1 was incorrect. The connection restriction in Kingfisher Lake was removed in September, 2017.

OEB Staff - Interrogatory # 3

Reference:

Exhibit A / Tab 6 / Attachment 3 / Report on Customer Service Research / Page 4

Interrogatory:

In the application, Remotes has provided survey results from the telephone survey conducted by Viewpoints Research. The research indicates that awareness of the Low-Income Energy Assistance Program (LEAP) is 33% while one in four is aware of the Ontario's Electricity Support Program (OESP).

What steps has Remotes taken to increase awareness of LEAP and OESP within the communities it serves?

Response:

Remotes asks about customer awareness of these programs in order to track and improve customer enrolment. In addition to the OEB's and the Ontario Native Welfare Administrators' Association (ONWAA) efforts to increase customer awareness of these programs, Remotes has taken several steps to increase awareness including:

1. All dunning and collection related correspondence to customers includes information about OESP and LEAP;

2. All customers who call into the office regarding overdue balances/payments/payment arrangements are told about the programs and are encouraged to apply;

3. Information about the programs is included in Remotes' newsletter to customers;

4. Letters explaining the programs were sent to Band Councils and to Tribal Councils (technical advisors to the First Nations);

5. Letters explaining the program were sent to Ontario Works/Social Assistance Offices;

6. In customer presentations, Remotes includes information about Ontario Energy Board Programs, describes the programs and shows the beneficial bill impact of OESP;

7. ONWAA is Remotes' LEAP provider and is also responsible for First Nation OESP applications. Following the receipt of the most recent customer survey, Remotes purchased radio ads that played on Wawatay Radio with a brief description of the program and ONWAA's contact information; and

8. As part of the corporate initiative to transition to a new bill, Remotes plans a regular bill message including ONWAA's phone number and saying "Having trouble paying your bills? Help is available. The Ontario Electricity Support Program can be accessed by calling 1-844-885-3157."

OEB Staff - Interrogatory # 4

Reference:

Exhibit A / Tab 5 / Schedule 2 / Pages 1-8

Interrogatory:

Remotes has provided information about its reliability indicators, specifically the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI).

The service reliability indicators (SAIDI and SAIFI) excluding loss of supply have not shown improvement over the years. In fact, SAIDI has worsened in 2015 and 2016. Please indicate the measures that Remotes has implemented and intends to implement to improve SAIDI and SAIFI indicators going forward. Please provide a detailed response.

Response:

Due to geographic challenges and our small business size it is unlikely that service reliability indicators will significantly improve over current levels of service, without significant investment in both equipment and resources. Reliability and all outages are reviewed regularly by the Remotes Outage Committee (“ROC”). The committee reviews our trouble response, defects, equipment in service, outage planning, etc. in an effort to reduce unexpected outages and our corresponding impact on the customers. Previous investments such as bird protection, viper switches, enhanced SCADA alarms, generation replacements are all examples of actions discussed and initiated through ROC recommendations.

OEB Staff - Interrogatory # 5

Reference:

Exhibit A / Tab 5 / Schedule 2 / Pages 1-8

Interrogatory:

Remotes has referred to some major outages that have impacted its reliability indicators. In many cases, the emergency was compounded by a delay in securing a plane to fly to the community.

a) When a major outage occurs, what are the steps involved in restoring power to the community?
b) What is the average length of a major outage before power is restored?
c) Has Remotes calculated the average cost of repairing a major outage? If yes, please provide details and the average amount.

Response:

a) Remotes considers a major outage as a community outage that lasts longer than 4 hours. The response to a major outage begins the same way as other outages. The Operators normally contact Remotes' staff when a power outage occurs. The operator and Remotes staff person triage the issue. If the operator cannot resolve the problem, the on call staff member calls the relevant distribution or generation staff to respond on site. The responding staff make a plan to go to site and secure the necessary equipment and transportation (depending on if it is road or air access). When a major outage occurs, Remotes also completes the steps for customer notification described in Attachment 1.

b) Based on 2013-2017 data, the average length of a major outage is 564 minutes.

c) Remotes has not calculated the average cost to repair a major outage; however, transportation costs alone mean that the cost is in excess of $10K.

hydro one **Remote Communities** A Subsidiary of Hydro One Inc.	Form No. CR-18	
	Revision: 04	Page: 1 of 5
Title: **CUSTOMER OUTAGE NOTIFICATION**	Issue Date: Oct, 2012	
	Review Date: Dec, 2019	

Document Approval

Prepared by: ______________________ **Date:** DEC 15/16
Kevin Mann, Manager - Customer Service & Business Development

Approved by: ______________________ **Date:** Dec 15/16
Kraemer Coulter, Director

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Revision History

Revision #	Description of Revision	Prepared by	Issue Date
00	Draft	Leslie Smith	June 30/02
01	Identify major outage internal notification requirement and provide further direction regarding external communication	Jim Kirkpatrick/Una O'Reilly	February 25, 2004
02	Update for Manager, Customer Service	Una O'Reilly	April, 2007
03	Update for Manager of Customer Service and on call to notify Managers of all unplanned outages and planned outages >4 hours.	Bob Giguere	Oct, 2012
04	Reviewed. Reference to text & What's App service made.	Kevin Mann	Dec, 2016

Note:
Should a review of this Policy result in no changes, the revision number will remain the same but the issue and review dates will be modified on the title page. An entry will be made in the Document Revision History table to reflect that the review occurred with no changes.

1.0 Policy

Hydro One Remote Communities will provide advance notice to customers and communities of planned outages[i], when possible.

Hydro One Remote Communities will make every effort to keep customers and communities informed during major prolonged unplanned outages.

2.0 Rationale

Notification of planned outages and communication to customers and communities during major outages is intended to minimize and mitigate the disruption to communities and customers.

3.0 Scope

- Prior outage notification and communications will be targeted only to the community or communities where outages are planned. Most planned outages are less than four hours.

- Unplanned community outages are defined as major or minor. A minor unplanned outage is less than four hours in duration. Major unplanned outages are longer than four hours in duration.

  Notification and communication during and after unplanned outages does not take priority over and above public and employee safety, environmental protection and/or the restoration of power.

4.0 Responsibilities

The supervisor in charge is responsible for notification and communication during both planned and unplanned outages.

For planned outages and unplanned outages during regular office hours, the supervisor in charge is either the Lines/Customer Service FLM or the Generation Mtce & Operations FLM. For unplanned outages, the supervisor in charge is the supervisor on call (an FLM or UTS).

The Manager - Customer Service or the Manager - Generation is responsible for all follow up communications, depending on the reason for the outage.

5.0 Procedure

5.1 Notification for Planned Outages

Communities will be given as much notice as possible (24 hours minimum) prior to planned community outages. In First Nation communities, Hydro One Remote Communities staff will consult with the Chief and Council in planning the timing of the outage.

Notification/communication for planned community outages will be communicated to customers through posted flyers, community contact/First Nation Band Office and local radio where available. Critical and key customers are to be contacted by phone prior to planned outages. Refer to the list of critical/key customers included within the Emergency Contact Listing and trouble manual.

For planned outages involving less than 10 customers, staff will go door to door to notify customers prior to the outage.

For planned emergency outages involving more that 10 customers, best effort will be made to notify Band office and local office.

Notification for planned outages will communicate the date, time, duration and reason for the outage. (E.g. Generation, Distribution or Connections)

5.2 Communication During Unplanned Outages

During unplanned outages, Hydro One Remote Communities will attempt to maintain communication with customers and key contacts within the community.

During office hours, frontline operations and maintenance staff receiving calls from customers (i.e., COSRs, customer care representatives, etc.) are to be updated on a continual basis, every one to two hours by the supervisor in charge. After hours, the answering service should be advised by the supervisor on call of the outage response plan and updated as required.

All customers that have called in to the office and/ or the answering service should be advised of the outage situation (i.e., general cause) and plans to respond/expected restoration time.

In the event of a major outage affecting the entire community (with an expected restoration time greater than 4 hours), critical customers and key community contacts are to be advised of the situation and Hydro One's plan to respond. This communication may be made by telephone and/or by utilizing the local agent in the community.

Critical customers and key community contacts are identified within the Local Community Emergency Telephone Listing. Key community contacts include Police, Local Government Services, Bell Canada and the First Nation. Critical customers are defined as those who have a medical need.

The Supervisor in charge will immediately inform the Manager - Customer Service, the Manager – Generation, the DCAM Superintendent and the Director of all unplanned community outages (> 1 hr.) by email, text, What's App text, or phone detailing all known relevant information (probable cause, restoration efforts, estimated restoration or response time, etc.) and provide follow-up information as it becomes available including when the power was restored. As well, those individuals listed above will be informed of any planned outage >4hrs affecting the entire community.

5.3 Communication After Unplanned Outages

After an unplanned major outage, communication will be required through the First Nation Band Office and/or in the case of a provincial/road/rail community, an identified community contact. The content of the communication will depend upon the unplanned outage circumstances (i.e., cause, Remotes' response, prevention).

[i] **Outages**
Outages can be planned or unplanned. Most planned outages are less than 4 hours.
Outages can affect an entire community, a "community outage", or a small number of customers.
Outages can be minor or major. Minor outages are less than 4 hours long. Major outages are more than 4 hours long.

OEB Staff - Interrogatory # 6

Reference:
Reponses to Letters of Comment

Interrogatory:
Following publication of the Notice of Application and the Community Meeting, the OEB received three letters of comment. Sections 2.1.6 of the Filing Requirements state that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the Board related to the distributor's application. If the applicant has not received a copy of the letters or comments received at the community meetings, they may be accessed from the public record for this proceeding.

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

Response:
a) Please find the three letters of comment as Attachments 1-A, 2-A and 3-A, with the responses attached as 1-B, 2-B and 3-B.

Filed: 2018-01-26
EB-2017-0051
Exhibit I-01-06
Attachment 1A

RECEIVED
DEC 07 2017
ONTARIO ENERGY BOARD

Ontario
Ontario Energy Board Commission de l'énergie de l'Ontario

ONTARIO ENERGY BOARD
LETTER OF COMMENT

**required fields please print*

Case Number: *EB-2017-0051

First Name: JERRY **Last Name:** HOBISCHUK

Company Name: [redacted]

Email Addr[redacted]

Address: *[redacted]

(

Comments: * Please continue on back of form if necessary. In making your comment, please consider telling us what you like and do not like about the application, what you think could be improved or what you think is missing.

I FOUND THE PRESENTATION BOTH INTERESTING & INFORMATIVE. I DID WALK AWAY FROM THE MEETING HOWEVER, THAT ONE OF THE COMMENTS, PRESENTED BY A REPRESENTATIVE FROM A REMOTE FIRST NATION COMMUNITY, DID NOT RESULT IN ANY CLOSURE.
THE REPRESENTATIVE REPORTED THAT HYDRO SERVICE WAS DISCONNECTED FROM SOME OF THE BANDS HOMES DURING THE WINTER MONTHS (DUE TO UNPAID SERVICE BILLS I ASSUME) & HOW THAT AFFECTED THOSE BAND MEMBERS HEALTH, WELFARE & SAFETY. IF IN FACT THIS

PRIVACY

By signing and giving this document to the Ontario Energy Board, you agree that your name and the content of your letter will be put on the public record and the OEB website. However, your personal telephone number, home address and email address will be removed. If you are a business, all your information will remain public.

I have read the Ontario Energy Board's privacy information and understand that my name and my comment will be made public.

Signature: [illegible] **Date:** Nov. 30/2017

5A

Additional comments...

WERE TRUE, IT WOULD BE VERY SERIOUS BORDERING ON CRIMINAL.

THE HYDRO ONE SPOKESPERSON STATED THAT IT IS THEIR POLICY "NOT TO DISCONNECT DURING THE WINTER MONTHS AND IN FACT THIS HAD NOT BEEN DONE.

SO IN CLOSING, IF THIS REPORT OF HOMES BEING DISCONNECTED DURING WINTER MONTHS WERE FALSE AND MISLEADING, IN MY OPINION, THIS WOULD ALSO BE VERY SERIOUS AND CRIMINAL.

Add Attachment (If you are attaching any documents please provide the information below)

Name of document:______________________ **Number of pages:** ______

Name of document:______________________ **Number of pages:** ______

Hydro One
Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

hydro one

Partners in Powerful Communities

January 18, 2018

Dear Mr. Hobischuk:

We are in receipt of your December 7, 2017 communication to the Ontario Energy Board regarding Hydro One Remote Communities (Remotes) Rate application.

In making its application to the OEB, Remotes seeks to recover costs that will allow us to meet our customers' needs for safe and reliable power, to ensure regulatory compliance, to maintain and operate the distribution and generating assets that are required to produce power and to offer a high standard of customer service.

I am writing in response to your concern about winter service disconnections. As noted at the meeting, Remotes does not perform service disconnections during the winter months. Remotes performs two collection/disconnection trips to each community annually as needed. Trips take place in the spring, from May to July and in the fall, from August to the end of October. Customers and Band Councils are notified frequently over a period of months before service disconnections take place and are given multiple opportunities to enter into payment arrangements and to access financial supports such as the Low-Income Emergency Assistance Program or the Ontario Electricity Support Program.

It has been Remotes' practice to reconnect customers within two weeks once their bills are paid. Historically, most customers have paid their outstanding balances before winter. In 2017, the Ontario Energy Board issued licence amendments to all Ontario distributors requiring services to be reconnected by December 1st if it is safe to reconnect the service.

Respectfully,

Kraemer Coulter
Managing Director
Hydro One Remote Communities Inc.

From: Beth Ponka (KINNA) [mailto:PonkaB@lao.on.ca]
Sent: Tuesday, November 28, 2017 3:23 PM
To: ConsumerVoice <ConsumerVoice@oeb.ca>
Cc: Chantal Walterson (KINNA) <WaltersC@lao.on.ca>; Susan Campbell (LCCLC) <campbels@lao.on.ca>
Subject: Proposed Rate Hike for Northern Communities

Ontario Energy Board

To whom it may concern:

I understand that Hydro One is considering an increase in hydro rates for several northern communities, including many that are located within the District of Thunder Bay.

Kinna-aweya Legal Clinic provides legal advice and assistance to low-income residents of the District of Thunder Bay, particularly Aboriginal people, who need assistance with poverty law issues. Our focus is on helping people get income maintenance benefits and maintain access to housing.

Families are already struggling to maintain their housing. People cannot afford to pay rent, pay utilities, and buy food.

It is unacceptable that Hydro One is proposing to further worsen this hardship. Many of the people who would be affected live in Indigenous communities and are the most impoverished residents of our District: meanwhile, generous salaries and profits are being made by the hydro companies, using the resources that have been usurped from the original inhabitants of Canada.

Please do not permit an increase in rates. Hydro companies must suppress their greed, and if necessary, sharpen their pencils and look internally, rather than further exacerbating the deep poverty and hardship that already exists in these communities.

Thank you for your consideration, Chi Miigwech.

Beth Ponka

Beth Ponka
Director of Administration | Kinna-aweya Legal Clinic
T: 807-766-7093 | F: 807-345-2842 | ponkab@lao.on.ca

Toll free: 1-888-373-3309
Kinna-aweya Legal Clinic | 86 S. Cumberland Street | Thunder Bay, Ontario | P7B 2V3
Visit us online: **kalc.ca** |

Hydro One
Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

Partners in Powerful Communities

January 18, 2018

Dear Ms Ponka (KINNA),

We are in receipt of your November 28, 2017 communication to the Ontario Energy Board (OEB) regarding Hydro One Remote Communities (Remotes) Rate application.

Remotes provides generation and distribution services to 21 off-grid communities in the remote north. Remotes is 100% debt financed and does not make a profit. Rates for our customers include both distribution and generation services.

In making its application to the OEB, Remotes seeks to recover costs that will allow us to meet our customers' needs for safe and reliable power, to ensure regulatory compliance, to maintain and operate the distribution and generating assets that are required to produce power and to offer a high standard of customer service.

The costs to provide electricity to remote, off grid communities are high, due to the inaccessibility of the communities, logistical challenges and fuel costs. Successive federal and provincial governments of all stripes have recognized that off-grid communities are economically disadvantaged. Consequently, rates for residential and commercial customers are kept affordable by capital contributions from Indigenous Affairs and Northern Development Canada, from a cross-subsidy paid by government customers, and from Remote Rate Protection monies. Remote Rate Protection is a fund established under provincial legislation and administered by the Ontario Energy Board. As a result of these government supports, rate increases for customers in Remote Communities have not exceeded the rate of inflation for the past 10 years.

Residential customers in Remotes' service territory also have access to Ontario Energy Board programs to assist them in paying their electricity bills. Lower-income customers are encouraged to apply for the provincial Ontario Electricity Support Program that offers a monthly bill credit. Low-Income customers also have access to annual grants to help them pay off overdue balances if they fall behind on bill payment.

In 2017, in recognition of indigenous contributions to the provincial electricity system, the provincial government also implemented a First Nation Delivery credit. For First Nation residential customers living on reserve in Remotes' service territory, the First Nation Delivery Credit reduces the customer's monthly service charge to zero.

Respectfully,

Kraemer Coulter
Managing Director
Hydro One Remote Communities Inc.

Ontario

Ontario Energy Board   Commission de l'énergie de l'Ontario

ONTARIO ENERGY BOARD
LETTER OF COMMENT

**required fields   please print*

Case Number: *EB-2017-0051

First Name: Kyle   **Last Name:** MacLaurin

Company Name: [redacted]

Email Address: [redacted]   **Phone Number: *** [redacted]

Address: [redacted]

Comments: * Please continue on back of form if necessary. In making your comment, please consider telling us what you like and do not like about the application, what you think could be improved or what you think is missing.

Any increase in energy rates will
negatively impact remote Communities.
The unemployment rate is extremely high
Due to limited availability of work,
this makes for Communities w limited
incomes. Having to choose between food
or Hydro is wrong.
Northern Ontario needs a northern
rate for Hydro. How Can Hydro one
Justify an increase when They were ordered
To cut $30 million in Admin costs.

PRIVACY

By signing and giving this document to the Ontario Energy Board, you agree that your name and the content of your letter will be put on the public record and the OEB website. However, your personal telephone number, home address and email address will be removed. If you are a business, all your information will remain public.

I have read the Ontario Energy Board's privacy information and understand that my name and my comment will be made public.

Signature: ________   **Date:** Nov 28/17

Ontario

Ontario Energy Board Commission de l'énergie de l'Ontario

ONTARIO ENERGY BOARD
LETTER OF COMMENT

**required fields please print*

Case Number: *EB-2017-0051

First Name: ____________________ **Last Name:** ____________________

Company Name: ____

Email Address: * ____________________ **Phone Number: *** ____________________

Address: * ____
(Street Address, City/Town, Postal Code)

Comments: * Please continue on back of form if necessary. In making your comment, please consider telling us what you like and do not like about the application, what you think could be improved or what you think is missing.

I would like to see F.N. leaders/
people partnership w/ Ont Energy Board.
a F.N. representative @ the Board in the future

PRIVACY

By signing and giving this document to the Ontario Energy Board, you agree that your name and the content of your letter will be put on the public record and the OEB website. However, your personal telephone number, home address and email address will be removed. If you are a business, all your information will remain public.

I have read the Ontario Energy Board's privacy information and understand that my name and my comment will be made public.

Signature: ____________________ **Date:** ____________________

Dear Ms. MacLaurin,

We are in receipt of your November 29, 2017 communication to the Ontario Energy Board regarding Hydro One Remote Communities (Remotes) Rate application.

Remotes provides generation and distribution services to 21 off-grid communities in the remote north. Remotes is 100% debt financed and does not make a profit. Rates for our customers include both distribution and generation services.

In making its application to the OEB, Remotes seeks to recover costs that will allow us to meet our customers' needs for safe and reliable power, to ensure regulatory compliance, to maintain and operate the distribution and generating assets that are required to produce power and to offer a high standard of customer service.

Remotes rate application also includes costs for shared services that are allocated to it from Hydro One based on established methodology. The $30 million in corporate management costs that you refer to in your letter do not have a material impact on Remotes' revenue requirement or on customer rates in its service territory.

The costs to provide electricity to remote, off grid communities are high, due to the inaccessibility of the communities, logistical challenges and fuel costs. Successive federal and provincial governments of all stripes have recognized that off-grid communities are economically disadvantaged. Consequently, rates for residential and commercial customers are kept affordable by capital contributions from Indigenous Affairs and Northern Development Canada, from a cross-subsidy paid by government customers, and from Remote Rate Protection monies. Remote Rate Protection is a fund established under provincial legislation and administered by the Ontario Energy Board.

As a result of these government supports, rate increases for customers in Remote Communities have not exceeded the rate of inflation for the past 10 years.

Respectfully,

Kraemer Coulter
Managing Director
Hydro One Remote Communities Inc.

OEB Staff - Interrogatory # 7

Reference:

Hydro One Transmission 2017 and 2018 Revenue Requirement and Charge Determinant Decision and Order (EB-2016-0160)

Interrogatory:

In the Hydro One Transmission Decision referenced above, the OEB disallowed the costs attributable to the Ombudsman Office in rates. How does this decision impact the Shared Services costs that Remotes has included in 2018 rates?

Response:

Remotes was not allocated any costs attributed to the Ombudsman Office. Therefore, the Decision in EB-2016-0160 does not affect Remotes' rates.

OEB Staff - Interrogatory # 8

Reference:

Exhibit B / Tab 1 / Distribution System Plan (DSP), Pages 11-12

Interrogatory:

Remote has provided a list of its Conservation and Demand Management (CDM) programs over the past five years. Most of the programs listed have been discontinued due to poor intake or due to difficulty in engaging Band Councils as partners. Remotes has further noted on page 97 of its DSP that Remotes' customers have expressed a disinterest in CDM and shown a preference toward renewable energy generation.

a) In Remotes' opinion, what are the main factors for the poor uptake of CDM programs over the years? Has Remotes considered including questions in its customer satisfaction survey to explore the reasons for the limited interest in CDM programs within the communities?
b) If Remotes' customers are not interested in CDM programs, has Remotes considered reducing the budget for CDM programs?
c) Remotes has provided a description of a number of these programs: Community Conservation, Main-in-rebate, commercial lighting retrofit etc. Which of the programs are funded by IESO or INAC? Are any programs funded by Remotes? If yes, please provide details including costs.

Response:

a) As noted in the DSP, Section 1.4.4.3, page 12 and 13, Remotes' customer base consists primarily of residential customers and lacks large commercial and industrial segments that provide material CDM program attainments for the rest of the province. Given the logistical challenges of appliance exchange programs in the north, Remotes and IESO residential programs focussed mainly on basic conservation items such as LED and Christmas light exchanges, wrapping hot water tanks and water pipes and on power saving items such as block heater timers. These programs were based on hiring local community members and keeping them employed to engage customers in the programs. There are limited opportunities for continued growth in these types of programs given the small size of each community. Customers have also faced generation constraints for many years and some may believe that conservation is tied to capacity limits as opposed to energy efficiency. Remotes believes that the rebate program it currently offers should continue to be available to its customers. In terms of renewable energy, Remotes customers are excited by economic opportunities for renewable energy development and want to see their communities benefit from the green energy economy. Customers also support replacing diesel with power from renewable sources. The community energy plans funded by the federal government and by the IESO have also shown community interest in renewable energy development.

b) Yes. Remotes has reduced the budget for CDM.

c) The programs described in the DSP, Section 1.4.4.1 are all programs funded by Remotes' ratepayers as follows:

Category	**Board Approved**	**Historic (Actuals)**				
	2013	**2013**	**2014**	**2015**	**2016**	**2017**
CDM	565	398	404	144	14	57

OEB Staff - Interrogatory # 9

Reference:

Exhibit B / Tab 1 / DSP, Pages 14-15

Interrogatory:

The evidence notes that the provincial government plans to connect 16 remote communities to the transmission system. Nine of these communities are presently served by Remotes and seven are operated by Independent Power Authorities (IPAs). The provincial and federal governments have indicated that all communities must be served by a licensed distribution company to connect to the grid. Five IPAs have requested service from Remotes.

a) When the nine communities that are presently served by Remotes move to receiving power from the transmission system, would they continue to be distribution customers of Remotes? Please provide a detailed response.
b) When the 16 communities are connected to the transmission system, will the number of customers served by Remotes (distribution) increase or decrease?
c) Assuming the communities are connected to a transmission system as per the timing in the North of Dryden Integrated Regional Resource Plan, what would be the impact on Remotes' revenues and load for the period 2017 to 2022?

Response:

a) Yes. Based on discussions to-date with the communities and with the federal and provincial governments, Remotes would continue to own and operate the distribution assets in Bearskin Lake, Kasabonika Lake, Kingfisher Lake, Kitchenuhmaykoosib Innninwug (Big Trout Lake), North Caribou Lake (Weagamow), Sachigo Lake, Wapekeka, Deer Lake and Sandy Lake. The customers in those communities would continue to be distribution customers of Remotes.

b) Based on discussions to-date with the communities and with the federal and provincial governments, when the transmission project is complete and in-service, the number of customers is expected to increase. The seven communities that currently operate Independent Power Authorities have written to the Minister of Energy to request service from Remotes. These communities include 1) Muskrat Dam, 2) Wawakapewin, 3) Wunnumin Lake, 4) Keewaywin, 5) North Spirit Lake, 6) Poplar Hill and 7) Pikangikum. Based on discussions with the communities and on asset inspections undertaken to date, Remotes assumed that it would take over generation and distribution service to

Wunnumin Lake in 2020, prior to transmission connection, as shown in Exhibit B, page 9, Table 1-3. Remotes anticipates taking over service to Pikangikum in 2019, as shown in in Exhibit B, page 9, Table 1-3.

c) Transmission service to all 16 communities is not included in Remotes' near-term plan as the project timing is uncertain. As indicated in the provincial Long Term Energy Plan, released in late October 2017, the provincial government is "Advocating for a fair cost-sharing arrangement with the federal government that ensures the project is fully funded and can proceed to construction." Consequently, Remotes has not yet made detailed budgeting assumptions related to the completed transmission project and the costs and revenues related to serving transmission-connected customers are not included in the 2018 revenue requirement. When the transmission project is in service, Remotes would expect to reduce its revenue requirement significantly related to lower diesel fuel and lower generation maintenance.

OEB Staff - Interrogatory # 10

Reference:

Exhibit B / Tab 1 / DSP, Page 20

Interrogatory:

Remotes has provided a summary of cost savings for the years 2017-2022 (Table 2-4). The sources of cost savings includes Winter Road Fuel Savings, First Nation Fuel Savings, Meter Reader Savings, Operator Savings and Webshare Savings.

Please provide a more detailed explanation of how the cost savings will be achieved and how they are calculated?

Response:

Winter Road and First Nations Fuel Savings

The cost savings are computed based on the quantity and unit cost of trucking fuel over winter roads and comparing within that same period, the same quantity and unit cost by flying it in. Similarly, First Nation fuel savings is the cost difference between trucking fuel in over winter roads and storing it in First Nation tank farms compared to flying it in.

Meter Reader Savings

The costs savings are determined by calculating the cost of a local person performing the work in the community (as per meter reading contracts, which is based on the number of meters read multiplied by the rate per meter) compared to a Remotes employee doing that same task, which is based on the technician labour hourly rate multiplied by the number of hours to complete the meter readings, plus travel costs.

Operator Savings

The costs savings are determined by calculating the cost of a local person performing the work in the community (as per operator contracts) compared to a Remotes employee performing that same task, which is based on the technician labour hourly rate multiplied by the number of hours worked per week, plus travel costs.

Webshare Savings

The cost savings were calculated based on reduced number of flights flying to site for tasks such as preliminary design updates. There is also less idle time spent travelling / flying to site, resulting in more time doing direct design work.

How cost savings will be achieved are as follows:

Winter Road and First Nations

Remotes negotiate annual agreements with First Nations for fuel purchase and storage. Prices vary due to commodity volatility, haul distances on winter roads, road tolls and community negotiating efforts. In all cases the price to haul fuel in over winter roads is cheaper than to fly it in. There is also the added benefit of reliability of supply once the fuel is delivered and available.

Remotes operations front line manager maintains contact with the fuel delivery company before and during the winter road season to discuss logistics as to where fuel is being delivered and the status of the winter road. Weather factors in greatly as to length of the season and days in between that the roads are passable (often warm spells may cause road closures for several days midseason). When fuel is purchased from the community, they coordinate all winter road logistics without Remotes involvement.

Meter Readers

Meter reading contracts are established with either the First Nation band or individuals living within the community. The meter reading contract lays out expectations and requirements related to the provision of the service. Meter readers are paid on a piece meal, per meter read basis. Once contracts are established on–site training is performed. Training includes meter identification, reading meters, hazards, and paperwork requirements, etc. As per the monthly billing cycles, readers are provided input sheets, perform the reads and return them to the office. Once the meter reads are in, the meter reading service provider is paid accordingly. Having locals complete this work provide significant travel and labour savings and disruption over having to send a technician to site.

Operators

Operator contracts are established with either the First Nation band or individuals living within the community. The operator contract lays out expectations and requirements related to the provision of the service.

Operators are paid on a monthly basis. Once contracts are established, on–site training is performed and annually thereafter. Training includes minor generator maintenance procedures for changing oil and filters, inspections, operation and control of the station, spill and emergency response, fueling operations, waste management, safety and environmental responsibilities, hazards, and paperwork requirements, etc. Having locals complete this work provide significant travel and labour savings and disruption over having to send a technician to site.

<u>Webshare</u>

The cost savings are determined by calculating the cost of air transportation to site and the Remotes employee performing that task of gathering and confirming the information required, which is based on the technician labour hourly rate multiplied by the number of hours worked per information required. An estimate of the number of times that this software is used in lieu of travel was gathered from the engineering, operations and maintenance staff. This cost per visit was multiplied by the estimated number of times the information is required and Webshare is used.

OEB Staff - Interrogatory # 11

Reference:

Exhibit B / Tab 1 / DSP, Page 21

Interrogatory:

Remotes has listed some of the initiatives undertaken to reduce costs. Usually, Remotes reads its own meters but contacts the First Nation band councils for local employment.

Has Remotes considered installing smart meters to allow it to read meters remotely and recognize cost savings?

Response:

Remotes has not conducted a detailed cost/benefit analysis of smart meter technology in its communities. Remotes customers do not pay TOU rates and Remotes operates outside of the provincial Smart Meter regime. In order to use smart-enabled meters, Remotes would need to install a smart meter network within each community to transfer readings from customers to a central point, and would also have to install infrastructure from that central point to the Thunder Bay office. The complexity and logistical challenges related to enabling communications infrastructure projects in the remote north would likely make the project more costly than in an urban centre, where communications infrastructure is already present. Remotes further notes that the communities it serves are economically disadvantaged. Opportunities for local employment are a priority for community leadership and for customers.

OEB Staff - Interrogatory # 12

Reference:
Exhibit B / Tab 1 / DSP, Page 23

Interrogatory:
Remotes has indicated that INAC is responsible for funding generation and distribution capital upgrades associated with load growth in First Nation communities served by Remotes.

For capital projects that receive funding from INAC, does Remotes add the cost of the projects to rate base?

Response:
No. These projects are considered contributed capital and are not included in rate base.

OEB Staff - Interrogatory # 13

Reference:

Exhibit B / Tab 1 / DSP, Page 24, Lines 35-40

Interrogatory:

Remotes has indicated that there is a lack of skilled trades contract resources living in the communities, and there are very few contractors who work in them. Remotes employs regular and casual staff, apprentices and contract staff to complete capital and maintenance work. Work in the communities requires a number of different skilled trades including line maintainers, distribution technicians, environmental technicians, mechanics, electricians and carpenters who specialize in distribution system upkeep, generator upkeep and civil construction.

Does Remotes provide any training within the communities to increase or develop the skills of locals within the communities? If yes, please elaborate on the kind of training provided and the benefits to Remotes of these initiatives.

Response:

Remotes employs and provides training to plant operator/agents that live in the community. Training includes:

- Minor generator maintenance procedures for changing oil and filters.
- Maintenance inspection procedures.
- Control of the station, i.e. start stop generators.
- Spill and other emergency response.
- Fuelling operations.
- Waste management.
- Safety and environmental responsibilities.

Remotes main benefits are cost savings and quicker emergency response time.

Remotes also employs and provides training to local meter readers that live in the community. Training includes:

- Meter identification
- Meter reading and data collection
- Account verification and documentation
- Theft of power, meter damage, etc.
- Safety and environmental responsibilities

Remotes main benefits are cost savings over the deployment of regular staff and quicker response times for check or re-reads as well as employment to the community.

Remotes does also employ occasional labourers and the training and oversight provided would be unique to the job at hand. Remotes main benefits are cost savings over the deployment of regular staff as well as employment to the community.

OEB Staff - Interrogatory # 14

Reference:

Exhibit B / Tab 1 / DSP, Page 33

Interrogatory:

The DSP indicates that Remotes performed a considerable amount of work to help the northern IPAs prepare for anticipated grid connection. Based on the proposed transmission line route, the IPAs would be connected before any of the communities served by Remotes are connected.

Was Remotes compensated for the considerable amount of work undertaken to help the northern IPAs prepare for anticipated grid connection? If yes, how were these costs calculated and accounted for?

Response:

Hydro One Remotes management team has been in active discussions with multiple communities, including those not currently served by Remotes related to grid preparation connection. Costs related to discussions with these communities fall under customer service programs, namely community relations. Data and information has also been provided as requested and recouped through existing programs.

Remotes was compensated for the work undertaken to help the northern IPAs prepare for the anticipated grid connection related to asset condition assessments. This work involved sending technical and trade staff in cooperation with the ESA to identify any asset defects requiring correction prior to Remotes providing service. The costs are calculated based on the actual costs incurred to carry out the service including labour and travel costs. There is an external mark-up percentage applied to the overall costs to recover corporate overheads and return on invested capital (interest and expenses). The revenue and expenses for the community assessments are included in Appendix 2-H Other Operating.

OEB Staff - Interrogatory # 15

Reference:

Exhibit B / Tab 1 / DSP, Page 33

Interrogatory:

The Filing Requirements indicate that applicants must provide a discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates. OEB staff notes that Remotes did not include the "value of those proposals to customers i.e. costs, benefits, and the impact on rates." The only information provided is results from a customer survey that is limited to measuring customer satisfaction.

a) Please provide a more extensive explanation of the value that was provided to customers of the proposals that were being considered for inclusion in this 2018 cost of service application. i.e. costs, benefits, and the impact on rates.
b) Please specifically state how customers' feedback informed and were incorporated into the main elements of Remotes 2018 cost of service application such as capital expenditures, business plan and OM&A costs.
c) What forms of outreach were employed to explain how the current application serves the needs and expectations of customers?
d) Please identify any initiatives considered and/or undertaken by Remotes, including any analysis conducted, to optimize plans and activities from a cost perspective, for example, balancing cost levels of OM&A versus capital.

Response:

a) Remotes notes that its customers do not pay rates that are based on cost. Consequently, the rate impact of specific capital and OM&A projects to be included in revenue requirement were not discussed with end-use customers. Instead, Remotes asked end-use customers about their priorities in terms of electricity service, including reliability, environmental protection, customer service and affordability.

   Remotes' approach to discussing service and value with Band Councils, who are also end-use customers, is generally more comprehensive in terms of costs and benefits. For example, discussion on purchases of First Nation fuel focus not only the economic benefit to the First Nation but also on the benefit to Remotes (and the ratepayers who support RRRP). Similarly, discussions on service reliability and the need for investments in regular maintenance in assets also take place. As highlighted in the DSP, Band Councils are closely involved in all projects related to load growth as these projects are federally funded and the Band Council must request the funding from INAC.

b) Please see Section 4.6 of the DSP pages 87-92 for lists of specific work activities undertaken in response to end-use customer engagement and reflected in this application.

c) Most outreach occurred prior to the preparation of the application, at the time the business plan and underpinning work programs were determined. As outlined in Section 4.6 of the DSP and in the Schedules under Exhibit A, Tab 4 Remotes discussed its work program and activities with end-use customers through:
   - Regular band/community meetings to discuss community needs and projects;
   - A workshop with end-use customers organized in cooperation with OSLP; and
   - A Customer Advisory Board meeting to determine customer priorities.

   Remotes notes that end-use customer outreach was also undertaken by OEB staff as part of the notice for the application, including a community meeting, community posters, letters and phone calls to customer contacts and band councils, media outreach and advertisements.

d) In general, Remotes has more needs and work than it can reasonably accomplish. Every year the teams work to identify projects in priority order, so that our work is spent on the projects providing the most impact to our strategic goals and customers. Remotes also actively works with Band Councils and INAC to get funding to increase system capacity (which reduces ratepayer costs). Generally, OMA vs. Capital decisions are also made based on the cost benefit of repairing or replacing.

OEB Staff - Interrogatory # 16

Reference:

Exhibit B / Tab 1 / DSP, Pages 45-46

Interrogatory:

Remotes is planning to install new viper switches on its distribution system to protect upstream customers from downstream faults and to improve the cold load pick up capability of the system.

a) What is the timeline of installing the new viper switches?
b) What is the total cost of installing the new viper switches and what portion of these costs are included in the 2018 Test Year?

Response:

a) Upfront engineering and investigation work is required in order to identify the preferred communities as well as preferred location. Viper ordering timelines are generally 3 months until delivery since they are specific specialized items. Viper switches also require approximately 1 week of programming and testing prior to installation. The physical installation of Viper switches generally takes less than two weeks depending on the location and structure chosen. Larger replacements poles are often required to allow for appropriate clearances. Overall, once a viper location is selected it would take 4+ months until it is in service, provided the work schedule allows for it.

b) The total cost of installing a viper switch in a Remote community is approximately $50-$75K. It is expected that 1 to 2 viper switches will be installed annually starting in 2018 and beyond, until such time as most mid to larger sized communities are addressed.

OEB Staff - Interrogatory # 17

Reference:
Exhibit B / Tab 1 / DSP, Pages 48

Interrogatory:
Remotes tracks its distribution losses as the difference between the energy generated and energy sold, measured as a percentage of the total energy generated (all in kWh). The target for the metric is 3.6% or less. Remotes has indicated that it exceeded its target in 2013, but has met the target since.

a) What were the reasons for not meeting the target in 2013?
b) Is electricity theft included in distribution losses?
c) Is electricity theft an issue in Remotes service territory? If yes, please provide the revenue loss as a result of electricity theft for the years 2013 to 2017.

Response:
a) For Remotes, the distribution losses include station service including staff house loads, so are not directly comparable to distribution losses. Since 2013, improvements have been made to the meter reading and measurement of the generation station service load.

b) Yes.

c) No. Electricity theft is not a major issue in our communities. Temporary unauthorized connections to other buildings do occur and present a safety concern, but not a theft concern. Local meter readers have been trained to look for electricity theft and as there are few underground ground services, theft can be detected visually.

OEB Staff - Interrogatory # 18

Reference:

Exhibit B / Tab 1 / DSP, Pages 51-52

Interrogatory:

Most of Remotes' electricity is generated using diesel fuel since it is currently the most reliable and cost-effective method. Generators within the 19 generating stations burn diesel fuel to produce electricity, directly emitting greenhouse gases to the atmosphere. Remotes has noted that it has increased its direct emissions from electricity generation for the past years. This is due to increase in the electricity demand. Therefore, Remotes' focus is to reduce its net emission intensity.

Has Remotes evaluated the use of alternative generation technologies apart from solar and wind that could decrease its net emission intensity and reduce emissions from greenhouse gases? Please provide a detailed response.

Response:

Remotes has explored and evaluated other alternative generation technology including water, bio-mass, hydrogen and Organic Rankine Cycle (ORC) technology, to name a few.

Remotes routinely meets with those interested in renewable technology within our service territory, regardless of technology or proposed solution. The design of the REINDEER program offering purchased power agreements at the avoided costs of diesel, drives innovative ideas in the private and competitive renewable market. Since many exciting alternative renewable generation technologies exist, Remotes remains hopeful that as the renewable technology evolves, the cost effectiveness of these alternatives will become more cost effective and can be utilized to reduce net emission intensity.

OEB Staff - Interrogatory # 19

Reference:

Exhibit B / Tab 1 / DSP, Page 70

Interrogatory:

While discussing the replacement of diesel generators that are in a poor condition, Remotes has noted that Hillsport and Sultan are small communities that have temporary units that can be moved among the sites to manage the impact of an unplanned failure.

a) Does Remotes provide service in other small communities that can take advantage of temporary movable units to manage the impact of an unplanned failure?
b) Has Remotes conducted any analysis or studies to understand the cost impact of using temporary small or medium sized generators that can be moved within communities to manage the impact of an unplanned failure? Please provide a detailed response.

Response:

a) Yes. In the context of "small communities", these units have applications at Biscotasing and Oba as well.

b) Remotes generation station design for fly-in sites accommodates one primary catastrophic unit failure. That is, after a single catastrophic generator failure, the remaining generators are capable of providing the peak community load.

   Remotes does have some small and medium sized spare units that are available in emergency power situations, where the existing station assets are not able to supply community load. These units are stored in Thunder Bay. These units are better suited for transportation by air, than the small units utilized at the road sites. These units are also used in the generation replacement program and station upgrades. The availability of spare units reduces the cost of emergency response.

OEB Staff - Interrogatory # 20

Reference:

Exhibit B / Tab 1 / DSP, Pages 73-74

Interrogatory:

Remotes owns 4,662 poles, a large proportion of which are between 25 and 35 years old. Over the next 5 years, Remotes plans to replace 115 poles identified to be in poor condition.

a) What is the average cost of replacing a pole?
b) What is the average life of a pole in Remotes communities and is it different from other parts of Ontario?

Response:

a) The cost range for replacing a pole is between $10K-30K, with an average cost of $18K. The cost to replace varies significantly based on the size and structure of the pole, its attachments, location, ground conditions, outage requirements and joint use aspects.

b) The average life is pole is based on the 2011 depreciation rate review performed by Foster Associates, which identifies a 55 year life. Given that our asset aging is still relatively new (28 year average) and not nearing end of life, it would be difficult to make full life cycle comparisons to the rest of the province. It is debatable whether the harsh weather conditions will benefit or compromise pole life. To date based on the ACA work performed and operational feedback, Remotes fully expects that pole life is similar to other utilities as there is no reason to suspect otherwise.

   Remotes notes that, as per the Hydro One Networks Distribution Study by Navigant, dated October 2016 and filed as evidence in EB-2017-0049, it would appear that Remotes' average pole life of 28 years is similar to the peer group and that our deemed life of 55 years is slightly higher than the peer average.

OEB Staff - Interrogatory # 21

Reference:

Exhibit B / Tab 1 / DSP, Page 86

Interrogatory:

In table 4-8, Remotes has provided a list of generation related capital projects for the years 2018 to 2022. One of the categories include SCADA and PLC Replacement and high speed internet.

a) Will Remotes be installing the high speed internet connection or will it be installed by a third party contractor?
b) What is the total cost of installing the high speed internet connection and what portion of these costs are included in 2018 capital expenditures?
c) Is Remotes sharing the cost of installing high speed internet with some telecom provider or the First Nation communities?
d) Will the high speed internet connection only benefit Remotes or the entire community and other companies?

Response:

a) High speed connections are being provided by a third party contractor.

b) The estimate for installing the high speed fibre connection for 3 sites is $3K. Additional labour and materials will need to be performed by Remotes staff to accommodate this new service. The cost for Remotes staff to complete the modifications inside our stations is $260K.

c) No, the high speed cable is in the community already, we are just having it connected to our stations.

d) The high speed internet connection will only benefit Remotes. This high speed connection supports secure and safe operations of the generation station. It will give Remotes information access about the plant to assist Operators in trouble shooting and assessing problems which should reduce cost and time related to repairs.

OEB Staff - Interrogatory # 22

Reference:

Exhibit B / Tab 1 / DSP, Page 87

Interrogatory:

Remotes has indicated that as per the Order-in-Council from the Provincial Government, 16 remotes communities are expected to be connected to the transmission system. Nine of these communities are presently served by Remotes and at least two more communities are expected to be served by Remotes in the future. While this will not affect investments according to Remotes, in the communities over the five-year period of the DSP, it has affected the investments INAC makes in generation assets. It is also expected that the construction activities of this new transmission line will affect Remotes planning considerations over the medium to long term.

a) How has the proposed construction of the transmission system affected the investments INAC makes in generation assets? How is this change expected to impact funding that Remotes receives from INAC?
b) Has Remotes considered deferring investments in generation overhaul or new generators as a result of the expected connection of some of the communities to the transmission system? If no, why not?

Response:

a) Remotes notes that, as described in the Section 2.1.6, pages 23 & 24 of the DSP, Remotes has revised the upgrade process to allow incremental increases to capacity. This incremental approach does reduce federal government investments in new generation capacity prior to the planned transmission project being put into service. The new process allows INAC and Remotes to respond to communities' needs to grow in the near term and, as such, seems to fit in well with the proposed transmission project.

b) Deferring investment in generation overhauls has not been considered since the expected transmission connections are not within the plan horizon and any deferrals would only be advisable if connection were imminent, i.e. transmission and distribution assets mostly constructed and connection pending. As long as the station is the only source of power, all station generators are required (i.e. cannot reliably operate a three generator plant with two generators). New generators are generally installed to allow for an increase to the station capacity prior to remove communities from load restrictions and, as stated, an incremental approach for contributed capital to support these upgrades has been adopted.

If like for like generator replacements are planned based on Remotes current practices, deferrals would be considered if actual transmission line construction has started. Remotes also is mindful that there may be a backup generation strategy/requirement that would require reliable generation assets once the transmission line is in place.

OEB Staff - Interrogatory # 23

Reference:

Exhibit B / Tab 1 / DSP, Page 92

Interrogatory:

In the DSP, Remotes has indicated that its service area is expected to expand to include three new communities during the forecast period. One of these, Cat Lake is already connected to the Hydro One Networks Inc. transmission system in northwestern Ontario; therefore, Remotes will only be responsible for power distribution in this community. The transfer is planned for 2018, is contingent upon an agreement with the community, and will result in a customer increase of 111.

a) If Remotes were to distribute electricity in Cat Lake in 2018, does it have OEB-approved distribution rates to charge customers in the community of Cat Lake? If yes, please provide the distribution rate that will be charged and explain how the rate was derived?
b) Has Remotes included the expected connection of 111 customers in the community of Cat Lake in its customer and load forecast?

Response:

a) Yes, rates for grid-connected customers were approved in EB-2012-0137. Please see the Attachment 1 for information on the basis for the grid connected rates that were proposed and accepted by the Board.

b) The number of customers in Cat Lake are included in the DSP customer forecast. However, the load, costs and revenues related to serving Cat Lake are not included in the revenue requirement, as the timing for an agreement with the First Nation is uncertain. In January 2017, the community informed Remotes that the transfer of service to Remotes was not a community priority.

PROPOSED GRID-CONNECTED CUSTOMER RATES

1.0 INTRODUCTION

In 2010, the Ontario Government amended the *Electricity Act, 1998* (the “Electricity Act”) to require Remotes to serve grid-connected communities in accordance with government regulation. The decision to permit Remotes to serve these customers was made to give remote communities connecting to the grid an option of being served by an established electricity distribution company and in anticipation that these customers will qualify for rate protection if served by Remotes.

Remotes believes that service to geographically remote communities will be more expensive than service to communities that are more accessible. Moreover, the provision of electricity in First Nation communities across the remote north has historically been supported by the federal government. Remotes and most of the Independent First Nation Power Authorities have historically set rates for government customers above cost to help cover the operating costs and to keep rates for residential customers affordable. As a result, rates for residential and small commercial customers are quite low when compared to rates for grid-connected customers.

To ensure that residential customers whose communities connect to the grid do not experience significant rate increases, Remotes plans to include non-Standard A grid-connected residential and general service customers in its existing non-Standard A Residential and General Service rate classes. Offering grid-connected non-Standard A customers the same rates as other residential and general service customers in Remotes’ service territory will reduce potential rate impacts if communities that Remotes currently serves connect to the grid.

Under the RRRP regulation, Standard A (government funded) customers do not benefit from Rate Protection. Remotes anticipates that grid-connected Standard A customers will not be eligible for rate protection. Moreover, Remotes' Standard A rates, like those in most communities in the far north, are set slightly above the average cost of service.

To develop the grid-connected Standard A rate, Remotes first estimated the current "implicit" generation cost embedded in its Standard A rates. The implicit generation costs consist of the generation related costs as well as a proportionate share of Shared Services and Other Costs (Exhibit C1, Tab 2, Schedule 6). The implicit generation costs in Remotes' 2012 Standard A rate are shown below:

Table 1

2012 Generation Costs Excluding Fuel

2012 Generation Costs	**($000's)**
Operations & Maintenance (excluding fuel)	9,577
Environmental OM&A[1]	339
Generation Depreciation	2,371
Land Assessment and Remediation (Amortization)	3,473
Administrative	517
Total Generation Costs Excluding Fuel	**16,277**

To determine the per kWh generation cost, Remotes divided the total generation costs excluding fuel by the projected kWh sold.

[1] Environmental costs are comprised only of generation-related costs and include 50% of the legislative monitoring costs and environmental costs related to fuel spills.

Table 2

Per kWh Off-Grid Generation Costs

Total Generation Costs Excluding Fuel ($000)	16,277
kWh sold (000's projected)	55,806
Cost per kWh off-grid generation ($/kWh)	**0.2917**

Fuel costs vary from year to year depending on external factors such as market prices and the availability of winter roads. To determine an appropriate proxy for fuel costs, Remotes took the three-year average cost per kWh for air access communities.

Table 3

Air Access kWh Fuel Costs

	2009	2010	2011
MWh Sold	47,293	46,094	48,129
Annual Air Access Fuel Costs ($000's)	$17,057	$19,405	$20,374
Three Year Average MWh Sold	47,172		
Three Year Average Fuel Costs ($000's)	$18,945		
Three Year Average $/kWh	**0.4016**		

In order to estimate the cost of power if delivered through the transmission grid, Remotes considered the charges that would typically be paid by a grid-connected customer. The commodity charge is estimated to be the 2011 weighted average cost of power per the IESO December, 2011 Monthly Market Report. The estimated Wholesale Market Service Charge and RRRP charges are those currently in effect. The cost of Transmission service is estimated based on Retail Transmission Service Rates (RTSR) for General Service Energy customers requested for approval in Hydro One Networks Inc.'s 2013 rate application (EB-2012-0031). Line losses are estimated at Remotes' current line losses.

Table 4

Estimated Cost of Grid-delivered Power

Commodity	0.07200
Wholesale Market Service Charge	0.00520
RRRP	0.00110
RTSR - Network	0.00518
RTSR - Line	0.00358
Cost of Grid-delivered Power	0.0871
Line Losses @ 1.5%	0.0013
Total Cost of Grid-delivered Power	**0.0884**

In order to calculate the proposed Standard A Grid Connected Rate, Remotes took the 2012 Standard A General Service Air Access Rate and subtracted the generation and fuel costs and added the cost of Grid-delivered power.

Table 5

Proposed Grid Connected Standard A Rates

Standard A General Service Air Access Rates (Exhibit G1-1-1)	0.8951
Remotes' Generation Costs Excluding Fuel (Table 2)	(0.2917)
Air Access Fuel 3 Year Average (Table 3)	(0.4016)
Cost of Grid Power (Table 4)	0.0884
Grid-connected Standard A Rate	**0.2902**

OEB Staff - Interrogatory # 24

Reference:

Exhibit B / Tab 1 / DSP

Interrogatory:

While discussing capital expenditures, Remotes has referred to many projects/programs stating that expenditures are customer-initiated and fully recoverable.

a) Please explain what "fully recoverable" means? In the case of such expenditures, does Remotes recovers all of its expenses including OM&A costs that are usually capitalized?
b) Are any of the "fully recoverable" capital expenditures added to rate base?

Response:

a) "Fully recoverable" means that Indigenous and Northern Affairs Canada ("INAC") is responsible for funding capital related to system expansions and capital upgrades. Yes, Remotes recovers all of its expenses that are usually capitalized relating to such expenditures.

b) No.

OEB Staff - Interrogatory # 25

Reference:
Exhibit B / Tab 1 / DSP, Page 98

Interrogatory:
Remotes has not provided any information on customer engagement. There is some feedback from customers that is provided in the customer survey results and the Customer Advisory Group that offers advice on service policies and procedures, and ways to improve services within the communities. However, there is no information on how the perspective of customers was incorporated into the DSP and how Remotes was informed of its customers' preferences in creating the DSP and planned capital expenditures.

a) Please confirm whether Remotes initiated any customer engagement prior to formulating the DSP or preparing the cost of service application. If no, why not?
b) Please explain how Remotes planned capital expenditures reflect customer preferences identified through customer engagement.
c) Please identify any customer engagement that supports the further increases proposed in this application.

Response:
a) Yes, Remotes initiated end-use customer engagement, as documented in the Schedules under Exhibit A, Tab 4 and as outlined in the DSP. Remotes notes customer engagement is an ongoing, necessary and central part of Remotes' day to day business and that these customer engagements underpin the projects and work program that were approved in the business plan that underlies this application. Specifically with respect to capital projects, Remotes customers must apply to INAC for funding for capital projects associated with load growth. If customers do not support the project, the project will not proceed. All of the contributed capital upgrade projects referenced in the DSP are planned together with customers. Capital projects funded through rates that are associated with general reliability, economic life, and sustainment (ventilation, tank replacements etc.) projects that are funded through rates are also discussed with customers in the context of reliability, safety and environmental performance.

b) In terms of contributed capital, customers have indicated that they want their communities to be able to grow and want new customers to be able to connect to the distribution systems. The proposed sustainment, reliability and economic life capital investments set out in the DSP reflect the importance customers place on service reliability and environmental protection/performance.

c) Rates for Remotes’ customers are set under rules established by the Rural or Remote Rate Protection Regulation. Remotes’ rates do not, therefore, reflect the cost of service or the proposed capital plan. The rates proposed by Remotes follow a formulaic increase set out in the Regulation, consistent with previous cost of service rate filings. Consequently, the proposed rate increases were not discussed with customers in the context of the capital plan, as the rates are not dependent on the costs incurred.

OEB Staff - Interrogatory # 26

Reference:

Exhibit B / Tab 1 / DSP, Page 104, Table 4-14

Interrogatory:

Remotes has provided the net capital expenditures for the period 2013 to 2022 and the percentage change in each of the years. In 2013, 2014 and 2015, Remotes' capital expenditures were significantly lower than planned.

a) Please provide detailed reasons as to why actual capital expenditures in 2013, 2014 and 2015 were significantly lower than planned.
b) Please update table 4-14 with 2017 actual capital expenditures.
c) Considering that Remotes has underspent in previous years (2013 to 2016), how does Remotes plan to meet its forecast capital expenditures for the planned period, 2018 to 2022?
d) While capital expenditures have declined during the 2013 to 2016 period, system O&M expenditures have not experienced any corresponding decline with the exception of 2016. Please explain the reasons for the disconnect between capital expenditures and system O&M expenditures.

Response:

a) The reasons why actual capital expenditures in 2013, 2014 and 2015 were lower than planned have been provided in the Distribution System Plan, Section 4.4.1 Variances in Net Capital Expenditures and are provided below:

   Net capital expenditures in 2013 were below plan due to the delayed start for two generator unit replacements in Lansdowne due to the failure of the Deer Lake B unit; re-prioritization of civil staff house improvement projects to instead focus on garage improvements in three communities; deferral of protection upgrades and switchgear work due to increased engineering involvement in the planned replacements in Sandy Lake and Sachigo Lake; redeployment of technical and management staff to the CIS project and the nature of the work required to certify fire systems was determined to be maintenance in nature once the program started. The variance was partially offset by: unplanned costs for replacement of the Deer Lake B unit; and increased engine overhauls (two additional units).

Net capital expenditures in 2014 were 32% below plan due to a decision to cancel planned replacements of the Wapekeka C unit and the Fort Severn C unit due to an in-year agreement with INAC to fully fund an upgrade of both units; Bearskin B unit deferred due to lower than forecast operating hours; Marten Falls unit operating and reliability deficiencies were corrected, therefore the unit was not replaced; lower than planned garage construction costs in two communities and a decision to defer to 2015 some of the work associated with refurbishing the Sultan run-of-the-river hydroelectric plant after a catastrophic failure, as the work was more technically complex than originally expected. The variance was partially offset by day-tank replacement work required to meet fuel code requirements; and leaking roof of the Deer Lake staff house that necessitated capital repair and the completion of other civil work while staff were at site.

Net capital expenditures in 2015 were 62% below plan due to a decision to focus on fully recoverable INAC upgrade projects that would allow customers in three communities to connect to the electrical system. This resulted in the removal of connection restrictions for all three communities; engine replacements were lower as they were completed within the scope of these upgrade projects and day tank improvements, the Wapekeka 600-V upgrade and capital betterments work were also deferred due to this shift in priorities. The variance was partially offset by above-plan spending on the Lansdowne A unit engine replacement; and the completion of rebuild work at the Sultan run-of-the-river hydroelectric facility.

b) Refer to Appendix A for table 4-14 updated with 2017 actual expenditures.

c) Refer to the Distribution System Plan, section 4.4.2 Trends in Capital Expenditures that provides discussion on forecast capital expenditures and are provided below:

- Distribution system renewal – increased metering costs have been budgeted based on the anticipated service area additions;
- Generation system renewal – planned investments over the forecast period to replace generators, overhaul generators, and civil repair work at diesel generating stations are based on the conditions of the respective assets; and
- Generation system service – Additional SCADA and PLC upgrades and fuel system improvements to occur over the forecast period.

INAC faces funding constraints and an overwhelming need for infrastructure in First Nations communities. The need for electricity infrastructure competes with requirements for schools, housing, water treatment plants, etc. The timing for funding approvals and the amount of funding available is uncertain and requires planning flexibility to accommodate growth within these communities. The federal government also has rules related to the timeframe in which the funding is spent and a project is completed. If funding is not spent within the federal government's time frame, the funding is returned to federal general revenues or deployed to another needed project. Consequently, funding levels and projects may be determined late in INAC's fiscal year and if funding becomes available, Remotes adjusts its planned work program to accommodate upgrade projects.

Gross capital expenditures for years 2015 and 2016 are overspent to budget mostly driven by reprioritizing work to focus on INAC-funded generation upgrades, which are fully recoverable. Refer to Appendix B for table 4-14 with gross capital expenditures before funding by INAC and removals.

d) Remotes investigated the relationship between capital spending and system O&M costs. Regardless of the capital spending, generator maintenance is required every 2,500 engine-hours. Due to the associated flight and fuel costs of this maintenance, there is no reduction to system O&M costs from capital investment. O&M costs have increased due to higher unplanned maintenance of auxiliary and plant systems, renewable energy maintenance, safety improvements, building maintenance and engineering investigations.

Appendix A: Historical and Forecast Net Capital Expenditure and System O&M

Table 4-14: Historical and Forecast Net Capital Expenditure and System O&M

	Historical															Forecast				
	2013			2014			2015			2016			2017			2018	2019	2020	2021	2022
	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan				
Category	$'000		%	$'000		%	$'000		%	$'000		%	$'000		%	$'000				
System Access		123			31			42			70			23		0	0	0	0	0
System Renewal - Distribution		756			504			544			760			445		522	609	643	654	670
System Renewal - Generation		3,401			3,615			1,288			2,434			1,471		1,644	2,636	3,369	3,791	2,221
System Service - Distribution		0			0			0			0			0		0	0	0	0	0
System Service - Generation		456			(193)			(19)			0			1,059		505	726	675	391	848
General Plant		691			677			473			914			525		565	572	581	590	598
Net Capital Expenses	**7,747**	**5,427**	**-30%**	**6,834**	**4,634**	**-32%**	**6,058**	**2,328**	**-62%**	**5,060**	**4,178**	**-17%**	**3,727**	**3,523**	**-5%**	**3,236**	**4,543**	**5,268**	**5,426**	**4,337**
System O&M	18,662	18,335	-2%	18,092	18,601	3%	20,644	16,492	-20%	21,463	18,060	-16%	20,760	17,239	-17%	21,291	22,260	23,650	24,095	24,281
Total Spend	**26,409**	**23,762**	**-10%**	**24,926**	**23,235**	**-7%**	**26,702**	**18,820**	**-30%**	**26,523**	**22,238**	**-16%**	**24,487**	**20,762**	**-15%**	**24,527**	**26,803**	**28,918**	**29,521**	**28,618**

Appendix B: Historical and Forecast Gross Capital Expenditure and System O&M

Table 4-14: Historical and Forecast Gross Capital Expenditure and System O&M

	Historical															**Forecast**				
	2013			**2014**			**2015**			**2016**			**2017**			**2018**	**2019**	**2020**	**2021**	**2022**
	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	**Plan**				
Category	$'000		%	$'000		%	$'000		%	$'000		%	$'000		%	**$'000**				
System Access		597			605			800			534			820		912	1,065	1,121	1,143	1,166
System Renewal - Distribution		1,291			739			681			895			651		772	899	947	965	983
System Renewal - Generation		3,651			4,064			1,172			2,659			1,572		1,788	2,847	3,582	3,995	2,426
System Service - Distribution		0			0			0			0			0		0	0	0	0	0
System Service - Generation		499			167			7,054			2,588			6,648		5,853	6,852	6,392	5,412	5,810
General Plant		691			677			473			914			525		565	572	581	590	598
Gross Capital Expenses	**9,575**	**6,729**	**-30%**	**8,836**	**6,252**	**-29%**	**9,080**	**10,180**	**12%**	**7,175**	**7,590**	**6%**	**12,378**	**10,216**	**-17%**	**9,890**	**12,235**	**12,623**	**12,105**	**10,983**
Contributions & Removals	(1,828)	(1,302)		(2,002)	(1,618)		(3,022)	(7,852)		(2,115)	(3,412)		(8,651)	(6,693)		(6,654)	(7,692)	(7,355)	(6,679)	(6,646)
Net Capital Expenses	**7,747**	**5,427**	**-30%**	**6,834**	**4,634**	**-32%**	**6,058**	**2,328**	**-62%**	**5,060**	**4,178**	**-17%**	**3,727**	**3,523**	**-5%**	**3,236**	**4,543**	**5,268**	**5,426**	**4,337**
System O&M	18,662	18,335	-2%	18,092	18,601	3%	20,644	16,492	-20%	21,463	18,060	-16%	20,760	17,239	-17%	21,291	22,260	23,650	24,095	24,281
Total Spend	**26,409**	**23,762**	**-10%**	**24,926**	**23,235**	**-7%**	**26,702**	**18,820**	**-30%**	**26,523**	**22,238**	**-16%**	**24,487**	**20,762**	**-15%**	**24,527**	**26,803**	**28,918**	**29,521**	**28,618**

OEB Staff - Interrogatory # 27

Reference:

Exhibit B / Appendix A / Business Cases for Material Investments, Pages 15-18

Interrogatory:

Remotes has indicated that the A unit diesel generator in Big Trout Lake is forecast to reach 55,868 engine-hours in 2019 and is rated to be in very poor condition. Remotes has proposed an engine replacement for this generator in 2019.

a) What is the total cost to replace the A unit generator in Big Trout Lake?
b) Will ratepayers be paying for the cost of replacement?
c) Please confirm that replacement generators are paid for by ratepayers while generator installation in response to load growth is paid for by INAC or First Nation communities.
d) Remotes has indicated that it has 57 diesel generators in service. How many of these generators have been replaced (paid for by ratepayers) over time?

Response:

a) The total cost to replace the Big Trout Lake A Unit is $1,445K.

b) Yes, ratepayers will pay the replacement cost.

c) Yes, replacement (sustainment) of generators is paid for by ratepayers and capacity increasing generation funding contributed capital from INAC through the First Nation.

d) Since 2008, 21 generators have been replaced.

OEB Staff - Interrogatory # 28

Reference:

Exhibit B / Appendix A / Business Cases for Material Investments, Pages 23-27

Interrogatory:

Remotes has provided information about its planned generator overhauls. Medium-speed engines (1,800 rpm) are overhauled after 20,000 engine hours and low-speed engines (1,200 rpm) are overhauled after 42,000 hours. The average gross spending over the forecast period (2018 to 2022) is $703,000 per year with $608,000 budgeted for the 2018 Test Year.

What is the process involved in a generator overhaul and how long does it take to overhaul a typical generator?

Response:

It typically takes three weeks to overhaul 1,800 rpm engines and 4 weeks for 1,200 rpm engines. The process involves isolating the engine and complete disassembly of all external and internal parts such as pistons, crankshaft, fuel pump etc. The engine and parts are then inspected for wear tolerances or damage. Parts are either replaced, rebuilt (manufacturer) or reused. Once the engine is reassembled it is run through a series of tests to ensure proper functionality. During the overhaul all electrical and auxiliary parts (rads, pumps, fans etc.) and functions are inspected, repaired, replaced and tested as required as well.

OEB Staff - Interrogatory # 29

Reference:

Exhibit B / Appendix A / Business Cases for Material Investments, Pages 54-58

Interrogatory:

Remotes plans to connect the communities of Big Trout Lake and Wapekeka to combine the peak load. Remotes has indicated that the connection of the two communities through a distribution line would improve the ability to supply power from either diesel generation station under contingency situations, reducing the frequency and duration of outages in both communities. Remotes has also indicated that it has not connected stations together previously in the proposed manner.

Are there any other communities served by Remotes that can be connected in a similar manner as Big Trout Lake and Wapekeka?

Response:

All of the communities could in theory be connected together, hence the Wataynikaneyap, North of Dryden project. The proximity of the communities to one another and the cost of transmission/distribution connection make these type of projects largely unsuitable for a small business like Remotes. For Remotes, connecting communities would only make sense if the cost to build and maintain the community connect is lower than the avoided generation upgrade costs or if large scale renewable power is available.

In this context, two additional areas have been identified as offering possibility of connection between communities. Armstrong (Whitesand/Collins) could be connected to Gull Bay in a similar fashion, ideally when the biomass plant under development by Whitesand First Nation is operational. As well, the communities of Sandy Lake and Deer Lake could also be connected in a similar fashion, if the Duck River/Favourable Lake/Northwind hydroelectric project were to proceed. Road access between communities would be expected to lower construction cost of infrastructures and would also significantly reduce diesel fuel cost to those communities not in proximity to large scale renewable power.

OEB Staff - Interrogatory # 30

Reference:

Exhibit B / Appendix A / Business Cases for Material Investments, Pages 68-75

Interrogatory:

Remotes has indicated that its customers in Weagamow have requested funding through INAC to upgrade the generating station capacity. Subject to the availability and amount of INAC funding approved, the Weagamow upgrade would replace all four generators comprising the community's current generating station. Remotes has further noted that the community of Weagamow is anticipating connection to new transmission lines under the Remote Community Connection Plan.

a) Please explain the rationale for replacing all four generators when it is anticipated that in the medium term the community of Weagamow will be connected to a new transmission system? Has Remotes considered replacing some of the generators rather than all four considering that the community is expected to be connected to a transmission system?
b) What will be the expected utility of four new generators once the community is connected to a transmission system?

Response:

a) All four units at the Remotes generation station in Weagamow cannot accommodate a further upgrade, due to physical limitations of the existing building, switchgear, transformation and voltage. The existing fuel storage will be reused. The oldest generator installed at the site can no longer be replaced by a generator of the same rating due to changes in size of newer units that accommodate new emission regulations.

   Remotes may consider reusing one of the generator motors (725 kW) or repurposing the unit elsewhere in another location, depending on the timing of the station upgrade.

b) The four new generators will be available for stand-by in Weagamow or redeployment to other communities. A modular design for the station is being investigated, which would facilitate the use of these units as back up generation when the transmission connection is eventually made.

OEB Staff - Interrogatory # 31

Reference:

Exhibit B / Appendix A / Business Cases for Material Investments, Page 76

Interrogatory:

Remotes has expressed a concern with respect to transportation of heavy equipment to the community of Weagamow for the upgrade project. Remotes expects an all-season road to the community to be completed in 2017.

Please confirm whether the all-season road has been completed. If not, please provide an expected date of completion.

Response:

The bridge providing future year access to the community was completed in the fall of 2017 and given it is now the winter season; it is now allowing early and stable access to the community. Remotes' understanding is that the road portion of the project still requires work to meet the required standards and provide reliable and suitable year round access. Remotes expects the all-season road to be completed by the fall of 2018.

OEB Staff - Interrogatory # 32

Reference:

Exhibit B / Appendix B / North of Dryden Integrated Regional Resource Plan / Page 25

Interrogatory:

The northern portion of the North of Dryden sub-region is comprised of 21 remote communities, some of which are served by Hydro One Remotes. The Remote Community Connection Plan demonstrates a business case to connect 21 of 25 remote communities that currently rely on diesel generation, to the provincial transmission grid. For the purpose of this regional plan, 21 of the 25 communities are assumed to connect to Ontario's transmission system as per the IESO's Remote Community Connection Plan. Communities are expected to begin connecting in the early 2020s.

In Remotes' DSP, it has indicated that the Remote Community Connection Plan is still in its draft form, the connection dates for the communities served by Remotes are not firmly established at this time. Remotes also notes that the Remote Community Connection Plan will not affect investments in the communities over the five-year period of the DSP.

a) Does Remotes expect that a new transmission system will not be in place in the early 2020s providing grid connection to some of the communities served by Remotes? If yes, please provide reasons.
b) If some of the Remotes communities start getting connected to the transmission system in early 2020s, would Remotes need to re-evaluate some of its proposed investments in the DSP?
c) In Remotes opinion, what is the expected timeline of communities served by Remotes getting connected to the transmission system under the Remote Community Connection Plan?
d) Why is Remotes not considering altering or scaling down some of its proposed investment plans in light of the implementation of the Remote Community Connection Plan?

Response:

a) As noted in Exhibit I, Tab 1, Schedule 9, Remotes has not included the transmission connection of its communities in its near term business plan as the project timing remains uncertain. Remotes fully expects that the transmission project will go ahead; however its construction remains outside our five-year planning window.

b) Remotes does not foresee its communities being connected before the end of the rate period. As the project moves forward to construction, Remotes expects that INAC will no longer fund generation upgrades. Rate payer funded investments in maintaining generation service reliability are expected to be altered when the connection is imminent. Distribution investments will continue to be required. Remotes notes that discussions regarding back-up generation are ongoing. As such, Remotes believes that the generation investments planned in this filing will continue to be used and useful after transmission connection.

c) In Remotes' opinion, the connection timeline (with the exception of a distribution connection to Pikangikum) is outside of the forecast period.

d) Although there has good progress on the planning and development phases of the project, the implementation phase has not yet begun. The line is a large and complex construction project of a historic nature and, consequently, the timing of the construction and community connections is uncertain. Remotes notes that its net generation investments (those that are included in rate base) are required to keep plants operating. Until the project and community connections are imminent, Remotes believes that the investments necessary to maintain ongoing service reliability are required.

OEB Staff - Interrogatory # 33

Reference:

Exhibit D1 / Tab 1 / Schedule 1 / Table 1 / Page 2

Interrogatory:

Remotes has provided the OM&A cost categories for the 2018 Test Year. Total OM&A expenses for the 2018 Test Year are forecasted at $50.14 million.

a) Please reconcile the 2018 OM&A expenses provided in Exhibit D1 with generation and distribution related OM&A expenses provided on page 16 and 18 (Tables 2-1 and 2-2) of the DSP.
b) Please re-calculate the percentage year over year change for the period 2013 OEB-approved and 2013 actuals and confirm that the change is 9.8%.

Response:

a)

Table 1
OM&A Cost Categories

Program Areas	2018 Total Cost (in $K)	Reference
Summary of OM&A Expenses	**$50,143**	**Exhibit D1, Tab 1, Sch 1**
Generation	$44,159	Exhibit D1, Tab 1, Sch 2
Distribution	$2,203	Exhibit D1, Tab 1, Sch 3
Customer Care	$1,999	Exhibit D1, Tab 1, Sch 4
Community Relations	$305	Exhibit D1, Tab 1, Sch 5
Shared Services and Other Administrative Costs	$1,342	Exhibit D1, Tab 1, Sch 6
Cost of External Work	$135	Exhibit D1, Tab 2, Sch 1

The $4.5 million Distribution O&M as reported on Table 2-1 of the DSP is a summary of costs that were included in the categories noted below.

Distribution

Program Areas	2018 Total Cost (in $K)	Reference
Summary of Distribution OM&A Expenses	$4,493	DSP Table 2-1
Distribution	$2,203	
Customer Care	$1,974	
Community Relations	$165	
Shared Services and Other Administrative Costs	$51	

The $15.5 million Generation O&M as reported on Table 2-2 of the DSP is included in the $44.2 million noted below.

Generation

Program Areas	2018 Total Cost (in $K)	Reference
Summary of Generation OM&A Expenses	$44,159	
Generation	$15,496	DSP Table 2-2
Environment	$1,063	
Fuel	$27,600	

b) The 9.8% year over year change relates to the difference between 2012 and 2013 actuals. The year over year percentage change for the 2013 OEB-approved and 2013 actuals is 4.0%.

OEB Staff - Interrogatory # 34

Reference:
Exhibit D1 / Tab 1 / Schedule 2 / Table 2 / Page 5

Interrogatory:
Generation Maintenance related OM&A costs for the 2018 Test Year have almost doubled as compared to 2013 OEB-approved amounts (94% increase).

a) Please explain the drivers for the significant increase in Generation Maintenance related OM&A expenses.
b) Does Remotes expect the trend of significant increases to continue during the planning period (2018 to 2022)?
c) What were the total expenses for unplanned maintenance of engines during each of the years 2013 to 2017?
d) What steps has Remotes taken to reduce occurrences of unplanned maintenance of engines?

Response:
a) Generation Maintenance O&M have several drivers and expenses increased for:
- Unplanned generation maintenance
- Planned and unplanned auxiliary equipment maintenance
- Planned tank farm maintenance
- Planned facilities/buildings maintenance
- RET generator maintenance/trouble
- DCAM Sustainment
- Safety improvements
- Engineering investigations
- Additionally “other Development Projects” was added in 2017 that added to the overall increase.

b) Remotes expect the trend to increase at no more than CPI during the planning period of 2018 to 2022.

c)

Unplanned Maintenance - Engines (in $K)

Category	Historic (Actual)				Bridge
	2013	2014	2015	2016	2017
Unplanned Maintenance - Engines	1,622	1,272	1,017	1,393	1,544

d) Remotes is increasing the amount of engine oil and coolant samples for analysis to predict premature failures and advancing the planned maintenance schedule ahead when analysis results warrant it.

OEB Staff - Interrogatory # 35

Reference:

Exhibit D1 / Tab 1 / Schedule 2 / Tables 1-4 / Pages 2-9

Interrogatory:

Please update Tables 1 to 4 with actual 2017 costs.

Response:

The updated tables are provided below. The actual 2017 costs are draft pending the completion of the year-end audit.

Table 1
Generation Operations & Maintenance OM&A (in $K)

Category	Board Approved	Historic (Actual)					Bridge	Test
	2013	2013	2014	2015	2016	2017	2017	2018
Generation Maintenance	6,012	8,648	9,932	8,610	9,574	9,245	11,392	11,640
Generation Operations	4,573	4,306	4,260	4,337	4,358	4,241	4,819	4,919
Fuel	24,067	25,568	25,869	23,250	23,669	25,695	26,485	27,600
Other Power Supply Expenses	1,980	0	0	0	0	25	0	0
Total	**36,632**	**38,522**	**40,061**	**36,197**	**37,601**	**39,206**	**42,696**	**44,159**

Table 2
Generation Maintenance OM&A (in $K)

Category	Board Approved	Historic (Actual)					Bridge	Test
	2013	2013	2014	2015	2016	2017	2017	2018
Generation Maintenance	6,012	8,648	9,932	8,610	9,574	9,245	11,392	11,640

Table 3
Generation Operations OM&A (in $K)

Category	Board Approved	Historic (Actual)					Bridge	Test
	2013	2013	2014	2015	2016	2017	2017	2018
Generation Operations	4,573	4,306	4,260	4,337	4,358	4,241	4,819	4,919

Table 4
Fuel Purchases (in $K)

Category	Board Approved	Historic (Actual)					Bridge	Test
	2013	2013	2014	2015	2016	2017	2017	2018
Fuel	24,067	25,568	25,869	23,250	23,669	25,695	26,485	27,600

OEB Staff - Interrogatory # 36

Reference:

Exhibit D1 / Tab 1 / Schedule 2 / Table 5 / Page 11

Interrogatory:

Remotes has provided fuel costs including the average delivered cost per litre for 2018 in Table 5.

Please provide a similar table for the years 2013 to 2017 along with information on fuel lost as a result of spills, theft or other reasons.

Response:

The updated table is provided below.

Table 5
Total Cost of Fuel

Category	Board Approved	Historic (Actual)					Bridge	Test
	2013	2013	2014	2015	2016	2017	2017	2018
Fuel Efficiency (kWh/litre)	3.56	3.61	3.62	3.44	3.56	3.58	3.41	3.42
Total litres of fuel issued (in KL)	15,668	17,284	17,517	17,492	17,361	17,308	18,038	18,203
Average delivered cost per litre ($)	$1.536	$1.479	$1.477	$1.329	$1.363	$1.485	$1.468	$1.516
Total Cost of Fuel (in $K)	$24,067	$25,568	$25,869	$23,250	$23,669	$25,695	$26,485	$27,600

The amount of fuel lost has been minimal as evidenced in the table below:

Measure	2013	2014	2015	2016	2017
Litres Spilled	135	73	50	140	74
Litres lost to the Environment	0	10	0	0	0
Litres Recovered	135	63	50	140	74

OEB Staff - Interrogatory # 37

Reference:

Exhibit D1 / Tab 1 / Schedule 2 / Page 10-11

Interrogatory:

Remotes has indicated that the cost of delivery accounts for about 44% of the delivered price of fuel. Air delivery typically constitutes about 56% of fuel delivered to Remotes' communities.

a) Are there any communities that received fuel deliveries by air in 2013 but are now delivered using all-weather road or winter road?
b) When the nine communities served by Remotes get connected to the transmission system under the Remote Community Connection Plan, what changes does Remotes expect in terms of its fuel usage, costs and delivery?

Response:

a) There are no communities that have moved from air deliveries to all-weather or winter road deliveries.

b) The connection to the transmission system is not expected to occur within the current 5 year business plan, and as a result, no specific impact has been calculated at this time. However, when the connections do occur, overall fuel usage and the resultant costs are expected to reduce significantly.

OEB Staff - Interrogatory # 38

Reference:

Exhibit D1 / Tab 1 / Schedule 3 / Table 1 / Page 1

Interrogatory:

Remotes has provided distribution related OM&A expenses for the period 2013 to 2018. The expenses have been categorized under distribution maintenance and distribution operations.

a) Please update the table with actual 2017 costs.
b) The OEB-approved amount in 2013 rates was approximately $3.0 million. Remotes has not spent the approved amount in any of the following years, from 2013 to 2016. The decrease in expenditures ranges from 19% to 51%. What are the drivers for the 2018 forecasted distribution related OM&A expenses ($2.2 million) considering that Remotes has underspent its previous OEB-approved levels for the entire period 2013 to 2017?

Response:

a) The updated table is provided below. The 2017 actual costs are draft until completion of the year-end audit.

Table 4
Distribution OM&A (in $K)

Category	**Board Approved**	**Historic (Actual)**					**Bridge**	**Test**
	2013	**2013**	**2014**	**2015**	**2016**	**2017**	**2017**	**2018**
Distribution Maintenance	2,679	1,399	1,799	2,216	1,780	1,570	2,008	2,087
Distribution Operations	301	62	80	199	212	52	111	116
Total	**2,980**	**1,461**	**1,879**	**2,415**	**1,992**	**1,622**	**2,119**	**2,203**

b) The 2013 board approved rate included the addition of Cat Lake and Pikangikum. In particular, significant forestry work along the long distribution line to Cat Lake was expected ($600K), resulting in a large variance. That work was completed by Networks under Networks' temporary distribution licence. The 2018 forecast is more reflective of current results and work programs and includes the expectation that Forestry programs will continue at historical levels.

OEB Staff - Interrogatory # 39

Reference:

Exhibit D1 / Tab 1 / Schedule 3 / Page 3 / Lines 6-8

Interrogatory:

In its evidence Remotes has indicated that increased distribution operations expenditures in 2015 compared to 2014 reflect increased costs related to a project to automate distribution data collection.

a) Please provide more information on the project related to automate distribution data collection. How is this project different from the proposed investment on Supervisory Control and Data Acquisition (SCADA) and Programmable Logic Controllers (PLC) systems?
b) Did the automation of distribution data collection resulted in any cost savings? Please provide a detailed response.
c) Will the proposed investment in the SCADA and PLC systems achieve any cost savings during the planning period? If yes, please provide the estimated cost savings and how they have been accounted for in the test year.

Response:

a) Distribution data collection is a regulatory requirement and related to the asset condition of distribution assets. SCADA and PLC are required to safely operate, maintain and control generating systems.

b) Distribution data collection is a regulatory requirement and is required to develop the DSP as well as confirm or verify work programs. As per the OEB requirements, data collection activities are fundamentally designed to drive better asset decisions and investment, which should result in cost savings.

c) The SCADA/PLC hardware is obsolete and the software version is no longer supported by the vendor. The replacement should improve the reliability of our systems, by providing enhanced visibility of more station alarms, which may in turn identify operating concerns before fault or failure. The SCADA/PLC is also necessary to maintain existing fuel savings and operating efficiencies over running the plant manually and is a basic requirement for a modern plant.

OEB Staff - Interrogatory # 40

Reference:

Exhibit D1 / Tab 1 / Schedule 4 / Pages 2

Interrogatory:

With respect to customer care OM&A costs, higher customer care spending in 2013 as compared to the 2013 OEB-approved level is due to Remotes' involvement in the project design and implementation of the CIS billing system.

Please explain how customer care OM&A spending in 2013 increased as a result of implementation of a new billing system considering that costs related to major projects are usually capitalized.

Response:

Hydro One Networks owns the software and not Remotes. There were additional costs in 2013 related to the specific configuration/testing for Remotes customers and for training and support for Remotes staff. These expenditures were for the sole benefit of Remotes' customers.

OEB Staff - Interrogatory # 41

Reference:

Exhibit D1 / Tab 1 / Schedule 4 / Pages 2-3

Interrogatory:

Bad debt expense is made up of direct write-offs offset by recoveries, plus adjustments to the provision for bad debts. The bad debt allowance is based on a combination of applying model percentage against outstanding energy accounts receivables and specific identification of high risk receivables. Credits to bad debt expense in 2014 and 2016 reflect Remotes' success in negotiating payment arrangements with First Nation Band Councils. The credit in 2015 primarily reflects the successful early completion of a long term payment plan. Since January 2013, outstanding First Nation accounts receivable have been reduced from $4.4 million to $2.6 million in December 2016. In fact, bad debt has not been an expense in 2014, 2015 and 2016 and has contributed to revenues.

a) Please provide the actual bad debt expense for 2017.
b) Why has Remotes included a bad debt expense of $60,000 in 2018 considering that outstanding accounts receivable is $2.6 million and Remotes has been successful in recovering previous outstanding payments in 2014, 2015 and 2016?
c) Is Remotes of the opinion that it is not possible to recover any portion of outstanding accounts receivable of $2.6 million in 2018?
d) Please provide the average bad debt expense for the four years from 2014 to 2017.

Response:

a) The bad debt expense for 2017 was ($64,348).

b) Remotes has included a bad debt expense of $60,000 in 2018 to account for the conclusion of most of the payment plans which in past years resulted in a recovery of bad debts.

c) Hydro One Remotes fully expects to recover the majority of $2.6M outstanding as well as its upcoming monthly bills. Based on the $2.6M year-end balance, Remotes has an established bad debt allowance of $87K. If the current balances match normal accounts receivable recovery it would reasonable to assume that $87K would become uncollectable at some point, but not necessarily in the 2018 year.

d) The average bad debt expense for 2014 to 2017 is provided below:

Category	**Historic (Actuals in $K)**				
	2014	**2015**	**2016**	**2017**	**Average**
Bad Debt (Recovery)	$(175)	$(1,105)	$(21)	$(64)	$(341)

OEB Staff - Interrogatory # 42

Reference:

Exhibit D1 / Tab 1 / Schedule 5 / Page 1

Interrogatory:

Community Relations expenses include various customer outreach activities, including a Conservation and Demand Management (CDM) program, the Customer Advisory Board (CAB) and public safety measures such as the joint use program.

a) Please update Table 1 with 2017 actuals and provide a breakdown of Community Relations expenses as per the categories identified above.
b) Please explain the joint use program

Response:

a) The table with 2017 actuals is provided below:

Category	**Board Approved**	**Historic (Actuals)**				
	2013	**2013**	**2014**	**2015**	**2016**	**2017**
Total	**750**	**520**	**554**	**291**	**138**	**174**
CDM	565	398	404	144	14	57
Joint Use	52	43	61	47	57	37
CAB	30	17	14	7	4	0
Communications	40	35	10	32	17	29
Community Relations	63	27	65	61	46	51

b) The joint use program is for the long standing utility and telecommunication organzations sharing of pole and other assets.

OEB Staff - Interrogatory # 43

Reference:
Exhibit D1 / Tab 1 / Schedule 5 / Page 2

Interrogatory:
With respect to CDM programs, Remotes has indicated that it has directed its conservation efforts towards Standard A customers and offers application-based programs.

What are application-based programs and what kind of CDM programs are offered to Standard A customers?

Response:
Application-based programs require the customer to submit a completed application and proof or work performed in order to receive their incentive. Application based programs are driven by interest from the customer and include programs such as:

- Mail-in Rebate program – cash back for the purchase of energy star appliances based on a request and proof of purchase. Available to all customers.
- Commercial Lighting Retrofit Program – rebate amounts based on existing light assessment and proposed upgrades. Available to all commercial and Standard A customers.

OEB Staff - Interrogatory # 44

Reference:

Exhibit D1 / Tab 1 / Schedule 5 / Page 2 / Lines 17-20

Interrogatory:

The Customer Advisory Board (CAB) consists of residential and commercial customers from within Remotes' service territory. The CAB offers advice on service policies and procedures, and ways to improve services within the communities.

a) Does the CAB consists of Standard A and Non-Standard A customers?
b) How many customers are usually in the CAB?
c) Does the CAB provide advice or is consulted on Remotes' upcoming capital projects or its business plan? If no, why not?
d) Is the CAB aware of Remotes' DSP and did they provide any input on the DSP?

Response:

a) The CAB does not include Standard A customers. Standard A customers are either direct government customers (provincial/federal government ministries) or are funded by government through local Band Councils. Remotes has regular and ongoing communications with its end use Standard A customers. Work programs and customer needs are regularly discussed with Band Councils and with government agencies in its communities such as the MTO. The CAB was created specifically to better understand and respond to the views of end-use residential and commercial customers living in Remotes' service territory.

b) The CAB normally has 6 members.

c) The CAB was informed of the 2017 rate filing and the Board's updated filing requirements in 2016, when Remotes was working on the business plan that underpins the filing and when Remotes was beginning work on the submission.

d) The CAB did not review the DSP or provide direct input into the DSP document as the document was not completed until mid-2017; however, CAB views are reflected in Remotes' programs, including in the capital plans in Remotes' business plan. For example, the CAB has been very concerned about funding for generation capacity and had input into the process Remotes developed to work with INAC and local Band

Councils to increase capacity in the communities. Advice from the CAB is also reflected in Remotes OM&A initiatives. For example, the CAB has had ongoing input into Remotes' customer surveys (questions/wording), has suggested low cost ways to increase customer awareness of safety concerns, has suggested ways to increase customer awareness of programs, and has advocated for increased renewable energy use in the communities leading to the establishment of the REINDEER program.

OEB Staff - Interrogatory # 45

Reference:

Exhibit D1 / Tab 1 / Schedule 6 / Table 1 / Page 2

Interrogatory:

With respect to shared services, the costs related to System Services & Lease of Computer Equipment has increased from $180,000 in 2013 (OEB approved) to a projected costs of $261,000 in 2018.

Please explain the reasons for the significant increase in costs related to System Services and Lease of Computer Equipment.

Response:

The common asset allocation was implemented in 2013, and $180K was an estimate. The actual allocation was $219K. The amount is derived following each shared asset allocation study (usually every 2 years). The shared asset value is based on net book value changes from year to year, decreasing with depreciation and increasing with new investment. 2014 was a year with significant investments in software and hardware and those in-serviced amounts increased the account net book value.

Witness:

OEB Staff - Interrogatory # 46

Reference:
Exhibit D1 / Tab 1 / Schedule 6 / Table 1 / Page 2

Interrogatory:
In the case of services provided by Hydro One under the shared service model, the costs for Supply Chain Services has been constant for the entire period 2013 to 2018.

a) What services are included in Supply Chain Services?
b) Why is the allocated amount constant for the period 2013 to 2018?
c) How is the cost for Supply Chain Services allocated to Remotes?

Response:
a) Supply Chain Services provides the following to Hydro One Remotes:
   - management and procurement;
   - vendor management;
   - process development;
   - data management;
   - investment recovery.

b) The amount has remained constant as it is a negotiated rate. The negotiated rate considers the volume, value and complexity of our business supply chain activities, within the context of the overall cost of supply chain service to Hydro One Networks.

c) The cost is invoiced to Remotes on a monthly basis via billable journal entry.

OEB Staff - Interrogatory # 47

Reference:

Exhibit D1 / Tab 4 / Schedule 1

Interrogatory:

Please provide the actuarial valuation that underpins Remotes' 2018 pension contributions that are being sought for recovery in rates. In addition, please also provide the calculation that was used to allocate the applicant's share of the total Hydro One Inc. 2018 contributions (for both the Defined Benefit and Defined Contribution plans).

a) Please also provide the total actual 2017 contributions made to both the Defined Benefit and Defined Contribution plans by Remotes.
b) Please confirm that there has been no change in the methodology used to calculate and allocate Remotes' share of the total Hydro One Inc. contributions.

Response:

The requested Pension Valuation is found as Attachment #1 to this exhibit.

Pension expense is allocated to each entity based on the percentage of Base Pensionable Earnings of employees per plan per entity. For Remotes forecast for 2018, this is 0.98% for the Defined Benefit pension plan and 1.35 % for the Defined Contribution Plan. These percentages are applied to the forecast pension contributions of each plan for 2018.

a) Remotes share of Pension Contributions

Pension Plan	**Forecast 2018 Hydro One Pension Contributions Total $K**	**Forecast 2018 Remotes Base Pensionable Earnings %**	**Forecast 2018 Remotes Pension Contributions $K**	**Actual 2017 Remotes Pension Contributions $K**
Pension Defined Benefit	71,400	0.98%	699	859
Pension - Defined Contribution	1,100	1.35%	15	10

b) There has been no change in the methodology used to calculate and allocate Remotes' share of the Hydro One pension contributions.

HYDRO ONE INC.

HYDRO ONE PENSION PLAN

Actuarial Valuation as at December 31, 2016

May 31, 2017

Registration Number: 1059104

DISCLAIMERS

This document is an actuarial valuation report of a pension plan. It is technical in nature and the reader should seek expert advice to fully understand it. The actuarial results presented here are based on numerous economic and demographic assumptions as to future events. Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future actuarial valuations.

This report is based on the terms of engagement listed in Appendix A.

This report is based on the premise that all the plan's assets, including any letters of credit, are available to meet the plan's liabilities included in this valuation.

This report is based on the premise that the plan remains a going concern. This report does not address the disposition of any surplus assets remaining in the event of plan windup. If an applicable pension regulator or other entity with jurisdiction directs otherwise, certain financial measures contained in this report, including contribution requirements, may be affected.

The results presented in this report have been developed using a particular set of actuarial assumptions. Other results could have been developed by selecting different actuarial assumptions. The results presented in this report are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events.

Future contribution levels may change as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions and the legislative rules, or as a result of future experience gains or losses, none of which have been anticipated at this time.

The results were developed with various data as at the valuation date that were provided to us: plan membership data, plan assets data, plan provisions and statement of investment policy. Towers Watson Canada Inc. (“Willis Towers Watson”) has relied on these data after verifying them and assessing their reasonableness. However, Willis Towers Watson has not independently audited these data.

The information contained in this report was prepared for Hydro One Inc., for its internal use and for filing with the Pension authorities, in connection with the actuarial valuation of the plan prepared by Willis Towers Watson. This report is not intended, nor necessarily suitable, for other parties or for other purposes. Furthermore, some results in this report are based on assumptions mandated by legislation. These results may not be appropriate for purposes other than those for which they were prepared. Further distribution of all or part of this report to other parties (except where such distribution is required by applicable legislation) or other use of this report is expressly prohibited without Willis Towers Watson's prior written consent. Willis Towers Watson is available to provide additional information with respect to this report to the above-mentioned intended users upon request.

The numbers in this report are not rounded. The fact that numbers are not rounded does not imply a greater level of precision than if the numbers had been rounded.

Definitions:

Pension authorities means the Financial Services Commission of Ontario and the Canada Revenue Agency ("CRA").

Pension legislation means the *Pension Benefits Act (Ontario)* and Regulation thereto and the *Income Tax Act (Canada)* and Regulations thereto ("ITA").

Table of Contents

Introduction

Purpose

This report with respect to the Hydro One Pension Plan has been prepared for Hydro One Inc., the plan administrator, and presents the results of the actuarial valuation of the plan as at December 31, 2016.

The principal purposes of the report are:

- to present information on the financial position of the plan on going concern, solvency and hypothetical windup bases; and
- to provide the basis for employer contributions.

Significant Events Since Previous Actuarial Valuation (December 31, 2015)

Since the previous valuation a number of prospective changes have been made with respect to benefits and member contributions impacting active and disabled members of different employee groups within the plan.

For Management employees, member contribution rates were increased at various dates, as outlined in Appendix F. Also, the future Best Average Earnings ("BAE") and early retirement criteria were amended as follows:

- for members represented by Power Workers Union ("PWU") and the Society, for service accrued after March 31, 2025, the BAE will be based on the highest 60 consecutive months of earnings (updated from highest 36 consecutive months of earnings used for service accrued until March 31, 2025) as outlined in the respective collective agreements; and
- for members represented by PWU, for service accrued after March 31, 2025, the early retirement criteria for an unreduced pension will be changed from the "rule of 82 points" to the "rule of 85 points" as outlined in the collective agreement.

Details regarding these plan changes are provided in Appendix F. There have been no other changes to the plan provisions.

There have been no changes to the legislative and actuarial standards. Changes to the going concern basis are described in Appendix C. Changes to the solvency basis are described in Appendix D.

In 2016, the General Regulation under the Ontario *Pension Benefits Act h*as been amended to provide temporary solvency relief. This is the first valuation of the plan on or after December 31, 2015. The plan administrator decided not to apply any new funding relief measures.

Subsequent Events

We completed this actuarial valuation on April 7, 2017.

On May 19, 2017 the Ontario Ministry of Finance announced certain changes to the funding framework for defined benefit pension plans registered in Ontario and that related Regulations required to implement the changes would be released in the fall of 2017. This report has been prepared on the basis of the funding rules in effect at the time the report was prepared. The impact of the new funding rules will be reflected in an update to this report or in a subsequent report, as appropriate.

Except as noted above, to the best of our knowledge and on the basis of our discussions with Hydro One Inc., no other events which would have a material financial effect on the actuarial valuation occurred between the actuarial valuation date and the date this actuarial valuation was completed.

Next Valuation

The next actuarial valuation of the plan must be performed no later than December 31, 2019.

Section 1: Going Concern Financial Position

1.1 Statement of Financial Position

	December 31, 2016	December 31, 2015
Going Concern Value of Assets	$ 6,514,349,000	$ 6,071,094,000
Actuarial Liability		
Active and disabled members	$ 2,004,991,863	$ 2,208,495,000
Retired members and beneficiaries	4,031,088,676	3,860,866,000
Terminated vested members	44,570,154	39,400,000
Total	$ 6,080,650,693	$ 6,108,761,000
Additional voluntary contribution	20,000	20,000
Total Actuarial Liability	$ 6,080,670,693	$ 6,108,781,000
Actuarial Surplus (Unfunded Actuarial Liability)	$ 433,678,307	$ (37,687,000)
Prior Year Credit Balance	(48,000,000)	(48,000,000)
Actuarial Surplus (Unfunded Actuarial Liability) After Prior Year Credit Balance (PYCB)	$ 385,678,307	$ (85,687,000)
Funded ratio[1]	106%	99%
Excess Actuarial Surplus[2]	$ 0	$ 0

Notes:

[1] After reflecting prior year credit balance.
[2] Considered to be nil if there is a hypothetical windup or solvency deficit.

Comment:

- The prior year credit balance is employer contributions made prior to the actuarial valuation date that are in excess of the minimum required and are set aside as a reserve for application towards future contribution requirements.

1.2 Reconciliation of Financial Position

Actuarial surplus (unfunded actuarial liability) as at December 31, 2015 before reflecting prior year credit balance		$ (37,687,000)
Net special payments		24,705,000
Application of:		
▪ Actuarial surplus	$ 0	
▪ Prior year credit balance	0	0
Expected interest on:		
▪ Actuarial surplus (unfunded actuarial liability)	$ (2,035,098)	
▪ Net special payments	658,265	
▪ Application of actuarial surplus	0	
▪ Application of prior year credit balance	0	(1,376,833)
Plan experience:		
▪ Investment gains (losses)	$ 292,379,000	
▪ Salary and YMPE gains (losses)	50,654,805	
▪ Cost-of-living adjustment gains (losses)	11,039,223	
▪ Retirement gains (losses)	(3,952,266)	
▪ Withdrawal gains (losses)	(2,481,510)	
▪ Mortality gains (losses)	(10,686,136)	
▪ Miscellaneous liability gains (losses)	50,078,061	387,031,177
Change in actuarial basis:		
▪ Salary Scale assumption	$ 142,938,469	
▪ Discount Rate assumption	(81,932,506)	61,005,963
Change in plan provisions[1]		0
Actuarial surplus (unfunded actuarial liability) as at December 31, 2016 before reflecting prior year credit balance		$ 433,678,307

Note:

[1] The changes in plan provisions are prospective in nature and do not have an impact on the actuarial liabilities as of the valuation date.

1.3 Contributions (Ensuing Year)

	December 31, 2016	December 31, 2015
Employer Normal Actuarial Cost		
Normal actuarial cost in respect of benefits	$ 120,072,874	$ 130,815,000
Estimated member contributions [1]	(46,811,492)	(45,183,000)
Employer normal actuarial cost	$ 73,261,382	$ 85,632,000
Estimated payroll [1]	533,898,396	578,543,000
Employer normal actuarial cost as % of payroll	13.7%	14.8%

Note:

[1] The December 31, 2016 amount reflects adjustments for members expected to retire or terminate during the year and expected increases in contribution rates for Management employees.

Reconciliation of Employer Normal Actuarial Cost Contribution Rule

Employer normal actuarial cost as a % of payroll at December 31, 2015	14.8%
■ Changes in membership profile	(0.1)%
■ Changes in plan provisions	(1.0)%
■ Changes in actuarial basis[1]	0.0%
Employer normal actuarial cost as a % of payroll at December 31, 2016	13.7%

Note:

[1] Reflects impact of net change in actuarial basis (i.e. change in discount rate assumption, salary scale assumption and reflection of expected payroll).

1.4 Reconciliation of Prior Year Credit Balance

Prior year credit balance as at December 31, 2015			$	48,000,000
Actual employer contributions:				
■ Normal actuarial cost	$	82,065,000		
■ Going concern amortization payments		9,119,000		
■ Solvency amortization payments		15,586,000		
■ Transfer deficiency payments		0		
■ Prior year credit balance		0		
■ Other contributions		0		106,770,000
Minimum employer contributions required:				
■ Normal actuarial cost	$	(82,065,000)		
■ Going concern amortization payments		(9,119,000)		
■ Solvency amortization payments		(15,586,000)		
■ Transfer deficiency payments		0		
■ Other contributions		0		(106,770,000)
Application against unfunded actuarial liability				0
Prior year credit balance as at December 31, 2016			$	48,000,000

Section 2: Solvency and Hypothetical Windup Financial Position

2.1 Statement of Solvency and Hypothetical Windup Financial Position

	December 31, 2016	December 31, 2015
Solvency Value of Assets		
Market value of assets	$ 6,916,827,000	$ 6,743,615,000
Provision for plan windup expenses	(7,000,000)	(16,859,000)
Total solvency value of assets	$ 6,909,827,000	$ 6,726,756,000
Solvency Liability		
Active and disabled members	$ 2,369,597,002	$ 2,434,330,000
Retired members and beneficiaries	4,127,326,152	3,988,651,000
Terminated vested members	46,840,401	42,265,000
Total	$ 6,543,763,555	$ 6,465,246,000
Additional voluntary contribution	20,000	20,000
Total Solvency Liability	$ 6,543,783,555	$ 6,465,266,000
Solvency Surplus (Unfunded Solvency Liability)	$ 366,043,445	$ 261,490,000
Solvency ratio	Not less than 100%	Not less than 100%
Value of excluded benefits	$ 3,475,558,136	$ 3,079,824,000
Total Hypothetical Windup Liability	$ 10,019,341,691	$ 9,545,090,000
Hypothetical Windup Surplus (Unfunded Hypothetical Windup Liability)	$ (3,109,514,691)	$ (2,818,334,000)
Lesser of estimated employer contributions for the period until the next actuarial valuation and the prior year credit balance	$ 48,000,000	$ 48,000,000
Transfer ratio	69%	70%

	December 31, 2016	December 31, 2015
PBGF Information		
Ontario PBGF liability	$ 6,543,763,555	$ 6,465,246,000
Ontario asset ratio	Not less than 100%	Not less than 100%
Ontario portion of the fund	6,916,807,000	6,743,595,000
PBGF assessment base	0	0
Ontario additional PBGF liability	$ 0	$ 0

Comments:

- The solvency actuarial valuation results presented in this report are determined under a scenario where, following a plan windup, the employer continues its operations.
- The hypothetical windup valuation results presented in this report are determined under a scenario where, following a plan windup, the employer continues its operations.
- As the transfer ratio is less than 1.00, transfer deficiencies must be paid over a maximum period of five years unless the cumulative transfer deficiencies are within the limits prescribed by the Pension legislation or the employer remits additional contributions in respect of the transfer deficiencies. Pursuant to Regulations 19(4) or 19(5) to the Pension legislation, approval of the Superintendent will be required to make commuted value transfers if there has been a significant decline in the transfer ratio after the actuarial valuation date.

2.1.1 Determination of the Statutory Solvency Excess (Statutory Solvency Deficiency)

In calculating the statutory solvency excess (statutory solvency deficiency), various adjustments can be made to the solvency financial position.

	December 31, 2016	December 31, 2015
Solvency surplus (unfunded solvency liability)	$ 366,043,445	$ 261,490,000
Adjustments to solvency position:		
■ Present value of existing amortization payments	$ 58,727,046	$ 41,929,000
■ Smoothing of asset value	(402,478,000)	(672,521,000)
■ Averaging of liability discount rate	265,730,782	345,438,000
■ Prior year credit balance	(48,000,000)	(48,000,000)
■ Total	$ (126,020,172)	$ (333,154,000)
Statutory solvency excess (statutory solvency deficiency)	$ 240,023,273	$ (71,664,000)

Comment:

The present value of existing amortization payments reflects any changes made in this actuarial valuation to going concern amortization schedules.

Details of Present Value of Existing Payments

Type of payment	Effective date	Month of last payment recognized in calculation	Annual payment	Present value as at December 31, 2016 (at 3.00% per annum)
Solvency	Dec. 31, 2015	Dec. 2020	15,586,000	58,727,046

Section 3: Contributions

3.1 Estimated Minimum Employer Contribution

Year	2017	2018	2019
Employer Normal Actuarial Cost	$ 73,261,382	$ 71,354,000	$ 70,650,379
Employer Normal Actuarial Cost as a % of Payroll	*13.7%*	*13.8%*	*14.0%*
Amortization Payments			
■ Going Concern	$ 0	$ 0	$ 0
■ Solvency	0	0	0
Total	$ 0	$ 0	$ 0
Application of Prior Year Credit Balance[1]	0	0	0
Application of Surplus[2]	(73,261,382)	(71,354,000)	(70,650,379)
Estimated Minimum Employer Contribution	$ 0	$ 0	$ 0
Estimated Member Contributions	46,811,492	47,367,141	46,988,718

Notes:

[1] As at the actuarial valuation date a $48,000,000 Prior Year Credit Balance exists, which may be applied to reduce Employer contributions in 2017, 2018 or 2019.

[2] Subject to preparation of a cost certificate at beginning of year confirming updated financial position, surplus may be applied in 2018 and 2019.

3.2 Estimated Maximum Employer Contribution (Ensuing Year)

		December 31, 2016
Employer Normal Actuarial Cost	$	73,261,382
Greater of the Unfunded Actuarial Liability and the Unfunded Hypothetical Windup Liability		3,109,514,691
Estimated Maximum Employer Contribution	$	3,182,776,073

3.3 Timing of Contributions

Employer normal cost and member contributions: monthly and within 30 days of the month to which they pertain.

Amortization payments: monthly before the end of the month to which they pertain (or replaced by an equivalent letter of credit), if applicable.

Adjustment to contributions made since the valuation date: within 60 days from the date that this report is filed with the Pension authorities.

Section 4: Actuarial Opinion

In our opinion:

- the membership data on which the actuarial valuations are based are sufficient and reliable for the purposes of the going concern, solvency and hypothetical windup valuations,
- the assumptions are appropriate for the purposes of the going concern, solvency and hypothetical windup valuations, and
- the methods employed in the actuarial valuations are appropriate for the purposes of the going concern, solvency and hypothetical windup valuations.

This report has been prepared, and our opinion has been given, in accordance with accepted actuarial practice in Canada. The actuarial valuations have been conducted in accordance with our understanding of the funding and solvency standards prescribed by the Pension legislation.

Towers Watson Canada Inc.

David Kenny
FCIA

Suzanne Jacques
FCIA

Toronto, Ontario
May 31, 2017

Appendix A: Significant Terms of Engagement and Certificate of the Plan Administrator

A.1 Significant Terms of Engagement

For purposes of preparing this actuarial valuation report, the plan administrator has directed that:

- The actuarial valuation is to be prepared as at December 31, 2016.
- The investment policy dated November 11, 2016, which is the most up-to-date version, should be considered. There are no expectations that the target asset class distribution will be modified in the future.
- For the purposes of the going concern valuation, the terms of engagement require the use of a margin for adverse deviations mentioned in Appendix C.
- The going concern value of assets is to be determined using the averaging technique described in the Asset Valuation Method section in Appendix C.
- The going concern actuarial cost method to be used is the projected unit credit (benefit accrual method) described in the Actuarial Cost Method section in Appendix C.
- For purposes of determining the solvency liabilities of the plan, the value of benefits arising from future inflation are to be excluded.
- The solvency and hypothetical windup valuation results are to be determined under a scenario where the employer continues to operate and certain expenses are paid from the pension fund (consistent with past practice) while the employer pays other plan expenses.
- This report is to be prepared on the basis that the employer is entitled to apply the actuarial surplus, if any, to meet its contribution requirements under the plan.

Should these directions from the plan administrator be amended or withdrawn, Willis Towers Watson reserves the right to amend or withdraw this report.

A.2 Certificate of the Plan Administrator

I hereby certify that to the best of my knowledge and belief:

- the significant terms of engagement contained in Appendix A of this report are accurate and reflect the plan administrator's judgement of the plan provisions and/or an appropriate basis for the actuarial valuation of the plan;
- the information on plan assets, including the information on the investment policy and intended changes to the asset mix distribution after the valuation date, if any, forwarded to Towers Watson Canada Inc. and summarized in Appendix B and in Section 4 of this report is complete and accurate;
- the data forwarded to Towers Watson Canada Inc. and summarized in Appendix E and in Section 4 of this report are a complete and accurate description of all persons who are members of the plan, including beneficiaries who are in receipt of a retirement income, in respect of service up to the date of the actuarial valuation;
- the summary of plan provisions contained in Appendix F of this report is accurate; and
- other than the events mentioned in the Introduction of this report, there have been no events which occurred between the actuarial valuation date and the date this actuarial valuation was completed that may have a material financial effect on the actuarial valuation.

Signature

May 31, 2017

Date

Robert Cultraro

Name

SVP, Chief Investment and Pension Officer

Title

Appendix B: Assets

B.1 Statement of Market Value

	December 31, 2016	December 31, 2015
Total assets	$ 6,909,437,000	$ 6,745,869,000
Net outstanding amounts:		
■ Contributions receivable		
- Employer normal actuarial cost	$ 7,390,000	$ 0
- Members contributions	0	0
- Amortization payments	0	0
- Others	0	0
■ Transfers receivable (payable)	0	0
■ Benefits payable	0	(2,254,000)
■ Expenses and other payables	0	0
■ Total net outstanding amounts	$ 7,390,000	$ (2,254,000)
Total	$ 6,916,827,000	$ 6,743,615,000

Comment:

The data relating to the assets are based on the financial statements prepared and provided by KPMG. The data relating to net outstanding amounts were furnished by Hydro One Inc.

B.2 Asset Class Distribution

The following table shows the target asset allocation stipulated by the plan's investment policy in respect of major asset classes and the actual asset allocation as at December 31, 2016.

	Target asset allocation	Asset allocation as at December 31, 2016
Canadian equities	12.0%	13.9%
Foreign equities	38.0%	47.4%
Bonds and debentures	33.0%	31.6%
Real estate and infrastructure	10.0%	1.5%
Cash and short-term investments	2.0%	4.0%
Private Equities	5.0%	1.6%
Total	100.0%	100.0%

B.3 Reconciliation of Assets

Assets as at December 31, 2015			$ 6,745,869,000
Receipts:			
■ Contributions:			
- Employer normal actuarial cost	$ 74,675,000		
- Employer amortization payments	24,705,000		
- Members' current service contributions	44,305,000		
- Past service contributions	366,000		
- Reciprocal Transfers	125,000		
- Provision for non-investment expenses	0	$	144,176,000
■ Investment return, net of investment expenses			371,126,000
■ Total receipts		$	515,302,000
Disbursements:			
■ Benefit payments:			
- Pension payments	$ (301,029,000)		
- Lump sum settlements	(25,161,000)		
- Other benefit payments	0	$	(326,190,000)
■ Non-investment expenses			(25,544,000)
■ Total disbursements		$	(351,734,000)
Assets as at December 31, 2016			$ 6,909,437,000

Comments:

- This reconciliation is based on the financial statements prepared and provided by KPMG.
- The rate of return earned on the market value of assets, net of all expenses, from December 31, 2015 to December 31, 2016 is approximately 5.2% per annum.
- For further details on the non-investment expenses noted above, refer to the financial statements prepared by KPMG.

B.4 Development of the Going Concern Value of Assets

	Adjusted Market Value Beginning from:				
	December 31, 2012	December 31, 2013	December 31, 2014	December 31, 2015	December 31, 2016
Adjusted market value as at December 31, 2012	$ 5,004,546,000				
Net cash flow for 2013	(126,979,000)				
Assumed investment return	271,805,000				
Adjusted market value as at December 31, 2013	5,149,372,000	$ 5,743,450,000			
Net cash flow for 2014	(106,744,000)	(106,744,000)			
Assumed investment return	295,612,000	330,068,000			
Adjusted market value as at December 31, 2014	5,338,240,000	5,966,774,000	$ 6,311,204,000		
Net cash flow for 2015	(117,373,000)	(117,373,000)	(117,373,000)		
Assumed investment return	306,262,000	342,717,000	362,695,000		
Adjusted market value as at December 31, 2015	5,527,129,000	6,192,118,000	6,556,526,000	$ 6,745,869,000	
Net cash flow for 2016	(182,014,000)	(182,014,000)	(182,014,000)	(182,014,000)	
Assumed investment return	293,615,000	329,525,000	349,203,000	359,427,000	
Adjusted market value as at December 31, 2016	$ 5,638,730,000	$ 6,339,629,000	$ 6,723,715,000	$ 6,923,282,000	$ 6,909,437,000
Going Concern Value of Assets					
Average of the five adjusted market values as at December 31, 2016					$ 6,506,959,000
Net outstanding amounts					7,390,000
Going concern value of assets as at December 31, 2016					$ 6,514,349,000

Comment:

The rate of return earned on the going concern value of assets, net of all expenses, from December 31, 2015 to December 31, 2016 is approximately 10.3% per annum.

Appendix C: Actuarial Basis - Going Concern Valuation

C.1 Methods

Asset Valuation Method

The going concern value of assets was calculated as the average of the market value of invested assets at the valuation date and the four previous years' adjusted market values. The market values at December 31 of each of the four preceding years were accumulated to the valuation date with net cash flow (i.e., contributions less benefit payments) and assumed investment return. Net cash flow was assumed to occur uniformly throughout each year. Assumed investment return for a year was calculated assuming that each year, the assets earned interest at the going concern discount rate in effect for that year. Finally, this 5-year average of adjusted market values was then adjusted for net additional outstanding amounts.

The objective of the asset valuation method is to produce a smoother pattern of going-concern surplus (deficit) and hence a smoother pattern of contributions, consistent with the long-term nature of a going concern valuation.

Such smoothing is achieved by use of an averaging process which systematically recognizes investment returns different from expectations over a 5-year period, with 20% recognized at the valuation date and the remainder at a rate of 20% per year. This method will be expected to average periods of outperformance with periods of underperformance.

The expected return of the going concern discount rate has been selected to equal the expected return on the assets over long periods of time, with a margin for adverse directions. As such, it is anticipated that, on average, the asset valuation method will tend to produce a result that is somewhat less than the market value of assets.

Actuarial Cost Method

The actuarial liability and the normal actuarial cost were calculated using the projected unit credit (benefit accrual) method.

Additional Voluntary Contributions

For the purposes of the going concern valuation, the determination of the actuarial liability for the additional voluntary contributions does not involve the use of an actuarial cost method, nor does it involve actuarial assumptions. By definition, the actuarial liability under the additional voluntary contributions corresponds with the market value of the members' additional voluntary contribution accounts at the actuarial valuation date.

C.2 Actuarial Assumptions

	December 31, 2016	December 31, 2015
Economic Assumptions (per annum)		
Liability discount rate	5.30%	5.40%
Inflation rate	2.00%	Same
Rate of salary increase	2.50% plus merit and promotion (see table 1)[1]	2.50% plus merit and promotion (see table 2)
Escalation of YMPE under Canada/Québec Pension Plan [2]	3.00%	Same
Escalation of *Income Tax Act (Canada)* maximum pension limitation [3]	3.00%	Same
Interest on members' contributions	2.00%	Same
Demographic Assumptions		
Mortality	95% of the 2014 Private Sector Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	Same
Retirement from active membership	Age and service related rates (see table 3)	Same
Withdrawal	Age-related rates (see table 4)	Same
Disability incidence/recovery	Age-related rates (see table 5)	Same
Other		
Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form	90%	Same
Years male spouse older than female spouse	3	Same
Provision for non-investment expenses	None; return on plan assets is net of all expenses	Same

Notes:

[1] For PWU for 2017, 1.0% increase plus merit and promotion. For Society for 2017 and 2018, 0.5% increase plus merit and promotion (per current collective bargaining agreements).

[2] The YMPE of $55,300 for 2017 is the starting value for the YMPE projection as at the current actuarial valuation and is indexed starting in 2018.

[3] The *Income Tax Act (Canada)* maximum pension limit of $2,914.44 per year of service in 2017 is the starting value for maximum pension limit projection as at the current valuation and is indexed starting in 2018.

Table 1 — Merit and Promotion Scale

Age	First 4 Years of Employment	Subsequent Years
Under 25	7.5%	2.0%
25 - 29	5.5%	2.0%
30 - 34	3.5%	2.0%
35 - 39	3.5%	1.5%
40 – 44	3.5%	1.5%
45 - 49	2.0%	1.0%
50 - 54	2.0%	1.0%
55 - 59	1.0%	0.5%
60 & over	1.0%	0.0%

Table 2 — Merit and Promotion Scale (Prior Valuation)

Age	First 4 Years of Employment	Subsequent Years
Under 25	7.0%	1.0%
25 - 29	3.0%	1.0%
30 - 34	3.5%	1.5%
35 - 39	3.5%	1.5%
40 – 44	3.5%	2.0%
45 - 49	3.5%	1.5%
50 - 54	2.0%	1.5%
55 - 59	2.0%	1.5%
60 & over	2.0%	0.0%

Table 3 — Retirement Rates

	Eligible for Unreduced Retirement		
Age	Based on points (82 or 85)	35 years of service and over	Not Eligible for Unreduced Retirement
Under 55	10%	30%	0%
55 to 59	15%	30%	5%
60 to 64	12%	30%	7%
65	50%	30%	20%
66 to 69	25%	30%	15%
70 and over	100%	100%	100%

Table 4 — Withdrawal Rates

Service (years)	Male & Female
Under 20	1%
20 and over	0%

Table 5 — Disability Rates

Age	Male & Female
Under 30	0%
30 to 35	0.105%
35 to 40	0.110%
40 to 45	0.115%
45 to 50	0.120%
50 to 55	0.295%
55 to 59	1.000%
60 and above	1.878%

C.3 Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the going concern valuation is summarized below.

The going concern assumptions do not include margins for adverse deviations, except as noted below.

Liability discount rate

The assumption is an estimate of the expected long-term return on plan assets adjusted as follows:

■ Expected long-term return on plan assets before adjustments	5.79%
■ Investment management fees	(0.04)%
■ Adjustment for non-investment expenses paid by the plan	(0.10)%
■ Margin for adverse deviations	(0.40)%
■ Rounding effect (discount rate is rounded to 10 basis points)	0.05%
■ Expected long-term return on plan assets after adjustments and margin	5.30%

Inflation rate

Estimate of future rates of inflation considering economic and financial market conditions.

Rate of salary increase

■ Assumed rate of inflation per annum	2.00%
■ Effect of real economic growth and productivity gains in the economy	0.50%
■ Individual employee merit and promotion based on a scale which varies by age and service	
■ Total rate of salary increase	2.50% plus merit and promotion (see table 1)

Escalation of YMPE under C/QPP and ITA limit

Indexed annually based on increases in the Industrial Aggregate Wage index for Canada, assumed to be a rate of inflation of 2.00% per annum, plus 1.00% per annum for the effect of real economic growth and productivity gains in the economy.

Mortality

Base mortality rates from the CPM2014Priv table, with a multiplier of 95% based on a review of the plan's actual mortality experience over the period 2007-2015 are considered reasonable for the actuarial valuation. Applying improvement scale CPM-B generationally provides allowance for improvements in mortality after 2014 and is considered reasonable for projecting mortality experience into the future.

Retirement from active membership

The rates of retirement were developed based on a review of plan experience for the years 2007 to 2015 and an assessment of future expectations. All members are assumed to commence their pension at their retirement date.

Pension commencement after termination of employment

All terminated members are assumed to commence their pension at the age that produces the highest liability.

Withdrawal

The rates of withdrawal were developed based on a review of plan experience for the years 2007 to 2015 and an assessment of future expectations.

Percentage of involuntary terminations of employment

No allowance has been made for involuntary terminations of employment since assuming otherwise would not have a material impact on the actuarial valuation results.

Disability incidence/recovery

The rates of disability incidence/recovery are based on a prior assessment performed by Mercer (Canada) Limited. The use of a different assumption would not have a material impact on the actuarial valuation results.

Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form

When provided, the actual data for the spouse and form of payment were used for retired members. For other members, the assumed percentage of members with a spouse is based on the percentages for the general population and an assessment of future expectations for members of the plan.

Years male spouse older than female spouse

When provided, the actual data for the spouse were used for retired members. For other members, the assumption is based on surveys of the age difference in the general population, a review of plan data for the years 2006 to 2015, and an assessment of future expectations for members of the plan.

Provision for non-investment expenses

The liability discount rate is net of all expenses. The assumed level of expenses reflected in the liability discount rate is based on recent experience of the plan and an assessment of future expectations.

Appendix D: Actuarial Basis - Solvency and Hypothetical Windup Valuations

D.1 Methods

Asset Valuation Method

The market value of assets, adjusted for net outstanding amounts, has been used for the solvency and hypothetical windup valuations. The resulting value has been reduced by a provision for plan windup expenses.

The adjustment in respect of the smoothing of solvency assets for purposes of determining the statutory solvency deficiency was calculated as the difference between the going concern value of assets used for the going concern valuation and the market value of assets.

Liability Calculation Method

The solvency and hypothetical windup liabilities for members were calculated using the traditional unit credit cost method.

Other Considerations

The solvency and hypothetical windup valuations have been prepared on a hypothetical basis. In the event of an actual plan windup, the plan assets may have to be allocated between various classes of plan members or beneficiaries as required by applicable Pension legislation. Such potential allocation has not been performed as part of these solvency and hypothetical windup valuations.

D.2 Solvency Incremental Cost Actuarial Method

To calculate the Solvency Incremental Cost ("SIC"), we used the same method as for the solvency valuation.

No new entrants have been considered on the basis that such assumptions would not have a material impact on the SIC. The benefits and members' contributions were projected using the going concern valuation assumptions and the plan provisions.

We adjusted the expected settlement method at the end of the projection period to reflect demographic evolution. Regardless of that change, we used the discount rate applicable on the settlement method at the valuation date for each member. The liability discount rates (before averaging) are expected to remain at their current level over the projection period.

D.3 Actuarial Assumptions

	December 31, 2016	December 31, 2015
Economic Assumptions (per annum)		
Liability discount rate (before averaging for solvency and for hypothetical windup)		
■ Annuity purchase (non-indexed)	3.10%	3.10%
■ Annuity purchase (fully-indexed)	-0.09%	-0.05%
■ Annuity purchase (partially-indexed)[1]	0.71%	0.74%
■ Commuted value (non-indexed)	2.20% for 10 years, 3.50% thereafter	2.10% for 10 years, 3.70% thereafter
■ Commuted value (fully-indexed)	1.10% for 10 years, 1.30% thereafter	1.30% for 10 years, 1.80% thereafter
■ Commuted value (partially-indexed)[1]	1.40% for 10 years, 1.90% thereafter	1.50% for 10 years, 2.30% thereafter
Liability discount rate (after averaging for solvency)		
■ Annuity purchase	3.44%	3.58%
■ Commuted value	2.44% for 10 years, 3.84% thereafter	2.52% for 10 years, 3.96% thereafter
Discount rate for determining amortization payments[2]	3.00%	3.40%
Escalation of *Income Tax Act (Canada)* maximum pension limitation[3]	1.13% for 10 years, 2.14% thereafter	1.16% for 10 years, 2.20% thereafter
Demographic Assumptions		
Mortality	CPM2014 Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	Same
Withdrawal	N/A	Same
Disability incidence/recovery	N/A	Same
Retirement/pension commencement	Described in detail in D.4	Same
Other		
Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form	90%	Same
Years male spouse older than female spouse	3	Same

	December 31, 2016	December 31, 2015
Percentage of members receiving settlement by commuted value transfer[4]	Retired members and beneficiaries: 0% Other members: ■ Not eligible for retirement: 60% ■ Eligible for retirement: 20%	Same Other members: ■ Not eligible for retirement: 70% ■ Eligible for retirement: 40%
Provision for expenses solvency and hhypothetical windup expenses	$7,000,000	0.25% of assets

Notes:

1 Applicable to New Society and New Management members only.

2 Equal to the liability-weighted average of the liability discount rates for settlements by commuted value transfer (rate in effect for the first 10 years) and annuity purchase.

3 The *Income Tax Act (Canada)* maximum pension limit is $2,914.44 per year of service in 2017 and is indexed starting in 2018.

4 The balance are assumed to receive settlement by annuity purchase.

D.4 Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the solvency and hypothetical windup valuations is summarized below.

The actuarial assumptions used in the solvency and hypothetical windup valuations do not include margins for adverse deviations.

Liability discount rate for solvency (before averaging) and hypothetical windup

Portion of the solvency and hypothetical windup liabilities expected to be settled by a group annuity purchase: Based on the CIA annuity purchase guidance applicable at the valuation date. The duration of the liabilities assumed to be settled through the purchase of non-indexed annuities is 11.9.

Portion of the solvency and hypothetical windup liabilities expected to be settled by commuted value transfer: Prescribed rates at the valuation date.

Liability discount rate for solvency (after averaging)

The average discount rates for calculation of the statutory solvency deficiency are based on the following:

- Benefits that are expected to be settled by a group annuity purchase, the average of the annualized approximate annuity purchase rates at December 31, 2016 and the four previous year-ends[1], determined as follows:

December 31, 2012	3.44%
December 31, 2013	4.38%
December 31, 2014	3.18%
December 31, 2015	3.10%
December 31, 2016	3.10%
Average	3.44%

Note:

[1] The approximate annuity purchase interest rates prior to October 1, 2015 have been adjusted to reflect the change in the mortality table assumption applicable to the determination of liabilities settled by group annuity purchase.

- Benefits that are expected to be settled by commuted value transfers, the average of the interest rates determined under the *Standards of Practice for Pension Commuted Values,* published by the Canadian Institute of Actuaries, at December 31, 2016 and the four previous year-ends[1], determined as follows:

	Rate for 10 years	Rate after 10 years
December 31, 2012	2.40%	3.60%
December 31, 2013	3.00%	4.60%
December 31, 2014	2.50%	3.80%
December 31, 2015	2.10%	3.70%
December 31, 2016	2.20%	3.50%
Average	2.44%	3.84%

Note:

[1] The *Standards of Practice for Pension Commuted Values* effective on December 31, 2016 are assumed to have always been in effect when determining the interest rates prior to October 1, 2015.

Escalation of Income Tax Act (Canada) maximum pension limitation

The maximum pension is indexed annually with the expected increase in the Industrial Aggregate Wage index (commuted value transfers, inflation rate, plus 1.0%).

Pre-retirement and Post-retirement pension increases

For the solvency valuation, as permitted under the Pension legislation, pension increases are assumed to be nil. For the hypothetical windup valuation, the assumption has been determined by applying the increase provision specified in the plan to the inflation assumption.

Mortality

For benefits that are expected to be settled by group annuity purchase and commuted value transfer: Prescribed table. No pre-retirement mortality has been assumed in order to approximate the value of pre-retirement death benefits.

Retirement/pension commencement

For active and disabled members:

- Members eligible to retire: pension commences at the age that produces the highest actuarial value (including statutory grow-in rights).

- Members with age plus continuous service greater than or equal to 55 years and employed in Ontario or Nova Scotia: pension commences at the age that produces the highest actuarial value of pension (including statutory grow-in rights).
- Other members: pension commences at the age that produces the highest actuarial value

For deferred vested members:

- Members are assumed to retire at the earliest age at which they qualify for an unreduced pension.

For the benefits that are expected to be settled by a group annuity purchase, this is consistent with the expected assumption that will be used by insurers to price the group annuity. For benefits that are expected to be settled by commuted value transfers, this assumption is in accordance with the Canadian Institute of Actuaries' Standards of Practice for Pension Commuted Values.

Percentage of members with eligible spouses at pension commencement and electing joint and survivor pension form

See rationale for going concern assumptions in Appendix C.

Percentage of members receiving settlement by commuted value transfer

This assumption has been determined by considering the benefit provisions of the plan, legislative requirements to offer specific settlement options to various classes of members, and, in particular, the options to be provided to members upon plan windup.

The assumption also reflects the expectation that members further from retirement are more likely to elect to settle their pension benefit by a commuted value transfer, while members closer to retirement are more likely to elect to settle their pension benefit through a group annuity purchase where this option is available. In addition, the assumption reflects past plan experience for terminating and retiring members.

Provision for expenses

Allowance was made for normal administrative, actuarial, legal and other costs which would be incurred if the plan were to be wound up (excluding costs relating to the resolution of surplus or deficit issues). The actuarial valuation is premised on a scenario in which the employer continues to operate after the windup date. In establishing the allowance for plan windup costs, certain administrative costs were assumed to be paid from the pension fund (consistent with past practice) while other costs were assumed to be borne directly by the employer.

Appendix E: Membership Data

Summary of Membership Data

Active members

	December 31, 2016	December 31, 2015
■ Number	5,310	5,355
■ Average age	44.1	44.1
■ Average credited service	13.0	13.3
■ Annual payroll	$ 550,645,330	$ 543,523,888
■ Average payroll	$ 103,700	$ 101,498
■ Accumulated contributions with interest	$ 374,506,285	$ 367,013,623

Disabled Members

	December 31, 2016	December 31, 2015
■ Number	137	131
■ Average age	54.3	54.9
■ Average credited service	22.3	23.4
■ Annual payroll	$ 12,298,641	$ 11,169,636
■ Average payroll	$ 89,771	$ 85,264
■ Accumulated contributions with interest	$ 9,357,538	$ 9,230,244

Comment:

The following distribution relates to active and disabled members. The following meanings have been assigned to age and credited service:

- Age: Age as at December 31, 2016
- Credited Service: Credited service as at December 31, 2016
- Payroll: Estimated 2017 pensionable earnings

Active and Disabled Members

		Credited Service								
Age		0 - 4	5 - 9	10 - 14	15 - 19	20 - 24	25 - 29	30 - 34	35 +	Total
< 25	Number	35								35
	Average Earnings	77,466								77,466
25 - 29	Number	333	140							473
	Average Earnings	87,701	94,944							89,845
30 - 34	Number	312	692	40						1,044
	Average Earnings	90,693	99,199	106,071						96,920
35 - 39	Number	146	364	184	21					715
	Average Earnings	94,786	99,702	108,952	108,281					101,330
40 - 44	Number	82	233	153	53					521
	Average Earnings	97,691	105,111	107,878	115,547					105,817
45 - 49	Number	51	194	101	41	25	122			534
	Average Earnings	100,550	104,419	112,913	115,371	114,284	109,094			108,027
50 - 54	Number	55	174	95	93	32	420	153	8	1,030
	Average Earnings	105,114	103,287	108,809	107,024	105,991	110,875	110,846	111,512	108,596
55 - 59	Number	34	124	59	65	17	177	159	74	709
	Average Earnings	91,969	102,265	107,267	114,299	116,122	107,555	112,538	124,596	109,578
60 - 64	Number	14	50	33	38	6	54	40	66	301
	Average Earnings	92,786	105,568	108,867	107,559	129,779	106,132	112,811	102,387	106,435
65 +	Number	2	15	16	6	2	14	16	14	85
	Average Earnings	102,240	110,902	103,624	93,971	209,079	115,982	118,793	119,195	114,131
Total	Number	1,064	1,986	681	317	82	787	368	162	5,447
	Average Earnings	91,730	100,993	108,834	110,921	114,875	109,618	112,136	114,435	103,349

Average Age = 44.3 Average Credited Service = 13.3

Retired members

	December 31, 2016	December 31, 2015
Number	5,562	5,502
Average age	71.7	71.5
Total annual pension	$ 238,697,672	$ 240,389,865
Average annual pension[1]	$ 42,916	$ 43,691
Total temporary annual pension	$ 24,729,454	$ 24,642,237

Beneficiaries and survivors

	December 31, 2016	December 31, 2015
Number	1,772	1,777
Average age	80.9	80.4
Total annual pension	$ 45,251,888	$ 44,098,256
Average annual pension[1]	$ 25,537	$ 24,816
Total temporary annual pension	$ 510,660	$ 460,627

Terminated vested members

	December 31, 2016	December 31, 2015
Number	309	294
Average age	53.9	53.5
Total annual pension[2]	$ 3,151,778	$ 2,872,957
Average annual pension	$ 10,200	$ 9,772

Notes:

1 Excluding temporary annual pension.
2 Prior to application of Income Tax Act maximum pension limits.

Review of Membership Data

The membership data were supplied by Hydro One Inc.'s third-party administrator, Morneau Shepell, as at December 31, 2016.

Elements of the data review included the following:

- ensuring that the data were intelligible (i.e., that an appropriate number of records was obtained, that the appropriate data fields were provided and that the data fields contained valid information);
- preparation and review of membership reconciliations to ascertain whether the complete membership of the plan appeared to be accounted for;
- review of consistency of individual data items and statistical summaries between the current actuarial valuation and the previous actuarial valuation;
- review of reasonableness of individual data items, statistical summaries and changes in such information since the previous actuarial valuation date; and
- comparison of the membership data and the plan's financial statements for consistency.

However, the tests conducted as part of the membership data review may not have captured certain deficiencies in the data. We have also relied on the certification of the plan administrator as to the quality of the data.

Membership Reconciliation

	Actives	Disabled	Terminated vested	Retired	Beneficiaries and survivors	Total
As at December 31, 2015	5,355	131	294	5,502	1,777	13,059
■ New entrants (including re-employed)	232	0	0	0	0	232
■ From disabled	6	(6)	0	0	0	0
■ To disabled	(22)	22	0	0	0	0
■ Terminated (with lump sum payment)	(16)	0	(4)	0	0	(20)
■ Termination (with vested pension entitlement)	(33)	0	33	0	0	0
■ Retirement	(206)	(9)	(13)	228	0	0
■ Deceased (without beneficiary)[1]	(2)	0	(1)	(72)	(110)	(184)
■ Deceased (with beneficiary)	(4)	(1)	0	(96)	102	0
■ New ex-spouse	0	0	0	0	3	3
■ Data corrections	0	0	0	0	0	0
■ Net change	(45)	6	15	60	(5)	31
As at December 31, 2016	5,310	137	309	5,562	1,772	13,090

[1] Includes pensioners whose guarantee period has expired.

Appendix F: Summary of Plan Provisions

The following is an outline of the principal features of the plan which are of financial significance to valuing the plan benefits. This summary is based on the most recently restated plan document as at November 7, 2016 and amendments up to and including the valuation date, as provided by Hydro One Inc. It is not a complete description of the plan terms and should not be relied upon for administration or interpretation of benefits. For a detailed description of the benefits, please refer to the plan document.

Membership

The following categories of employees are members of the Pension Plan:

a) All regular employees (see Note 1a and Note 1b);

b) Employees for whom the Office and Professional Employees International Union was the bargaining agent prior to July 30, 1982;

c) Continuing construction employees who were members admitted to the Ontario Electricity Financial Corporation Pension Plan and its predecessors;

d) Employees who became continuing construction clerical employees after July 29,1982 and before August 8, 1984;

e) Employees who have completed three months of continuous employment as a probationary employee (see Note 1a and Note 1b).

Note 1a: Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 are eligible after completing three months of continuous employment but are not required to join the Pension Plan.

Note 1b: Management employees who were not eligible to elect to become a member of the Pension Plan on or after September 30, 2015 are no longer eligible to join the Pension Plan.

Any other employee who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the Year's Maximum Pensionable Earnings ("YMPE"), as defined under the Canada Pension Plan in each of the two previous consecutive calendar years, may elect to become a member of the Pension Plan.

Normal Retirement Date

a) Female members whose continuous employment commenced prior to January 1, 1976: The first day of the month when she in fact retires, coincident with or next following the attainment of age 60 or any subsequent month up to the month coincident with or next following her 65th birthday.

b) All other members: The first day of the month coincident with or next following the attainment of age 65.

Amount of Accrued Pension

Life Pension

a) 2% of the member's "high three-year average" (see Note 6) for each year of credited service, subject to a maximum of 35 years (see Note 2 and Note 3).

Note 2: For Management employees hired on or after January 1, 2004, and Society represented employees hired on or after November 17, 2005 the reference to "high three-year average" is changed to "high five-year average" for pensionable service while a Management or Society-represented employee.

Note 3: For members represented by PWU and the Society, for service accrued after March 31, 2025 for current employees and new hires, the benefit calculated will be determined using "high five-year average" (updated from "high three-year average" used for service accrued until March 31, 2025) as outlined in the respective collective agreements.

LESS

b) 0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 6) for each year of credited service included in (a) above subsequent to December 31, 1965, subject to a maximum of 35 years – see Note 4.

Note 4: Effective July 1, 2001, for members of the PWU, and effective January 1, 2004, for Society represented members hired before November 17, 2005; the factor is reduced from 0.625% to 0.50%.

Bridge Pension (see Note 5)

0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 6) for each year of credited service included in (a) above, subject to a maximum of 30 years, multiplied by 35, and divided by 30. This is generally payable until age 65.

The bridge benefit is reduced for early retirement in accordance with the same early retirement reduction provision applicable to the early retirement life pension described below.

Note 5: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, no bridge pension is payable for pensionable service while a Management or Society-represented employee. Effective January 1, 2018, Society represented employees hired on or after November 17, 2005 will be entitled to a bridge benefit equal to 0.625% up to the average YMPE for each year of service from January 1, 2018 onward while the member is earning a benefit under the basic formula.

Note 6: "High three-year average"/ "high five-year average" is the average of the member's base annual earnings plus bonuses up to a set percentage during the 36/60 consecutive months when the base earnings were highest. For earnings after 1999, the percentage of bonus under the performance achievement plan included in pensionable earnings is 50%. The "average YMPE" is the average of the YMPE's during the 60 consecutive months when the base earnings were highest.

Early Retirement

Age Plus Service (See Note 7 and Note 8)

A member may retire prior to the normal retirement date without any reduction in the accrued pension, if the sum of the member's age and years of continuous employment is equal to or greater than 82 or the member has 35 years of continuous employment, whichever occurs first (see Note 7).

Note 7: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, retirement without reduction is available when the sum of the employee's age and years of pensionable service is equal to or greater than 85 or the employee has 35 years of pensionable service, whichever occurs first.

Note 8: For members represented by PWU, for service accrued after March 31, 2025, the early retirement criteria for an unreduced pension will be changed from the sum of the employee's age and years of pensionable service is equal to or greater than 82 to the 85 as outlined in the collective agreement.

25 or More Years of Continuous Employment (see Note 9)

A member who does not qualify for the early retirement provisions above who is at least age 55 and has 25 or more years of continuous employment may retire prior to age 60, in which case the member's accrued pension is reduced by 3% for each year by which early retirement precedes age 60. These reductions also apply to members who elected a deferred pension when they left the Pension Plan and had 25 or more years of continuous employment.

Female Members with More Than 15 Years or Other Members with 15 or More Years but Less than 25 Years of Continuous Employment (see Note 9)

A female member whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other member with 15 or more years but less than 25 years of continuous employment, who does not qualify for any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. In such a case the member's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the member's normal retirement date.

These reductions apply with respect to a female member whose employment commenced prior to 1976 and who has a deferred pension and at least 25 years of continuous employment at retirement. For any other members who have a deferred vested pension and have fewer than 25 years of continuous employment and are at least age 55 when they request that the pension payments begin, the deferred vested pension will be actuarially reduced (unless the member was eligible for an unreduced early retirement provision in effect when the member terminated active employment).

Other Members

A member, who does not qualify under any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. If the retirement occurred prior to July 1, 2012, the member is also required to have at least two years of Pension Plan membership. In such a case, the pension is the actuarial equivalent of the member's deferred pension provided that the reduction shall not be less than the minimum early retirement reduction required under the *Income Tax Act* (Canada).

Terminated Members with Deferred Pensions

A terminated member with a deferred pension may retire under any of the previously mentioned provisions for early retirement without reduction provided that such provision was in effect on the date of termination. In addition, if the member's employment is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the *Pension Benefits Act* (Ontario) ("PBA"), resulting in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination.

Note 9: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 all references to "continuous employment" are to be replaced with "pensionable service" for service while a Management or Society-represented employee.

Postponed Retirement

Members who work past their normal retirement date shall continue to accrue benefits until December 1st of the calendar year they reach age 71 (or the Income Tax Act age limit, if different), they reach the 35 year service limit, or they terminate employment, whichever occurs first. If a member reaches 35 years of service and ceases contributions to the Pension Plan, service after 35 years is not counted in the calculation of the member's pension, but the pension is calculated using the member's base earnings up to the date of postponed retirement. If the member works past age 71, the member's pension will commence to be paid not later than December 1st of the year in which the member turns age 71.

Pension Increases

Pension increases of 100% (see Note 10) of the increase in the Consumer Product Index ("CPI") (Ontario), for the 12-month period ending in June of the previous year , will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions to an annual maximum of 8% each year after 1999. Any excess will be carried forward to use in future years up to the 8% limit.

Note 10: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, pension increases of 75% CPI (Ontario) for the 12-month period ending in June of the previous year will be given every January 1, to an annual maximum increase of 6%, with no carry forward.

Disability

A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Employee Contributions

Members represented by the Management hired on or after January 1, 2004 contribute at the following rates until they complete 35 years of credited service (see Note 11):

Up to and including March 31, 2017,

i. 7.00% of base annual earnings up to the YMPE; and

ii. 9.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

i. 7.75% of base annual earnings up to the YMPE; and

ii. 9.75% of base annual earnings in excess of the YMPE;

On and after April 1, 2018,

i. 8.25% of base annual earnings up to the YMPE; and

ii. 10.75% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Management hired before January 1, 2004 contribute at the following rates until they complete 35 years of credited service (see Note 11):

Up to and including March 31, 2017,

iii. 7.00% of base annual earnings up to the YMPE; and

iv. 9.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

iii. 8.00% of base annual earnings up to the YMPE; and

iv. 10.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2018,

i. 8.75% of base annual earnings up to the YMPE; and

ii. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Society hired on or after November 17, 2005 contribute at the following rates until they complete 35 years of credited service (see Note 11):

Up to and including March 31, 2017,

v. 7.00% of base annual earnings up to the YMPE; and

vi. 9.00% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

v. 7.75% of base annual earnings up to the YMPE; and

vi. 9.75% of base annual earnings in excess of the YMPE;

On and after April 1, 2018,

iii. 8.25% of base annual earnings up to the YMPE; and

iv. 10.75% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Members represented by the Society hired before November 17, 2005 contribute at the following rates until they complete 35 years of credited service (see Note 11):

Up to and including March 31, 2017,

vii. 7.50% of base annual earnings up to the YMPE; and

viii. 9.50% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

vii. 8.25% of base annual earnings up to the YMPE; and

viii. 10.25% of base annual earnings in excess of the YMPE;

On and after April 1, 2018,

iii. 8.75% of base annual earnings up to the YMPE; and

iv. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Note 11: For Society represented members hired before November 17, 2005, contributions increase by 0.5% in the event that after January 1, 2004 a valuation report reveals that the solvency assets are lower than 106% of the solvency liabilities. Effective April 1, 2018 this clause is no longer applicable.

Members represented by the PWU contribute at the following rates until they complete 35 years of credited service:

Up to and including March 31, 2017,

i. 8.25% of base annual earnings up to the YMPE; and

ii. 10.25% of base annual earnings in excess of the YMPE;

On and after April 1, 2017,

i. 8.75% of base annual earnings up to the YMPE; and

ii. 11.25% of base annual earnings in excess of the YMPE;

up to the limits established by the Income Tax Act.

Death Before Retirement

No Surviving Spouse or Eligible Dependent Children

Fewer than two years of Pension Plan membership (Deaths prior to July 1, 2012)

The member's beneficiary or estate receives a cash refund of the member's contributions plus interest.

Two or more years of Pension Plan membership

The beneficiary or estate will receive the following:

- For pre-1987 service: a cash refund of the member's contributions plus interest.
- For post-1986 service: a lump sum equal to the commuted value of the member's pension earned since 1986, plus a refund of any excess contributions.

For deaths occurring on or after July 1, 2012, the beneficiary or estate will be entitled to the death benefits described above regardless of the member's length of service.

Surviving Spouse (see Note 12)

Fewer than two years of Pension Plan membership and less than 10 years of continuous employment

The beneficiary or estate receives a cash refund of the member's contributions plus interest.

Fewer than two years of Pension Plan membership and more than 10 years of continuous employment

The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned to the date of death.

More than two years of Pension Plan membership, but less than 10 years of continuous employment

For pre-1987 service: The beneficiary or estate receives a cash refund of the member's contributions plus interest.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:
  a. a lump-sum payment equal to the commuted value of the pension earned after 1986, or
  b. an immediate or deferred pension with a commuted value equal to pension earned after 1986.

More than two years of Pension Plan membership, and more than 10 years of continuous employment

For pre-1987 service: The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned prior to 1987.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and

- The surviving spouse chooses either:
- a lump-sum payment equal to the commuted value of the pension earned after 1986, or
- an immediate or deferred pension with a commuted value equal to pension earned after 1986. The immediate pension will not be less than 66.67% of the pension earned after 1986.

Note 12: For deaths occurring on or after July 1, 2012, the surviving spouse's entitlement to death benefits for post-1986 service shall be determined without reference to whether the member had more or less than two years of Pension Plan membership. In addition, for deaths occurring on or after July 1, 2012, if the surviving spouse is entitled to the death benefits in respect of the member's post-1986 service, the surviving spouse is also entitled to an amount equal to the member's contributions, with interest, in respect of pre-1987 service, rather than the designated beneficiary or estate.

Dependent Children, No Surviving Spouse

If the member completed 10 years of continuous employment, the survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest. A payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.

Death After Retirement

A survivor's pension, being an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse, subject to other options chosen at the time of retirement. If the survivor spouse subsequently dies and is survived by the dependent children, or the member does not have a surviving spouse and is survived only by dependent children, the 66.67% survivor pension is split among the dependent children and is payable to age 18 (longer if disabled or in full-time attendance at a school or university).

If the member does not have a surviving spouse at retirement, the normal form of pension is a pension payable for life with a guarantee of 60 payments.

Optional forms of pension are available on an actuarially equivalent basis.

Termination of Employment (see Note 14)

Less Than One Year of Pension Plan Membership

A cash refund of the member's contributions plus interest.

More Than One Year But Fewer Than Two Years of Pension Plan Membership

The member is entitled to elect a cash refund of the member's contributions plus interest, or may leave the earned pension benefit in the Pension Plan to be paid upon retirement.

More Than Two Years but fewer than 10 Years of Pension Plan Membership and, either under Age 45, or Fewer Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to a cash refund of the member's contributions plus interest, or may leave all of the earned pension benefit in the Pension Plan until retirement.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More Than Two Years but fewer than 10 Years of Pension Plan Membership, and Age 45 or Older with More Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) 75% of the commuted value of the pension and receive a refund of 25% of the commuted value of your earned pension; or to leave 75% of the earned pension benefit in the Pension Plan until retirement, and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More Than 10 Years of Pension Plan Membership, But Younger Than Age 45

For service from 1965 to 1986: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More than 10 Years of Pension Plan Membership and Age 45 or Older

For pre-1965 service: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value.

For service from 1965 to 1986: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value; or to transfer (see Note 13) the greater of the commuted value of 75% of the earned pension or the member's contributions with interest and receive a refund of 25% of the commuted value of the earned pension.

For post 1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer the commuted value of the earned pension.

If a member is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the PBA, which could result in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination. If grow-in benefits apply, this may affect the value of the benefits the member is entitled to receive on termination of employment or retirement.

Note 13: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.

Note 14: In respect of terminations occurring on or after July 1, 2012, a member is entitled to the earned pension benefits for all service regardless of length of Pension Plan membership, continuous employment or age.

Excess Contributions

Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the vested deferred pension accrued after 1986 is refunded to the member (or to the spouse, beneficiary or estate, as applicable in the case of death before retirement).

Upon termination of employment, if a member who has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987. (See Note 15)

Note 15: For terminations occurring on or after July 1, 2012, entitlement to excess contributions in respect of pre-1987 service shall be determined without reference to age or years of continuous employment.

Maximum Benefits

The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the Income Tax Act (Canada).

Appendix G: Sensitivity Analysis and Other Disclosures

G.1 Sensitivity Information

Amounts determined with a discount rate 1% lower:

Going concern actuarial liability	$ 7,019,634,850
Solvency actuarial liability	$ 7,496,855,401
Employer normal actuarial cost as a percentage of payroll	20.9%

G.2 Solvency Incremental Cost

Solvency Incremental Cost (up to next valuation date)	$ 746,029,299

Actuarial Information Summary

See the instructions for completing this form. If an item does not apply, enter "N/A".

Part I – Plan Information and Contributions

A. 001. Name of registered pension plan
Hydro One Pension Plan

B. 002. Registration number

Canada Revenue Agency: 1059104 Other: ______

C. 003. Is this plan a designated plan?
☐ Yes ☑ No

D. 004. Valuation date of report
Year 2016 Month 12 Day 31

E. 005. End date of period covered by report
Year 2019 Month 12 Day 30

F. 006. Purpose of the report (indicate all reasons for which the report was prepared)

☐ Initial report for a newly established plan
☑ Regular (triennial or annual) report for an ongoing plan
☐ Interim report in respect of an amendment to an ongoing plan
☐ Partial termination
☐ Termination
☐ Conversion
☐ Other (explain) ______

G. Contributions (prior to application of any credits or surplus) for covered period

Periods (see instructions)	Period 1	Period 2	Period 3	Period 4
007. Period start date (YYYY-MM-DD)	2017-01-01	2018-01-01	2019-01-01	
008. Period end date (YYYY-MM-DD)	2017-12-31	2018-12-31	2019-12-30	
Normal cost (defined benefit provision) **009.** Members	46,811,492	47,367,141	46,988,718	
010. Employer	73,261,382	71,354,000	70,650,379	
010a. Explicit expense allowance included in employer normal cost above				
Normal cost (money purchase provision) **011.** Members				
012. Employer				
Special payments Special payments for going-concern unfunded liability and solvency deficiency **013.** Employer	0	0	0	
013a. Members	0	0	0	
Fixed contributions **014.** Estimated dollar amounts of fixed employer and, if applicable, member contributions (defined benefit provision)				
014a. Estimated dollar amounts of fixed employer and, if applicable, member contributions (money purchase provision)				

Part II – Membership and Actuarial Information

H. Membership information	Number	Average age	Average pensionable service	Average salary	Average annual pension
015. Active members	5,447	44.40	13.20	103,349	N/A
016. Retired members	7,334	73.90	**N/A**	**N/A**	38,717
017. Other participants	309	53.90	**N/A**	**N/A**	10,200

I. Actuarial basis for going-concern valuation (see instructions)

020. Asset valuation method

☐ Market ☑ Smoothed Market ☐ Book ☐ Book and Market combination ☐ Other (specify) ______

021. Liability valuation method

☑ Accrued benefit (unit credit) ☐ Entry age normal ☐ Individual level premium ☐ Aggregate ☐ Attained Age

☐ Other (specify) ______

I. Actuarial basis for going-concern valuation (continued)
Selected actuarial assumptions
Where a flat rate is used, enter the rate under "Ultimate rate" and "N/A" under "Initial rate" and "Number of years".

Valuation interest rate	Initial rate (%)	Number of years	Ultimate rate (%)
025. Active members	N/A	N/A	5.30
026. Retired members	N/A	N/A	5.30
027. Rate of indexation	N/A	N/A	2.00
028. Rate of general wage and salary increase	N/A	N/A	2.50
029. YMPE escalation rate	N/A	N/A	3.00
030. *Income Tax Regulations*' maximum pension limit escalation	N/A	N/A	3.00
031. Rate of CPI increase	N/A	N/A	2.00

035. Year *Income Tax Regulations*' maximum pension limit escalation commences 2018

036. Mortality table

☐ 1994 GAM Static ☐ 1994 Group Annuity Reserving (GAR) ☐ 1994 UP ☐ 80% of 1983 GAM ☐ CPM2014

☐ CPM2014Publ ☑ CPM2014Priv ☐ Other (specify) ____________

036a. Improvement scale

Has a projection of mortality improvement been made? .... ☑ Yes ☐ No

i) Has an assumption of generational mortality improvements been made? .... ☑ Yes ☐ No

ii) If applicable, what is the year in which the mortality improvements have been projected? .... ____

iii) Which scale have you used?

☐ Scale AA ☑ Scale CPM-B ☐ Scale CPM-B1D2014 ☐ Other (specify) ____________

036b. Adjustment to the mortality table

i) Has an adjustment to the mortality table been made? .... ☑ Yes ☐ No

ii) If **yes**, which percentage did you apply to .... Male 0.95 Female 0.95

037. Allowance for promotion, seniority, and merit increases

☐ Included in (line **028**) above ☑ Separate scale based on age or service ☐ No allowance

038. Allowance for expenses

038a. Allowance for investment expenses

☑ Implicit ☐ Explicit ☐ Both explicit and implicit

038b. Allowance for administrative expenses

☑ Implicit ☐ Explicit ☐ Both explicit and implicit

039. If a multi-employer plan, number of hours of work per member per plan year ____________

040. Was a withdrawal scale used? .... ☑ Yes ☐ No

041. Were variable retirement rates used? .... ☑ Yes ☐ No

042. If **no**, what is the assumed retirement age? .... ____

J. Actuarial basis for solvency valuation

Valuation interest rate	Initial rate (%)	Select period	Ultimate rate (%)
045. Benefits to be settled by lump sum transfer	2.20	10	3.50
046. Benefits to be settled by purchase of deferred annuity	N/A	N/A	3.10
047. Benefits to be settled by purchase of immediate annuity	N/A	N/A	3.10
048. Rate of indexation	N/A	N/A	N/A

049. Mortality table

Lump sum: ☐ 1994 UP Generational ☐ CPM2014Priv ☑ CPM2014 ☐ CPM2014Publ ☐ Other (specify) ____________

Annuity Purchase: ☐ 1994 UP Generational ☐ CPM2014Priv ☑ CPM2014 ☐ CPM2014Publ ☐ Other (specify) ____________

049a. Improvement scale used

Lump sum: ☐ Scale AA ☑ Scale CPM-B ☐ Scale CPM-B1D2014 ☐ Other (specify) ______ ☐ None

Annuity Purchase: ☐ Scale AA ☑ Scale CPM-B ☐ Scale CPM-B1D2014 ☐ Other (specify) ______ ☐ None

K. Balance sheet information (DB provisions, see instructions)

050. Market value of assets, adjusted for receivables and payables 6,916,807,000

051. Amount of contributions receivable included in market value above 7,390,000

Going-concern valuation

052. Going-concern assets 6,514,329,000

053. Optional ancillary contributions account balance included in going-concern assets above for a flexible pension plan (if applicable) ______

Going-concern liabilities

060. For active members 2,004,991,863

061. For retired members 4,031,088,676

062. For other participants 44,570,154

063. For optional ancillary benefits to be provided under a flexible pension plan (if applicable) .... ______

064. Other reserve .... ______

065. Reserve type ☐ Expenses ☐ Ad-hoc indexing ☐ Provision for Adverse Deviation ☐ Other (specify) ______

070. Net funded position—surplus/deficit 433,678,307

071. Additional voluntary contributions 20,000

072. Money purchase assets (if applicable) 0

Solvency valuation

Complete lines **080** to **100** only if the report contains an explicit solvency valuation

Solvency assets

080. Solvency assets with adjustment for expense provision, if any 6,909,807,000

081. Amount of wind-up expense provision reflected in line **080** 7,000,000

082. Optional ancillary contributions account balance included in solvency assets above for a flexible pension plan (if applicable) . ______

Solvency liabilities

090. For active members 2,369,597,002

091. For retired members 4,127,326,152

092. For other participants 46,840,401

093. For optional ancillary benefits to be provided under a flexible pension plan (if applicable) .... ______

094. Other reserve .... ______

095. Reserve type .... ☐ Expenses ☐ Other (specify) ______

100. Net solvency position—surplus/deficit 366,043,445

101. Incremental cost 746,029,299

If the plan provides benefit increases coming into effect during the period covered by the report but after the valuation date, have those increases been reflected in:

102. The going-concern liabilities in lines **060** to **064**? .... ☐ Yes ☐ No ☑ N/A

103. The solvency liabilities in lines **090** to **094**? .... ☐ Yes ☐ No ☑ N/A

Discount rate sensitivity

	Change in percentage using discount rate 1% lower	Change in amount using discount rate 1% lower	Change in amount using discount rate 1% higher
104. Going-concern liabilities	15.44	938,964,160	
105. Normal cost	31.90	38,323,384	
106. Solvency liabilities	14.56	953,071,872	

L. Actuarial gains or losses

110. Was a gain/loss analysis done? .... ☑ Yes ☐ No

111. If line **110** is **yes**, indicate the date of the last filed funding valuation report and the net funded position as of that date .... Year 2015 Month 12 Day 31 .... (37,687,000)

If line **110** is **yes**, indicate amount of gain or loss due to:

112. interest on surplus (unfunded liability)	(2,035,098)
113. special payments made	24,705,000
114. amount used for contribution holiday	0
115. change in actuarial assumptions	61,005,963
116. change in the asset valuation method	0
117. change in liability valuation method	0
118. plan amendments/changes	0
119. investment experience	292,379,000
120. retirement experience	(3,952,266)
121. mortality experience	(10,686,136)
122. withdrawal experience	(2,481,510)
123. salary increase experience	50,654,805
124. optional ancillary contributions forfeited	

Are there major contributing sources other than lines **112** to **124** above (if **yes**, specify)

125. cost of living	11,039,223
126. other	50,078,061
127. all other sources (combined)	658,265

M. Subsequent events

135. Are there any subsequent event(s) that have not been reflected in the valuation? (refer to SOP) ☐ Yes ☑ No

N. Statements of opinion

136. Does the report include the statements of opinion required by the SOP (data, assumptions, methods, accepted actuarial practice)? ☑ Yes ☐ No

136a. Are any of the actuary's statements of opinion qualified? ☐ Yes ☑ No

Financial Services Commission of Ontario — Commission des services financiers de l'Ontario

Part III – Information required by the Financial Services Commission of Ontario

O. Additional valuation information

Going-concern valuation

137. Are benefits under the pension plan provided by an annuity purchase? ☐ Yes ☑ No

138. If line **137** is **yes**,

a) enter the total asset value of the annuities purchased

b) enter the total liability of the annuities purchased

139. Have escalated adjustments been included in going-concern liabilities? ☑ Yes ☐ No ☐ N/A

Solvency valuation

140.1 If line **137** is **yes**,

a) enter the total asset value of the annuities purchased

b) enter the total liability of the annuities purchased

140.2 Enter the value of any solvency deficiency payment that is guaranteed by a letter of credit

140.3 Enter the expiry date of the letter of credit, if any — Year / Month / Day

141. Have any of the excludable benefits been excluded? ☑ Yes ☐ No ☐ N/A

142. If line **141** is **yes**, enter the total amount of liabilities being excluded 3,475,558,136

143. With respect to the type of benefits provided under the plan for service after the valuation date, complete the following table:

Provision type	Benefit accruals for service after valuation date (Yes/No)	Closed(Yes/No)
Defined Benefit	Yes	No
Defined Contribution	No	No

144. (i) Has an averaging method been applied to the market value of assets in determining the solvency asset adjustment? ☑ Yes ☐ No

a) If line **(i)** is yes, indicate the positive or negative amount by which the solvency assets are adjusted as a result of applying the averaging method: (402,478,000)

(ii) Has the averaging method used in determining the solvency asset adjustment changed since the last valuation? ☐ Yes ☑ No

If line **(ii)** is **yes**, complete **(ii)a** or **(ii)b**, as appropriate:

a) The change in method increases solvency asset adjustment by the amount of ______

b) The change in method decreases solvency asset adjustment by the amount of ______

P. Miscellaneous

145. Prior year credit balance	48,000,000
146. Transfer ratio (express in decimal format)	0.6900

Guarantee fund assessment

147. PBGF liabilities	6,543,763,555
148. PBGF assessment base	0
149. Amount of additional liability for plant closure and/or permanent layoff benefits as described in "E" of subsection 37(4) of *Regulation 909, R.R.O. 1990*, as amended	0
149a. Number of Ontario plan beneficiaries	13,090

Part IV – Information required by the Canada Revenue Agency

R. Additional information

173. Surplus/deficit determined at the valuation date as per the instructions:

173a. Going-concern basis ______

173b. Wind-up basis ______

173c. For designated plans, maximum funding valuation basis ______

174. Excess surplus determined at the valuation date:

174a. Going-concern basis ______

174b. For designated plans, maximum funding valuation basis ______

175. For designated plans, employer normal cost determined under the maximum funding valuation basis:

Period 1 ______

Period 2 ______

Period 3 ______

Period 4 ______

176. Minimum surplus required under applicable pension benefit legislation before contribution holiday:

176a. Going-concern basis ______

176b. Wind-up basis ______

177. Maximum amount that could be claimed as eligible employer contribution(s) – defined benefit provisions – under subsection 147.2(2) of the *Income Tax Act*:

177a. Unfunded liability ______

177b. Normal cost:

Period 1 ______

Period 2 ______

Period 3 ______

Period 4 ______

178. Do you have any employees contributing over the limit stipulated under paragraph 8503(4) of the *Income Tax Regulations?* ☐ Yes ☐ No

Part V – Information required by Retraite Québec

S. Additional Information

185. Date on which the valuation report was prepared .... ______

186. Value of additional liabilities arising from an improvement on a funding basis .... ______

187. Value of additional liabilities arising from an improvement on a solvency basis .... ______

188. Surplus assets that can be allocated to fund contributions .... ______

189. Special payments........ ______

190. Total of the letters of credit taken into account in the assets .... ______

191. Insured annuities from an insurer taken into account in the actuarial valuation on a solvency basis........ ______

T. Additional information for plans whose employer is a municipality, a municipal housing bureau, or an educational institution at the university level

For service prior to the establishment of the stabilization fund

192. Reserve on a funding basis .... ______

	Present Value	**Amortization payments**			
		Period 1	**Period 2**	**Period 3**	**Period 4**
193. Deficiency attributable to the employer					
194. Funding deficiency **194a.** Payable by the members					
194b. Payable by the employer					

For service following the establishment of the stabilization fund

195. Stabilization fund value .... ______

	Stabilization contributions			
	Period 1	**Period 2**	**Period 3**	**Period 4**
196. Members				
197. Employer				

	Present Value	**Amortization payments**			
		Period 1	**Period 2**	**Period 3**	**Period 4**
198. Technical funding deficiency **198a.** Payable by the members					
198b. Payable by the employer					

U. Additional information for pension plans other than those mentioned in Section T, and for which solvency funding does not apply.

199. Target level (as a percentage) of the required stabilization provision .... ______

	Stabilization contributions			
	Period 1	**Period 2**	**Period 3**	**Period 4**
200. Members				
201. Employer				

	Present Value	Amortization payments			
		Period 1	Period 2	Period 3	Period 4
202. Technical funding deficiency					
202a. Payable by the members					
202b. Payable by the employer					
203. Stabilization funding deficiency					
203a. Payable by the members					
203b. Payable by the employer					
204. Improvement funding deficiency					
204a. Payable by the members					
204b. Payable by the employer					

Part VI – Certification by Actuary

As the actuary who signed the funding valuation report (the report), I certify that this completed form accurately reflects the information provided in the report.

Dated this 31 (day) day of May (month), 2017 (year)

Signature of actuary: ______

Print or type name of actuary: Suzanne Jacques

Name of firm: Willis Towers Watson PLC

Telephone number: (416)960-7460

Email Address*: suzanne.jacques@willistowerswatson.com

*** Optional information. The Canada Revenue Agency will not communicate on plan specific matters with clients by email, since we cannot guarantee the confidentiality of emailed information.**

Personal information is collected under the authority of section 147.2 of the *Income Tax Act* and is used for the administration of a registered pension plan. It may also be used for any purpose related to the administration or enforcement of the Act such as audit and compliance. Information may also be shared or verified under information-sharing agreements to the extent authorized by law. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **cra.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, Personal Information Bank CRA PPU 226.

OEB Staff - Interrogatory # 48

Reference:

Exhibit D1 / Tab 4 / Schedule 1 / Table 2

Interrogatory:

At the above reference the applicant has indicated that it proposes to recover its test period OPEB costs on an accrual basis and provides a breakdown of the test period OPEB accrual expense in Table 2.

a) Please provide the actuarial valuation that underpins the test period accrual expense being sought in rates.
b) Please also provide the calculation used to allocate Remotes' share of the total Hydro One Inc. 2018 accrual expense.
c) Please confirm that there has been no change in the methodology used to calculate and allocate Remotes' share of the accrual expense.

Response:

a) This is the 2018 projection extract from the Willis Towers Watson accrual expense for this test year.

Figures in $000s	Projections 2018
Components of Benefit Cost	
Employer service cost	41,046
Interest cost	60,994
Expected return on plan assets	-
Net prior service (credit)/cost amortization	-
Net (gains)/loss amortization	5,617
Curtailments	-
Settlements	-
Special/contractual termination benefits	-
Disclosed benefit cost	107,657

Components of Benefit Cost	
Employer service cost	4,989
Interest cost	2,016
Expected return on plan assets	-
Net prior service (credit)/cost amortization	-
Net (gains)/loss amortization	-
Curtailments	-
Settlements	-
Special/contractual termination benefits	-
Disclosed benefit cost	7,005

Components of Benefit cost	
Employer service cost	1,371
Expected letter of credit fee	481
Interest cost	4,356
Expected return on plan assets	-
Net prior service cost amortization	-
Net loss/(gain) amortization	1,274
Curtailments	-
Settlements	-
Special/contractual termination benefits	-
Disclosed benefit cost	7,482

b) Remotes share of the 2018 OPEB expense

OPEBs	**Forecast 2018 Hydro One Total OPEBs $K**	**Forecast 2018 Remotes Earnings % Per benefit**	**Forecast 2018 Remotes OPEBs $K**
OPEBs	122,144	1.04%	1,271

c) There has been no change in the methodology used to calculate and allocate Remotes' share of the Hydro One pension contributions.

OEB Staff - Interrogatory # 49

Reference:

Exhibit D1 / Tab 4 / Schedule 1

Interrogatory:

At the above reference, Remotes discusses an upcoming update to the US GAAP accounting standard for pension and OPEB costs that will be effective from January 1, 2018.

a) Please explain why Remotes is proposing to defer the impact of this accounting change on the current application when there is sufficient time to amend the application as needed?
b) Please quantify what Remotes expects the impact to be on the test period pension and OPEB costs being sought in rates, as well as the impact on any other areas of the current application (i.e. depreciation).

Response:

a) Remotes is not proposing to defer the impact of this accounting change. In its application, Remotes noted that upon adoption on January 1, 2018 the impact of this accounting change will flow through the RRRP account (Exhibit D1, Tab 4, Schedule 1):

   The re-classification of these elements to OM&A would have an adverse impact on rates in a given year. As Remotes operates on a break-even basis, the net periodic post-retirement benefit cost other than service cost that would have been classified as capital prior to the issuance of ASU 2017-07 will flow through the RRRP account effective January 1, 2018.

b) Remotes' estimates that the impact of the change would be an increase to OM&A of approximately $213,000. As noted in Exhibit D1, Tab 4, Schedule 1, this increase in OM&A will flow through the RRRP account. The impact to 2018 depreciation expense is nominal.

OEB Staff - Interrogatory # 50

Reference:

Exhibit D1 / Tab 4 / Schedule 1, Report of the Ontario Energy Board on the Regulatory Treatment of Pension and OPEB Costs (EB-2015-0040), p. 8

Interrogatory:

In its September 14, 2017 Report on the Regulatory Treatment of Pension and OPEB costs (OEB Report), the OEB indicated that utilities proposing to set rates using a method other than accrual must support such a proposal with evidence, giving consideration to factors such as providing value to customers and assuring fairness to both present and future ratepayers, and the principles and practices enunciated in this Report.

Remotes has indicated that it has proposed to recover its pension expense for the test period on a cash basis because it believes that this method is more beneficial to its consumers than the accrual method as it results in a lower cost recovered through rates, it is more predictable, and the OEB had previously accepted cash payments related to its pension obligations as the basis of recovery since EB-2012-0137.

In accordance with the OEB Report, please provide evidence that supports the appropriateness of Remotes' continued use of the cash method to recover its pension costs. Please ensure that the evidence provided addresses the required areas as specified in the OEB Report. In addition, Remotes has indicated that the cash method results in lower rates to its consumers, however has not provided any analysis to support this statement. Therefore please also prepare an analysis similar to the one provided for OPEBs in Appendix 2-KA, which provides a historical analysis that compares the cash amount collected in rates and the accrual expense for the applicant's annual pension obligations (please complete the entire table).

Response:

As indicated in the application, Remotes has proposed to recover its pension expense for the test period on a cash basis because it believes that this will result in lower cost recovered through rates and is more predictable over time. On an overall basis, for the Hydro One Pension Plan as a whole the historic cash basis cost to date has been lower than the accrual basis cost and has been more stable. At this time, Remotes requires more time as this will require significant effort, but will be able to provide at a later date.

OEB Staff - Interrogatory # 51

Reference:

Report of the Ontario Energy Board on the Regulatory Treatment of Pension and OPEB Costs (EB-2015-0040), p. 9-12

Interrogatory:

As outlined in the OEB Report on the Regulatory Treatment of Pension and OPEB Costs, effective January 1, 2018, utilities must use a variance account to track the difference between the forecasted accrual amount in rates and actual cash payment(s) made, with an asymmetric carrying charge in favour of ratepayers applied to the differential.

a) Can the use of an asymmetric carrying charge still achieve the desired outcome (i.e. to provide value to ratepayers for over collections) in the context of the break-even model that the applicant's business operates under? Please explain.
b) If the response to the above is no, please provide other alternatives that could be considered in order to provide value to ratepayers with respect to any future over-collection of OPEB costs (i.e. accrual in excess of cash requirements).
c) Please explain what the applicant has historically done with amounts that were over-collected with respect to its OPEB costs, as illustrated in Table 2 of Exhibit D1, Tab 4, Schedule1 and Appendix 2-KA.

Response:

a) Due to the break-even model that Remotes operates under, any carrying charge will be either included as an allowed cost for Remotes Revenue Requirement or be recovered via the RRRP account, therefore not achieving the desired outcome.

b) Within the construct of break-even model under which it operates, Remotes' is not able to provide any other alternatives that could be considered in order to provide value to ratepayers with respect to any future over-collection of OPEB costs.

c) Recoveries in excess of cash benefit payments form part of Remotes' working capital, which is invested in capital and OM&A work programs.

OEB Staff - Interrogatory # 52

Reference:

Exhibit D1 / Tab 6 / Schedule 1 / Page 4 / Line 10

Interrogatory:

Remotes has indicated that expenses related to Land Assessment Remediation measures were lower in 2013 as compared to the amount approved in 2013 rates. The decrease between the 2013 OEB-approved amounts and 2013 actual amounts was as a result of a delay in the remediation of Pikangikum, Attawapiskat and Webequie.

a) Does Remotes provide service to the community of Attawapiskat?
b) Why did Remotes incur expenses for land remediation in the community of Attawapiskat and what kind of remediation measures were implemented?

Response:

a) No. Attawapiskat is and has been served by Attawapiskat Power Corporation since 2003. Attawapiskat was previously served by Ontario Hydro and subsequently by Remotes until the community was grid connected in 2003.

b) Remotes did not incur significant LAR expenses in 2013 related to Attawapiskat (i.e. $1k related to discussions and negotiations). At the time of the last filing, Remotes expected to contribute its share to the LAR clean-up of the site, but this project was delayed due to funding concerns by other parties who are responsible for a larger share of the clean-up.

   By way of background, Remotes is responsible for remediating the soil associated with diesel fuel storage tank(s) that were used by Ontario Hydro pre-1999. Under the Ontario *Environmental Protection Act*, Remotes could be subject to a Ministry Order to clean up contamination associated with Ontario Hydro's operations. Also parties affected by the contamination could start a claim against Remotes to remediate the contamination.

OEB Staff - Interrogatory # 53

Reference:

Exhibit D1 / Tab 7 / Schedule 1 and Exhibit D2 / Tab 8 / Schedule 1

Interrogatory:

For purposes of calculating the 2018 test period regulatory income taxes, the applicant has indicated that the balance being claimed with respect to CCA excludes any CCA related to the revaluation of assets that occurred as a result of Hydro One's 2015 IPO.

a) Similar to Hydro One's current distribution rates case, please confirm that it is the applicant's intention to defer litigation of the regulatory treatment of the tax benefits derived from Hydro One's recent IPO until the motion to review / appeal of the OEB's Decision on Hydro One's 2017/18 transmission rates case has been completed.
b) If the response to the above is no, then please recalculate the test period utility income taxes in Exh D2-8-1 in accordance with the OEB's recent Decision on Hydro One's 2017/18 transmission rates case whereby the OEB has ordered that the tax benefits from Hydro One's IPO be allocated 68%/32% between the shareholders and ratepayers respectively.

Response:

a) Confirmed.

b) See response to a). Please also see response to I-01-67.

OEB Staff - Interrogatory # 54

Reference:

Exhibit D1 / Tab 7 / Schedule 1

Interrogatory:

At the above reference the applicant has indicated that it has recorded a $682,000 tax adjustment to its December 31, 2016 audited RRRP variance account in order to reverse the impact of additional tax expense that was collected in rates because the Company was unable to claim CCA from January 1, 2015 to October 31, 2015 for tax purposes as a result of its IPO.

a) Have the amounts in question already been collected from ratepayers or are they in the December 31, 2016 RRRP variance account balance?
b) Please provide the detailed calculation of this adjustment along with a supporting narrative that explains these calculations.

Response:

a) The amounts are in the December 31, 2016 RRRP balance that have not been collected from rate payers.

b)

Description	Pre-Tax	Tax Rate	Tax Impact	
Additional CCA Deduction	(2,685,260)	26.5%	(711,594)	(i)
Other			29,233	(ii)
			682,000	

(i) The company was unable to claim CCA from January 1 to October 31 as a result of the IPO. Rate-payers should be held neutral from tax impacts associated with the IPO. Consequently, rate payers should be entitled to the CCA from January 1 to October 31 even though it cannot be claimed by the company. The additional CCA claimed from January to October is estimated to be $2,685,260 (Appendix A), which will be given back to rate payers.

(ii) This primarily relates to Ontario Corporate Minimum Tax due to a reduction of taxable income from the additional CCA deductions above.

OEB Staff - Interrogatory # 55

Reference:

Exhibit D2 / Tab 5 / Schedule 1

Interrogatory:

Remotes has provided a summary of wages and salaries for its staff over the historical and test period. The compensation for management staff has increased from $704,673 in 2013 to $819,814 in 2018, an increase of 16.3% over 2013 wages. However, the number of FTEs is the same as 2013 in this category. Similarly, society employees' total wages have increased from $1,406,944 in 2013 to $1,819,655 in 2018, an increase of 29.3% over 2013 with an addition of 0.5 FTE in 2018.

a) Please explain why the OEB should approve the significant wage increases proposed for 2018 as compared to inflation, for management staff and society employees.
b) Please confirm if the union agreement for wage increases in 2018 has been ratified by society employees.
c) Please confirm whether Remotes had undertaken any relevant studies of its proposed increases in compensation/headcount on the basis of compensation benchmarking, or any other external comparators.
d) Please explain the value that Remotes customers will receive as a result of the proposed salary increases in 2018.

Response:

a) The increase in management base pay from 2013 to 2018 is 10.8% which equates to roughly 2% per year and is consistent with inflation. Incentive Pay and Other Allowances fluctuate based on factors other than FTE's as management compensation includes a performance based aspect.

   There were 13.5 Society FTE's in 2013, 12.0 regular and 1.5 temporary. 2018 shows an increase of 2 regular FTE's, one of which is a supervisory position and therefore the main cause of the salary increase. Furthermore, the complement of Society employees is more experienced than in 2013; consequently, current staff is now closer to the top steps of the negotiated wage schedules.

b) Collective agreement between Hydro One and the Society of Energy Professionals was ratified (April 1, 2016 to March 31, 2019).

c) No.

d) The staffing resources indicated are necessary to provide safe and reliable power to end use customers. Management compensation is tied to performance. Performance metrics for management staff include specific targets that customers value, such as timely project completion, improvements to customer communications, improvements to reliability, safety and environmental performance.

OEB Staff - Interrogatory # 56

Reference:

Exhibit D2 / Tab 6 / Schedule 1

Interrogatory:

Remotes has provided a Regulatory Cost Schedule which includes certain one-time costs. One-time costs include intervenor costs and the amount for 2018 is $80,000.

a) What are the total estimated intervenor costs for this proceeding and how has Remotes accounted for the one-time nature of these costs?
b) Does Remotes expect to incur $80,000 in intervenor-related costs each year during a subsequent IRM period after rebasing?
c) Are there any other one-time costs? If yes, please itemize them and explain how they have been accounted for in the test year.

Response:

a) Intervenor costs were budgeted at $80,000. Remotes has accounted for the nature of these costs as an increase in the revenue requirement.

b) Remotes does not expect to incur $80,000 in intervenor-related costs each year during a subsequent IRM period.

c) $10,000 was also budgeted for one-time regulatory consultant costs in the test year. Remotes has accounted for the nature of these costs as an increase in the revenue requirement.

OEB Staff - Interrogatory # 57

Reference:
Exhibit D2 / Tab 7 / Schedule 1

Interrogatory:
1. With respect to the test period amortization of environmental costs being sought in rates:

    a) Please provide a continuity schedule of the environmental liability that starts from the audited closing 2016 balance and covers the bridge and test years. The format of the continuity schedule should be similar to Note 13 of the 2016 audited financial statements (excluding the breakout of the current portion).
    b) It is not clear from the evidence filed what actual support underpins the estimate for the test year amortization of environmental costs. Please confirm that the applicant maintains some sort of spreadsheet that tracks the estimated future expenditures by year and from which the balance for the test period has been derived. Please also explain the process and record keeping involved.
    c) Please provide a table that presents the amount of environmental cost amortization that was sought in rates over the last 5 applications (2013-2017) compared to the actual amortization costs incurred per the audited financial statements (please do the analysis by year). Provide explanations for any significant differences noted.
    d) The evidence indicates that Remotes' reviews environmental costs annually to determine if any revisions are required. Please confirm that this review was performed in 2017 and that the amortization amount being sought in the test period is consistent with the results of this review.

2. Please explain how the estimates for asset removal costs in the test period are calculated and provide a table that compares what was sought in rates over the last 5 applications (2013-2017) compared to what was actually incurred per the audited financial statements (please do the analysis by year).

Response:

1.

a)

Continuity Schedule – Environmental Liability (in $K)

	Historic	Bridge	Test
December 31 (thousands of dollars)	**2016**	**2017**	**2018**
Environmental liabilities, beginning of per	11,051	35,845	35,600
Interest accretion	309	918	915
Expenditures	(1,247)	(1,163)	(1,032)
Revaluation adjustment	25,732	-	-
Environmental liabilities, end of period	35,845	35,600	35,483

b) A spreadsheet is maintained that tracks all future environmental costs. As part of Remotes preparation of its annual business plan, a full review is carried out to determine if any revisions are required to this spreadsheet. This involves an extensive review of all costs associated with the program and the schedule of when remediation will take place. The spreadsheet is updated with current costs relating to labour, equipment and external contractor costs.

c)

Environmental Cost Amortization (in $K)

	2013	2014	2015	2016	2017
Actual	1,656	1,599	1,222	1,247	1,285
Board Approved (2013)	1,861	1,861	1,861	1,861	1,861
Variance	**(205)**	**(262)**	**(639)**	**(614)**	**(576)**

A significant amount was included in the 2013 Board approved amount for Attawapiskat ($738K). The project was delayed due to funding concerns by other parties who are responsible for a larger share of the clean-up and the costs have been reallocated to future years.

d) Remotes' carried out a review in 2017 and the amortization amount being sought in 2018 is $2.3M. This is an increase of $1.3M from the amount reported in this review mainly due to the timing of the remediation in Cat Lake and Webequie. The remediation of the sites will begin one year earlier than originally anticipated.

2. For routine, recurring projects and programs, removal costs are calculated based on a pre-determined percentage of total project costs. For non-routine one-off projects, project managers are consulted to determine what percentage should be applied.

Asset Removal Costs (in $K)

	2013	2014	2015	2016	2017
Actual	590	430	969	620	772
Board Approved (2013)	721	721	721	721	721
Variance	**(131)**	**(291)**	**248**	**(101)**	**51**

OEB Staff - Interrogatory # 58

Reference:

Exhibit D2 / Tab 9 / Schedule 1

Interrogatory:

At the above reference, Remotes has provided historical tax returns. Based on a review of these tax returns, Remotes has been eligible to receive certain tax credits. Please explain why the impact of these tax credits was not considered in the calculation of the test period utility income taxes.

Response:

Amounts were not considered material and therefore not included in the calculation of the test period. The tax credits in the 2016 tax return were $41,672.

OEB Staff - Interrogatory # 59

Reference:

Exhibit D2 / Tab 9 / Schedule 1 / Attachment 6, 2016 Income Tax Return / Schedule 4

Interrogatory:

Schedule 4 of Remotes' 2016 income tax return indicates that there are non-capital losses being carried forward that will reduce taxable income in future years. Please indicate how these losses have been factored into the calculation of the test period regulatory income taxes in Exhibit D2-8-1. If they have not, please provide an explanation as to why their exclusion is appropriate.

Response:

On Initial Public Offering, the shareholder paid departure taxes of $5M from the deemed disposition and reacquisition of assets under the In*come Tax Act*. The deemed disposition and reacquisition of assets also resulted in an increase to the overall tax basis ("Tax Bump"). As the shareholder paid the departure tax, any tax benefits related to the Tax Bump should be kept by the shareholder.

The losses on Schedule 4 of remotes 2016 income tax return arise as a result of the additional tax deduction related to the FMV bump. As these tax deductions are the benefit of the shareholder they have not been included in the test periods for Remotes.

OEB Staff - Interrogatory # 60

Reference:

Exhibit D2 / Tab 9 / Schedule 1 / Attachment 6, 2016 Income Tax Return / Schedule 10

Interrogatory:

The above reference illustrates that Remotes is entitled to receive a deduction for cumulative eligible capital (or effective January 1, 2017 the deduction under the new CCA Class 14.1) that is not being reflected in the calculation of the test period regulatory income taxes. Please explain what assets are included in the CEC pool and why the related deduction has been excluded from the calculation of the test period regulatory income taxes.

Response:

The assets included in the CEC pool relate the creation of tax goodwill as a result of the deemed disposition of assets on IPO. Consistent with the response in Exhibit I, Tab 01, Schedule 59, this is not included in the test period as the shareholder paid for the departure tax and should be entitled to the benefits associated with the Tax Bump.

Appendix A – Estimate of CCA from Jan 1, 2015 to October 31, 2015

Reporting Unit:	Mapping								
Hydro One Remote Communities Inc.									
Tax Year:	**October 30, 2015**								
	A	**B**		**E**	**(E X 50%)**	**F**	**G**	**H = (F X G)**	**I = (E - H)**
CCA Class	**Opening UCC**	**Additions**	**Transfers**	**Balance before CCA**	**50% of net additions**	**Balance for CCA**	**Rate (%)**	**CCA Claimed**	**Closing UCC**
1	16,950,816	449,902	0	17,400,718	224,951	17,175,767	4%	570,330	16,830,388
2	462,554	0	0	462,554	0	462,554	6%	23,039	439,515
3	670,613	0	0	670,613	0	670,613	5%	27,835	642,778
6	5,266,974	0	0	5,266,974	0	5,266,974	10%	437,231	4,829,743
7	0	0	0	0	0	0	15%	0	0
8	879,608	271,385	3,488	1,154,481	137,436	1,017,044	20%	168,857	985,623
9	0	0	0	0	0	0	25%	0	0
10	257,153	3,488	(3,488)	257,153	0	257,153	30%	64,042	193,111
12	983	884	0	1,867	442	1,425	100%	1,183	684
13	96,851	0	0	96,851		96,851	N/A	3,155	93,696
14	0		0	0	0	0	N/A	0	0
17	14,499,571	403,067	0	14,902,638	201,533	14,701,104	8%	976,314	13,926,324
35	0	0	0	0	0	0	7%	0	0
42	148,575	0	0	148,575	0	148,575	12%	14,801	133,774
43.1	859,585	95	0	859,680	48	859,633	30%	214,084	645,596
45	371	0	0	371	0	371	45%	139	232
46	0	0	0	0	0	0	30%	0	0
47	2,720,675	98,864	0	2,819,539	49,432	2,770,107	8%	183,966	2,635,573
50	624	0	0	624	0	624	55%	285	339
52	0	0	0	0	0	0	100%	0	0
	42,814,953	**1,227,684**	**0**	**44,042,637**	**613,842**	**43,428,795**		**2,685,260**	**41,357,378**
	Per 2014 T2								

OEB Staff - Interrogatory # 61

Reference:

Exhibit E1 / Tab 1 / Schedule 1 / Page 4

Interrogatory:

Please update the 2018 Cost of Capital in accordance with the OEB's Cost of Capital Parameter Updates for 2018 Cost of Service and Custom Incentive Rate-setting Applications issued on November 23, 2017.

Response:

The $44,445K amount in the 2018 Cost of Capital table in Exhibit E1, Tab 1, Schedule 1 is incorrect. The corrected amount is $45,519K and is provided in the revised table below.

2018 Cost of Capital

Particulars	(in $K)	% of Rate Base	Cost Rate (%)	Weighted Cost Rate %	Cost of Capital ($000s)
Deemed short-term debt	1,821	4.0%	1.76%	0.07%	32
Third Party long-term debt	43,000	94.5%	4.63%	4.37%	1,991
Deemed long-term debt	698	1.5%	4.63%	0.07%	32
Total	**45,519**	**100%**		**4.52%**	**2,055**

Based on the revised table, the updated 2018 Cost of Capital using the OEB's Cost of Capital Parameter Updates is provided below.

2018 Cost of Capital

Particulars	(in $K)	% of Rate Base	Cost Rate (%)	Weighted Cost Rate %	Cost of Capital ($000s)
Deemed short-term debt	1,821	4.0%	2.29%	0.09%	42
Third Party long-term debt	43,000	94.5%	4.63%	4.37%	1,991
Deemed long-term debt	698	1.5%	4.63%	0.07%	32
Total	**45,519**	**100%**		**4.54%**	**2,065**

OEB Staff - Interrogatory # 62

Reference:

Exhibit G1 / Tab 1 / Schedule 1 / Page 1-4 and DSP, Page 8

Interrogatory:

Remotes has provided information on how it prepares its load forecast. The methodology is different from other electricity distributors in Ontario. Remotes tracks detailed monthly data on customer numbers and kWh usage by community and by class. This historical data provides the baseline for forecasting revenue usage / kWh sold. Adjustments are made to this baseline data for future years based on average historical growth in usage and historical annual customer changes.

a) Please explain how the 2018 load forecast was derived and provide the supporting calculations and adjustments.
b) Please provide the load forecast model in Excel format.
c) In the DSP, Remotes has provided a summary of the forecast customer count for the period 2017 to 2022. Remotes expects to add 531 customers in 2019 related to the expansion in Pikangikum and 175 customers in 2020 in the community of Wunnumin Lake. The forecasted load is expected to increase from 62,565 MWh in 2018 to approximately 80,000 MWh in 2020 with the majority of load growth occurring in 2019. Has Remotes accounted for the load growth in 2019 and 2020 in its load forecast? If no, why not?
d) Why has Remotes not used a multiple regression model or some other econometric model to prepare its load forecast?

Response:

a) The 2018 load forecast is based on the 2017 forecast, with the customer base escalated for expected growth. Please see item b) for the supporting calculations and adjustments.

b) The load forecast model in Excel has been provided in Exhibit G2, Tab 2, Schedule 4.

c) Yes, Remotes has accounted for the load growth in 2019 and 2020 in its load forecast for both Pikangikum and Wunnummin communities.

d) In econometric modeling, load is linked to demographic/economic factors expected to affect the load. The estimated model is then used to forecast load based on forecasts related to the demographic/economic factors over the forecast horizon. Consequently, a consistent set of historical and forecast data on such factors are needed to develop a load forecast using econometric approach.

As mentioned in Section 2.0 of Exhibit G1-01-01, data on local demographic/economic factors covering both historical and forecast periods is not available for Remotes (e.g., Canada Mortgage and Housing Corporation reports do not include data on Remotes). Moreover, Canadian/provincial data on demographic/economic factors (as proxies for corresponding local data) could not capture trends in Remote communities' load. For example, an upturn in the overall Canadian or Ontario economy has not historically resulted in a similar increase in economic activity within these communities. This is partly due to difference in the dynamic of housing development in remote communities. As mentioned in Exhibit G1-01-01, a February 2011 audit report that evaluated INAC`s on-reserve housing support found that the rate of new housing construction on reserves does not directly correlate to an increased number of housing units.

OEB Staff - Interrogatory # 63

Reference:
Exhibit G1 / Tab 2 / Schedule 1 / Pages 3-4

Interrogatory:
In the table that provides current and proposed rates, Remotes has provided the rates for Standard A customers. With respect to services charges, Remotes does not have any service charges for Standard A customers.

a) Please confirm whether Standard A customers pay a monthly service charge. If not, why not?
b) If there are any errors in the table, please provide a revised corrected table.

Response:
a) Standard A customers do not pay a monthly service charge. The Standard A rate structure was developed by Ontario Hydro and was in place at the time of the Ontario Hydro de-merger and the creation of Hydro One and its subsidiaries, including Remotes. The Rural and Remote Rate Protection Regulation requires Remotes to forecast revenues based on the rates set out for those classes in the most recent rate order made by the Board.

b) N/A

OEB Staff - Interrogatory # 64

Reference:

Exhibit G1 / Tab 4 / Schedule 1 / Page 1

Interrogatory:

Remotes has two broad categories of customers, Standard A or government customers whose rates have been historically been set above cost, and those residential and general service customers who benefit from the Rural and Remote Rate Protection fund.

a) What rates do residential and commercial customers that are not on First Nation reserves pay?
b) What class and types of customers are included in Standard A?

Response:

a) Residential and commercial customers living off-reserve pay the same rates as customers on reserve. There are, however, some government-related charges or benefits that differ for First Nation customers on reserve. For example, on-reserve First Nation customers (that are not incorporated) are exempt from HST; and, in 2017, the provincial government introduced a First Nation Delivery Credit for First Nation residential customers living on reserve, in recognition of First Nations' contributions to the provinces energy system. In the case of Remotes, the provincial government pays the Monthly Service Charge for First Nation residential customers living on reserve.

b) The Standard A category of customer includes both residential and commercial (general service) customers who receive ongoing government funding and are therefore not eligible for rate protection. Remotes has four classes of Standard A customers. There classes are: 1) Road/Rail Residential, 2) Road Rail General Service; 3) Air Access Residential and 4) Air Access General Service. Road/Rail Standard A customers pay lower rates than Air Access Standard A customers because the cost of transporting fuel over roads is cheaper than flying it in.

OEB Staff - Interrogatory # 65

Reference:
Exhibit G1 / Tab 5 / Schedule 1 / Page 4

Interrogatory:
Remotes has provided the bill impacts for the different categories of customers.

Remotes has provided the bill impacts for Non Standard A general service three phase. These are customers who use three phase power. How is this customer class different from residential and residential seasonal customers? What type of power do residential and residential seasonal customers use?

Response:
Three phase customers are commercial customers who use larger motors, pumps or other equipment. The distribution connection requires a feeder with three primary conductors. A three phase customer also normally uses more power than a single phase customer. Distribution connections for residential and residential seasonal customers normally only require a single primary conductor as these customers normally use much smaller equipment.

OEB Staff - Interrogatory # 66

Reference:

Exhibit G1 / Tab 5 / Schedule 1 / Page 5

Interrogatory:

Remotes has provided a definition of Standard A customers and has noted the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.;
- social housing;
- a recreational or sport facility;
- a radio, television or cable television facility; and
- a library

What rates do customers that fall in the above categories pay?

Response:

Customers who fall into the categories above pay non Standard A rates. Social housing facilities would pay Non Standard A residential rates, the others would pay Non Standard A general service rates.

OEB Staff - Interrogatory # 67

Reference:

Exhibit H1 / Tab 1 / Schedule 1, Exhibit H2 / Tab 1 / Schedule 1 / Attachments 1-4

Interrogatory:

At the above reference, Remotes has requested the disposition of its December 31, 2016 audited Rural and Remote Rate Protection (RRRP) Variance Account balance.

a) Given that the amounts recorded in the RRRP variance account for both 2015 and 2016 will be impacted by the final allocation (between shareholder and ratepayers) of the tax benefits arising from Hydro One's 2015 IPO, will Remotes be seeking to defer the disposition of its December 31, 2016 RRRP variance account balance until the motion to review / appeal of the OEB's Decision on Hydro One's 2017/18 transmission rates case has been completed?

b) If the response to the above is no, then please recalculate the amounts recorded to the RRRP variance account in both 2015 and 2016 based on the OEB's recent Decision on Hydro One's 2017/18 transmission rates case, whereby the OEB has ordered that the tax benefits from Hydro One's IPO be allocated 68%/32% between the shareholders and ratepayers respectively.

Response:

a) No

b) The allocation between shareholders and ratepayers has already been reflected in the application. Refer to Exhibit D1, Tab 7, Schedule 1, page 7.

	2015*	2016
CCA from Tax Bump	(330,881)	(2,197,068)
Tax Rate	26.50%	26.50%
Tax Effected Amount	(87,683)	(582,223)
Rate Payer 32%	(28,059)	(186,311)

The decrease in tax expense, would increase net income and decrease RRRP.

* CCA for 2015 is only from October 31, 2017 to December 31, 2017.

Energy Probe Research Foundation - Interrogatory # 1

Reference:

Exhibit A, Tab 3, Schedule 1, page 2, table 1

Interrogatory:

Please re-calculate the breakdown of the revenue requirement, but hold the percentage of revenue requirement recovered through rates (as opposed to RRRP funds) the same in this application as was approved in EB-2012-0137.

Response:

Table 1 in Exhibit A, Tab 3, Schedule 1 contained incorrect data in the column Approved in EB-2012-0137 and has been corrected in the table below.

Revised Table 1
Breakdown of Revenue Requirement (in $K)

	Approved in EB-2012-0137	In this Application	$ Change	% Change
Revenue Requirement	50,105	56,689	6,584	13.1%
Recovered through rates	17,260	17,612	352	2.0%
Recovered through other revenues	586	999	413	70.5%
Recovered by RRRP	**32,259**	**38,078**	**5,819**	**18.0%**

Based on the revised table, the breakdown of the revenue requirement has been re-calculated as follows:

Breakdown of Revenue Requirement (in $K)

	Approved in EB-2012-0137	2013 % Allocation	2018 Allocation per BA-2013 % Allocation
Revenue Requirement	50,105		56,689
Recovered through rates	17,260	34.4%	19,528
Recovered through other revenues	586	1.2%	663
Recovered by RRRP	**32,259**	**64.4%**	**36,498**

Energy Probe Research Foundation - Interrogatory # 2

Reference:

Exhibit A Tab 3 Schedule 1Pages 2 and 3; Business Plan 2017-2022

Interrogatory:

Preamble: The 2018 Rates Application is based on Rebasing/Cost of Service

Please indicate in detail with reference to the RRFE, how rates will be set for 2019-2022, including timing of future applications.

Response:

Hydro One Remote Communities is not operated in the same manner as other LDCs. Consistent with the Board's Decision in RP-1998-0001, Remotes is 100% debt-financed and is operated as a break-even company with no return on equity. Remotes' customers do not pay rates based on cost. Rates are set based on rules prescribed by O. Reg 442/01. That statute requires the Board to calculate Rate Protection for these customers. Further, in its Decision in proceeding EB-2014-0084, the Board noted that, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances". As noted in the Hydro One Remotes' 2014 Price Cap Incentive Rate application (proceeding EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection."

The Remotes' Price Cap Index rate was prepared on the basis of a single forward 2018 test-year cost of service basis and provides three years of historical data and an executive summary of Hydro One Remotes' Business Plan 2017 to 2022 (Exhibit A, Tab 3, Schedule 2, Attachment 1). The application also meets the requirements of the *Filing Requirements for Transmission and Distribution Applications* (issued November 14, 2006, and updated on July 20, 2017). The completed Ontario Energy Board ("OEB") 2018 Cost of Service Checklist found submitted as Exhibit A, Tab 2, Schedule 2, Attachment 3 and Table of OEB Work Forms and Chapter 2 Appendices found as Exhibit A, Tab 2, Schedule 2, Attachment 4, demonstrate that Hydro One Remotes has addressed all applicable filing requirements.

In alignment with the *Ontario Energy Board Renewed Regulatory Framework* ("RRFE") outcomes, Hydro One Remotes sets annual targets and plans for improvement in the areas of financial strength, customer relations, operational excellence, productivity, environmental stewardship and health and safety to measure and monitor its performance on an internal scorecard (Exhibit A, Tab 5, Schedule 1, Attachment 1). The Hydro One Remotes Electricity Distributor Scorecard (Exhibit A, Tab 5, Schedule 1, Attachment 2) is submitted to the OEB on an annual basis to demonstrate continuous improvement in performance outcomes.

METSCO Engineering Solutions Inc. attests that the Distribution System Plan (“DSP”) also demonstrates and supports the four key RRFE objectives: customer focus; operating effectiveness, public policy responsiveness and financial performance (Exhibit B1, Tab 1, Schedule 1). The DSP contains the five-year capital plan that reflects the fundamental principles of good asset management; coordinated, longer-term optimized planning; a common set of performance expectations and is under-pinned by on-going customer engagement activities, the promotion generation of electricity from renewable energy sources, and strategies to improve productivity, promote economic efficiency and cost effectiveness.

Remotes expects to make annual price cap adjustments to customer rates through the Board’s established annual process.

Energy Probe Research Foundation - Interrogatory # 3

Reference:

HORCI Business Plan 2017-2022

Interrogatory:

Preamble: The HORCI Business Plan 2017-2022 Projects that operating costs (OM&A) will increase from $50 million to $60 million and the RRRP increase from $38 million to $60 million over the next 5 years 2018-2022.

a) Please indicate the main drivers for these significant increases.
b) Discuss how such an outlook fits with the goals of the OEB and RRFE.
c) Discuss how HORCI will mediate this scenario.

Response:

a) The business plan document (Exhibit A, Tab 3, Schedule 1) shows RRRP projected to increase to $44M, not $60M. Distribution and generation program increases over the plan period primarily relate to expected increases in the work programs associated with service to Pikangikum, Cat Lake and Wunnumin Lake in 2018, 2019 and 2020. The costs associated with service to these communities have not been included in the revenue requirement associated with this filing. Fuel costs are expected to increase related to projected increases to market prices and increased customer consumption.

b) Remotes believes that its plan is consistent with the goals of the OEB as set out in the RRFE. Remotes' business plan is based on meeting the needs and preferences of its customers. Please also see the response to I-02-02.

c) Remotes' service territory is inherently costly to serve and both the number of communities and number of customers served are expected to increase over the plan period. Remotes will continue to manage its fuel transportation costs as described throughout this application.

Energy Probe Research Foundation - Interrogatory # 4

Reference:
Exhibit A, Tab 3, schedule 2, page 2-3

Interrogatory:
Preamble: Remotes states that costs to the utility will increase significantly in the event that a winter road is not built.

a) Since 2013, how many times has a winter road not been built?
b) What increased costs are directly attributable to the lack of a winter road?
c) Please provide a table clearly laying out what additional costs will be borne by Hydro One in the event that a winter road is not built?
d) How does Hydro One deal with the increased costs from the lack of a winter road? Does it come from the RRRP variance account?

Response:
a) One community did not have a winter road built in 2015 and 2017. Five communities did not have a winter road built in 2016.

b) The cost to fly-in fuel is considerably higher due to the cost of air freight which includes the cost of ground transportation to get the fuel on the planes plus the cost of air transportation.

c) The additional costs to be borne by Hydro One in the event that a winter road is not built depend on the location of the community. The table in Appendix A provides the 2017 additional costs.

d) Yes, the increased costs from the lack of a winter road are funded by the RRRP variance account.

Appendix A: Additional Costs incurred if Winter Roads not built

Table: Additional Costs Incurred if Winter Road not Built

	Winter Roads					First Nations					Total Costs (in $K)
Community	Litres by Winter Road (in KL)	$/L Winter Road	$/L Air	$/L Impact	Additional Costs (in $K)	Litres by FN (in KL)	$/L	$/L Air	$/L Impact	Additional Costs (in $K)	**Additional Costs (in $K)**
Bearskin	340	$1.306	$1.974	$0.668	$227	0	$0.000	$0.000	$0.000	$0	**$227**
Big Trout Lake	530	$1.226	$1.837	$0.612	$324	0	$0.000	$0.000	$0.000	$0	**$324**
Deer Lake	170	$1.154	$1.433	$0.279	$47	0	$0.000	$0.000	$0.000	$0	**$47**
Fort Severn	180	$1.546	$2.858	$1.312	$236	564	$2.167	$2.858	$0.691	$390	**$626**
Kasabonika	220	$1.152	$1.682	$0.531	$117	0	$0.000	$0.000	$0.000	$0	**$117**
Kingfisher	260	$1.105	$1.621	$0.516	$134	0	$0.000	$0.000	$0.000	$0	**$134**
Lansdowne	240	$1.405	$1.446	$0.041	$10	0	$0.000	$0.000	$0.000	$0	**$10**
Marten Falls	30	$1.274	$1.455	$0.180	$5	0	$0.000	$0.000	$0.000	$0	**$5**
Sachigo Lake	220	$1.305	$1.847	$0.543	$119	650	$1.331	$1.847	$0.516	$336	**$455**
Sandy Lake	580	$1.074	$1.900	$0.826	$479	1,000	$1.107	$1.900	$0.793	$793	**$1,272**
Wapakeka	70	$1.224	$1.844	$0.620	$43	0	$0.000	$0.000	$0.000	$0	**$43**
Weagamow	300	$1.415	$1.456	$0.041	$12	0	$0.000	$0.000	$0.000	$0	**$12**
Webequie	110	$1.645	$1.693	$0.048	$5	0	$0.000	$0.000	$0.000	$0	**$5**
Total	**3,250**	**$1.257**	**$1.695**	**$0.438**	**$1,761**	**2,214**	**$1.443**	**$1.900**	**$0.457**	**$1,518**	**$3,279**

Energy Probe Research Foundation - Interrogatory # 5

Reference:

Exhibit A Tab 3 Schedule 2, attachment 1, pages 2-3

Interrogatory:

a) Please provide any updates on cost/schedule of the Kingfisher Lake project.
b) Please provide any cost estimates of the Gull Bay First Nation solar and battery project?
c) How are the costs from the Gull Bay solar and battery project recovered? Is Hydro One directly responsible for those costs?
d) Will the power and costs from the Gull Bay project be calculated in the same way as other renewable energy projects – i.e. in the form of diesel power saved?

Response:

a) The Kingfisher Lake project generators are in-service as of the end of December 2017. Some wrap up work such as pipe painting, site clean-up and removal from site is expected to be completed by the end of March 2018. The cost for the project is expected to be $5.7M.

b) The Gull Bay First Nation project is an Ontario Power Generation (OPG) project. Remotes is not aware of the cost estimates for this project.

c) Remotes is not aware of how the proponent (OPG) expects to recover costs. The energy generated from this project will be purchased under a Power Purchase Agreement and the current REINDEER rate for stand-alone renewable generation in Gull Bay is $0.261/kWhr. Remotes is a collaborator on this project and will assist 50% of the diesel station modification costs but Remotes will not contribute to the CIA or Connection Costs. The proponent (OPG) is responsible for all other costs.

d) Yes, Remotes calculates the rates for stand-alone renewable projects as part of the REINDEER program. This rate is based on the 3-year average cost of diesel fuel savings for the community of Gull Bay.

Energy Probe Research Foundation - Interrogatory # 6

Reference:

Exhibit A, Tab 3, Schedule 3, pages 1-3

Interrogatory:

Please provide any cost-benefit analysis done in regards to the REINDEER program?

Response:

There has not been any formal cost-benefit analysis performed for the REINDEER program.

Fundamentally, the REINDEER program, under the stand alone operating model is based on the avoided cost of fuel, and as a result the financial cost-benefit of the program is essentially neutral. Either we pay for fuel for diesel generation or we pay the equivalent rate for renewable energy purchasing. The financial cost benefit of this activity is neutral to Remotes, however non-financial benefits include the environment because of reduced diesel emissions.

Under the REINDEER program, under the net metering model, Hydro One Remotes could be subject to financial losses when Standard A accounts have net metering installations, since the Std A revenue is in excess of cost. As a criterion for connection and in order to limit or reduce the potential for financial losses, projects must be sized according to the facility’s load and may not exceed 50% of annual energy consumption. Again, the environment benefits in a non-financial way.

Energy Probe Research Foundation - Interrogatory # 7

Reference:

Exhibit A, Tab 3, Schedule 3; DSP Figure 2-8

Interrogatory:

Please provide the results of the REG and Net Metering Programs for each historic year and a forecast for the 2018 Test Year. Please include totals and the following breakdown:

- HORCI-owned, FN/private-owned and Government REG installations and MWh
- FN and Government Net Metering installations and MWh.

Response:

An listing of installed Reindeer projects (FN/private-owned and/or Government owned) by year and capacity is provided in Table 1 below are provided in the first table below.

Table 1

Row Labels	Total Number of Installs	Sum of Nameplate Capacity (kW)
2014	**5**	**182**
Customer Owned Solar	**5**	**182**
Net Metering	5	182
2015	**1**	**20**
Customer Owned Solar	**1**	**20**
Net Metering	1	20
2016	**9**	**116.5**
Customer Owned Solar	**9**	**116.5**
Net Metering	5	76.5
Stand Alone	4	40
2017	**1**	**30**
Customer Owned Solar	**1**	**30**
Net Metering	1	30
Grand Total	**16**	**348.5**

Table 2 shows Remotes REG assets (Total Renewables); and the "Stand Alone" (Purchased REINDEER Renewable) projects that were put into service in 2017. Remotes is not able to provide the kWh for the net metering projects.

Table 2

	Historic (Actual in kWh)					Bridge	Test
	2013	2014	2015	2016	2017	2017	2018
Hydroelectric Dam	1,431,944	1,590,028	1,591,976	1,292,638	2,184,222	1,834,000	1,860,000
Wind Farm	16,650	17,100	34,540	25,070	35,750	26,000	26,000
Total Renewables	1,448,594	1,607,128	1,626,516	1,317,708	2,219,972	1,860,000	1,886,000
Purchased	-	-	-	-	36,374	380,000	380,000
	1,448,594	**1,607,128**	**1,626,516**	**1,317,708**	**2,256,346**	**2,240,000**	**2,266,000**

Since the REINDEER projects in service is fundamentally based on the actions of other parties as well as provincial and federal funding programs, Remotes does not forecast new projects in future periods. Hydro One Remotes continues to support the connection of renewable projects and remains hopeful that the progress made to date will continue.

Energy Probe Research Foundation - Interrogatory # 8

Reference:

Exhibit A, Tab 3, Schedule 3 attachment 1, page 2

Interrogatory:

Please update Hydro One's diesel cost forecasts for 2017 and subsequent years if they have changed.

Response:

The updated diesel fuel forecast is below in Table 1. The updated REINDEER rates (based on the reference to Exhibit A, Tab 3, Schedule 3 cited above) is below as Table 2.

Table 1

Fuel Purchases (in $K)

	Actual	Forecast (in $K)				
	2017	2018	2019	2020	2021	2022
Fuel cost	$25,695	$25,926	$27,912	$30,146	$34,111	$34,385

Table 2

REINDEER Standalone Rates 2018	
Community	$/kWh
ARMSTRONG	0.217
BEARSKIN	0.446
BIG TROUT	0.443
BISCO	0.337
DEER LAKE	0.383
FORT SEVERN	0.618
GULL BAY	0.261
HILLSPORT	0.375
KASABONIKA	0.413
KINGFISHER	0.391
LANSDOWNE	0.363
MARTEN FALLS	0.445
OBA	0.349
SACHIGO	0.364
SANDY LAKE	0.379
SULTAN	0.400
WAPEKEKA	0.490
WEAGAMOW	0.339
WEBEQUIE	0.411

Energy Probe Research Foundation - Interrogatory # 9

Reference:

Exhibit A, Tab 3, Schedule 1Page 6; G2, Tab 1, Schedule 1

Interrogatory:

a) Please provide Forecast and Actual Loads for 2013-2017 with a breakdown/estimate of Billing Units per Class

b) Please provide the key assumptions for the 2018 Load Forecast, including communities connected, changes in customer count, conservation, REG, Net Metering etc..

c) There is Conflicting evidence regarding when Cat Lake will become a Remotes Distribution Service area. Please clarify, including what is the condition and what will happen to the Cat Lake generators and other assets?

d) Please provide a sensitivity assessment of the 2018 Load Forecast on Billing Units and Rates.(e.g.± 10%)

e) Has Remotes assessed the impact of weather on the Load Forecast? Please provide relevant information related to the sensitivity of the 2018 forecast to weather.

Response:

a)

Load Forecast vs Actual (2013-2017)

	2013					
	KWh		Revenue		KwH	Revenue
	Forecast	Actual	Forecast	Actual	% Variance	% Variance
Residential - Year Round - Non Std. 'A'	34,119,803	36,786,816	3,790,839	4,009,719	7.8%	5.8%
Residential - Seasonal	293,284	291,477	70,357	67,827	-0.6%	-3.6%
General Service - Non Standard 'A' (Phase 1&3)	12,305,731	10,221,041	1,317,581	1,101,088	-16.9%	-16.4%
Street Lighting	239,678	235,767	22,418	21,772	-1.6%	-2.9%
Residential - Road Access - Std. 'A'	39,546	41,879	22,685	24,350	5.9%	7.3%
General Service - Road Access - Std. 'A'	631,449	610,901	398,887	380,400	-3.3%	-4.6%
Residential - Air Access - Std. 'A"	1,232,369	1,216,181	1,098,533	1,069,141	-1.3%	-2.7%
General Service - Air Access - Std. 'A'	8,820,759	9,224,362	8,057,868	8,307,739	4.6%	3.1%
Unbilled	1,631,358	-	319,305	-	-100.0%	-100.0%
Total	59,313,977	58,628,424	15,098,473	14,982,035	-1.2%	-0.8%

	2014					
	KWh		Revenue		KwH	Revenue
	Forecast	Actual	Forecast	Actual	% Variance	% Variance
Residential - Year Round - Non Std. 'A'	36,726,937	38,513,780	4,128,137	4,404,317	4.9%	6.7%
Residential - Seasonal	267,650	293,871	81,569	79,283	9.8%	-2.8%
General Service - Non Std 'A' (Phase 1&3)	10,591,523	11,345,731	1,176,044	1,270,456	7.1%	8.0%
Street Lighting	208,406	275,928	19,846	26,451	32.4%	33.3%
Residential - Road Access - Std. 'A'	50,589	46,009	30,407	28,258	-9.1%	-7.1%
General Service - Road Access - Std. 'A'	636,605	714,942	410,169	467,553	12.3%	14.0%
Residential - Air Access - Std. 'A"	1,352,428	1,305,644	1,231,678	1,206,381	-3.5%	-2.1%
General Service - Air Access - Std. 'A'	9,344,311	9,842,743	8,705,597	9,301,908	5.3%	6.8%
Unbilled	-	-	-	-		
Total	59,178,449	62,338,648	15,783,447	16,784,607	5.3%	6.3%

	2015					
	KWh		Revenue		KwH	Revenue
	Forecast	Actual	Forecast	Actual	% Variance	% Variance
Residential - Year Round - Non Std. 'A'	39,319,861	38,143,476	4,513,639	4,405,018	-3.0%	-2.4%
Residential - Seasonal	214,445	315,414	75,379	83,664	47.1%	11.0%
General Service - Non Standard 'A' (Phase 1&3)	11,311,484	11,089,136	1,285,529	1,261,254	-2.0%	-1.9%
Street Lighting	229,866	291,955	22,780	28,630	27.0%	25.7%
Residential - Road Access - Std. 'A'	40,536	44,235	24,678	27,598	9.1%	11.8%
General Service - Road Access - Std. 'A'	602,467	740,650	400,416	489,896	22.9%	22.3%
Residential - Air Access - Std. 'A"	1,383,008	1,301,291	1,300,151	1,216,551	-5.9%	-6.4%
General Service - Air Access - Std. 'A'	9,897,671	9,174,261	9,518,789	8,777,016	-7.3%	-7.8%
Unbilled	1,864,646	-	471,757	-	-100.0%	-100.0%
Total	64,863,984	61,100,418	17,613,118	16,289,627	-5.8%	-7.5%

	2016					
	KWh		Revenue		KwH	Revenue
	Forecast	Actual	Forecast	Actual	% Variance	% Variance
Residential - Year Round - Non Std. 'A'	38,988,962	40,513,072	4,520,358	4,724,056	3.9%	4.5%
Residential - Seasonal	233,694	370,225	76,966	105,980	58.4%	37.7%
General Service - Non Standard 'A' (Phase 1&3)	12,160,285	11,192,755	1,386,648	1,294,095	-8.0%	-6.7%
Street Lighting	268,151	276,217	26,807	27,472	3.0%	2.5%
Residential - Road Access - Std. 'A'	46,420	52,698	29,230	33,385	13.5%	14.2%
General Service - Road Access - Std. 'A'	754,316	728,847	505,224	488,319	-3.4%	-3.3%
Residential - Air Access - Std. 'A"	1,368,415	1,401,454	1,294,599	1,326,847	2.4%	2.5%
General Service - Air Access - Std. 'A'	9,404,379	9,904,451	9,113,140	9,597,680	5.3%	5.3%
Unbilled	1,478,228	-	406,364	-	-100.0%	-100.0%
Total	64,702,850	64,439,719	17,359,336	17,597,835	-0.4%	1.4%

	2017					
	KWh		Revenue		KwH	Revenue
	Forecast	Actual	Forecast	Actual	% Variance	% Variance
Residential - Year Round - Non Std. 'A'	38,493,908	39,208,450	4,567,706	4,669,347	1.9%	2.2%
Residential - Seasonal	310,541	314,224	85,592	85,693	1.2%	0.1%
General Service - Non Standard 'A' (Phase 1&3)	10,902,685	10,736,149	1,311,822	1,264,482	-1.5%	-3.6%
Street Lighting	263,244	210,782	26,598	21,375	-19.9%	-19.6%
Residential - Road Access - Std. 'A'	47,546	48,652	30,555	31,327	2.3%	2.5%
General Service - Road Access - Std. 'A'	706,570	762,539	482,915	520,830	7.9%	7.9%
Residential - Air Access - Std. 'A"	1,358,699	1,286,753	1,309,319	1,241,292	-5.3%	-5.2%
General Service - Air Access - Std. 'A'	9,298,513	9,594,765	9,187,720	9,475,788	3.2%	3.1%
Unbilled	-	330,137	-	96,841	100.0%	100.0%
Total	61,381,706	62,492,451	17,002,226	17,406,975	1.8%	2.4%

b) The 2018 load forecast is based on the 2017 forecast, with the customer base escalated for expected growth. Remotes 2017 forecast is based on historical kWh usage and customer numbers. This historical data is also averaged over 3 years to take into consideration the effect of weather. This data is adjusted for increases in customer numbers and in usage.

c) Negotiations on a service agreement with Cat Lake have not been concluded and it is uncertain when an agreement will be reached. Therefore Remotes has not included the costs and revenues associated with service to this community in its Revenue Requirement. Because the community is expected to join Remotes' service territory at a future point, the number of customers was included in the DSP. The distribution and transmission assets meet Hydro One standards. The generating station is inoperable. As part of the discussions with the community, INAC funded a capital project to decommission the generating station and remove it from the community. The generating station has been decommissioned and will be removed over winter road. It is contemplated that, when the asset transfer takes place, Remotes would own the distribution assets and Networks would own the transmission assets.

d) Sensitivity Assessment – 2018 Load Forecast

2018 Load Forecast - Proposed Rates					Sensitivity Assessement			
					+ 10 per cent		- 10 per cent	
Residential - Year Round - Non Std. 'A'	**# Customers**	**Estimated kWh**	**Rate**	**Revenue**	**Rate**	**Revenue**	**Rate**	**Revenue**
Monthly Service Charge	2,695		19.68	636,412	21.65	700,096	17.71	572,806
Electricity Charges - 1st 1,000 kWh		26,831,785	0.0926	2,484,623	0.1019	2,733,086	0.0833	2,236,161
Electricity Charges - Next 1,500 kWh		10,645,490	0.1236	1,315,783	0.1360	1,447,361	0.1112	1,184,204
Electricity Charges - All Additional kWh		1,457,947	0.1862	271,470	0.2048	298,617	0.1676	244,323
Total		**38,935,222**		**4,708,287**		**5,179,160**		**4,237,494**
Residential - Seasonal								
Monthly Service Charge	147		33.26	58,504	36.59	64,538	29.93	52,804
Electricity Charges - 1st 1,000 kWh		312,406	0.0926	28,929	0.1019	31,822	0.0833	26,036
Electricity Charges - Next 1,500 kWh		-	0.1236	-	0.1360	-	0.1112	-
Electricity Charges - All Additional kWh		-	0.1862	-	0.2048	-	0.1676	-
Total		**312,406**		**87,433**		**96,359**		**78,840**
General Service 1-Phase - Non Std. 'A'								
Monthly Service Charge	306		33.46	122,664	36.81	135,152	30.11	110,579
Electricity Charges - 1st 6,000 kWh		5,930,738	0.1038	615,611	0.1142	677,172	0.0934	554,050
Electricity Charges - Next 7,000 kWh		409,062	0.1377	56,328	0.1515	61,961	0.1239	50,695
Electricity Charges - All Additional kWh		88,046	0.1862	16,394	0.2048	18,034	0.1676	14,755
Total		**6,427,846**		**810,997**		**892,317**		**730,078**
General Service 3-Phase - Non Std. 'A'								
Monthly Service Charge	43		41.89	21,699	46.08	23,777	37.70	19,454
Electricity Charges - 1st 25,000 kWh		4,827,342	0.1038	501,078	0.1142	551,186	0.0934	450,970
Electricity Charges - Next 15,000 kWh		198,166	0.1377	27,287	0.1515	30,016	0.1239	24,559
Electricity Charges - All Additional kWh		16,497	0.1862	3,072	0.2048	3,379	0.1676	2,765
Total		**5,042,005**		**553,136**		**608,358**		**497,747**
Street Lighting								
	8		-					
Electricity Charges		263,245	0.1029	27,088	0.1132	29,797	0.0926	24,379
Total		**263,245**		**27,088**		**29,797**		**24,379**
Residential - Road Access - Std. 'A'								
Electricity Charges - 1st 250 kWh	8	22,623	0.6097	13,793	0.6707	15,173	0.5487	12,414
Electricity Charges - All Additional kWh		25,148	0.6967	17,520	0.7664	19,272	0.6270	15,768
Total		**47,771**		**31,314**		**34,445**		**28,182**
General Service - Road Access - Std. 'A'								
	22							
Electricity Charges		710,230	0.6967	494,817	0.7664	544,299	0.6270	445,335
Total		**710,230**		**494,817**		**544,299**		**445,335**
Residential - Air Access - Std. 'A"								
Electricity Charges - 1st 250 kWh	135	404,750	0.9205	372,572	1.0126	409,830	0.8285	335,315
Electricity Charges - All Additional kWh		1,014,137	1.0100	1,024,278	1.1110	1,126,706	0.9090	921,850
Total		**1,418,887**		**1,396,850**		**1,536,535**		**1,257,165**
General Service - Air Access - Std. 'A'								
	288							
Electricity Charges		9,408,294	1.0100	9,502,376	1.1110	10,452,614	0.9090	8,552,139
Total		**9,408,294**		**9,502,376**		**10,452,614**		**8,552,139**
Summary	**3,652**	**62,565,904**		**17,612,299**		**19,373,884**		**15,851,359**

e) This historical data is averaged over 3 years to take into consideration the effect of weather.

Energy Probe Research Foundation - Interrogatory # 10

Reference:

Exhibit A, Tab 4, Schedule 1, attachment 2 page 31

Interrogatory:

a) How did Hydro One calculate the total bill for other distributors?
b) What power consumption was used to calculate monthly bills?
c) Are Hydro One's various residential rate classes included in the chart (UR, R1 and R2)?

Response:

a) The Ontario Energy Board staff provided the bill calculation.

b) Board staff used 750 kWh for residential customers and 2,000 kWh for general service customers, consistent with the methodology approved by the Board in EB-2009-0278.

c) The calculation provided by Board staff does not appear to include Hydro One Networks.

Energy Probe Research Foundation - Interrogatory # 11

Reference:

Exhibit A, Tab 5, Schedule 1; Exhibit D2, Tab3, Schedule 4

Interrogatory:

Preamble: The Scorecard includes $/Mwh as a metric, but no data are reported.

a) Please provide in tabular and chart format, the Total cost/customer and per MWH generated/distributed for the historic years 2013-2016, 2017 Bridge(E) and 2018 Test year(F). Reconcile to Table 1 D1-01-02 and Table 1 D1-01-03
b) Please provide in Tabular and Chart format, the O&M Costs (excluding Fuel) per unit of Load expressed as $/Mwh for each of Generation and Distribution for the historic years 2013-2016, 2017 Bridge(E) and 2018 Test year(F)
c) Ref. Exhibit A, Tab 5, Schedule 1; Exhibit B1. DSP Section 2.3
d) Please provide the definition(s) HORCI uses for Loss of supply, specifically whether this/these are based on loss of generation or all parts of the system.
e) Provide a detailed description of the steps HORCI will be undertaking in 2018-2022 to reduce outages due to Loss of Supply and Scheduled Maintenance. Address each in detail including also programs to reduce outages due to defective equipment.
f) What are the 2018-2022 internal Targets for reducing Loss of Supply and Scheduled maintenance and defective equipment
g) Please provide a chart/projection of the SAIDI and SAIFI with/without Loss of Supply 2018-2022 and compare to historic and bridge years.

Response:

a)

Total Cost per Customer & MWh (in $K)

	Historic (Actuals)				Bridge	Test
	2013	2014	2015	2016	2017	2018
Fuel	25,568	25,869	23,250	23,669	26,485	27,600
Generation Maintenance	8,648	9,932	8,610	9,574	11,392	11,640
Generation Operations	4,306	4,260	4,337	4,358	4,819	4,919
OESP Payments to IESO	-	-	-	61	-	-
Distribution Operations & Maintenance	1,461	1,879	2,415	1,992	2,119	2,203
Collecting & Billing	3,584	2,285	919	2,014	2,271	2,304
Admin Expenses	1,645	1,714	1,582	1,829	1,299	1,477
Total OM&A	45,212	45,939	41,113	43,497	48,385	50,143
MWh	58,628	62,339	61,100	64,440	61,382	62,566
Number of Customers	3,513	3,546	3,530	3,554	3,627	3,762
OM&A per MWh	0.7712	0.7369	0.6729	0.6750	0.7883	0.8014
OM&A per Customer	12.8699	12.9552	11.6467	12.2389	13.3402	13.3288

b)

Total Cost per MWh (excluding fuel) (in $K)

	Historic (Actuals)				Bridge	Test
	2013	2014	2015	2016	2017	2018
Generation Maintenance	8,648	9,932	8,610	9,574	11,392	11,640
Generation Operations	4,306	4,260	4,337	4,358	4,819	4,919
OESP Payments to IESO	-	-	-	61	-	-
Distribution Operation & Maintenance	1,461	1,879	2,415	1,992	2,119	2,203
Collecting & Billing	3,584	2,285	919	2,014	2,271	2,304
Admin Expenses	1,645	1,714	1,582	1,829	1,299	1,477
Total OM&A (excluding fuel)	19,644	20,070	17,863	19,828	21,900	22,543
MWh	58,628	62,339	61,100	64,440	61,382	62,566
OM&A per MWh (excluding fuel)	0.3351	0.3220	0.2924	0.3077	0.3568	0.3603

c) No question referenced.

d) Remotes uses the following definition: “Loss of Supply (generation station is the cause).”

e) Loss of supply is directly attributed to the maintenance and operation of generation assets. Routine and planned maintenance are critical in maintaining strong operating assets. Improvements in SCADA, re-investment in unit replacements and well as timely troubleshooting are also all necessary for reducing loss of supply outages. Scheduled maintenance is often done strictly for safety reasons as Remotes is not fully equipped to perform the work under live conditions. Reductions in scheduled outages could be identified if we made significant asset and training investments, but it is not worth it given the few outages taken overall.

f) Since Remotes is an integrated utility, Remotes' targets for reliability metrics are based on the 5-year average for SAIDI and SAIFI including loss of supply. Targets are aimed at improving results over the 5-year average. Targets are determined annually, once full year results are available. Since 2012, Remotes has set specific internal performance targets for generation availability (based on the actual minutes that generation is available across its system). Targets for generation availability include all unplanned generation outages across its system. Incremental improvements to the target are set each year. There are no defined internal Targets for reducing Loss of Supply and Scheduled maintenance and defective equipment. But given that Loss of Supply and Scheduled maintenance and defective equipment represent the most significant portion of our outages, improvements in these will be necessary to achieve our 5-year SAIDI/SAIFI target. The Remotes' Outage Committee (ROC) reviews each outage to determine trends and root causes, leading to actions to avoid future reoccurrences.

g) Remotes has not set annual reliability targets. Targets are based on improvements to the 5-year average for SAIDI and SAIFI including loss of supply and are aimed at improving results annually.

Energy Probe Research Foundation - Interrogatory # 12

Reference:

Exhibit A, Tab 5, Schedule 1, page 9

Interrogatory:

a) Since 2013, how many major events has Hydro One Remotes excluded as a result of its own definition of force majeure that wouldn't have been excluded using standard metrics (those used by Hydro One Distribution, for example)?
b) Does Hydro One keep a log of these events? If so, please provide that evidence.

Response:

a) Since 2013, Remotes has experienced two major outages that meet its definition of a major event. For the purposes of internal reporting, Remotes' definition of a major event is as follows:

   Major catastrophic events that are beyond the utility's control will be excluded from performance reporting, but will be reported to the OEB. A major catastrophic event is defined as:

   1. widespread system damage causing customer interruptions that affect an entire community; or
   2. an outage that affects an entire community for a duration of at least 12 hours because staff cannot access the community due to circumstances beyond the control of the company (ie, as a result of adverse weather that prevents a plane from landing).

   Remotes uses this definition for internal reporting because it is appropriate for its service territory. For the purposes of OEB reporting, Remotes uses the IEEE standard. Remotes did not adopt Networks' definition of a major event because its assets and service territory are different from Networks. Given the wide geographic dispersal of communities, storm events have not affected more than a single community in the past. Furthermore, each of the distribution systems are fairly geographically compact (i.e., the homes and buildings are physically close to one another, so there are fewer feeder related outages affecting large numbers of customers than in Networks). Finally, because of the number of customers in each community, using Networks standard of 10% of customers out of power would lead to hundreds of outages being excluded annually from performance reporting.

b) Since 2013, two outages have met Remotes' internal definition of a major event day and were excluded from internal reporting. Please see the attached information on these outages.

Note that the July, 2017 Report Card in evidence in A-05-01-01 incorrectly classified an ice storm related outage in Landsdowne as a major event. That outage did not meet the criteria above and was included in internal performance results when the error was detected.

Major Event Days Internal Metric 2013-2017

2015

Location	Date MM/DD/YY	Outage Start Time 24 hour Clock	Number of Outages	Information Source	Duration in Minutes	Number of Customers Out of Power	Customer-Hours of Interruptions	Code	Time to respond minutes	Response time under 2 hrs. (1=yes)
Wapekeka	04/02/15	12:27:50	1	ST	1409	150	3523	5	0	1

2017

Location	Date MM/DD/YY	Outage Start Time 24 hour Clock	Number of Outages	Information Source	Duration in Minutes	Number of Customers Out of Power	Customer-Hours of Interruptions	Code	Time to respond minutes	Response time under 2 hrs. (1=yes)
Hillsport	03/07/17	15:15:00	1	TP	1170.00	35	683	6	0	1

Appendix 2-G
Service Reliability and Quality Indicators
2012 - 2016

Service Reliability

Index	Including outages caused by loss of supply						Excluding outages caused by loss of supply						Excluding Major Event Days					
	2012	2013	2014	2015	2016	2017	2012	2013	2014	2015	2016	2017	2012	2013	2014	2015	2016	
SAIDI	16.116	11.932	8.486	13.303	12.170	10.433	7.949	4.208	6.068	10.083	9.107	7.776	16.116	11.932	8.486	13.303	12.170	10.433
SAIFI	11.193	15.685	14.021	11.691	13.059	11.747	3.641	4.218	3.372	4.387	4.945	4.154	11.193	15.685	14.021	11.691	13.059	11.747

No Major Event Days based on IEEE Standard

5 Year Historical Average -Updated for 2017 Results

SAIDI	11.265	7.448	11.265
SAIFI	13.241	4.215	13.241

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016	2017
Low Voltage Connections	90.0%	100.0%	100.0%	98.4%	100.0%	100.0%	81.6%
High Voltage Connections	90.0%						
Telephone Accessibility	65.0%	N/A	N/A	95.1%	99.9%	100.0%	100.0%
Appointments Met	90.0%						
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	99.9%	100.0%
Emergency Urban Response	80.0%						
Emergency Rural Response	80.0%	95.4%	99.1%	98.9%	99.1%	99.3%	99.2%
Telephone Call Abandon Rate	10.0%	N/A	N/A	1.3%	0.5%	0.0%	0.0%
Appointment Scheduling	90.0%						
Rescheduling a Missed Appointment	100.0%						
Reconnection Performance Standard	85.0%	N/A	100.0%	100.0%	93.2%	94.9%	94.8%

Remotes does not have high voltage connections.
Remotes does not make appointments with customers. Due to the inaccessibiity of its service territory, work is bundled and performed when a crew is in the community.
Remotes' telephone system was not able to track telephone calls. In 2014, the system was replaced and this metric has since been tracked.
As determined in EB-2011-0021, the reconnection performance standard for Remotes is 2 weeks, to allow for work to be bundled and performed when a crew is in the community.
Connection of new services low voltage does not include connection of micro-embedded generation facilities.
Reconnection Performance Standard was not tracked until 2013, when the Board issued its Decision on EB-2011-0021
Reconnection Performance Standard Includes customers reconnnected under the OEB's winter reconnection program.

Energy Probe Research Foundation - Interrogatory # 13

Reference:

Exhibit A, Tab 5, Schedule 1, pages 10-12

Interrogatory:

a) Please update the performance charts with 2017 data.
b) Update the scorecards with 2017 data.

Response:

a) and b) refer to Attachments 1, and 2 for the charts and internal scorecard updated with 2017 data. Note that the training metric is no longer tracked. Instead 2017 training focused on specific courses and skill shortfalls identified, to ensure that priority training is performed and risks are limited. Attachment 3 provides the 2016 OEB scorecard, which was not available at the time of filing.

Figure 1 Achievement of Environmental Management System Objectives

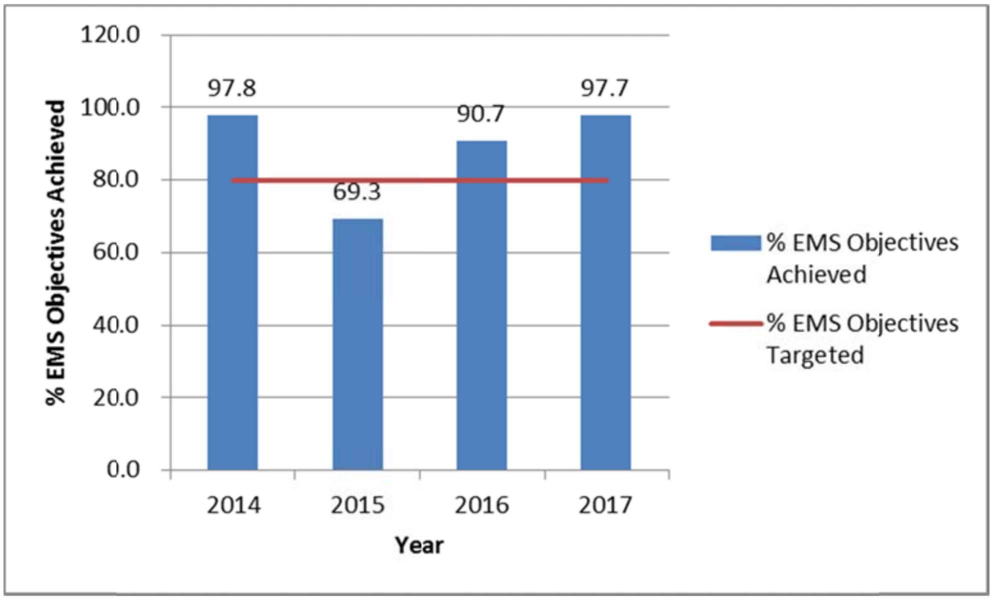


Figure 2 CIS Accounts Receivable

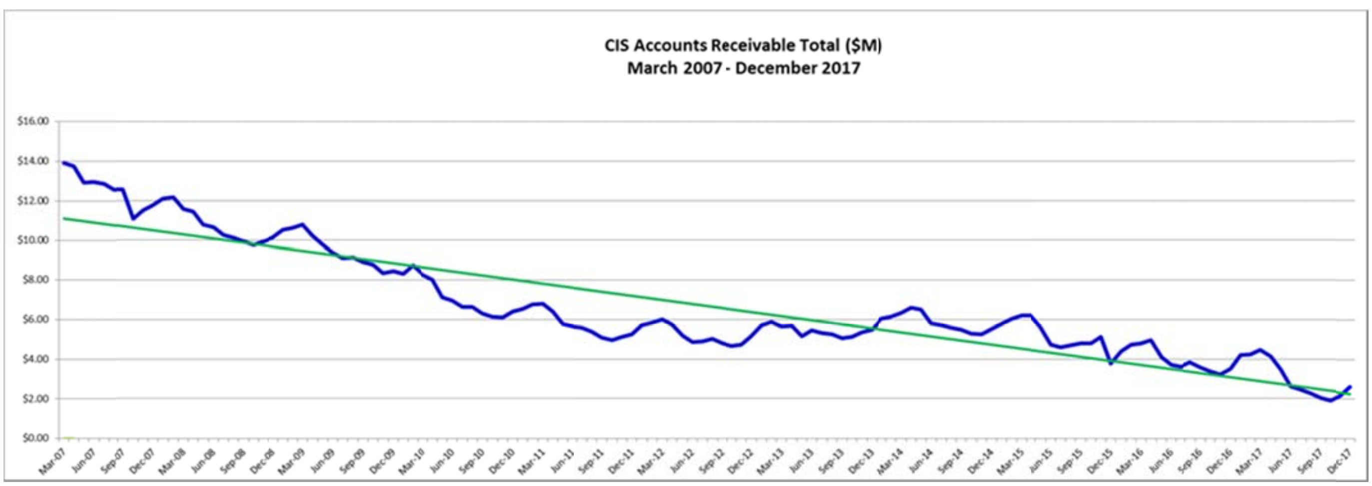


Figure 3 Completion of Mandatory Training

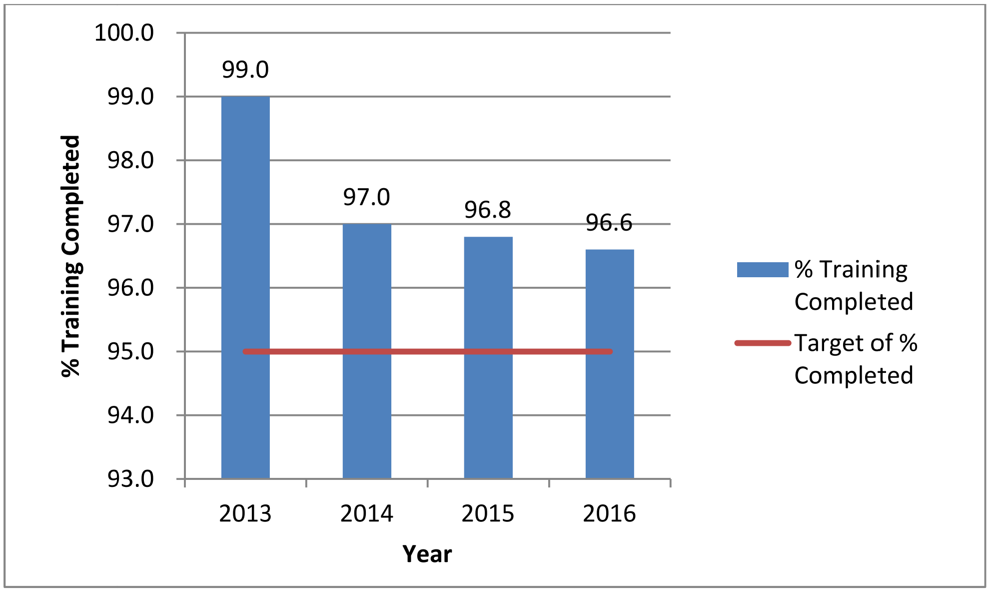


Figure 4 **Acheivement of Health and Safety Management System Objectives**

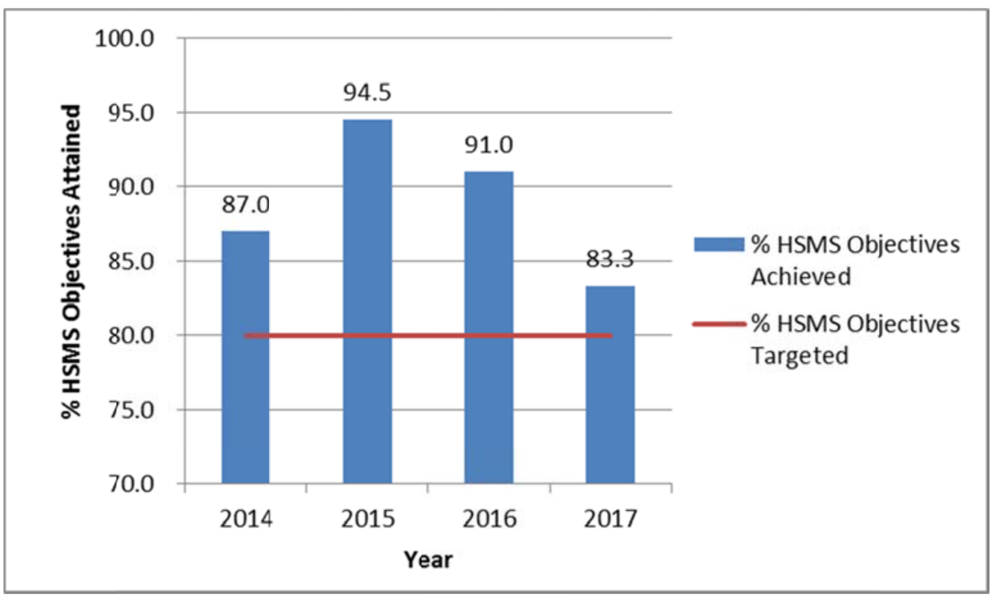


Figure 5 Remotes' SAIDI Performance

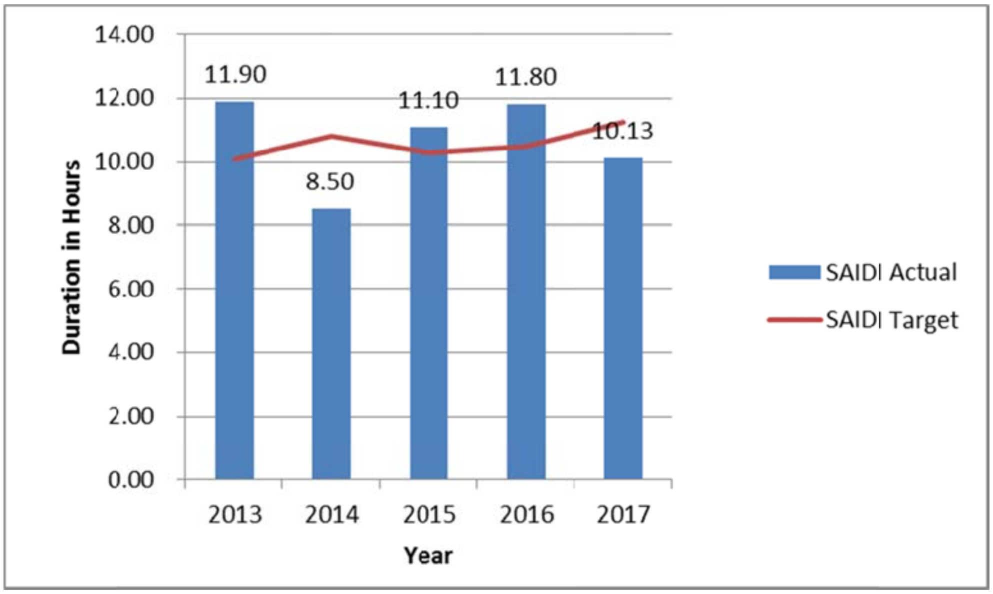


Figure 6 Remotes' SAIFI Performance

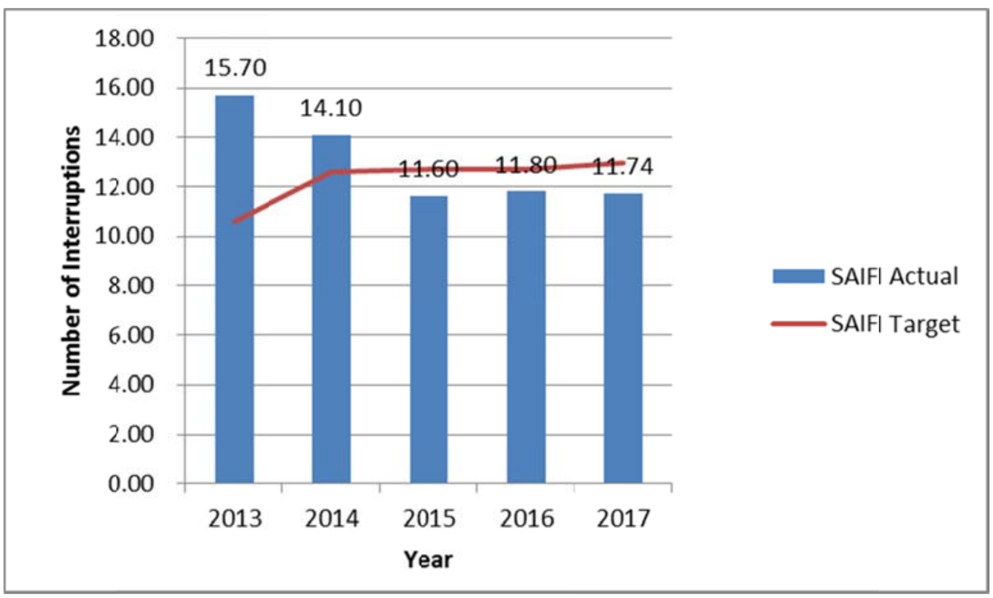
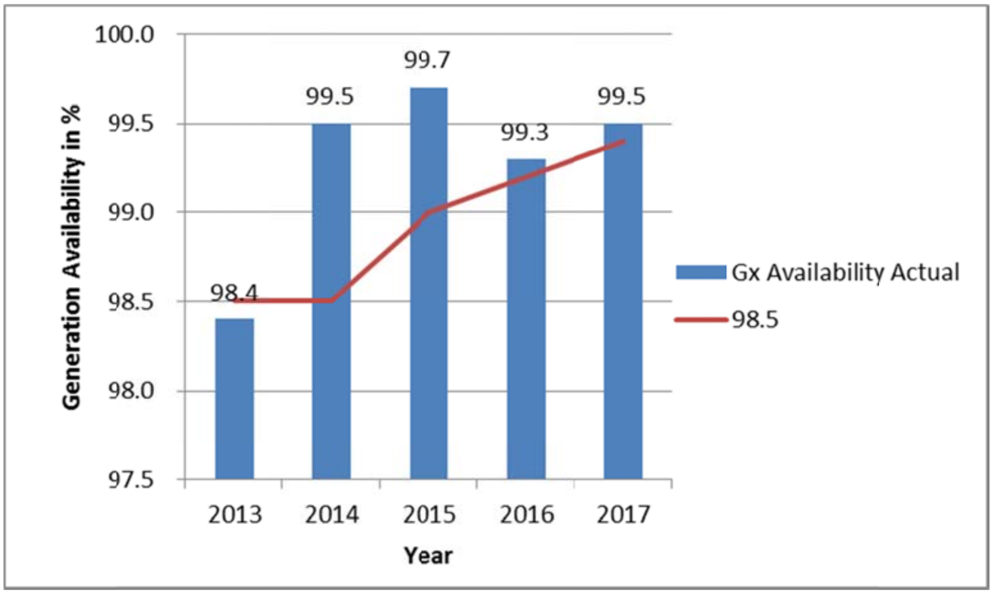


Figure 7 Percentage of Generation Availability



HYDRO ONE REMOTE COMMUNITIES INC.

DECEMBER 2017

SCORECARD

	Strategic Objective	Performance Measure	Year to Date Actual	Year to Date Target	Status YTD	Year End Target	Year End Projected
Business Excellence	Financial Strength	Distribution System Plan & Cost of Service Filing Milestones	23	23	★	23	★
Customer Relations	Inspire Customer Loyalty and Improve Community Relationships	Customer Satisfaction Survey Results	90%	≥ 90%	●	≥ 90%	●
		Director's FN/Tribal Council Meetings	18	8	★	8	★
		Customer & Community Outreach Initiatives[1]	18	21	▲	21	▲
Operational Excellence	Maintain/Improve System Reliability[2]	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point	10.13	11.24	★	11.24	★
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point	11.74	12.97	★	12.97	★
		Generation Availability	99.5%	99.4%	●	99.4%	●
Productivity	Improve Efficiency of Operations	Kingfisher Upgrade Milestones (on time, on budget)	13	13	●	13	●
Environmental Stewardship	Environmental Protection	Litres lost to the Environment	0	≤100	●	≤100	●
		Hydro One Spills[3]	7	≤6	▲	6	▲
		Category A Spills	0	0	●	0	●
		EMS Objectives and Achievements	42	34	★	34	★
Health & Safety	Injury Free Workplace	Lost Time Injury	0	0	●	0	●
		Total Recordable Injury	2	≤2	●	≤2	●
		High MRPH Incidents	0	≤1	★	≤1	★
		HSMS Objectives and Achievements	25	24	●	24	●

Legend ★ Better than plan ● On plan ▲ Worse than plan

[1] Customer initiatives are below plan due to unplanned work on other customer initiatives (Fair Hydro Plan, New Bill Project and the Big Trout Lake-Wapekeka Tie Line).

[2] Reliability results including loss of supply are better than the historical average. SAIDI results have improved by 9%, while SAIFI has improved by 10%. In reviewing the major storm events as part of the OEB COS process, one of the major storm events does not technically meet our standard for a major event and is now included in the results. SAIDI and SAIFI including the single major event are better than the historical average.

[3] The majority of 2017 Hydro One spills are related to an increase in glycol spills related to generation equipment failure and have occurred inside the DGS. As a result, no litres have been lost to the environment.

Scorecard - Hydro One Remote Communities Inc.

9/11/2017

Performance Outcomes	Performance Categories	Measures		2012	2013	2014	2015	2016	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	98.40%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time								90.00%	
		Telephone Calls Answered On Time		0.00%	0.00%	95.00%	98.70%	100.00%		65.00%	
	Customer Satisfaction	First Contact Resolution					N/A	100			
		Billing Accuracy				96.71%	96.46%	97.27%		98.00%	
		Customer Satisfaction Survey Results					91.4%	91			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness					69.25%	69.25%			
		Level of Compliance with Ontario Regulation 22/04 [1]					C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents				0	0			0
			Rate per 10, 100, 1000 km of line				0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		7.84	4.21	6.06	10.08	9.11			6.04
		Average Number of Times that Power to a Customer is Interrupted [2]		3.61	4.22	3.37	4.39	4.95			3.73
	Asset Management	Distribution System Plan Implementation Prog					113.2%	160			
	Cost Control	Efficiency Assessment									
		Total Cost per Customer [3]									
		Total Cost per Km of Line [3]									
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]									
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time						100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.39	0.32	0.46	0.62	1.98			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio									
		Profitability: Regulatory Return on Equity	Deemed (included in rates)								
			Achieved								

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

2016 Scorecard Management Discussion and Analysis ("2016 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2016 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

Hydro One Remote Communities Inc. ("Remotes") is an integrated generation and distribution company serving 3,600 customers in 21 off-grid communities. These communities are isolated and scattered across Ontario's north. As compared to other Ontario distributors Remotes has unique financial, operational and geographical attributes.

Remotes is 100% debt financed and conducts its operations under a cost recovery model to achieve a breakeven result of operations. Any surplus or deficiency in revenues is added to or drawn from the Rural or Remote Rate Protection Variance Account for future disposition by the Ontario Energy Board ("OEB"). Fifteen of the communities are First Nations, which are served under agreements with the federal government. In these communities, the federal government funds capital associated with load growth. Replacement capital, operations, maintenance and administrative costs are funded through Remotes' revenue requirement.

Due to the lack of grid connection, most of the electricity that Remotes generated is from diesel technology, which is currently the most feasible smaller-scale generation technology for the communities served by Remotes. Remotes also operates two small run of the river hydroelectric plants and, at the end of 2016, had 15 customer/community-owned solar installations connected to its distribution systems. Fuel is Remotes' single largest cost. Fuel costs are inherently volatile, related to changes in commodity price, method of delivery and volumes required to generate electricity.

Thirteen communities are not accessible by year-round road and can only be reached by aircraft, winter road or, in the case of one community, also by barge. The size and isolation of Remotes' service territory means that transportation of fuel, equipment and staff are key cost drivers. Construction and project risk are high due to the lack of transportation infrastructure.

Because Remotes is an integrated generation company with unique financing and operations, some metrics are not included in the results. The Ontario Energy Board has recognized that Remotes is not directly comparable to other Ontario distributors. In its Decision in proceeding EB-2014-0084, the Board noted that, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances. As noted in Hydro One Remotes' 2014 Price Cap Incentive Rate application (proceeding EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection."

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2016, Remotes processed 31 new connection requests for residential and small business low-voltage customers (those with service less than 750 Volts). 100% of these requests were completed within five business days (or as agreed to by the customer and the distributor), The industry target is 90%.

- **Scheduled Appointments Met On Time**

Because of high transportation costs and uncertainty about flight availability/ability to land, Remotes does not schedule appointments with customers. Work is generally organized through Band Councils or contractors since most customers do not have telephones. As a result, no appointments are missed or rescheduled.

- **Telephone Calls Answered On Time**

Remotes' billing and customer service staff received 6,666 phone calls from customers in 2016, answering 100% of these calls on time, as prescribed in the Ontario Energy Board's (OEB) Distribution System Code (DSC). The DSC requires call centre staff to answer calls within 30 seconds, 65%of the time, whenever the customer reaches an agent either directly or by means of a transfer. Remotes does not use an automated Interactive Voice Response (IVR) system.

Customer Satisfaction

- **First Contact Resolution**

First Contact Resolution (FCR) reports the success of the distributor in resolving a customer's issue during the first contact. Remotes measures FCR based on the number of issues that can be resolved by the billing agent as compared to those that must be brought to a supervisor for resolution. In 2016, 100% of calls were resolved by the billing agent without a supervisor's decision.

- **Billing Accuracy**

In 2016, Remotes issued 40,827 bills, with an accuracy rate of 97.27%, an improvement over previous years. Remotes does not meet the industry standard of 98.00%. This is largely because Remotes has not installed smart meters and relies on manual readings. Manual readings are more likely to result in higher planned and unplanned estimates. Remotes generally contracts with local community members to read the meters, and the readings are then faxed to the office and entered into the system by the billing team. If the faxed readings are late, they result in an unplanned estimate. There were 604 unplanned estimates in 2015. Remotes also has approximately 140 seasonal customers whose premises are generally difficult to access in the winter and who are billed quarterly with one physical meter read per year. In 2016, Remotes implemented quarterly physical meter readings for seasonal customers, if the properties can be accessed. There were 49 planned estimates related to seasonal customers an 88% improvement year over year.

- **Customer Satisfaction Survey Results**

Remotes conducts biennial surveys of its customers to help it plan work and respond to customer priorities. Remotes engaged a professional research company with the ability to speak First Nation languages to conduct a random telephone survey of its customers in 2015. When asked “Overall, are you very satisfied, somewhat satisfied, dissatisfied or very dissatisfied with the electricity service you get from Hydro One Remotes,” 91.4% reported being satisfied or very satisfied. The major reasons for satisfaction were that ‘electricity is there when needed’ (64.5%) and ‘good/better services’ (19.5%). Dissatisfied customers said that expensive rates/bills were the major reason for dissatisfaction. As part of the survey, Remotes tested customer awareness of its programs, and asked customers for their opinions on how service could be improved. Actions are being taken to improve awareness of programs to reduce bills (Low-Income Emergency Assistance Program and Ontario Electricity Support Program) and to address the service improvements that customers identified. Along with asking customers service-related questions, information was also sought on the penetration of electric heat and air conditioning and customer access to the internet to help Remotes plan its programs.

Safety

- **Public Safety**

In April 2015, the Electrical Safety Authority (ESA) made recommendations to the OEB for a scorecard public safety measure that includes three main components: A) Public Awareness of Electrical Safety, B) Compliance with Ontario Regulation 22/04, and C) the Serious Electrical Incident Index. Components B and C were reported in previous years and results for *Component A – Public Awareness of Electrical Safety* were tracked for the first time in 2015, for reporting in 2016. This measure will be updated for reporting in 2018.

- **Component A – Public Awareness of Electrical Safety**

In the spring of 2016, Remotes engaged a professional research company with the ability to speak First Nation languages to conduct a random phone survey to gauge electrical safety awareness among people living in its service territory. The survey was designed by the ESA and assessed participants’ safety awareness in six core areas: the likelihood to call before digging, the impacts of touching a power line, safe distances when around power lines, safe distances when around downed power lines, danger of tampering with electrical equipment, and actions to be taken when an occupied vehicle is in contact with a power line. For 2015, the Company reported an overall index score of 69.25%. The score was determined by applying the index score to each response in the categories mentioned above, where “best answers” received a score of 1 and “incorrect answers” received a score of 0. Most respondents understood the danger of touching an overhead wire (84%) and tampering with electrical equipment (81.5%), but fewer were able to correctly identify in feet or meters how close they could come to an overhead line (17%). About the same number (18%) said they would call before digging (there are very few underground cables in Remotes’ service territory). To improve the public’s awareness of hazards, an ad campaign was launched on Wawatay radio during the summers of 2016 and 2017 focusing on proximity to overhead wires. Remotes has also placed safety hazard posters in central locations in communities, identifying common hazards. Ongoing educational efforts include warning signs at hydroelectric and diesel generating stations, school presentations and information on electrical hazards in bill inserts.

- **Component B – Compliance with Ontario Regulation 22/04**

Remotes was assessed by the ESA as Compliant (C) to Ontario Regulation 22/04. Ontario Regulation 22/04 was introduced in early 2004 following recommendations from the ESA to ensure electrical safety and to track and report the safety records and compliance of electricity distributors. Distribution companies are required to submit declarations of compliance on the design, construction, and maintenance of distribution systems in accordance with the regulation, on an annual basis. An external auditor reviews and submits a final report, along with a signed declaration of compliance by an officer of the company, to the ESA for review and to establish a final result. The performance target for compliance with Ontario Regulation 22/04 is for the distributor to be fully compliant, and is recorded as Compliant (C), Non-Compliant (NC), or Needs Improvement (NI).

- **Component C – Serious Electrical Incident Index**

For 2016, the ESA identified no recordable serious public incidents, resulting in an index value of 0.0 for Remotes. The Serious Electrical Incident Index was designed to track and help improve public electrical safety on the distribution systems over time. Based on the distributor's total kilometers of line, the measure normalizes serious electrical incidents per 10, 100, or 1,000km of line reporting both the actual number and rate of incidents per kilometer – for Remotes, the index is normalized per 242 km of line. The distributor and any of its contractors or operators are required to report any serious electrical incident within 48 hours to the ESA. A serious electrical incident is defined as any electrical contact or any fire or explosion that caused or may have caused injury or death in any part of the distribution system operating at greater than 750 Volts (except if caused by lightning strikes). Remotes maintains a policy of reporting all public safety incidents to the ESA.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

For 2016, SAIDI performance was worse than the five year average but better than 2015. Planned outages contributed slightly less to the SAIDI result than in 2015, but were higher than average over the period and related to pole replacements, installation of viper switches and installation of bird protection. Defective equipment also contributed to the poorer result, but was better than performance in 2015. There was a long outage caused by the failure of the potential transformers located on the station transformer. The length of outage was compounded by bad weather that delayed the crew from getting to site. In Weagamow, the operator was forced to shut down the station due to a fire on the step up structure outside the plant. Remotes notes that, although not reflected on the scorecard, 2016 showed improvement in overall generation availability across its system. Planned distribution outages are expected to be higher in the next few years and are expected to improve reliability in the longer term. In particular, viper switches will improve cold load pickup related to loss of generation, will help reduce community-wide outages associated with catastrophic failure of a generation unit and will permit sectionalizing load to reduce the impact of community-wide distribution outages.

- **Average Number of Times that Power to a Customer is Interrupted**

Frequency of customer distribution outages was reported at 4.95 outages per customer for 2016. Planned outages will continue to be high as investments are required in the distribution system to improve long term reliability.

Asset Management

- **Distribution System Plan Implementation Progress**

The Distribution System Plan (DSP) implementation progress is a distributor-defined performance metric. For Remotes, the DSP is the Company's forecasted distribution capital expenditures required to maintain and improve the distribution system over the next five years. For 2016, the company exceeded its planned project expenditures by 60%, reflecting an increase in non-recoverable distribution system improvement in the largest community served. Remotes expects this measure to be updated as part of its 2017 Cost of Service filing.

Cost Control

The OEB has recognized that Remotes is not directly comparable to other Ontario distributors. In its decision in proceeding EB-2014-0084, the Board noted that, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances. As noted in Hydro One Remotes' 2014 Price Cap Incentive Rate application (proceeding EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection."

Conservation & Demand Management

- **Net Cumulative Energy Savings (Percent of target achieved)**

The Conservation First Framework is focused on reducing peak demand on the grid and is not related to Remotes' operations. As such, Remotes is excluded from the province-wide targets. Federal and provincial conservation programs that are designed to meet the unique needs of customers living in isolated communities in the far north are available to customers in Remotes' service territory. Remotes also has a small conservation program that focuses on energy efficient products and customer education about energy usage.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Due to technical challenges associated with integrating renewable generation in isolated distribution systems, the IESO FIT (Feed-in-Tariff) programs are not available to customers in Remotes' service territory. Remotes does offer a program to allow renewable generation to connect to its distribution systems, but, when they occur, most of the installations are small and do not require a Connection Impact Assessment (CIA).

- **New Micro-embedded Generation Facilities Connected On Time**

5 new micro-embedded solar installations connected to Remotes' distribution systems in 2016. All of them were completed on time. This metric measures the company's success in connecting micro-embedded generation facilities (less than 10kW) 95% of the time within a five business day window.

Financial Ratios

Remotes is 100% debt-financed and is operated as a break-even company with no meaningful return on equity. Therefore, given its financial structure, along with its unique operating characteristics, financial ratios are not comparable with those of other Ontario distribution utilities.

Note to Readers of 2016 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “can”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include legislative or regulatory developments, an unexpected increase in call centre volumes, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgement on the reporting date of the performance scorecard, and could be markedly different in the future. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

Energy Probe Research Foundation - Interrogatory # 14

Reference:

Exhibit A, Tab 3, Schedule 1 Table 2; D2-05-01 and D2-05-02

Interrogatory:

a) Please reconcile 2018 Compensation/Salary Cost between A-03-01 Table 2; D2-05-01 and D2-05-02.
b) Based on Appendix 2K data, please explain in detail why HORCI added 10 FTE and $1.5 million in compensation in 2013, following the EB-2012-0137 Board-approval of Staffing/compensation Costs.
c) Please describe the cost offsets that HORCI used to accommodate this increase.
d) Please discuss what is to prevent similar increases following the 2018 rebasing year?

Response:

a) The reconciliation is provided below:

D2-05-01	Total Pay - Salary and Wages	8,012,424.00
D2-05-03	App. 2KA: Other Post Employment Benefits (OPEB)	1,271,315.00
D2-05-02	**App. 2K: Compensation -All Employees**	**9,283,739.00**
D2-05-02	App. 2: Compensation -All Employees	9,283,740.00
D2-05-01	Less: Casual Employees - Salary and Wages	(1,208,121.00)
	Less: Casual Employees - Benefits	(184,031.00)
A-03-01	**Table 2 - Compensation - Regular Employees**	**7,891,588.00**

b) The filed 2013 data was based on year-end regular staff head count and did not include casual staff. The information in A-03-01 was provided to show a like-to-like comparison of regular employees in 2013 and 2018. The actual number of regular staff added was 3.

c) 3 additional regular staff resources were hired where Remotes could not secure casual staff to complete the work program. Staff resources were required to 1) establish a fire certification program for its stations as required for regulatory compliance and to complete the program approved by the Board in 2013; 2) an additional Operations Officer was required to improve safety and reliability training and support for local operators; and 3) as indicated in Exhibit B, Section 4.4, page 108, to hire a staff member with specialized information technology, networking and programming skills required to complete necessary SCADA and PLC projects.

d) Due to the nature of its funding, Remotes recognizes that it has a unique responsibility to balance its overall costs with the need to provide safe and reliable electricity to its customers. A resourcing justification is required to establish the need for all permanent hires that evaluates the cost and benefit of additional personnel compared to other resourcing options taking into account historical and future workload as well as business objectives. Approval for additional personnel is provided by senior management in conjunction with human resource staff and policy.

HYDRO ONE REMOTE COMMUNITIES INC.

DECEMBER 2017

SCORECARD

Strategic Objective		Performance Measure	Year to Date		Status	Year End	
			Actual	Target	YTD	Target	Projected
Business Excellence	Financial Strength	Distribution System Plan & Cost of Service Filing Milestones	23	23	★	23	★
Customer Relations	Inspire Customer Loyalty and Improve Community Relationships	Customer Satisfaction Survey Results	90%	≥ 90%	●	≥ 90%	●
		Director's FN/Tribal Council Meetings	18	8	★	8	★
		Customer & Community Outreach Initiatives[1]	18	21	▲	21	▲
Operational Excellence	Maintain/Improve System Reliability[2]	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point	10.13	11.24	★	11.24	★
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point	11.74	12.97	★	12.97	★
		Generation Availability	99.5%	99.4%	●	99.4%	●
Productivity	Improve Efficiency of Operations	Kingfisher Upgrade Milestones (on time, on budget)	13	13	●	13	●
Environmental Stewardship	Environmental Protection	Litres lost to the Environment	0	≤100	●	≤100	●
		Hydro One Spills[3]	7	≤6	▲	6	▲
		Category A Spills	0	0	●	0	●
		EMS Objectives and Achievements	42	34	★	34	★
Health & Safety	Injury Free Workplace	Lost Time Injury	0	0	●	0	●
		Total Recordable Injury	2	≤2	●	≤2	●
		High MRPH Incidents	0	≤1	★	≤1	★
		HSMS Objectives and Achievements	25	24	●	24	●
Legend		★ Better than plan	● On plan		▲ Worse than plan		

[1] Customer initiatives are below plan due to unplanned work on other customer initiatives (Fair Hydro Plan, New Bill Project and the Big Trout Lake-Wapekeka Tie Line).

[2] Reliability results including loss of supply are better than the historical average. SAIDI results have improved by 9%, while SAIFI has improved by 10%. In reviewing the major storm events as part of the OEB COS process, one of the major storm events does not technically meet our standard for a major event and is now included in the results. SAIDI and SAIFI including the single major event are better than the historical average.

[3] The majority of 2017 Hydro One spills are related to an increase in glycol spills related to generation equipment failure and have occurred inside the DGS. As a result, no litres have been lost to the environment.

Energy Probe Research Foundation - Interrogatory # 15

Reference:

Exhibit A, Tab 6, Schedule 1

Interrogatory:

Preamble: In the Board's decision in the EB-2016-0160 proceeding it determined Hydro One's executive compensation was too high.

"The OEB finds that the significant increases in compensation levels for senior executives and for members of the Board of Directors that Hydro One Limited has introduced have not been justified for recovery in OEB regulated rates for transmission services."

a) Hydro One Remotes is proposing to recover a portion of executive costs (President/CEO/Chairman services) in its rates. Has Hydro One Remote adjusted those costs in the wake of the Board's Decision?
b) What is the dollar amount of corporate management costs that are included in Hydro One Remote's rates?

Response:

a) The increases did not impact the amount allocated to Remotes, so a downward adjustment was not required.

b) Corporate management costs of $63,000 are included in Remote's rates.

Energy Probe Research Foundation - Interrogatory # 16

Reference:

Exhibit A, Tab 6, Schedule 1

Interrogatory:

Preamble: In a recent conference relating to Hydro One's distribution application, the utility admitted that it was planning on ending its contract with Inergi?

Will ending the Inergi contract have any impact on Hydro One Remote's costs? If so, what is the dollar figure?

Response:

It is Remotes understanding that Hydro One is planning to end its contract with Inergi for services related to Hydro One's Customer Call Centre. Remotes has its own billing staff and does not foresee any differences in its costs related to these plans.

Energy Probe Research Foundation - Interrogatory # 17

Reference:

Exhibit A, Tab 6, Schedule 1, attachments 1 and 2

Interrogatory:

Please update these two attachments.

Response:

As requested, Attachment 1 to this interrogatory is the SLA for General Counsel and Secretary Services, President/CEO/Chairman Services/Chief Financial Officer and Attachment 2 is the SLA for General Counsel and Secretary Services, Financial Services, Corporate Services, Tele-communications-related Services.

THIS AGREEMENT made in duplicate this 1st day of January, 2017 (the "Effective Date").

BETWEEN:

HYDRO ONE INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC., HYDRO ONE NETWORKS INC., HYDRO ONE TELECOM INC., and HYDRO ONE SAULT STE. MARIE LP, by its General Partner, Hydro One Sault Ste. Marie Inc.

(individually, the "Services Recipient" and collectively, the "Services Recipients")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to each of the Services Recipients by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide to each of the Services Recipients (as may be required by each of them respectively from time to time during the term of this Agreement) the following services (the "**Services**"), which Services are more particularly described in Schedule "A" attached hereto:

- General Counsel & Secretary (including Corporate Executive Office) services
- President / CEO / Chairman services
- Chief Financial Office services (including Strategic Financial services)

3.0 FEES PAYABLE

(a) The price for the performance of the Services for each of the Services Recipients shall be as identified in Schedule "A" attached hereto, exclusive of any sales and use taxes, as may be applicable. The relevant price for the Services shall be paid by each of the Services Recipients to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party. Each electronic journal transfer amount shall include HST (as this term is defined in clause 4.0(a)(iv) below) calculated at the rate applicable at the time such journal transfer is recorded in the books of the Services Provider. In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a `result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, a Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the said Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the said Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider;
- (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services; and
- (iv) it is a HST registrant in good standing under the *Excise Tax Act* (Canada), and that its HST registration number is 869994731RT0001. For the purposes of this Agreement, HST means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

(b) Each Services Recipient represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law:** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's document entitled "Security Policy" (SP 1686 R1) dated December 2016 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipients' premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: Each of the Services Recipient and the Services Provider shall, after the Effective Date, meet at least twice during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. A director-level employee of each affected party (as chosen by each party respectively) shall confer in an effort to resolve the Dispute. If the director-level employees are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Limited for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "**Receiving Party**") shall maintain in strict confidence all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "**Disclosing Party**") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "**Disclosing Party Representatives**") (collectively the "**Confidential Information**"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "**Receiving Party Representatives**") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as this term is defined in the *Personal Information Protection and Electronic Documents Act* (Canada), as it may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party, including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

Each of the Services Recipients shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the said Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

This Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

The Services Provider shall indemnify each of the Services Recipients and the Services Recipient's respective successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the Services Provider's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Each Services Recipient shall indemnify the Services Provider and the Services Provider's successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the said Services Recipient's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, no party hereto shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other parties or any of them or by any third party claiming through or under the other parties or any of them.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE TELECOM INC.
65 Kelfield Street,
Rexdale, Ontario M9W 5A3
Attention: **Mukul Sarin**
Telephone: 416-240-6843
Telecopier: 416-240-6802

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT12
Telephone: 416-345-6698

HYDRO ONE NETWORKS INC.
483 Bay Street,
Toronto, Ontario M5G 2P5
Attention: **Scot Hutchinson**
TCT7
Telephone: 416-345-5569
Telecopier: 416-345-6969

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483 Bay Street,
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Attention: **Scot Hutchinson**
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Telephone: 416-345-5569
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HYDRO ONE SAULT STE. MARIE LP
2 Sackville Road, Suite B
Sault Ste. Marie, ON P6B 6J6
Attention: **Arnold Parcels**
Telephone: 705-941-5652
Telecopier: 705-941-5600

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by any of the Services Recipients without the prior written consent of the Services Provider and by the Services Provider without the prior written consent of the affected Services Recipient, in either case which consent shall not be unreasonably withheld; provided, however, that a party may assign this Agreement or any rights, remedies or liabilities to any of its affiliates (as this term is defined in the Ontario *Business Corporations Act*, as amended) without the need for prior consent, in which case the assignor shall provide the other party with written notice of the assignment within 10 days after the effective date thereof. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

11.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

12.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE TELECOM INC.

Name: Paul Madore
Title: President and CEO
I have authority to bind the corporation.

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Kraemer Coulter
Title: Managing Director
I have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Name:
Title:
I have authority to bind the corporation.

HYDRO ONE INC.

Name:
Title:
I have authority to bind the corporation.

HYDRO ONE SAULT STE. MARIE LP, by its General Partner, Hydro One Sault Ste. Marie Inc.

Name: Arnold Parcels
Title: General Manager
I have authority to bind the corporation.
The corporation has the authority to bind the limited partnership.

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HYDRO ONE REMOTE COMMUNITIES INC.

Name: Kraemer Coulter
Title: Director
I have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Maureen Wareham

Name: Maureen Wareham
Title: officer / Secretary
I have authority to bind the corporation.

HYDRO ONE INC.

Name: Chris Lopez
Title: SVP, Finance
I have authority to bind the corporation.

HYDRO ONE SAULT STE. MARIE LP, by its General Partner, Hydro One Sault Ste. Marie Inc.

Name: Arnold Parcels
Title: General Manager
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The corporation has the authority to bind the limited partnership.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

Services	SERVICES TO BE PROVIDED BY HYDRO ONE INC. TO: (in $Thousands)			
	Hydro One Networks Inc.	Hydro One Remote Communities Inc.	Hydro One Telecom Inc.	Hydro One Sault Ste. Marie LP
General Counsel & Secretary (including Corporate Executive Office)	1,117.4	28.2	11.7	4.2
President / CEO / Chairman Services	6,883.3	20.8	41.3	35.0
Chief Financial Office Services (including Strategic Financial services)	1,068.2	13.0	26.0	43.2
Totals	**9,068.9**	**62.0**	**79.0**	**82.4**

DESCRIPTION OF SERVICES:

General Counsel and Secretary

The Services Provider shall provide the Services Recipient with professional legal advice and input. This advice shall include, but shall not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licences), contracts, and environmental and health and safety issues. The Services Provider will also provide guidance on business ethics and support in the form of a business code of conduct.

President / CEO / Chairman services

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate goals are achieved.

Chief Financial Officer services (including Strategic Financial services)

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate financial goals are achieved.

The Services Provider shall provide the Services Recipient with strategic approval with respect to investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting will also be provided by the Services Provider to the Services Recipient as required by the Services Recipient.

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

THIS AGREEMENT made in duplicate this 1st day of January, 2017 (the "Effective Date").

BETWEEN:

HYDRO ONE NETWORKS INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC, HYDRO ONE INC., HYDRO ONE TELECOM INC., HYDRO ONE B2M LP INC. and HYDRO ONE SAULT STE. MARIE LP, by its General Partner, Hydro One Sault Ste. Marie Inc.

(individually, the "Services Recipient" and collectively, the "Services Recipients")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to each of the Services Recipients by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide to each of the Services Recipients (as may be required by each of them respectively from time to time during the term of this Agreement) the following services (collectively, the "**Services**"), which Services are more particularly described in Schedule "A" hereto:

- General Counsel and Secretary (including Corporate Executive Office) services
- Financial services
- Corporate services
- Telecommunications Services
- Other services
- System Services for Hydro One Remote Communities Inc. ("Remotes") and Hydro One Telecom Inc. ("Telecom") only

Any additional terms and conditions applicable to a given Service shall be set out in Schedule "A".

3.0 FEES PAYABLE

(a) The price for the performance of the Services for each of the Services Recipients shall be as identified in Schedule "A" attached hereto, exclusive of any sales and use taxes, as may be applicable. The relevant price for the Services shall be paid by each of the Services Recipients to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party. In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, a Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the said Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the said Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

(c) The parties acknowledge and agree that, with the exception of Hydro One Inc., they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for purposes of HST. For the purposes of this Agreement, "HST" means the federal Harmonized Sales Tax chargeable in accordance with Part IX of the *Excise Tax Act* (Canada), as amended, or any similar value-added tax that may be applicable during the term of this Agreement to the Services to be provided hereunder.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
- (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) Each Services Recipient represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **<u>Compliance with Standards and Applicable Law:</u>** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's document entitled "Security Policy" (SP 1686 R1) dated December 2016 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) <u>**Safety and Security Measures**</u>: When any part of the Services is to be performed at any of the Services Recipients' premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) <u>**Meetings**</u>: Each of the Services Recipient and the Services Provider shall, after the Effective Date, meet at least twice during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. A director-level employee of each affected party (as chosen by each party respectively) shall confer in an effort to resolve the Dispute. If the director-level employees are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Limited for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "**Receiving Party**") shall maintain in strict confidence all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "**Disclosing Party**") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "**Disclosing Party Representatives**") (collectively the "**Confidential Information**"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "**Receiving Party Representatives**") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as this term is defined in the *Personal Information Protection and Electronic Documents Act* (Canada), as it may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party, including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

Each of the Services Recipients shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the said Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

The Services Provider shall indemnify each of the Services Recipients and the Services Recipient's respective successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the Services Provider's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Each Services Recipient shall indemnify the Services Provider and the Services Provider's successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the said Services Recipient's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, no party hereto shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other parties or any of them or by any third party claiming through or under the other parties or any of them.

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The authorized representatives of the parties hereto for purposes of this Agreement are the following:

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Telephone: 705-941-5652
Telecopier: 705-941-5600

HYDRO ONE B2M LP INC.
185 Clegg Road
Markham, Ontario L6G 1B7
Attention: **Jeffrey Smith**
Telephone: 905-946-6018

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

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Title: Director
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HYDRO ONE INC.

Name: Title: Title:
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Name: Arnold Parcels
Title: General Manager
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HYDRO ONE B2M LP INC.

Name: Jeffrey Smith
Title: Managing Director
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I have the authority to bind the corporation.

11.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

12.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE TELECOM INC.

Name: Paul Madore
Title: President and CEO
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Kraemer Coulter
Title: Director
have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Maureen Wareham

Name: Maureen Wareham
Title: officer / secretary
I have authority to bind the corporation.

HYDRO ONE INC.

Name: Chris Lopez
Title: SVP, Finance
I have authority to bind the corporation.

HYDRO ONE SAULT STE. MARIE LP, by its General Partner, Hydro One Sault Ste. Marie Inc.

Name: Arnold Parcels
Title: General Manager
I have authority to bind the corporation.
The corporation has the authority to bind the limited partnership.

HYDRO ONE B2M LP INC.

Name: Jeffrey Smith
Title: Managing Director
I have the authority to bind the corporation.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

	SERVICES TO BE PROVIDED BY HYDRO ONE NETWORKS INC. TO: (in $Thousands)				
SERVICES	**Hydro One Inc.**	**Hydro One Remote Communities Inc.**	**Hydro One Telecom Inc.**	**B2M**	**Hydro One Sault Ste. Marie LP**
General Counsel and Secretary Services	944.1	382.7	101.9	63.1	71.3
Financial Services	72.5	247.4	535.7	104.9	103.7
Corporate Services		268.7	270.8	56.5	165.7
Telecommunication Services		140.8	284.4		
Other Services		262.7	964.4		
System Services and Lease of Computer Equipment		260.8	617.4		
Totals	**1,016.6**	**1,563.1**	**2,774.6**	**224.5**	**340.7**

DESCRIPTION OF SERVICES:

The following provides a generic description of all Services to be provided by the Services Provider. Any additional terms and conditions which may be applicable to a Service are set out under its description.

GENERAL COUNSEL AND SECRETARY SERVICES

The Services Provider shall provide the Services Recipient with professional legal advice and input which shall include, but not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licenses), contracts, and environmental and health and safety issues.

FINANCIAL SERVICES

The Services Provider shall provide financial services support to the Services Recipient by providing timely and reliable financial information. The Services Provider will also provide services relating to business planning, budgeting and financial reporting. As required, services relating to treasury/pension/investor relations, taxation, internal audit and risk management, insurance, financial systems and services, cost and inventory accounting and decision support will also be provided. Other financial services such as transaction processing (accounts payable and receivable), and fixed asset and general accounting will also be provided.

CORPORATE SERVICES

The Services Provider shall provide corporate services in five main areas:

- Human Resources / Labour Relations – provision of human resource policy, strategy and standards to meet legal and other requirements. This includes staff planning, leadership development, succession planning and change management as well as labour relations services, pay equity, diversity, health services and performance management, compensation, health and benefits programs and administration of payroll, benefit plans and incentive plans.
- Business Architecture – provision of information systems support for Cornerstone Phase 1 and 2 as well as the management of legacy tools to support real time operations.
- Information Management – provision of computer and applications management support, internal telecommunications management, IT capital projects and IT strategy management and Inergi applications support management.
- Corporate Security – provision of advice, guidance and investigative support services to ensure the protection of assets and optimize the reliable delivery of electricity.
- First Nations & Métis Relations – provision of leadership and consultation support to address issues with First Nations & Métis communities.
- Corporate Communications – provision of strategy, program and support for corporate communications, public affairs and media relations, as well as corporate and shareholder relations and strategy programs related to internal communications.

TELECOMMUNICATIONS SERVICES

The Services Provider shall provide the Services Recipient with various telecommunications-related services including field and engineering, logistics, corporate, construction, telecommunication and information technology services.

OTHER SERVICES

The Services Provider shall provide the Services Recipient with:

- Customer Services Operation – provision of bill production and dispatch and settlements service, as well as data services related to field-based service orders.
- Information Management – provision of infrastructure operations, including a variety of activities such as system testing and integration, Internet and database management services, as well as services related to mainframe infrastructure operations, end user and desk-top support.

SYSTEM SERVICES (REMOTES AND TELECOM ONLY)

The Services Provider agrees to provide each Services Recipient, as a service, use of the Services Provider's core business systems (the "**Systems**") which are primarily based on:

(i) SAP Enterprise Asset Management Solution;
(ii) SAP Enterprise Resource Planning, SAP Enterprise Business Intelligence solution;
(iii) in the case of Hydro One Remote Communities Inc. only, SAP Customer Relationship and Billing solution; and
(iv) other system software such as middleware, data management software, virtualization software, operating systems, system tools.

Accordingly, the Services Provider hereby grants to the Services Recipient a non-exclusive, non-transferable license to access the Systems, via the Internet, and to use the System as a service, in object code form only, solely for its business purposes in accordance with the terms set out in this Agreement and the Third Party Terms (the "**License**"). As a condition of the License, the Services Recipient must sign and comply with SAP Canada Inc.'s form of "Authorized Affiliate Agreement" and any other forms required by third party licensors of the Systems (the "**Third Party Terms**") and this Agreement. Additionally, the Services Recipient shall not directly or indirectly:

(i) reverse engineer, decompile, disassemble or otherwise attempt to discover the source code or underlying algorithms of the Systems;
(ii) modify, translate or create derivative works based on the Systems;
(iii) rent, lease, distribute, sell, resell, assign or otherwise transfer rights to the Systems;
(iv) remove any proprietary notices from the software contained in the Systems.

Each Services Recipient hereby acknowledges that the copyright in use of the Systems as a service is the property of the Services Provider or its third party licensors and that the Services Provider and/or its third party licensors have exclusive ownership of the Systems.

No warranty is expressed or implied herein save as provided by the supplier(s) of the Systems in supplier's form of warranty delivered to the Services Recipient, and the Services Recipient accepts such warranty of the Systems in lieu of any and all other warranties of merchantability and fitness for a particular purpose. This warranty is exclusive, and no other warranty whether written or oral is expressed or implied. The Services Provider specifically disclaims the implied warranties of merchantability and fitness for a particular purpose in relation to the Systems.

The Services Provider may terminate the License to the Services Recipient by providing it with written notice of termination. The Services Recipient may terminate its License by providing the Services Provider with thirty (30) days prior written notice of termination. Upon termination of the License, the Services Recipient shall immediately cease using the Systems.

The Services Recipient shall:

(i) use the Systems lawfully, for business purposes only, and in accordance with the Services Provider's policies and third party licensor's manuals, warranties or instructions relating thereto;
(ii) not upload or distribute files containing viruses, corrupted files or any other similar software or programs that may damage the operation of the Systems;

(iii) not interfere or disrupt networks connected to the Systems;

(iv) not post, promote or transmit through the Systems any unlawful, harassing, libelous, abusive, threatening, harmful, vulgar, obscene, hateful, racially, ethnically or otherwise objectionable material of any kind or nature;

(v) not transmit or post any material that encourages conduct which could constitute a criminal offense or give rise to civil liability; and

(vi) comply with the Hydro One computer policies, procedures, and computer data management and access protocols which apply to use of the Systems, including the "Security Policy" (SP 1686 R1) dated December 2016 , as amended.

LEASE OF COMPUTER EQUIPMENT (REMOTES AND TELECOM ONLY)

The Services Provider hereby leases to the Services Recipient, and the Services Recipient hereby leases from the Services Provider, computer servers which house the Systems (the "Equipment") for the term of this Agreement. This is a net lease between the parties (the "Lease").

No warranty is expressed or implied herein save as provided by the supplier of the Equipment in supplier's form of warranty delivered to the Services Recipient, and the Services Recipient accepts such warranty of the Equipment in lieu of any and all other warranties of merchantability and fitness for a particular purpose. This warranty is exclusive, and no other warranty whether written or oral is expressed or implied. The Services Provider specifically disclaims the implied warranties of merchantability and fitness for a particular purpose in respect of the Equipment.

The Services Recipient agrees that the Services Provider may assign, sell or encumber any part of its interest in the Equipment, and to recognize such transfer, assignment or encumbrance thereof and be bound thereby, and to promptly execute and deliver to the Services Provider such documentation as any transferee, assignee, or encumbrance of the Services Provider may require to secure and/or complete such transaction.

Title to the Equipment shall remain in the Services Provider. The Services Recipients shall have no right, title or interest in the Equipment except as expressly provided herein. The Equipment shall always remain and be deemed personal and moveable property notwithstanding that the Equipment may hereinafter become, in any manner, attached or affixed to, imbedded in or permanently resting upon realty.

The Services Provider may terminate the Lease to the Services Recipient by providing it with written notice of termination. The Services Recipient may terminate its Lease with the Services Provider by providing the Services Provider with thirty (30) days prior written notice of termination, without affecting the Lease between the other Services Recipient.

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

Energy Probe Research Foundation - Interrogatory # 18

Reference:

Exhibit B1, Tab 1, Schedule 1

Interrogatory:

Preamble: On page 20 of the DSP, Hydro One Remotes lays out its summary of annual cost savings.

a) Are the savings between 2018-2022 incremental or cumulative?
b) Can Hydro One confirm that it's proposing to increase annual cost savings by just $273K between 2018 and 2022.
c) Can Hydro One confirm that it increased annual cost savings by $3.3 million between 2013 and 2016.

Response:

a) The savings between 2018-2022 are incremental.

b) Yes, that is correct. The Winter Road and First Nation fuel savings depend on the quality of the winter roads and the duration of the winter road season. If the winter road conditions can support more litres to be trucked versus flown in, the cost savings could potentially increase.

c) Table 2-4: Summary of Cost Savings 2017-2022 was incorrect. Refer to the revised table in Appendix A. The increased annual cost savings between 2013 and 2016 is $1.0 million, not the $3.3 million.

Appendix A: Revised Table 2-4: Summary of Cost Savings 2017-2022

Table 2-4: Summary of Cost Savings 2017-2022

	Historical ($)				Forecast ($)					
Cost Savings	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Winter Road Fuel Savings	1,144,998	3,516,961	1,170,388	496,576	570,783	570,783	570,783	570,783	570,783	570,783
First Nation Fuel Savings	407,642	347,572	177,023	658,264	643,151	643,151	643,151	643,151	643,151	643,151
Meter Reader Savings	1,149,901	1,250,543	1,296,989	1,370,443	1,343,032	1,349,573	1,356,009	1,362,505	1,369,199	1,375,802
Operator Savings	8,700,903	9,449,573	9,556,411	9,848,608	9,790,318	9,861,849	9,934,095	9,971,020	10,044,718	10,119,154
Webshare Savings	0	0	79,200	79,200	79,200	79,200	79,200	79,200	79,200	79,200
Total	**11,403,444**	**14,564,648**	**12,280,011**	**12,453,092**	**12,426,484**	**12,504,556**	**12,583,239**	**12,626,659**	**12,707,051**	**12,788,090**

Energy Probe Research Foundation - Interrogatory # 19

Reference:

Exhibit B1, Tab 1, Schedule 1

Interrogatory:

Preamble: On page 47 of the DSP, Hydro One's evidence shows that spending as a percentage of its business plan has decreased from 2014 to 2016.

a) Please provide a detailed response for why Hydro One's performance on spending its approved budgets has gotten worse in recent years.

Response:

a) Hydro One Remotes spending on both capital and OMA is drastically impacted by the variability and timing of INAC funding. If and when INAC funding becomes available, the focus for our business becomes removing connection restrictions through upgrades or executing customer connections. INAC operates on a year-by-year funding cycle. Overall, Hydro One Remotes is a small business with limited capacity and the overall envelope of work cannot be significantly altered, just the split amongst project types. The significant and largely unplanned amounts of INAC funding have affected spending on approved budgets.

Energy Probe Research Foundation - Interrogatory # 20

Reference:

Exhibit B1, Tab 1, Schedule 1

Interrogatory:

Preamble: On page 49 of the DSP, Hydro One says that diesel generation efficiency depends "largely" on the load profile of the community the generator is servicing.

a) What is the most efficient load profile?
b) When Hydro One pays renewable energy generators for the power they provide based on avoided diesel costs, does it consider the impact these renewable energy generators have on the efficiency levels of diesel generators?

Response:

a) Each diesel generator has a different fuel efficiency curve that charts load against efficiency for a fixed RPM. A flat load profile is the most efficient load profile.

b) Remotes pays renewable energy generators either a net metered amount or the REINDEER rate for the community. Considerations to the impacts on fuel efficiency on the diesel generators caused by renewable generation would be very difficult to project, although flattening of the load curve could provide some fuel savings, there would be some losses associated with running smaller diesel generators as the station load decreases with increasing renewable generation. The diesel generating units operate between 50% and 90% of their prime rating. The fuel efficiency curve varies approximately 11% over this range, but the efficiency is not necessarily highest at 90%. Remotes does not, therefore, consider the REINDEER impacts of fuel efficiency on the operation of diesel generators.

Energy Probe Research Foundation - Interrogatory # 21

Reference:

Exhibit B1, Page 59 Figures 3-1 and 3-2 to 3-6 Distribution System Plan 2018-2022

Interrogatory:

Preamble: Figure 3-6 shows the age demographics of the 57 Diesel units in the generation fleet assets (Table 3-2) ranging from 1-22 years

a) Please explain why this is not a normal distribution (like Transformers and Poles Figures 3-8, 3-9).
b) What is the basis of the regulatory depreciation rate/life for diesel units?
c) Please provide documentation on the ACA methodology, cycle and process for assessment of need for Renewal of diesel generation assets, as shown in Figure 3-5.In particular, please provide the links between ACA and run hours and/or other parameters.
d) Does HORCI base its diesel unit renewal policy solely on run hours and/or other factors, such as historic reliability, load/customers served?
e) Please explain in detail the criteria and weightings used in the renewal/replacement decisions for P1 Generation Assets.

Response:

a) Once a generator is in service its life span is not dependant on its age in years. Because all stations have more than one generator (generally three), each generator does not run continuously and because generators are not all the same size at the same station one generator may run significantly more (or less) hours per year than the other generator(s) due to loading selection. Therefore their aging to end of life is not strictly chronological. The other factor that has affected the distribution is the ongoing upgrading (replacement) to generators to accommodate the growing loads in communities. This has varied based on INAC funding over the years.

b) An in-depth depreciation study was completed by a 3rd party (Foster & Associates) to determine the useful life of Remotes' assets, including diesel units and was approved as part of EB-2012-0237 That study is attached to this IR as I-02-21 - Attachment 1.

c) Age, RPM and Hours Operated are contributing factors to determine the ACA. Age is only a problem when unit replacement parts become unavailable. Age is a minor factor. Major component parts wear less on lower RPM generators when compared to higher RPM generators for the same number of hours, thus lower RPM generators are in service for more hours before replacement. Given the above, the Hours Operated is the major factor used to determine replacement of the generators.

d) All replacements forecast in the DSP are based on projected Hours Operated.

e) There are two factors considered, Age and Hours Operated. Age is a minor factor and Hours Operated is a major factor.

2011 Depreciation Rate Review

Remote Communities, Inc.

CONTENTS

DISTRIBUTION

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a 2011 review and update of depreciation rates and parameters for Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) owned and operated by Hydro One Inc. (Hydro One). The review requested by the Company was conducted under the direction and supervision of Dr. Ronald E. White whose professional qualifications are provided in Section V.

Foster Associates is a public utility economic consulting firm headquartered in Rockville, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer applications for conducting depreciation and valuation studies.

PLANT ACCOUNT STRUCTURE

The hierarchical structure of plant accounting records maintained by the Company for major asset categories provides: a) Uniform System of Account (USoA) categories; b) cost of asset components (Profile ID); c) vintage identification (Asset ID); and d) property unit identification within vintages (CAT ID).

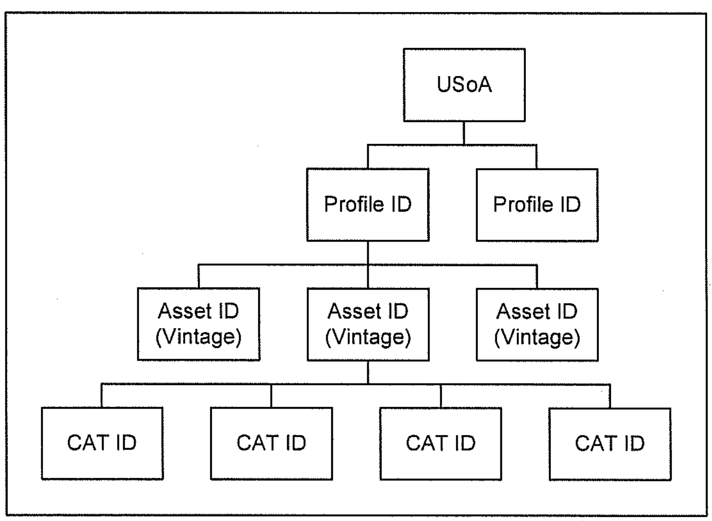


Fig. 1 Account Structure

The lowest level at which the installed cost of a property unit (*e.g.*, a single pole or transformer) can be estimated is by vintage year of placement within a Profile ID. (The cost of a property unit within a vintage can be estimated by dividing the vintage cost by the recorded number of installed property units). A Profile ID is an aggregation of vintage costs sharing common physical or functional attributes. All vintages of line transformers less than or equal to 230 KVA, for example, or all vintages of underground service conductors are classified in unique Profile IDs. It is neither practical nor feasible, however, to estimate service lives and maintain accumulated depreciation reserves for each property unit.

CURRENT DEPRECIATION RATES

Depreciation rates currently used by Hydro One Remote Communities were developed in a 2006 depreciation review conducted by Foster Associates.

Life tables were constructed in the 2006 review for each USoA plant account for which retirements were recorded over the period 2000–2005. Life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

Absent the availability of sufficient retirement activity to conduct statistical service life studies, depreciation rates developed in the 2006 review were derived from a composite of parameters (*i.e.*, projection lives and projection curves) recommended by the former Ontario Hydro internal Depreciation Review Committee (DRC) for asset profiles contained in a USoA category. The dominant projection curve and dollar–weighted average projection life (rounded to the nearest integer) of the constituent asset profiles were selected to describe the forces of retirement acting upon a USoA plant account.[1]

2011 DEPRECIATION RATE REVIEW

[1]In 1954, by joint agreement of the Engineering, Operations and Comptroller's Division of Ontario Hydro, average service lives were estimated for each of the Company's various plant accounts. The estimated lives were based on engineering/financial judgment and information gathered regarding service lives used by other utilities. Statistical studies based on survivor curves were introduced in 1959 to further improve the estimation of life expectancies. The DRC was established in 1973 to provide formal engineering review for various classes of assets. The role of the committee was expanded in 1975 to include responsibility for recommending service lives and service costs (*i.e.*, provisions for fixed asset removal costs) of all assets. The DRC annually reviewed the service lives of all major facilities and a selection of plant components, with the objective of reviewing all plant components at least once every five years. DRC recommendations were based on factors such as operating experience, retirement history, engineering judgment, expected regular maintenance and system requirements. The DRC review process was discontinued by Hydro One in 1998.

The principal findings and recommendations of the Hydro One Remote Communities 2011 Depreciation Rate Review are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a comparative summary of current and proposed parameters including projection life, projection curve, average service life, and average remaining life. Statement E displays the computation of proposed USoA projection lives derived from recommended IFRS profile lives.

SCOPE OF REVIEW

Principal activities undertaken in the 2011 review included:

- Collection of plant and reserve data;
- Reconciliation of assembled database to Company records;
- Discussions with Hydro One and Hydro One Remote Communities plant accounting and operations personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been adopted, the Company is currently using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.,* credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the intangible and general plant categories summarized in Table 1 below.

Account Number	Description	Amortization Period
A	B	C
1915	Office Furniture and Equipment	7 yrs.
1920	Computer Hardware - Minor	5 yrs.
1935	Stores Equipment	8 yrs.
1940	Tools, Shop and Garage Equipment	6 yrs.
1945	Measuring and Testing Equipment	5 yrs.
1960	Miscellaneous Equipment	5 yrs.

Table 1. Amortization Accounts

RECOMMENDED DEPRECIATION RATES

Table 2 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended for Hydro One Remote Communities.

	Accrual Rate			2011 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Generation	6.75%	5.07%	-1.68%	$2,195,319	$1,649,399	($545,920)
Transmission	3.39%	2.23%	-1.16%	202,453	133,405	(69,048)
General Plant	3.30%	2.67%	-0.63%	232,212	188,064	(44,148)
Total	5.77%	4.33%	-1.44%	$2,629,984	$1,970,868	($659,116)

Table 2. Hydro One Remote Communities

The composite accrual rate recommended for Hydro One Remote Communities is 4.33 percent. The current equivalent rate is 5.77 percent. The recommended change in the composite rate is a reduction of 1.44 percentage points.

A continued application of current rates would provide annualized depreciation expense of $2,629,984 compared with an annualized expense of $1,970,868 using the proposed rates. The resulting 2011 expense reduction is $659,116.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Remote Communities. The proposed rates are subject to approval by the Ontario Energy Board.

SCOPE

The steps involved in conducting the 2011 depreciation review can be grouped into four major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2011 review for Hydro One Remote Communities included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by the Company provides aged transactions for all plant accounts.

Prior to 1998, plant accounting records were maintained in a legacy Fixed Asset Management System (FAMS) developed by Ontario Hydro. FAMS was replaced with an SAP system in 1998. The SAP system was replaced with a PeopleSoft asset accounting system in 2000. The PeopleSoft system was configured with the asset profiles maintained in the SAP system and uploaded with age distributions of surviving plant at December 31, 1999.[2] The PeopleSoft system was replaced in August 2009 by an updated version of the SAP system.

Plant and reserve data used in conducting the 2011 depreciation review was assembled by Hydro One personnel and coded by Foster Associates. Plant accounting transactions recorded between January 1, 2008 and July 31, 2009 were extracted from the PeopleSoft system, coded and appended to the database used in conducting the 2008 update. Transactions recorded between August 1, 2009 and December 31, 2010 were extracted from the SAP system. An additional dataset of profile plant and reserve balances at December 31, 2010 was assembled and reconciled to aggregate USoA balances. (See Statement E).

Age distributions of surviving plant (*i.e.*, plant surviving by vintage year of placement) at December 31, 2010 were derived by Foster Associates from the vintaged plant transactions and reconciled to age distributions provided by Hydro One. The complexity of the process through which the database was compiled and mapped to USoA plant categories prevented Foster Associates from reconciling the database to any public reports of Hydro One. The integrity of the assembled database, however, was verified by Hydro One Remote Communities.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

[2]In 2003, Hydro One undertook a two–phase project to a) map asset profiles maintained in PeopleSoft to USoA plant account classifications; and b) align quantities maintained in a Power System Data Base (PSDB) to the re–mapped USoA account classifications. The PSDB provides property unit identification and quantities associated with investments maintained in PeopleSoft. Asset profiles maintained in SAP were not mapped to USoA plant account classifications. This limitation prohibited using pre–2000 plant accounting activity in the 2006 depreciation review.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available.

An actuarial life analysis program designed and developed by Foster Associates was employed in this review. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this review. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

As noted above, the database for Hydro One Remote Communities contains plant accounting transactions for activity years 2000–2010. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[3] A similar limitation applies to the database of Hydro One Remote Communities which contains minimal retirement activity during the available activity years. Retirements must be sufficiently distributed across vintages within these years in order to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each USoA plant account for which retirements were recorded over the period 2000–2010. Without exception, life tables

[3]Plant maturity is achieved when the age distribution of surviving plant resembles a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

As was noted in the 2006 review, limitations in conducting life analyses were also imposed by vintage years "banded" by Hydro One in 1992 and again in 1998 when age distributions from a Fixed Asset Management System (FAMS) were uploaded to SAP. All pre–1950 vintages were assigned a vintage year of 1950. Plant installed between 1951 and 1955 was assigned a vintage year of 1955. Similarly, plant installed during the intervals 1956–1960, 1961–1965 and 1966–1970 were assigned vintage years 1960, 1965 and 1970, respectively. Although discontinued in 1971, the banding of pre–1970 vintages will continue to produce unreliable life indications until most of the earlier vintages have been retired from service.

Pending the availability of sufficient retirement activity to conduct service life studies, it is the opinion of Foster Associates that a composite of the parameters estimated for the asset profiles contained in a USoA account provides the best available estimate of service life statistics for the current depreciation review.

CLASS/CATEGORY SERVICE LIVES

Confronted with an inability to obtain meaningful service life indications from statistical analyses, attention was shifted in the 2011 review to the profile lives derived in preparing for the implementation of International Financial Reporting Standards (IFRS) in 2008. The motivation for estimating USoA service lives from asset profile service lives (now termed class/category in SAP) has been strengthened by a requirement that Canadian rate–regulated entities transition to IFRS no later than January 1, 2013. This requirement carries with it a set of accounting rules (IAS 16) that changes depreciation accounting for long–lived assets. For example, IAS 16 requires that property, plant and equipment assets be componentized into items of property; that depreciation be calculated at the item level; and the carrying amount (*i.e.* cost less accumulated depreciation) be "derecognized" on disposal or when no further economic benefits are expected from its use.[4]

The *Recognition Principle* of IAS 16 prescribes that the cost of an *item* of property, plant and equipment shall be recognized as an asset if, and only if: a) it is probable that future economic benefits associated with the item will flow to the

[4]Group depreciation accounting neither reports nor recognizes gains or losses resulting from the retirement of property units before or after the expiration of an estimated service life. Under–depreciation of property units retired earlier than predicted is offset by over–depreciation of property units remaining in service beyond the estimated average service life of a group. This treatment is consistent with the regulatory principle that opportunities should be preserved for the recovery of capital devoted to public service.

entity; and b) the cost of the item can be measured reliably. Importantly, IAS 16 does not prescribe the unit of measure for recognition, *i.e.*, what constitutes an item of property plant and equipment. Individually insignificant items may be aggregated and the Recognition Principle applied to the aggregated value.

Based on these principles and recognizing that a USoA category may include a greater diversity of plant items than contemplated under an item procedure, a Profile ID (or class/category) is considered to be an appropriate and practical aggregation of plant items under IAS 16. This level of aggregation means that service lives will be estimated by Profile ID and gains or losses will be computed for plant items retired prior to achieving an age equal to an applied service life.

The requirement to estimate item service lives at the class/category level for IFRS reporting strongly suggests that USoA lives used for US GAAP reporting should mirror Profile ID lives estimated for assets aggregated into USoA categories. This functional relationship was preserved in the 2011 review by adopting composited Profile ID lives estimated for each class/category as a surrogate for a USoA projection life (P–Life). Profile lives used in the computation of proposed depreciation rates were estimated by an internal project team assigned to review and update estimates previously developed by the DRC. Members of the review team included Hydro One and Hydro One Remote Communities engineers, accountants and other subject matter experts having managerial responsibilities for the assets under review. Meetings of the project team were facilitated by Foster Associates.

Unlike the item accounting procedure prescribed under IAS 16, group depreciations rates developed under US GAAP are formulated with recognition of retirement dispersion. This requirement was satisfied in the 2011 review by selecting an Iowa survivor curve considered descriptive of the forces of retirement acting upon each USoA category. Recommended survivor curves were selected by Foster Associates based on experience and an understanding of the parametric form of the associated probability density functions. Proposed projection lives derived from harmonic weighting of the profile lives recommended by the project team are summarized in Statement E.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is appropriate for Hydro One Remote Communities at this time. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current review) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

With the exception of amortizable categories in which theoretical or computed reserves replace recorded reserves, all remaining reserves were redistributed by multiplying the calculated reserve for each USoA primary account by the ratio of the sum of recorded reserves to the sum of calculated reserves. The sum of redistributed reserves is, therefore, equal to the sum of recorded depreciation reserves before the redistribution.

Statement C provides a comparison of recorded, computed and rebalanced reserves for Hydro One Remote Communities on December 31, 2010. The recorded reserve was $20,185,154 or 44.3 percent of the depreciable plant investment. The corresponding computed reserve is $18,447,389 or 40.5 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $1,737,765 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. Broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2011 review were developed using a system composed of the straight–line method, vintage group procedure, remaining–life technique. It is the opinion of Foster Associates that this system will remain appropriate for Hydro One Remote Communities, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected intangible and general support asset accounts is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Amortization accounting for these rate categories relieves Hydro One Remote Communities of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balances prior to posting retirements would overstate the annualized amortization expense. Accrual rates contained in Statement A have been applied to plant balances containing vintages that will be retired upon approval of the proposed amortization periods. Accrual rates contained in Statement A should be applied to current plant balances. Accrual rates equal to the reciprocal of the amortization period should be applied to these categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life statistics recommended for Hydro One Remote Communities. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2011 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2010.
- Statement D provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, and average remaining life.
- Statement E displays the computation of proposed USoA projection lives derived from recommended IFRS profile lives.

Current depreciation accruals shown on Statements B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by Hydro One Remote Communities for the mix of investments recorded on December 31, 2010. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio}}{\text{Remaining Life}}.$$

HYDRO ONE REMOTE COMMUNITIES

Statement A

Comparison of Current and Proposed Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Current			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
GENERATION PLANT							
1620 Buildings and Fixtures	42.57		1.81%	25.95		27.96%	2.78%
1665 Fuel Holders, Producers and Accessories	34.87		2.30%	26.30		27.08%	2.77%
1670 Prime Movers	3.02		12.89%	3.98		73.21%	6.73%
1675 Generators	26.15		2.61%	6.93		62.22%	5.45%
1680 Accessory Electric Equpment	33.30		2.32%	9.51		48.28%	5.44%
1685 Miscellaneous Power Plant Equipment	26.31		2.34%	19.74		23.18%	3.89%
Total Generation Plant			6.75%	8.71		53.04%	5.07%
DISTRIBUTION PLANT							
1805D Land - Depreciable	67.28		1.34%	37.28		27.86%	1.94%
1806 Land Rights	58.57		1.36%	78.83		23.18%	0.97%
1830 Poles, Towers and Fixtures	32.67		2.53%	44.99		19.75%	1.78%
1835 Overhead Conductors and Devices	32.36		2.53%	38.24		25.77%	1.94%
1845 Underground Conductors and Devices	12.69		5.06%	15.74		52.34%	3.03%
1850 Line Transformers	27.26		2.89%	29.92		28.00%	2.41%
1860 Meters	1.17		20.00%	13.16		13.43%	6.58%
Total Distribution Plant			3.39%	33.62		24.90%	2.23%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	30.50	-5.0%	2.58%	41.11		19.43%	1.96%
1955 Communication Equipment	3.50	-5.0%	15.78%	1.00		96.62%	3.38%
Total Depreciable			2.58%	41.11		19.67%	1.96%
Amortizable							
1915 Office Furniture and Equipment	← 7 Year Amortization →			← 7 Year Amortization →			14.29%
1920 Computer Hardware - Minor	1.97		20.00%	← 5 Year Amortization →			19.25%
1935 Stores Equipment	← 8 Year Amortization →			← 8 Year Amortization →			12.37%
1940 Tools, Shop and Garage Equipment			16.67%	← 6 Year Amortization →			16.67%
1945 Measurement and Testing Equipment	← 5 Year Amortization →			← 5 Year Amortization →			17.34%
1960 Miscellaneous Equipment	← 5 Year Amortization →			← 5 Year Amortization →			20.00%
Total Amortizable			16.00%	3.95		36.06%	15.91%
Total General Plant			3.30%	29.52		20.50%	2.67%
TOTAL HYDRO ONE REMOTE COMMUNITIES			5.77%	12.01		44.31%	4.33%

HYDRO ONE REMOTE COMMUNITIES

Statement B

Comparison of Current and Proposed Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/10 Plant Investment	2011 Annualized Accrual Current	Proposed	Difference
A	B	C	D	E=D-C
GENERATION PLANT				
1620 Buildings and Fixtures	$ 4,497,937	$ 81,413	$ 125,043	$ 43,630
1665 Fuel Holders, Producers and Accessories	5,372,646	123,571	148,822	25,251
1670 Prime Movers	13,703,994	1,766,445	922,279	(844,166)
1675 Generators	5,355,631	139,782	291,882	152,100
1680 Accessory Electric Equipment	1,361,324	31,583	74,056	42,473
1685 Miscellaneous Power Plant Equipment	2,244,654	52,525	87,317	34,792
Total Generation Plant	$ 32,536,186	$ 2,195,319	$ 1,649,399	$ (545,920)
DISTRIBUTION PLANT				
1805D Land - Depreciable	$ 294,456	$ 3,946	$ 5,712	$ 1,766
1806 Land Rights	234,126	3,184	2,271	(913)
1830 Poles, Towers and Fixtures	1,786,753	45,205	31,804	(13,401)
1835 Overhead Conductors and Devices	1,473,430	37,278	28,585	(8,693)
1845 Underground Conductors and Devices	186,177	9,421	5,641	(3,780)
1850 Line Transformers	1,738,469	50,242	41,897	(8,345)
1860 Meters	265,884	53,177	17,495	(35,682)
Total Distribution Plant	$ 5,979,295	$ 202,453	$ 133,405	$ (69,048)
GENERAL PLANT				
Depreciable				
1908 Buildings and Fixtures	$ 6,664,558	$ 171,946	$ 130,625	$ (41,321)
1955 Communication Equipment	20,332	3,208	687	(2,521)
Total Depreciable	$ 6,664,558	$ 171,946	$ 130,625	$ (41,321)
Amortizable				
1915 Office Furniture and Equipment	$ 39,115	$ 5,588	$ 5,588	$ -
1920 Computer Hardware - Minor	41,096	8,219	7,913	(306)
1935 Stores Equipment	148,458	18,358	18,358	
1940 Tools, Shop and Garage Equipment	6,078	1,013	1,013	
1945 Measurement and Testing Equipment	19,089	3,309	3,309	
1960 Miscellaneous Equipment	102,856	20,571	20,571	
Total Amortizable	$ 356,692	$ 57,058	$ 56,752	$ (306)
Total General Plant	$ 7,041,582	$ 232,212	$ 188,064	$ (44,148)
TOTAL HYDRO ONE REMOTE COMMUNITIES	$ 45,557,063	$ 2,629,984	$ 1,970,868	$ (659,116)

HYDRO ONE REMOTE COMMUNITIES
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
GENERATION PLANT							
1620 Buildings and Fixtures	$ 4,497,937	$ 812,304	18.06%	$ 1,148,684	25.54%	$ 1,257,845	27.96%
1665 Fuel Holders, Producers and Accessories	5,372,646	1,348,331	25.10%	1,328,554	24.73%	1,454,808	27.08%
1670 Prime Movers	13,703,994	12,353,668	90.15%	9,162,620	66.86%	10,033,360	73.21%
1675 Generators	5,355,631	1,637,429	30.57%	3,043,200	56.82%	3,332,400	62.22%
1680 Accessory Electric Equpment	1,361,324	278,787	20.48%	600,231	44.09%	657,272	48.28%
1685 Miscellaneous Power Plant Equipment	2,244,654	413,762	18.43%	475,106	21.17%	520,257	23.18%
Total Generation Plant	$ 32,536,186	$ 16,844,280	51.77%	$ 15,758,395	48.43%	$ 17,255,943	53.04%
DISTRIBUTION PLANT							
1805D Land - Depreciable	$ 294,456	$ 48,021	16.31%	$ 74,910	25.44%	$ 82,028	27.86%
1806 Land Rights	234,126	62,601	26.74%	49,564	21.17%	54,275	23.18%
1830 Poles, Towers and Fixtures	1,786,753	369,664	20.69%	322,260	18.04%	352,885	19.75%
1835 Overhead Conductors and Devices	1,473,430	391,383	26.56%	346,776	23.54%	379,731	25.77%
1845 Underground Conductors and Devices	186,177	102,438	55.02%	88,982	47.79%	97,438	52.34%
1850 Line Transformers	1,738,469	491,226	28.26%	444,564	25.57%	486,811	28.00%
1860 Meters	265,884	75,924	28.56%	32,615	12.27%	35,715	13.43%
Total Distribution Plant	$ 5,979,295	$ 1,541,258	25.78%	$ 1,359,671	22.74%	$ 1,488,883	24.90%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	$ 6,664,558	$ 1,362,978	20.45%	$ 1,182,766	17.75%	$ 1,295,166	19.43%
1955 Communication Equipment	20,332	24,321	119.62%	17,940	88.24%	19,645	96.62%
Total Depreciable	$ 6,684,890	$ 1,387,299	20.75%	$ 1,200,706	17.96%	$ 1,314,811	19.67%
Amortizable							
1915 Office Furniture and Equipment	$ 39,115	$ 10,193	26.06%	$ 10,193	26.06%	$ 10,193	26.06%
1920 Computer Hardware - Minor	41,096	17,225	41.92%	15,111	36.77%	15,111	36.77%
1935 Stores Equipment	148,458	6,768	4.56%	71,098	47.89%	71,098	47.89%
1940 Tools, Shop and Garage Equipment	6,078	1,435	23.61%	1,519	24.99%	1,519	24.99%
1945 Measurement and Testing Equipment	19,089	7,034	36.85%	7,035	36.85%	7,035	36.85%
1960 Miscellaneous Equipment	102,856	369,662	359.40%	23,661	23.00%	23,661	23.00%
Total Amortizable	$ 356,692	$ 412,318	115.59%	$ 128,617	36.06%	$ 128,617	36.06%
Total General Plant	$ 7,041,582	$ 1,799,616	25.56%	$ 1,329,323	18.88%	$ 1,443,428	20.50%
TOTAL HYDRO ONE REMOTE COMMUNITIES	$ 45,557,063	$ 20,185,154	44.31%	$ 18,447,389	40.49%	$ 20,188,253	44.31%

HYDRO ONE REMOTE COMMUNITIES

Current and Proposed Parameters
Vintage Group Procedure

Statement D

Account Description	Current Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
GENERATION PLANT												
1620 Buildings and Fixtures	50.00	SQ	50.00	42.57			35.00	S6	34.85	25.95		
1665 Fuel Holders, Producers and Accessories	40.00	SQ	39.98	34.87			35.00	S6	34.94	26.30		
1670 Prime Movers	5.00	SQ	4.98	3.02			10.00	S6	12.01	3.98		
1675 Generators	33.00	SQ	32.88	26.15			16.00	S6	16.05	6.93		
1680 Accessory Electric Equipment	39.00	SQ	38.98	33.30			17.00	S6	17.01	9.51		
1685 Miscellaneous Power Plant Equipment	35.00	SQ	35.00	26.31			25.00	S6	25.04	19.74		
Total Generation Plant									16.88	8.71		
DISTRIBUTION PLANT												
1805D Land - Depreciable	75.00	SQ	75.00	67.28			50.00	S6	50.00	37.28		
1806 Land Rights	75.00	SQ	75.00	58.57			100.00	S6	100.00	78.83		
1830 Poles, Towers and Fixtures	40.00	L1.5	40.13	32.67			55.00	S2	54.89	44.99		
1835 Overhead Conductors and Devices	40.00	R2	40.20	32.36			50.00	S2	50.01	38.24		
1845 Underground Conductors and Devices	20.00	L1.5	20.57	12.69			30.00	S3	30.15	15.74		
1850 Line Transformers	35.00	S0.5	35.23	27.26			40.00	R2	40.20	29.92		
1860 Meters	5.00	SQ	5.00	1.17			15.00	R5	15.00	13.16		
Total Distribution Plant									43.52	33.62		
GENERAL PLANT												
Depreciable												
1908 Buildings and Fixtures	40.00	SQ	39.99	30.50	-4.2	-5.0	50.00	S4	49.98	41.11		
1955 Communication Equipment	7.00	SQ	7.00	3.50	-4.2	-5.0	7.00	S6	8.50	1.00		
Total Depreciable									49.98	41.11		
Amortizable												
1915 Office Furniture and Equipment	7.00	SQ	7.00	1.98			7.00	SQ	7.00	5.18		
1920 Computer Hardware - Minor	5.00	SQ	5.00	1.97			5.00	SQ	5.00	3.16		
1935 Stores Equipment	8.00	SQ	8.00	2.70			8.00	SQ	8.00	4.17		
1940 Tools, Shop and Garage Equipment	6.00	SQ	6.00				6.00	SQ	6.00	4.50		
1945 Measurement and Testing Equipment	5.00	SQ	5.00	3.39			5.00	SQ	5.00	3.16		
1960 Miscellaneous Equipment	5.00	SQ	5.00	2.29			5.00	SQ	5.00	3.85		
Total Amortizable									6.17	3.95		
Total General Plant									36.39	29.52		
TOTAL HYDRO ONE REMOTE COMMUNITIES									20.17	12.01		

HYDRO ONE REMOTE COMMUNITIES Statement E
Asset Category Summary
December 31, 2010
Harmonic Weighting

Description	P-Life		Proposed P-Life		Plant		Depreciation Reserve	
	USoA	IFRS	USoA	IFRS	USoA	IFRS	USoA	IFRS
A	B	C	D	E	F	G	H	I
1620 Buildings and Fixtures								
GENX-FSL -YD FACILITIES		35		35		134,244		27,070
GENX-FSL -LANDSCAPING		35		35		4,014		911
GENX-FSL REM- BLDG&STR		35		35		4,201,228		801,444
GENX-FSL -OTHER SITE IMPR		50		50		158,451		48,357
Total 1620	50-SQ	34	35-S6	35	4,497,937	4,497,937	812,304	877,781
1665 Fuel Holders, Producers and Accessories								
GENX -FSL REM-FUEL HANDLNG		35		35		5,372,646		1,261,256
Total 1665	40-SQ	35	35-S6	35	5,372,646	5,372,646	1,348,331	1,261,256
1670 Prime Movers								
GENX -FSL REM- DIESEL ENG		10		10		13,703,994		12,760,425
Total 1670	5-SQ	10	10-S6	10	13,703,994	13,703,994	12,353,668	12,760,425
1675 Generators								
GENX- HYD REM - TURBINES		50		50		659,034		153,061
GENX-FSL -AC STNDBY PWR		15		15		15,589		4,473
GENX-FSL REM ALT & AUX GEN		15		15		4,681,007		1,480,410
Total 1675	33-SQ	19	16-S6	18	5,355,631	5,355,631	1,637,429	1,637,943
1680 Accessory Electric Equipment								
GENX-FSL REM-WND&SOL GEN		20		20		41,445		9,515
GENX -FSL REM-STN TRANSF		20		20		549,409		166,836
GENX - FSL -ELE AUX SYST/CAB		15		15		770,470		108,799
Total 1680	39-SQ	17	17-S6	18	1,361,324	1,361,324	278,787	285,150
1685 Miscellaneous Power Plant Equipment								
GENX-FSL -INSTR&CNTRL EQU		15		15		652,896		168,674
GENX-FSL REM FIRE PROT SYS		35		35		624,060		145,935
GENX-FSL -COMMON SERV SYS		35		35		967,698		52,852
Total 1685	35-SQ	29	25-S6	26	2,244,654	2,244,654	413,762	367,461
1805 Land - Depreciable								
RURAL LANDS < 1975		50		50		294,456		48,781
Total 1805	75-SQ	50	50-S6	50	294,456	294,456	48,021	48,781
1806 Land Rights								
RURAL INTL CLRING & OVRBLDG		100		100		234,126		64,552
Total 1806	75-SQ	100	100-S6	100	234,126	234,126	62,601	64,552
1830 Poles, Towers, and Fixtures								
RURALSUPPORTS-WOOD,CONCRET		65		55		1,781,559		380,940
STEEL POLES SUPPORT		75		75		4,509		857
RURAL1995 YE ADJ STRM DAMAG		75		55		685		24
Total 1830	40-L1.5	65	55-S2	55	1,786,753	1,786,753	369,664	381,822
1835 Overhead Conductors and Devices								
RURAL SWITCHES/LOAD INTERPTR		50		40		90,308		20,951
RURAL OIL SECTNLZER&RECLSR SW		50		40		72,058		15,601
RURAL INSTALSECTNLZR&RCLSR SW		50		45		1,681		278
RURAL CONDUCTOR PRIM&SEC OVERH		75		50		1,304,105		339,098
RURAL VOLTAGE REGULATORS		50		40		5,278		1,524
Total 1835	40-R2	72	50-S2	49	1,473,430	1,473,430	391,383	377,451
1845 Underground Conductors and Devices								
RURAL CONDCTR SUBMARINE CBL		40		30		104,065		52,922
RURAL U/GRD CONDUCTOR-PRIME		50		30		59,349		28,701
RURAL U/GRD CONDR SEC SERV		50		30		19,929		12,013
RURAL U/GRD FUSE HOUSING		50		30		2,834		1,574
Total 1845	20-L1.5	44	30-S3	30	186,177	186,177	102,438	95,210

HYDRO ONE REMOTE COMMUNITIES
Asset Category Summary
December 31, 2010
Harmonic Weighting

Statement E

Description	P-Life USoA	P-Life IFRS	Proposed P-Life USoA	Proposed P-Life IFRS	Plant USoA	Plant IFRS	Depreciation Reserve USoA	Depreciation Reserve IFRS
A	B	C	D	E	F	G	H	I
1850 Line Transformers								
RURAL OH TRFRMRS <=25 KVA		45		40		649,083		227,260
RURAL OH TRFMRS >25&<=50 KVA		45		40		175,487		33,117
RURAL OH TRFMRS>50&<=75 KVA		45		40		88,178		10,763
RURAL OH TRFMR >75&<=100 KVA		45		40		15,051		1,672
POLE TOP TRFS >200&<=300 KVA		45		40		45,575		15,908
POLE TOP TRFS >300&<=500 KVA		45		40		16,935		6,980
RURAL TRSF INSTAL		45		40		616,738		146,088
RURAL-U/GRD TRSF 0-50KVA		45		40		25,832		10,116
RURAL-U/GRD TRSF 301-500KVA		45		40		73		14
RURAL U/GRND TRFRMRS INSTAL		45		40		105,518		24,454
Total 1850	35-S0.5	45	40-R2	40	1,738,469	1,738,469	491,226	476,372
1908 Buildings and Fixtures								
GENRL-ADM&SERV-LANDSCAPING		50		50		55,635		4,287
GENRL-ADM&SERV_BLD FRAME&MTL		50		50		4,580,885		1,011,169
GENRL-ADM & SERV-BLD FRAME		50		50		1,734,577		244,651
GENRL -ADM & SERV-FENCE,GATE		50		30		133,057		10,885
GENRL- ADM & SERV-DISTN SYS		50		50		1,384		289
GENRL -ADM & SERV_AUX EQ BLD		50		50		159,020		32,448
Total 1908	40-SQ	50	50-S4	50	6,664,558	6,664,558	1,362,978	1,303,728
1955 Communication Equipment								
GENRL-ADM & SERV -TELCM WIRE		7		7		20,332		20,332
Total 1955	7-SQ	7	7-S6	7	20,332	20,332	24,321	20,332
TOTAL INVESTMENT					44,934,487	44,934,488	19,696,912	19,958,266
Reconciling Accounts								
Deer Lake					3,919,707	3,919,707	3,827,832	3,827,832
1860 - Meters (Depreciable)	5-SQ	5	15-R5	5	265,884	265,884	75,924	97,069
1915 - Office Furniture and Equiipment	7-SQ	7	7-SQ	7	39,115	39,115	10,193	10,193
1920 - Computer Hardware - Minor	5-SQ	5	5-SQ	5	41,096	41,096	17,225	16,135
1935 - Stores Equipment	8-SQ	8	8-SQ	8	148,458	148,458	6,768	71,097
1940 - Tools, Shop and Garage Equipment	6-SQ	6	6-SQ	6	6,078	6,078	1,435	1,435
1945 - Measurement and Testing Equipment	5-SQ	5	5-SQ	5	19,089	19,089	7,034	7,034
1960 - Miscellaneous Equipment	5-SQ	5	5-SQ	5	102,856	102,856	369,662	23,924
Total Reconciling Accounts					4,542,283	4,542,283	4,316,073	4,054,719
TOTAL HYDRO ONE REMOTE COMMUNITIES					49,476,770	49,476,771	24,012,985	24,012,985

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the Hydro One Remote Communities depreciation review to estimate appropriate projection curves, projection lives and statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 1850 – Line Transformers. Documentation for all other plant accounts is contained in the review work papers. The supporting schedules developed in the Hydro One Remote Communities review include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis; and

Schedule E – Graphics Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I. The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant
Account: 1850 Line Transformers

Dispersion: 40 - R2
Procedure: Vintage Group

Generation Arrangement

	December 31, 2010							
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2010	0.5	71,282	40.00	39.55	0.9887	1.0000	70,475	1,782
2009	1.5	56,835	40.00	38.65	0.9661	1.0000	54,908	1,421
2008	2.5	33,600	40.01	37.75	0.9436	1.0000	31,707	840
2007	3.5	68,843	40.02	36.87	0.9213	1.0000	63,423	1,720
2006	4.5	104,194	40.03	35.98	0.8990	1.0000	93,672	2,603
2005	5.5	100,848	40.04	35.11	0.8769	1.0000	88,431	2,519
2004	6.5	74,500	40.06	34.25	0.8549	1.0000	63,686	1,860
2003	7.5	48,337	40.08	33.39	0.8330	1.0000	40,263	1,206
2002	8.5	99,663	40.06	32.54	0.8121	1.0000	80,941	2,488
2001	9.5	184,839	39.96	31.69	0.7932	1.0000	146,610	4,626
2000	10.5	139,423	39.74	30.86	0.7765	1.0000	108,267	3,509
1999	11.5	20,446	39.54	30.03	0.7596	1.0000	15,531	517
1998	12.5	10,022	40.23	29.21	0.7263	1.0000	7,278	249
1997	13.5	3,395	40.32	28.41	0.7046	1.0000	2,392	84
1996	14.5	28,840	40.37	27.61	0.6838	1.0000	19,719	714
1994	16.5	73,286	40.10	26.04	0.6493	1.0000	47,588	1,828
1993	17.5	93,930	39.38	25.26	0.6415	1.0000	60,255	2,385
1992	18.5	121,740	40.56	24.50	0.6041	1.0000	73,542	3,001
1991	19.5	139,060	40.77	23.75	0.5826	1.0000	81,022	3,411
1990	20.5	187,014	40.76	23.01	0.5646	1.0000	105,593	4,588
1989	21.5	22,234	40.98	22.28	0.5438	1.0000	12,091	543
1988	22.5	8,240	40.87	21.57	0.5277	1.0000	4,348	202
1987	23.5	8,003	41.25	20.86	0.5056	1.0000	4,047	194
1986	24.5	11,989	41.39	20.16	0.4872	1.0000	5,840	290
1985	25.5	4,767	41.61	19.48	0.4682	1.0000	2,232	115
1984	26.5	15,064	41.62	18.81	0.4519	1.0000	6,807	362
1983	27.5	1,654	41.61	18.15	0.4362	1.0000	721	40
1982	28.5	2,313	41.69	17.50	0.4199	1.0000	971	55
1981	29.5	2,447	42.02	16.87	0.4015	1.0000	982	58
1978	32.5	254	43.20	15.05	0.3484	1.0000	89	6
1976	34.5	1,026	43.20	13.91	0.3220	1.0000	330	24
1960	50.5	380	50.98	6.85	0.1344	1.0000	51	7
Total	11.9	$1,738,469	40.20	29.92	0.7442	1.0000	$1,293,815	$43,246

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

Age Distribution

Vintage	Age as of 12/31/2010	Derived Additions	2000 Opening Balance	Experience to 12/31/2010 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2010	0.5	71,282		71,282	1.0000	0.5000
2009	1.5	56,835		56,835	1.0000	1.5000
2008	2.5	33,600		33,600	1.0000	2.5000
2007	3.5	68,843		68,843	1.0000	3.5000
2006	4.5	104,194		104,194	1.0000	4.5000
2005	5.5	100,848		100,848	1.0000	5.5000
2004	6.5	74,500		74,500	1.0000	6.5000
2003	7.5	48,337		48,337	1.0000	7.5000
2002	8.5	102,541		99,663	0.9719	8.4533
2001	9.5	204,532		184,839	0.9037	9.3180
2000	10.5	148,818		139,423	0.9369	10.0634
1999	11.5		22,481	20,446	0.9095	10.8212
1998	12.5		10,823	10,022	0.9259	12.4630
1997	13.5		3,395	3,395	1.0000	13.5000
1996	14.5		28,840	28,840	1.0000	14.5000
1994	16.5		86,626	73,286	0.8460	16.0801
1993	17.5		118,948	93,930	0.7897	16.2876
1992	18.5		125,660	121,740	0.9688	18.3762
1991	19.5		142,602	139,060	0.9752	19.4820
1990	20.5		190,479	187,014	0.9818	20.3636
1989	21.5		23,950	22,234	0.9284	21.4642
1988	22.5		11,076	8,240	0.7440	22.2270
1987	23.5		8,525	8,003	0.9389	23.4694
1986	24.5		13,282	11,989	0.9026	24.4513
1985	25.5		4,767	4,767	1.0000	25.5000
1984	26.5		15,506	15,064	0.9715	26.3353
1983	27.5		1,989	1,654	0.8316	27.1301
1982	28.5		2,737	2,313	0.8450	27.9948
1981	29.5		2,605	2,447	0.9394	29.1061
1978	32.5		254	254	1.0000	32.5000
1976	34.5		1,201	1,026	0.8546	33.8818
1965	45.5		98		0.0000	45.0000
1960	50.5		475	380	0.8000	49.2000
Total	11.9	$1,014,330	$816,318	$1,738,469	0.9496	

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	1,232,846	65,078	605	36,323	1,333,642
2001	1,333,642	357,340		236,083	1,927,064
2002	1,927,064	318,238	24,463	(462,889)	1,757,950
2003	1,757,950	107,020	15,862	(520,273)	1,328,835
2004	1,328,835	79,024	39,261	22,725	1,391,323
2005	1,391,323	71,972	3,219	52,460	1,512,536
2006	1,512,536	35,361	1,047	46,530	1,593,380
2007	1,593,380	101,146	1,822	(53,077)	1,639,628
2008	1,639,628	55,770	9,453	(27,386)	1,658,559
2009	1,658,559	47,549	8,613	(20,939)	1,676,556
2010	1,676,556	93,226	31,313		1,738,469

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	1,186,767	101,098		(20,505)	1,267,360
2001	1,267,360	277,366			1,544,726
2002	1,544,726	109,159	17,081	(305,161)	1,331,642
2003	1,331,642	48,337	5,447	(10,657)	1,363,875
2004	1,363,875	74,500	14,183	(25,078)	1,399,113
2005	1,399,113	108,101	3,219		1,503,995
2006	1,503,995	104,194	1,047	39,479	1,646,621
2007	1,646,621	68,843	1,822	(87,511)	1,626,131
2008	1,626,131	33,600	9,453		1,650,278
2009	1,650,278	56,835	8,613		1,698,500
2010	1,698,500	71,282	31,313		1,738,469

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None
Placement Band: 1960-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2004	66.5	123.5	SC	3.03	173.0	R2 *	3.75	45.5	R3 *	4.09
2001-2005	64.9	92.5	O2	3.34	174.5	R2 *	5.86	44.9	R3 *	4.44
2002-2006	64.9	108.9	SC	3.16	177.2	R2.5 *	7.41	45.0	R4 *	4.33
2003-2007	66.4	71.5	L1	3.15	183.3	R4 *	8.64	48.2	R4 *	4.39
2004-2008	68.7	118.8	SC	4.33	184.1	R4 *	8.28	47.2	R4 *	3.61
2005-2009	91.4	184.3	R4 *	0.85	186.9	R4 *	1.45	51.5	R4 *	4.59
2006-2010	0.0	57.2	L0.5	19.39	138.5	SC *	23.10	41.6	R2 *	14.25

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None

Placement Band: 1960-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2010	45.4	64.3	L0.5	6.51	74.8	O2	7.15	42.6	R2	4.54
2002-2010	44.0	61.4	L0.5	5.97	152.5	SC *	11.67	41.1	R2	5.34
2004-2010	43.8	56.5	L0.5	5.49	157.8	R0.5 *	13.38	41.0	R2.5 *	6.11
2006-2010	0.0	57.2	L0.5	19.39	138.5	SC *	23.10	41.6	R2 *	14.25
2008-2010	0.0	49.0	L0.5	16.26	145.4	SC *	24.36	38.4	R1.5 *	12.22
2010-2010	0.0	30.6	L1.5 *	8.80	56.7	O4 *	10.67	31.0	L1 *	9.01

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None
Placement Band: 1960-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2001	100.0				No Retirements					
2000-2003	84.2	183.0	R4 *	4.81	101.2	R2.5	4.48	56.4	R3 *	4.35
2000-2005	66.2	104.2	SC	3.05	174.8	R2 *	5.09	46.8	R3	3.66
2000-2007	67.0	125.6	SC	4.55	182.6	R4 *	8.06	50.8	R4	4.29
2000-2009	73.7	176.5	R2.5 *	4.90	183.5	R4 *	6.52	49.7	R4 *	2.78
2000-2010	45.4	64.3	L0.5	6.51	74.8	O2	7.15	42.6	R2	4.54

HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None

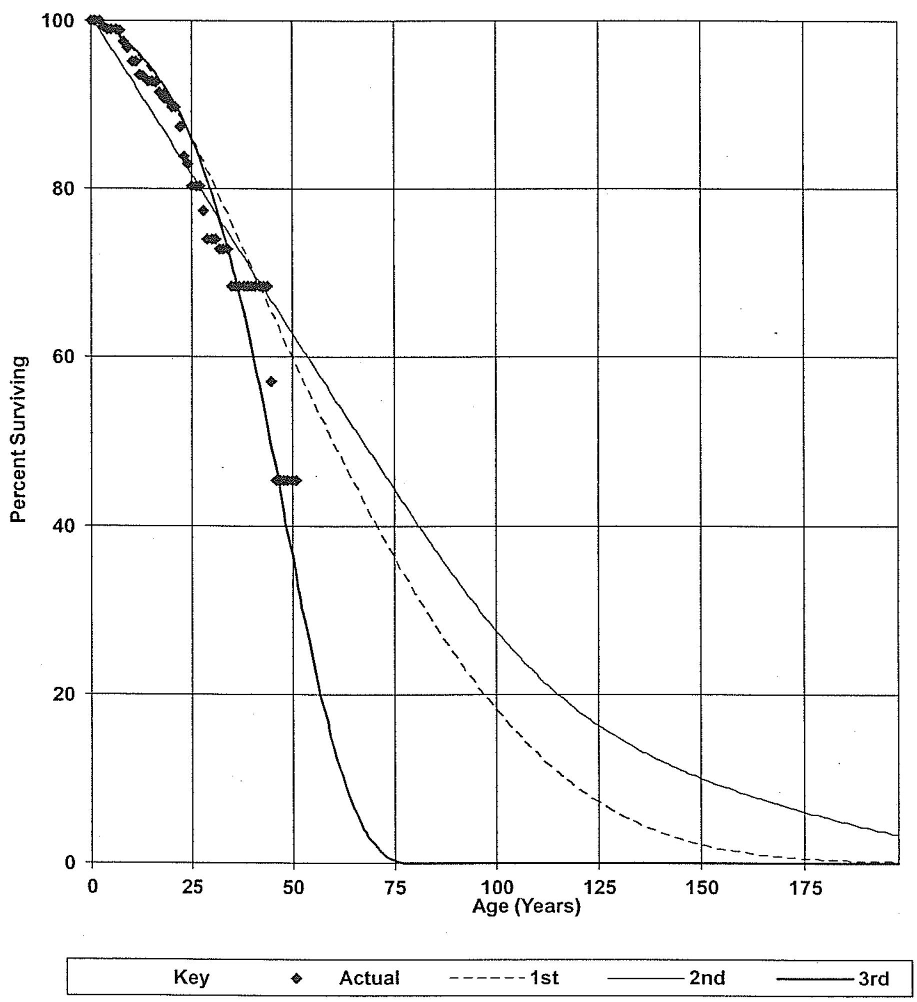
Placement Band: 1960-2010 Observation Band: 2000-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 64.3-L0.5 2nd: 74.8-O2 3rd: 42.6-R2



HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None

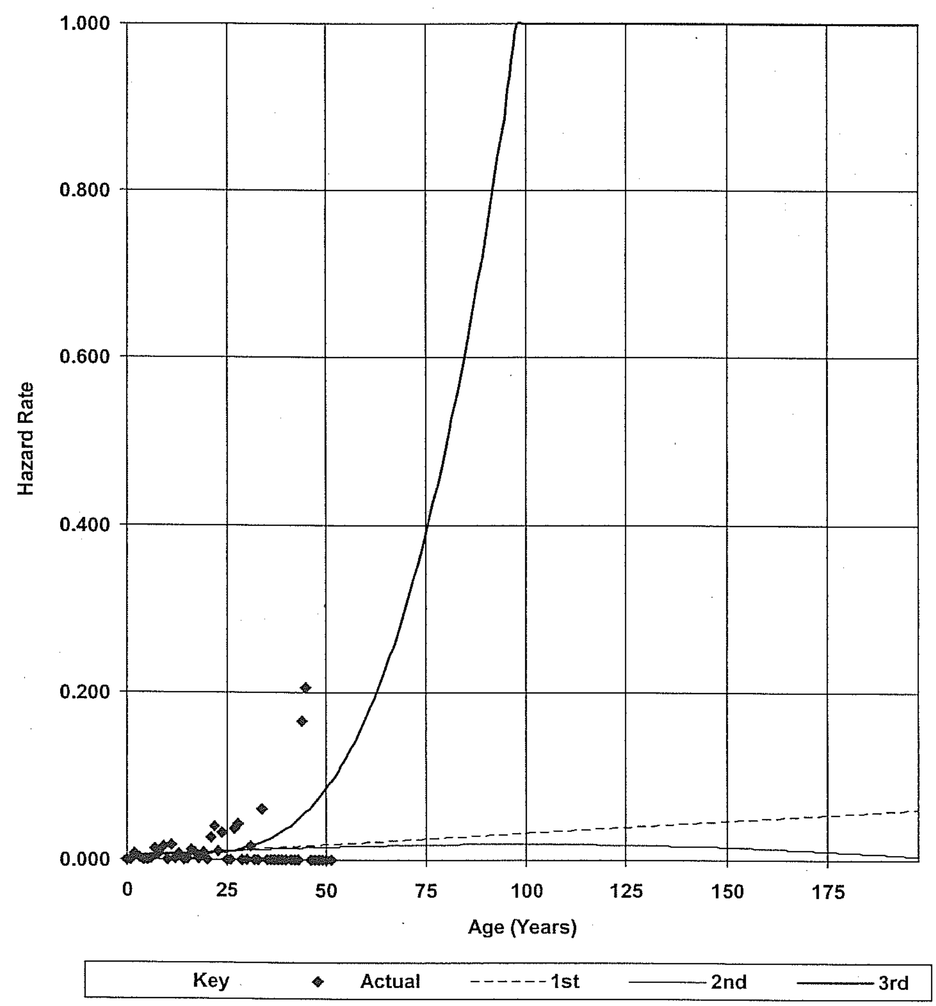
Placement Band: 1960-2010 Observation Band: 2000-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 64.3-L0.5 2nd: 74.8-O2 3rd: 42.6-R2



HYDRO ONE REMOTE COMMUNITIES

Distribution Plant

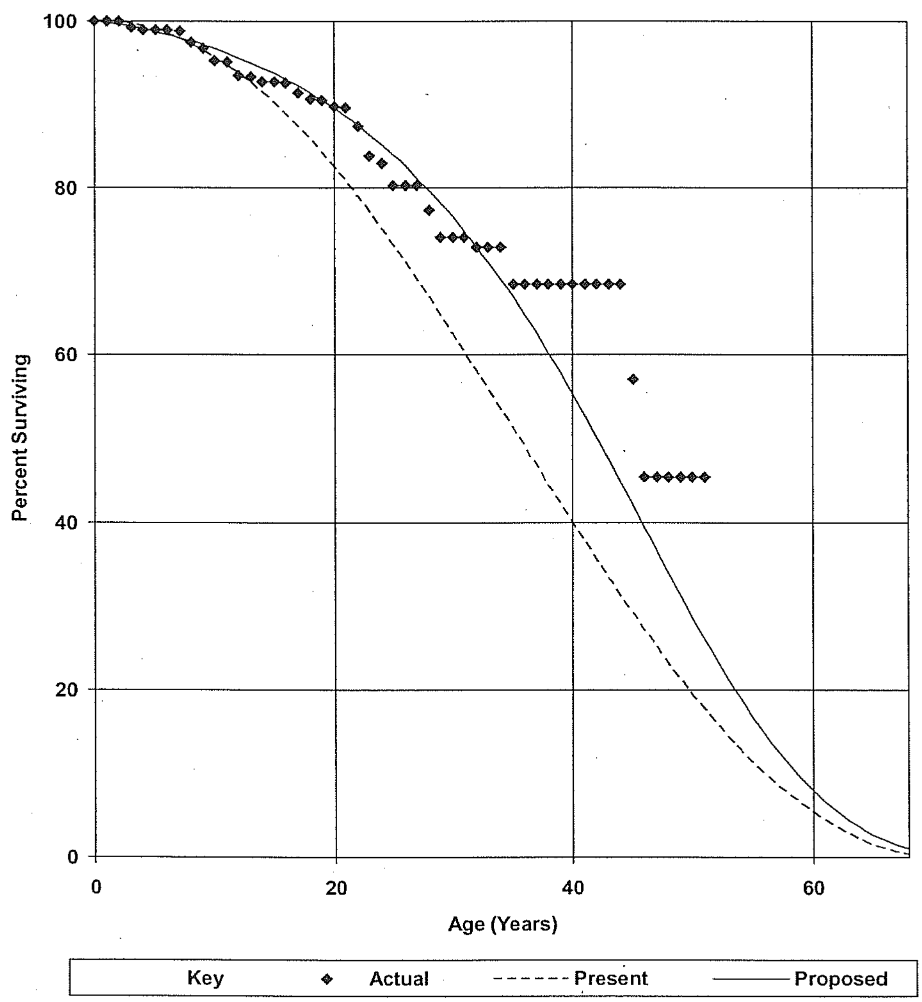
Account: 1850 Line Transformers

T-Cut: None

Placement Band: 1960-2010

Observation Band: 2000-2010

Present and Proposed Projection Life Curves Present: 35.0-S0.5 Proposed: 40.0-R2



PROFESSIONAL QUALIFICATIONS

NAME AND ADDRESS

Ronald E. White, Ph.D.
Foster Associates, Inc.
17595 S. Tamiami Trail, Suite 212
Fort Myers, FL 33908

EDUCATION

1961 - 1964 Valparaiso University

Major: Electrical Engineering

1965 Iowa State University

B.S., Engineering Operations

1968 Iowa State University

M.S., Engineering Valuation

Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University

Ph.D., Engineering Valuation

Minor: Economics

Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

EMPLOYMENT

2007 - Present	Foster Associates, Inc. Chairman
1996 - 2007	Foster Associates, Inc. Executive Vice President
1988 - 1996	Foster Associates, Inc. Senior Vice President
1979 - 1988	Foster Associates, Inc. Vice President
1978 - 1979	Northern States Power Company Assistant Treasurer
1974 - 1978	Northern States Power Company Manager, Corporate Economics
1972 - 1974	Northern States Power Company Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

PUBLICATIONS

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

TESTIFYING WITNESS

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc, testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC*Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of remaining-life technique and proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

SPEAKER

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.Page 48

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Energy Probe Research Foundation - Interrogatory # 22

Reference:
Exhibit B1 DSP Tables 3-6 and 3-7: Figure 4-1 and Table 4-2

Interrogatory:
a) Please provide an explanation why the 2018-2022 Capital Plan for System Renewal of generators is appropriate/optimal from a risk/reliability/cost perspective.
b) Did HORCI decision/planning rely on Business Cases for each year (such as those filed for 2018) or undertake a multi-year cost/reliability assessments/scenarios to support its Plan? If the latter please file this(ese).
c) For other P1 Distribution Assets, does HORCI use the same ACA Models and approach as Hydro One Networks? Please discuss/compare and provide examples for Poles and Transformers.

Response:
a) The major factor determining generator replacement/renewal is Generator Hours Operated. This factor is used to forecast the optimal time to replace generators and avoid major component failure (catastrophic failure). The Hours Operated maintenance and replacement is consistent with the manufactures' recommended maintenance procedures. The Capital Plan for System Renewal is designed to prevent catastrophic failures caused by major component failures. The risk and cost of catastrophic failure can be several times the planned replacement costs for a generator and result in major community power outages. Another specific risk factor of catastrophic failure is employee and operator safety.

b) A business case for each year is not filed for generator replacements. Remotes follows the engine-hours forecast, Table 3-7 in Exhibit B, to determine the need for unit replacement.

c) Yes. Hydro One Remote Communities uses the same ACA models and approach as Hydro One Networks, since the ACA approach and requirement is described in legislation. Please refer to page 62, 73-75 of the DSP in Exhibit B for an overview of the ACA and further ACA information.

Energy Probe Research Foundation - Interrogatory # 23

Reference:

No Reference-DSP-Customer Owned Generators

Interrogatory:

a) Please list by Customer, Location and installed Capacity all customer owned generators (above a reasonable materiality threshold) in HORCI service territory
b) What is the current interconnected capacity
c) What is the potential interconnected capacity
d) List all current agreements and locations and capacity for mutual generation support/back up

Response:

a) Please refer to EP IR#7 response for the updated renewable installed capacity. In addition to the renewable capacity listed, the community of North Caribou Lake First Nation (Weagamow) owns a 1MW diesel unit, which is used to support the total community load. This unit was designed to be temporary and is operated under contract by Hydro One Remotes in conjunction with our assets.

b) As shown in EP IR#7, plus 1MW for the diesel asset described above.

c) The potential interconnected capacity on an annual basis would be the total load for all communities we serve or the peak capacity. The REINDEER renewable program allows for full diesel generation offset.

d) North Caribou First Nation – Temporary 1,000 kW Upgrade Project Operating Agreement (circa 2000, plus multiple amendments)

Energy Probe Research Foundation - Interrogatory # 24

Reference:

Exhibit B1 Distribution System Plan Section 4.1.8.3 Page 96.

Interrogatory:

Preamble: HORCI is now expected to become a standalone electricity distributor in Cat Lake and other communities that under the Remote Communities Connection Program are/will be connected to Hydro One Networks or First Nations transmission.

Please provide a discussion and comments on a hypothetical Business Model that separates Generation and GSU from Distribution and Customer Service.

Response:

Remotes has not contemplated establishing a business model to separate its generation and distribution activities into separate businesses when it starts serving customers who are grid connected. Except for the source of electricity (purchased rather than self-generated) and increased coordination with the grid control centre related to outage planning and execution, customer service and distribution activities would remain the same as in other communities.

Remotes believes, given the small number of customers expected to be served in total (fewer than 10,000), shared resources, such as shared management staff, shared air and land transportation, shared customer service staff and shared billing staff establishing a separate business model would not be cost effective.

Energy Probe Research Foundation - Interrogatory # 25

Reference:

Exhibit B1, Tab 1, Schedule 1, page 109 of DSP, Table 4-15

Interrogatory:

Please provide this table with net capital expenditures with 2017 data and compare actual to budget spending.

Response:

The table below has been updated with 2017 data.

Table 4-15: Historical Net Capital Expenditures by Category

Category	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2017 Budget	2017 Variance
System Access	122,909	30,765	42,407	69,913	23,184	-	23,184
System Renewal - Distribution	755,858	504,031	543,694	759,715	444,504	501,360	(56,856)
System Renewal - Generation	3,401,157	3,615,497	1,287,531	2,434,356	1,471,123	1,728,000	(256,877)
System Service - Distribution	-	-	-	-	-	-	-
System Service - Generation	456,184	(193,493)	(18,768)	-	1,059,476	413,000	646,476
General Plant	690,724	677,492	472,718	914,193	525,355	1,085,000	(559,645)
Total	**5,426,832**	**4,634,292**	**2,327,582**	**4,178,177**	**3,523,643**	**3,727,360**	**(203,717)**

Energy Probe Research Foundation - Interrogatory # 26

Reference:

Exhibit D1, Tab 1, Schedule 2, page 14

Interrogatory:

Preamble: Hydro One was planning on purchasing power from Cat Lake and Pikangikum in 2013, but that never occurred.

What happened to the money in 2013 that was budgeted for the cost of purchases related to those communities? Did it flow back into the RRRP variance account?

Response:

As shown in Exhibit H, the costs and customer revenues budgeted to serve Cat Lake and Pikangikum in 2013 was flowed back into the variance account. However, increases to budgeted fuel and generation costs for existing customers offset those savings.

Energy Probe Research Foundation - Interrogatory # 27

Reference:

Interrogatory:

Preamble: According to O. Reg. 197/17, First Nations Delivery Credit, "an on-reserve consumer who is a member of a band within the meaning of the Indian Act (Canada) is eligible to receive a delivery credit from a licensed distributor…"

a) Does this apply to Hydro One Remotes?
b) Does the Delivery Credit have any impact on Hydro One Remote's revenue application?
c) If so, is there a threshold of revenue requirement that Hydro One Remote is supposed to receive from customers (which will be funded from the Delivery Credit) versus that which will come from the RRRP?

Response:

a) Yes. First Nation non Standard A residential customers living on reserve receive a credit for the Monthly Service Charge.

b) No.

c) No.

Energy Probe Research Foundation - Interrogatory # 28

Reference:

Exhibit C1, Tab 1, Schedule 1; Exhibit C2, Tab 2, Schedule 1

Interrogatory:

a) Starting with the EB-2012-0137 Board-Approved 2013 Rate Base of $41,091,000, and Capital Expenditures of $6,135,000, please provide schedule that provides a reconciliation to the continuity schedule at Exhibit C2-02-01Attachment 1

b) Provide a schedule that shows forecast and actual asset additions and associated opening and closing Rate Base for the historic years 2013-2017. Reconcile to the Continuity schedules at Exhibit C2-02-01Attachments 2-6, C2-04-01 and to the 2018 Rate Base amount of $44,445,000 in C1, Tab 1, Schedule 1

c) If Capital Expenditures and In-service assets in 2018 and beyond are as stated in evidence, "lumpy", what does HORCI intend to do to ensure Rate base and rates reflect actual In Service Assets?

d) Please discuss options including an In-Service Asset revenue requirement deferral/variance account (similar to Hydro One Networks).

Response:

The Test Year accumulated depreciation in Table 1 of Exhibit C1, Tab 1, Schedule 1 is incorrect. The revised table with the corrected accumulated depreciation is provided below.

Description	**Board Approved 2013**	**Test Year 2018**
Gross Plant	60,084	71,866
Accumulated Depreciation	(24,740)	(30,108)
Net Plant	**35,344**	**41,759**
Cash Working Capital	5,746	3,761
Distribution Rate Base	**41,090**	**45,519**
$ Change		*4,429*
% Change		*11%*

a) The 2013 reconciliation is provided below.

	2013 OEB Approved ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	58,973	7,486	(5,264)	61,195	60,084
Accumulated Depreciation	(26,074)	(2,596)	5,264	(23,406)	(24,740)
Net Plant	**32,899**	**4,890**	-	**37,789**	**35,344**
Cash Working Capital					5,746
Distribution Rate Base					**41,090**

	2013 Actual ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	54,790	9,204	(5,089)	58,905	56,848
Accumulated Depreciation	(25,779)	(2,563)	5,085	(23,257)	(24,518)
Net Plant	**29,011**	**6,641**	**(4)**	**35,648**	**32,330**
Cash Working Capital					5,878
Distribution Rate Base					**38,207**

	2013 Variance ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	(4,183)	1,718	175	(2,290)	(3,237)
Accumulated Depreciation	295	33	(179)	149	222
Net Plant	**(3,888)**	**1,751**	**(4)**	**(2,141)**	**(3,015)**
Cash Working Capital					132
Distribution Rate Base					**(2,883)**

Construction Work in Progress:

	2013 ($K)		
	OEB Approved	**Actual**	**Variance**
Opening	2,739	7,250	(4,511)
Capital Spend	6,035	5,212	823
Assets Placed In service	(7,386)	(8,989)	1,603
Closing	**1,388**	**3,473**	**(2,085)**

Assets Placed in Service:

	2013 ($K)		
	OEB Approved	**Actual**	**Variance**
From CWIP	7,386	8,989	(1,603)
Minor Fixed Assets	100	215	(115)
Closing	**7,486**	**9,204**	**(1,718)**
	-	-	

From I-02-28 (a)
Response to I-02-28 (b) - Forecast vs Actual Asset Additions
Response to I-02-28 (b) - Forecast vs Actual Rate Base
Agrees to C2-02-01
Agrees to C2-02-01 and C2-04-01

b) The 2013 reconciliation is provided in a).

The 2014 reconciliation is provided below.

	2014 FORECAST per 2014 Business Plan ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	63,677	6,894	(1,417)	69,154	66,416
Accumulated Depreciation	(25,754)	(3,004)	1,417	(27,341)	(26,548)
Net Plant	**37,923**	**3,890**	**-**	**41,813**	**39,868**
Cash Working Capital					3,319
Distribution Rate Base					**43,187**

	2014 Actual ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	58,905	5,970	(1,274)	63,601	61,253
Accumulated Depreciation	(23,257)	(2,594)	1,263	(24,588)	(23,923)
Net Plant	**35,648**	**3,376**	**(11)**	**39,013**	**37,331**
Cash Working Capital					3,445
Distribution Rate Base					**40,776**

	2014 Variance ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	(4,772)	(924)	143	(5,553)	(5,163)
Accumulated Depreciation	2,497	410	(154)	2,753	2,625
Net Plant	**(2,275)**	**(514)**	**(11)**	**(2,800)**	**(2,538)**
Cash Working Capital					126
Distribution Rate Base					**(2,411)**

Construction Work in Progress:

	2014 ($K)		
	BP FORECAST	**Actual**	**Variance**
Opening	1,567	3,473	(1,906)
Capital Spend	6,634	4,447	2,187
Assets Placed In service	(6,694)	(5,782)	(912)
Closing	**1,507**	**2,138**	**(631)**

Assets Placed in Service:

	2014 ($K)		
	BP FORECAST	**Actual**	**Variance**
From CWIP	6,694	5,782	912
Minor Fixed Assets	200	188	12
Closing	**6,894**	**5,970**	**924**
	-	-	

Response to I-02-28 (b) - Forecast vs Actual Asset Additions
Response to I-02-28 (b) - Forecast vs Actual Rate Base
Agrees to C2-02-01
Agrees to C2-02-01 and C2-04-01

1 The 2015 reconciliation is provided below.

	2015 FORECAST per 2015 Business Plan ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	64,471	6,187	(1,256)	69,402	66,937
Accumulated Depreciation	(24,545)	(2,875)	1,256	(26,164)	(25,355)
Net Plant	**39,926**	**3,312**	-	**43,238**	**41,582**
Cash Working Capital					3,725
Distribution Rate Base					**45,307**

	2015 Actual ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	63,601	3,278	(1,506)	65,373	64,487
Accumulated Depreciation	(24,588)	(2,711)	1,506	(25,793)	(25,191)
Net Plant	**39,013**	**567**	-	**39,580**	**39,297**
Cash Working Capital					3,083
Distribution Rate Base					**42,380**

	2015 Variance ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	(870)	(2,909)	(250)	(4,029)	(2,450)
Accumulated Depreciation	(43)	164	250	371	164
Net Plant	**(913)**	**(2,745)**	-	**(3,658)**	**(2,286)**
Cash Working Capital					(642)
Distribution Rate Base					**(2,927)**

Construction Work in Progress:

	2015 ($K)		
	BP FORECAST	**Actual**	**Variance**
Opening	1,497	2,138	(641)
Capital Spend	5,843	2,046	3,797
Assets Placed In service	(5,972)	(2,996)	(2,976)
Closing	**1,368**	**1,188**	**180**

Assets Placed in Service:

	2015 ($K)		
	BP FORECAST	**Actual**	**Variance**
From CWIP	5,972	2,996	2,976
Minor Fixed Assets	215	282	(67)
Closing	**6,187**	**3,278**	**2,909**
	-	-	

Response to I-02-28 (b) - Forecast vs Actual Asset Additions
Response to I-02-28 (b) - Forecast vs Actual Rate Base
Agrees to C2-02-01
Agrees to C2-02-01 and C2-04-01

2

The 2016 reconciliation is provided below.

	2016 FORECAST per 2016 Business Plan ($K)					
Description	**Opening**	**Additions**	**Retirements**	**Adjustment**	**Closing**	**Rate Base**
Gross Plant	66,859	5,235	(1,212)		70,882	68,871
Accumulated Depreciation	(26,378)	(3,037)	1,212		(28,203)	(27,291)
Net Plant	**40,481**	**2,198**	**-**		**42,679**	**41,580**
Cash Working Capital						3,794
Distribution Rate Base						**45,374**

	2016 Actual ($K)					
Description	**Opening**	**Additions**	**Retirements**	**Adjustment**	**Closing**	**Rate Base**
Gross Plant	65,373	4,656	(1,915)	(582)	67,532	66,453
Accumulated Depreciation	(25,793)	(2,751)	1,914		(26,630)	(26,212)
Net Plant	**39,580**	**1,905**	**(1)**	**(582)**	**40,902**	**40,241**
Cash Working Capital						3,262
Distribution Rate Base						**43,503**

	2016 Variance ($K)					
Description	**Opening**	**Additions**	**Retirements**	**Adjustment**	**Closing**	**Rate Base**
Gross Plant	(1,486)	(579)	(703)	(582)	3,350	932
Accumulated Depreciation	585	286	702	-	(1,573)	(494)
Net Plant	**(901)**	**(293)**	**(1)**	**(582)**	**1,777**	**438**
Cash Working Capital						(532)
Distribution Rate Base						**(94)**

Construction Work in Progress:

	2016 ($K)		
	BP FORECAST	**Actual**	**Variance**
Opening	1,049	1,188	(139)
Capital Spend	4,885	4,068	817
Assets Placed In service	(5,060)	(4,546)	(514)
Closing	**874**	**710**	**164**

Assets Placed in Service:

	2016 ($K)		
	BP FORECAST	**Actual**	**Variance**
From CWIP	5,060	4,546	514
Minor Fixed Assets	175	110	65
Closing	**5,235**	**4,656**	**579**
	-	-	

Response to I-02-28 (b) - Forecast vs Actual Asset Additions
Response to I-02-28 (b) - Forecast vs Actual Rate Base
Agrees to C2-02-01
Agrees to C2-02-01 and C2-04-01

The 2017 reconciliation is provided below.

	2017 COS Forecast ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	67,532	3,606	(474)	70,664	69,098
Accumulated Depreciation	(26,630)	(2,877)	474	(29,033)	(27,832)
Net Plant	**40,902**	**729**	**-**	**41,631**	**41,267**
Cash Working Capital					3,629
Distribution Rate Base					**44,895**

	2017 Actual ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	67,532	2,094	(1,659)	67,967	67,750
Accumulated Depreciation	(26,630)	(2,848)	1,657	(27,821)	(27,226)
Net Plant	**40,902**	**(754)**	**(2)**	**40,146**	**40,524**
Cash Working Capital					3,327
Distribution Rate Base					**43,851**

	2017 Variance ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	-	(1,512)	(1,185)	(2,697)	(1,349)
Accumulated Depreciation	-	29	1,183	1,212	606
Net Plant	**-**	**(1,483)**	**(2)**	**(1,485)**	**(743)**
Cash Working Capital					(301)
Distribution Rate Base					**(1,044)**

Construction Work in Progress:

	2017 ($K)		
	COS Forecast	**Actual**	**Variance**
Opening	710	710	-
Capital Spend	3,553	3,386	167
Assets Placed In service	(3,431)	(1,956)	(1,475)
Closing	**832**	**2,140**	**(1,308)**

Assets Placed in Service:

	2017 ($K)		
	COS Forecast	**Actual**	**Variance**
From CWIP	3,431	1,956	1,475
Minor Fixed Assets	175	138	37
Closing	**3,606**	**2,094**	**1,512**
	-	-	

Response to I-02-28 (b) - Forecast vs Actual Asset Additions

Response to I-02-28 (b) - Forecast vs Actual Rate Base

Agrees to C2-02-01

1 The 2018 reconciliation is provided below.

	2018 COS Forecast ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	70,664	3,197	(793)	73,068	71,866
Accumulated Depreciation	(29,033)	(2,942)	793	(31,182)	(30,108)
Net Plant	**41,631**	**255**	**-**	**41,886**	**41,759**
Cash Working Capital					3,761
Distribution Rate Base					**45,519**

	2018 Forecast with Opening Balance Adjustment ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	67,967	3,197	(793)	70,371	69,169
Accumulated Depreciation	(27,821)	(2,942)	793	(29,970)	(28,896)
Net Plant	**40,146**	**255**	**-**	**40,401**	**40,274**
Cash Working Capital					3,761
Distribution Rate Base					**44,034**

	2018 Variance ($K)				
Description	**Opening**	**Additions**	**Retirements**	**Closing**	**Rate Base**
Gross Plant	(2,697)	-	-	(2,697)	(2,697)
Accumulated Depreciation	1,212	-	-	1,212	1,212
Net Plant	**(1,485)**	**-**	**-**	**(1,485)**	**(1,485)**
Cash Working Capital					-
Distribution Rate Base					**(1,485)**

Construction Work in Progress:

	2018 ($K)		
	COS Forecast	**ADJ Forecast**	**Variance**
Opening	832	2,140	(1,308)
Capital Spend	3,060	3,060	-
Assets Placed In service	(3,021)	(3,021)	-
Closing	**871**	**2,179**	**(1,308)**

Assets Placed in Service:

	2018 ($K)		
	COS Forecast	**ADJ Forecast**	**Variance**
From CWIP	3,021	3,021	-
Minor Fixed Assets	176	176	-
Closing	**3,197**	**3,197**	**-**
	-	-	

From I-02-28 b) - $44,445 per original filing, restated at $45,519
Response to I-02-28 (b) - Forecast vs Actual Asset Additions
Response to I-02-28 (b) - Forecast vs Actual Rate Base
Agrees to C2-02-01
2 Agrees to C2-02-01 and C2-04-01

c) Remotes conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any differences between approved rate base and in-service assets would not result in higher returns to Remotes.

d) Remotes believes that the RRRP variance account protects ratepayers from changes to the capital program.

Energy Probe Research Foundation - Interrogatory # 29

Reference:

Exhibit C1, Tab 2, Schedule1; EB-2017-0049 Exhibit C1,Tab 2, Schedule 1 Attachment 7

Interrogatory:

Preamble:

1)The Remotes' overhead capitalization rate is a calculated percentage representing the amount of Common Corporate Functions and Services ("CCFS") overhead costs that are required to support capital projects in a given year.

2) Shared Services Costs include Corporate Common Expenses

3) Hydro One Distribution in the second reference indicates

Hydro One proposes:

- Increasing 2015 OEB-approved Corporate Management expense by inflation from $2.4 million to $2.5 million in the 2018 test year plus recovery for $1.3 million in costs associated with Hydro One's Ombudsman;
- Decreasing 'Other OM&A – Other Costs' (page 33 of Exhibit C1, Tab 1, Schedule 7) by $1.3 million to remove Long Term Incentive Plan ("LTIP") costs related to the CEO, CFO and CLO.

a) Have these adjustments been incorporated into Remotes' 2018 CCFS costs for capitalization and shared services?

b) If not please make the necessary adjustments

Response:

a) Hydro One Ombudsman costs and LTIP costs relating to the CEO, CFO and CLO were not allocated to Remotes.

b) No adjustment is required.

Energy Probe Research Foundation - Interrogatory # 30

Reference:

Exhibit D1, Tab 1, Schedule 2 Page 5 and Table 2

Interrogatory:

a) Please provide more detail on the major additions and costs of the Generation Maintenance Program between 2013 and 2017.
b) Please Provide specific information on annual labour costs over the period
c) Please explain in more detail why the Generation Maintenance Program and costs is increasing further in the Test Year (labour costs, higher achievement etc.).

Response:

a) The costs of the Generation Maintenance Program have both a planned and unplanned component. Planned work is on generators and auxiliary equipment. The planned component follows manufacturer maintenance guidelines for generator repair or scheduled inspection and maintenance of auxiliary equipment. The unplanned component either fixes existing malfunctioning equipment outside of regular planned maintenance components or makes unplanned improvements to existing equipment and process as required by operations.

During the years 2013 – 2017, planned maintenance was performed on all engines as prescribed by the manufacturer. Planned maintenance on auxiliary equipment includes battery banks, cooling system checks, fire system checks, generator control panel checks, secondary heating checks, ventilations system checks, bulk fuel tank checks and lifting device checks.

Over the same period, unplanned work included replacing malfunctioning equipment including variable speed motor drives on cooling and ventilation system, leak detection equipment, bulk fuel level sensors, secondary heat piping replacement, battery replacements, fire system replacements, SCADA computer and screen replacements, and generator controls replacement. Other equipment modifications allowing for better voltage regulation and generator synchronization and fuel filtering and metering improvements were also done.

b)

Generation Maintenance - Labour Costs (in $K)

Category	Historic (Actual)				
	2013	**2014**	**2015**	**2016**	**2017**
Labour Costs	4,634	5,413	4,341	4,824	4,630

c) The generation maintenance program costs are increasing in 2018 due to an increased focus on safety improvements as well an increase on the maintenance of auxiliary equipment and fuel tanks.

Energy Probe Research Foundation - Interrogatory # 31

Reference:

Exhibit D1, Tab 1, Schedule 2 Pages 11-12

Interrogatory:

a) Please provide Table(s) that show for each historic and Bridge year 2013-17:
   - Actual Fuel volumes delivered
   - The Fuel Loss between Purchase and Utilization- Volume and % for each year.
   - The average landed cost of the fuel $ and per unit for each year
   - The breakdown of the fob Purchase Price and Delivery Costs.

b) Please provide unit delivery cost ranges per km for air delivery (56%) all-weather road delivery (13%), winter road delivery (18%) and First Nation contracts (13%).

c) Please describe in more detail HORCI's program for lowering fuel costs in 2018.

Response:

a) The table is provided below:

	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual
Actual Volume Issued	17,284,327	17,516,627	17,491,683	17,360,821	17,307,991
Average Cost per load	$ 14,389	$ 16,678	$ 12,657	$ 11,166	$ 13,603
Average per unit Cost	$ 1.47	$ 1.47	$ 1.32	$ 1.35	$ 1.48

Even though metering, temperature and inventory measurement impacts fuel loss, the impact is immaterial. All purchased fuel is essentially utilized in the year purchased, with only some variances carried in inventory (i.e. inside the tanks) over the year end cut-off.

The breakdown of the fob Purchase Price and Delivery Costs are as follows:

- Variable commodity price for each supplier are set semi-monthly (Winnipeg and Thunder Bay Rack Rates are both used, depending on the supplier).
- Delivery includes Supplier Cap and Trade per litre costs.
- Distribution rates and profit margin are fixed yearly for air and road delivery (per litre basis)
- Variable surcharge, or surcharge reductions, on distribution rates are tied to current fuel commodity prices to ensure delivery rates (air and road) represent current market conditions.
- Fixed total pricing for each supplier are set semi-monthly based on the average prior month costing or the month end rack rate (depending on contract and supplier).

- Variable rates for winter road deliveries for: full loads, 3/4 loads and 1/2 loads or less.

b) This metric is not tracked due to extensive unknown factors that include variable staging areas, starting areas, load size, sub-contracted carriers, and unknown routes for winter roads.

In March 2017, examples of cost per litre range are listed below.

Delivery Type	Range from	Range to	Period Covered
Air Delivery	$ 1.41	$ 2.79	Mar-17
All-weather Road Delivery	$ 0.89	$ 1.04	Mar-17
Winter Road Delivery	$ 1.01	$ 1.54	Mar-17
First Nation fixed contracts	$ 1.34	$ 2.40	2017 WR Season

c) For 2018, Remotes is expecting the winter road fuel supplier to dedicate more trucks to Remotes fuel needs. This will allow more fuel to be delivered to Remotes storage tanks. As well, there is more likelihood that more fuel will be delivered to First Nation's storage tanks that Remotes utilizes under contractual agreements. Overall, this will increase road delivery, resulting in a reduction in air delivery. This will lower the fuel costs.

An all-season road and bridge was constructed to North Caribou Lake in late 2017. Therefore, more expensive fly-in fuel will no longer be required in 2018 and in future years to this community.

Energy Probe Research Foundation - Interrogatory # 32

Reference:

Exhibit D1, Tab 1, Schedule 3 Page 2

Interrogatory:

a) Please Provide a Table and a Chart showing details of the Forestry Program 2013-2017(E) and 2018(F) including line kms serviced, annual costs and Unit costs.
b) Provide/include a projection for the outlook period 2019-2022.

Response:

a)

	2013	2014	2015	2016	2017	2018 Test
Total Forestry - $	$ 313,313	$ 391,893	$ 548,524	$ 261,500	$ 134,393	$ 457,000
Program/Planned Forestry	$ 313,313	$ 391,893	$ 539,800	$ 244,956	$ 112,321	
Short Term Forestry Assistance	$ -	$ -	$ 8,724	$ 16,544	$ 22,072	
Program/Planned Forestry km's	96	81	73	32	31	
Short Term Forestry Assistance km's			4	4	8	
	96	81	77	36	39	
# Communities where Forestry Work was performed						
Forestry Program	7	6	5	1	2	
Short Term Forestry Assistance			2	2	4	
Program/Planned Forestry km's - $/km	$ 3,264	$ 4,838	$ 7,395	$ 7,655	$ 3,623	
Short Term Forestry Assistance km's - $/km	$ -	$ -	$ 2,181	$ 4,136	$ 2,759	

* Due to a small, variable Forestry work program the per unit costs are a flawed measure. Travel and logistical costs weigh heavily on our business operations.

b) The projection for the outlook period 2019-2022 is similar to the 2018 test year.

Energy Probe Research Foundation - Interrogatory # 33

Reference:

Exhibit B1 DSP Figure 1-7; Exhibit D1, Tab 1, Schedule 5 Page 2

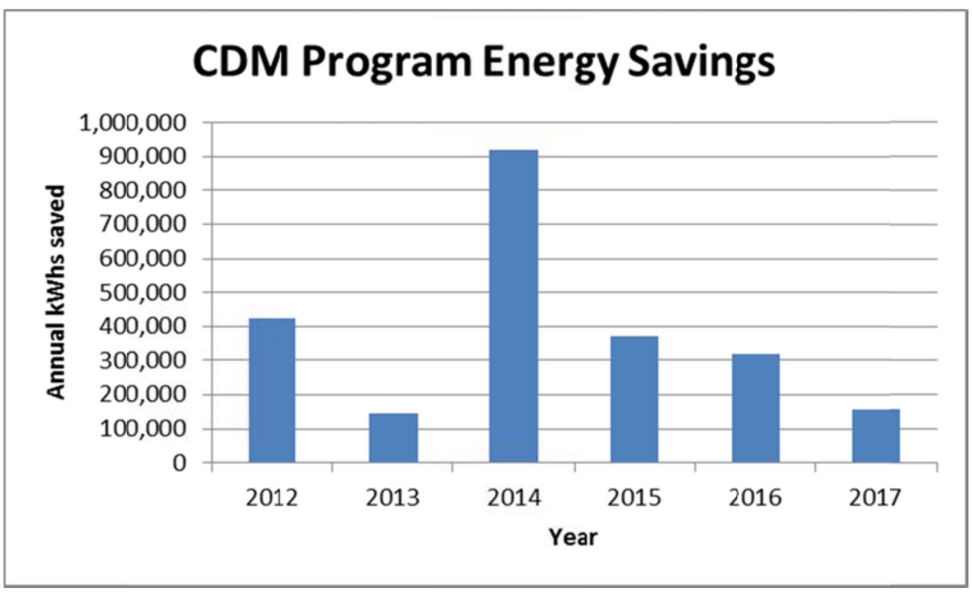
Interrogatory:

Preamble: Remotes therefore decided to continue to offer residential programs through an application-based program, and to also offer its commercial customers separate application-based programs. The move to application-based programs resulted in lower program spending part way through 2015 and 2016 and is also reflected in the bridge and test years.

a) Please update DSP figure 1-7 for 2017
b) Please provide information on the 2018 Residential and Commercial application-based CDM Programs, including budgets, Kwh targets and measures.
c) Please provide a summary of 2018 CDM Programs offered by IESO
d) Please provide a summary of the conservation programs offered by Federal Government

Response:

a) Here is the updated DSP Figure 1-7



b) Please see attached for information related to our application-based CDM program. No targets or measures have been established for 2018 CDM Programs. As indicated in Exhibit D2, Tab 3, Schedule 3 (OMA Programs Table – Appendix 2-JC) the budgeted amount for 2018 is $112,000.

c) Remotes does not have this information.

The Conservation First Framework is related to a Directive to the OEB from the Minister of Energy issued March 26, 2014. Paragraph 2(i) of the Minister's Directive excludes Remotes from the framework (see excerpt below).

2. Despite paragraph 1, the Board shall not amend the licence of any Distributor that meets the conditions set out below:

I. with the exception of embedded distributors, the Distributor is not connected to the Independent Electricity System Operator ("IESO") - controlled grid; or
II. the Distributor's rates are not regulated by the Board.

Remotes also notes that the Minister has issued various directives to the IESO to establish programs that are targeted to indigenous communities and to which the community itself must apply.

d) Remotes does not have this information.

HYDRO ONE REMOTE COMMUNITIES INC.

CONSERVATION AND RENEWABLE ENERGY (CaRE) PROGRAM INITIATIVES

Commercial Lighting Retrofit Program Introduction

This Program assists our customer's with upgrades to lighting systems in existing buildings. Many buildings still contain inefficient lighting systems which, depending on the use of the building can result in high operating costs. Upgrading inefficient lighting can also assist in the reduction of greenhouse gas (GHG) emissions within the community.

Hydro One Remote Communities Inc. (Remotes) will assist by providing a cash-back rebate UP TO 100% the cost of fixtures and lamps required in order to perform a lighting retrofit in a building. All applications from Remotes' customers will be considered. Eligible buildings include all Standard A and/or Commercial Customers as well as Multi-Residential Rentals.

Upon request, Remotes will conduct a lighting audit to determine what is currently in place and review energy efficient upgrade options. Subsidy is based the Remotes' preferred option. The preferred option is determined by the cost of retrofit material vs. rate of recovery. Remotes will not consider retrofits that will take longer than 3 years to recoup costs. Should a Customer prefer a more expensive retrofit where the rate of recovery exceeds this period the Customer will be eligible for up to the subsidy limit (Remotes' option) only. The Customer will absorb any and all additional costs. For example, if Remotes' option costs $10,000 in materials and the customer's preferred option is $15,000 the Customer will be reimbursed up to $10,000 and you will be expected to absorb the extra $5000.

Remotes will cover 100% the cost of the lighting audit should the project be carried out. In the event that the Customer does not proceed with the project after the assessment has been carried out or does not complete the project within 12 months of receipt of material, the Customer will be billed for 50% of those audit costs.

Eligible Subsidy percentages are as follows:

- 50% rebate on all lamps and fixtures (interior and exterior) required for the lighting retrofit for Standard A applicants
- 100% rebate on all lamps and fixtures (interior and exterior) required for the lighting retrofit for Multi-Residential (Rentals) or Commercial Customers

Successful applicants will complete the following steps:

1. Send an email to Remotes providing the list of businesses to be audited, including the billing account number and address.
2. Sign a letter of understanding, provided by Hydro One Remotes.
3. Once received, a lighting Auditor will contact the Customer directly to arrange for a lighting audit in the approved buildings.
4. The lighting Auditor will provide Remotes with recommendations for improvements to lighting including potential saving and cost of lighting. A summary will be shared with the Customer along with recommendations illustrating Remotes' preferred option and the proposed subsidy amount.
5. If still interested, the Customer will notify Remotes which buildings will move forward.
6. The Customer will then contact the lighting Auditor directly to order, ship and pay for all the required equipment at the location of your choice.

7. The Customer will hire, make arrangements and pay for a licensed Electrician to install products in order to satisfy the lighting retrofit.
8. The Customer or Electrician will make arrangements for an Electrical Safety Authority (ESA) inspection ensuring the work meets the regulations for safety purposes. The Electrician can apply on the Customer's behalf if those arrangements have been made at the time of hire.
9. Once work is complete, the Customer will send Remotes the following information in order to receive a rebate:
   - Confirmation that installation is complete (letter from Electrician or ESA)
   - A copy of the inspection from ESA
   - A copy of the paid receipt from the lighting supplier for all material required for the retrofit

Disclaimers

1. Hydro One Remotes will only consider rebates on initial orders for material and not replacement costs. For example if material is ordered and shipped to the Customer in advance of installation and in the meantime items require reordering because they have been damaged, mismanaged, or misplaced Remotes will only consider a rebate on the initial order.
2. Remotes does not cover the cost of an Electrician or the ESA Inspection. This cost will be absorbed by the Customer.
3. Remotes will not consider projects where the business owner installs product by themselves unless they are a licensed Electrician. However if the retrofit only requires changing of light bulbs without the replacement of fixtures an Electrician is not required therefore and the ESA inspection is waived.
4. Remotes does not take responsibility for disposal of the old lamps or fixtures.

To apply for the Program or get more information contact RemotesCare@HydroOne.com

Street Lighting Retrofit Program Introduction

For the most part, current street lighting stock in the Hydro One Remote Communities territory are no longer considered energy efficient to today's standards. Most of the current stock contains Low Pressure Sodium (LPS) and High Pressure Sodium (HPS) streetlights. There are products available today that are far more energy efficient, offer better quality of light as well as a much longer lifespan than what has historically specified for use. Remotes now recommends the use of Emitting Diode (LED) street lighting.

Remotes is prepared to assist our Customers who have existing LPS or HPS street lights to make this transition to LED. Remotes is prepared to reimburse existing customers the differential cost of purchasing LED replacement fixtures and lamps when changing out their older LPS or HPS systems. Remotes will work closely with a community representative to coordinate the project and will also provide a detailed estimate illustrating the benefits, kWh and cost savings over the life of their current and proposed street lights and a proposed reimbursement amount.

The following items must be met by the successful applicant:

- Identify a key individual to work closely with Remotes for the planning and coordinating the work;
- Provide enough supporting documentation in the form of price quotes and technical specifications for the replacement of the existing street lighting stock, one for replacement of the same product and one for an LED option, based on supplier recommendations;
- Identify all existing light fixtures, lamp sizes, wattages and types within the community in order for Remotes to determine required upgrades;
- Absorb all project costs;
- Order and make ready all stock required for the installation work which will be performed by Remotes' staff and
- Assume responsibility and costs associated from inaccuracies within submitted information which may result in delays or cost overruns because of incorrect amounts, specifications or sizing of proposed lighting systems.

To apply for the Program or get more information contact Remotes Customer Service RemotesCustomerService@HydroOne.com.

Remotes Mail-In Rebate Program

Under Separate Cover

hydro one

Remote Communities, Inc. – MAIL-IN REBATE PROGRAM APPLICATION

ENERGY STAR

Please fill out this application, enclose all required information and forward to the below address. Incomplete applications will not be approved for Rebate. **NOTE: You must be a customer of Hydro One Remote Communities to be eligible for this Rebate Program.**

CUSTOMER NAME: ______________________________ **ACCOUNT #:** 29______________________________
(This is the name and address the rebate cheque will be send to) *(Located on your Hydro One Remote Communities Bill. All Remotes' Account Numbers start with 29)*

MAILING ADDRESS AND/OR CUSTOMER HOUSE ID NUMBER / COMMUNITY NAME / and POSTAL CODE:

____

____

The following are Products eligible for Rebate:
Please fill in and provided required back-up information to all that apply. All products must be electric and meet the specified requirements, see reverse page. Products are eligible for rebate up to 6 months after purchase. Please allow 90 days from receipt of application for Reimbursement. Applications will be accepted by Mail or Scanned and Emailed to the following: **Remotes CDM Mail-in Rebates, c/o HYRDO ONE REMOTE COMMUNITIES INC. 680 Beaverhall Place, Thunder Bay, ON, P7E 6G9 or Remotes.Care@HydroOne.com.**
Note: Faxed Applications will NOT be accepted.

Product	Quantity	Manufacturer	Model #	Eligible Rebate	Total Rebate
Energy Star Refrigerator				$175	
Energy Star Freezer				$125	
Energy Star Dishwasher				$120	
Energy Star Dehumidifier				$45	
Energy Star Washer				$200	
Energy Star Rated Ceiling or Floor Fan				$10	
Energy Star Rated LED Light Bulbs (12 watt or Less)				$3	
Energy Star Rated Clothes Dryer (928 kWh or less/yr as per EnerGuide label)				$200	
Energy Efficient Range (500 kWh or less/yr as per EnerGuide label				$170	
Smart Power Bar (with Auto-Off or Timer)			N/A	$4	
Clothes Line (pole style with line or umbrella style)			N/A	$15	
Block Heater Timer			N/A	$3	
Exterior Motion Sensor			N/A	$5	
Interior Occupancy Sensor			N/A	$8	
Programmable Thermostat (To be used for electric heat only)			N/A	$8	
Low-Flow Showerhead (1.5 LPM or less)			N/A	$3	
Faucet Aerator(s) (1.5 GPM or less)			N/A	$1	
Electric Hot Water Tank Blanket (R-10 or greater)			N/A	$10	
TOTAL REBATE AMOUNT REQUESTED					

Remote Communities, Inc. – MAIL-IN REBATE PROGRAM
INSTRUCTIONS & GUIDELINES

The following guidelines assist you with your application by determining if your Energy Star/Energy Efficient purchases are eligible for Rebate. All Rebate Applications will be reviewed upon arrival and approved based on completeness and eligibility. Remotes will only respond to those applications that have been approved.

INFORMATION WILL NOT BE RETURNED TO THE CUSTOMER, THEREFORE DO NOT SEND ORIGINAL RECEIPTS.

Please allow 90 days for approval after receipt of application. Forward questions to the following email address: Remotes.Care@HydroOne.com

BACK-UP INFORMATON: All Back-up information must accompany the application

- Provide copy of paid receipt for each item eligible for rebate
- Provide proof of Status for all Energy Star noted products (must have Energy Star Symbol)
- Provide proof of eligibility for following products as per the recommendations on application: Dryers, Ranges, LED Exterior Bulbs, Programmable Thermostat, Low-Flow Shower Heads, Faucet Aerators, and Electric tank blankets. Proof of eligibility may include: copy of manufactures specifications showing Energy Star and/or EnerGuide labels, or copy of packaging showing that eligibility has been met.

All Appliances MUST BE ELECTRIC and meet the following minimum requirements:

Energy Star Rated Refrigerators
Auto defrost models only
Must be 14 cu.ft. or greater in size
With or without freezer
Freezer may be located top, side or bottom

Energy Star Rated Freezers
With or without auto defrost feature
Chest or upright
Must be 10 cu.ft. or greater

Energy Star Rated Washing Machine
Top or front load
Standard size only

Energy Star Rated Dishwasher
Built-in or Portable
Standard size only

Energy Star Rated Dehumidifier
(A) capacity under 35 litres/day, or
(B) capacity 35.5 – 87.5 litres/day
Please specify on application

***** NEW*** Energy Star Rated Clothes Dryer**
Top or front load
Standard size only

Energy Efficient Range
30" or greater
Self-Clean or not
Convection or Not
Any type cook top surface
Window in oven or not
Must have an energy consumption equal to or less than 500 kWh/year

Revised 2017

Energy Probe Research Foundation - Interrogatory # 34

Reference:

Exhibit B1 DSP Figure 1-7; Exhibit D1, Tab 1, Schedule 5, Page 2

Interrogatory:

a) Please provide references to any Studies that HORCI has made or has access to regarding efficient lighting retrofit in Remote Communities.

b) Please provide in Tabular form, estimates, with supporting notes/calculations based on the OEB/IESO CDM Manual:
- Total HORCI Service area Lighting Loads MWh
- Commercial Lighting Loads MWh
- Current penetration of Commercial Efficient Lighting (LED etc)
- Residential Lighting Loads MWh
- Potential MWh savings from efficient lighting. (Gross and Net of calculated increase in residential electric heat load)
- Current estimated penetration of Residential efficient lighting (LED etc)
- Electricity Cost Savings potential (based on Avoided cost) at 10-80% penetration levels.
- Lighting retrofit costs at 10-80% penetration levels.

c) List in detail and discuss all barriers and necessary incentives to deployment of energy efficient lighting in HORCI-serviced communities

Response:

a) Remotes prepared a discussion paper in 2013 to determine the available energy savings to support their Street Lighting Retrofit Program. See attachment 1.

b) As discussed in 1-02-33 Remotes is not included in the OEB/IESO framework and does not have the information to answer this question.

c) The Minister of Energy has established several programs through the IESO that offers Remotes' communities opportunities to build capacity in conservation and energy generally. There are several barriers to the establishment of conservation programs including the deployment of energy efficient lighting. The size of the communities and lack of large chain stores means province-wide rebate programs are not generally available to residents in Remote Communities. Because customers are largely residential, there are few if any opportunities for commercial/industrial conservation. The inaccessibility of the communities make it difficult to establish good exchange programs since shipment, removal and logistics are complex and costly. Housing stock is not built to the provincial building code and some communities do not have adequate funding to maintain the housing, making it difficult to set up programs related to the energy efficiently when more urgent housing issues exist. Customers are economically disadvantaged and may not have upfront capital to participate in programs (note that Remotes customers may be eligible for the Green Ontario programs targeted to the low-income customer segment to be established and delivered by the IESO). There are no businesses within the communities that execute CDM programs including lighting retrofits. Wide-spread knowledge and understanding of energy use and efficiency remains a challenge. Community members would need to acquire the training and would require ongoing support (office, tools, oversight, car) or external vendors would need to be hired. In order for Remotes itself to deploy a successful efficient lighting program in their service territory Remotes would need the following:

- Increased resources including staff to promote/work with to each community.
- Increased funding and resources to identify all potential projects in each community.
- Increased funding to perform all the leg work, order all the required supplies and hire vendors to install the lighting to ESA standards.

Energy Probe Research Foundation - Interrogatory # 35

Reference:

D1, Tab 5, Schedule 1 Table 3 -Service Costs and Labour Rates

Interrogatory:

Preamble: The 2018 HORCI labour rate for a RC Technician is $169 plus expenses.

a) Please provide a Table and Chart showing the Board approved 2013 RCT labour rate and estimates of the rates for 2014-2017.
b) Provide Total RCT costs including labour and expenses for each year and position this as a percentage of Total Service costs.
c) Has Remotes' benchmarked its costs, including labour rates to other Canadian Utilities that service Remote Communities (e.g. BC Hydro/Fortis, Manitoba Hydro and Hydro Quebec)? If so please provide copies/summary extracts of the benchmark studies.
d) If not, given the RRFE requirements for Benchmarking, will Remotes undertake such Benchmarking Studies?

Response:

a) Remote Communities Technician Rate:

OEB Approved	Actual			
2013	2014	2015	2016	2017
$184	$182	$175	$181	$181

b) D1, Tab 5, Schedule 1 Table 3 "Service Costs and Labour Rates" does not exist.

c) No. Remotes has not benchmarked its costs to other Canadian Utilities that service off-grid communities.

d) The operating circumstances for each off-grid utility vary significantly by jurisdiction and it is clear that costs would not be comparable. Benchmarking has been discussed by the utilities but is generally agreed that it is of limited value given the significant differences amongst utilities. Best practices are often exchanged throughout the year and at the bi-annual Prime Power Diesel Inter Utility Conference (PPDIUC). By example, the size, loads and customer count of communities vary, loads, assets in service, number of communities served, geographic dispersion, provincial legislation, accessibility (roads) and provincial government supports for customers are not comparable. Other notable differences include staffing and the ability to contract services, plant design, generation type, renewables, and distribution complexity and distance. As a further example, Hydro One Remotes is the only off-grid utility in Canada that flies in fuel within its regular operations. The other notable influence is whether the organization’s structure is stand-alone from its parent or fully or partially integrated. Based on these differences as well as other Hydro One Remotes feels that benchmarking other off-grid utilities is of limited value.

VECC - Interrogatory # 1

Reference:

A-3-1 Page 8 Performance Management

Interrogatory:

a) With respect to improved project management, please explain the changes made over the past five years to improve productivity.

Response:

a) Prior to 2013, projects were assigned to engineering staff. In 2013, Remotes created a job to focus on project management. From this, Remotes has developed project management processes for estimating, monitoring and reporting. The pre-planning process, including the purchase of equipment for winter roads has also been improved, leading to cost savings associated with transportation and to improvements in the timing of project completion. These processes are now standard in Remotes' business. We continue to track and utilize Lessons Learned on projects and apply them to future projects.

VECC - Interrogatory # 2

Reference:

A-3-2 Revenue Deficiency

Interrogatory:

a) Please confirm the 2018 revenue deficiency.

b) Please provide the key drivers that make up the revenue deficiency.

Response:

a) Refer to Table 2 in Exhibit F1, Tab 1, Schedule 1, which provides the 2018 revenue deficiency.

b) The key drivers that make up the revenue deficiency primarily relate to 1) inflation over the past 5 years (RRRP has not changed since 2013), 2) increased generation maintenance, primarily related to increased maintenance of auxiliary and plant systems, which were found to be a leading cause of outages and 3) increased fuel costs associated with higher prices and increased consumption.

VECC - Interrogatory # 3

Reference:

A-4-1 Attachment 3 Page 4

Interrogatory:

Preamble: Remotes' evidence regarding Electricity Rebates & Programs indicates most Hydro One Remotes customers were not aware of various electricity-related rebates and programs available to them.

a) Please describe the step Remotes has undertaken or plans to undertake to improve the awareness of its customers of electricity-related rebates and programs including LEAP and OSEP.

Response:

a) Please see the answer to I-01-03.

VECC - Interrogatory # 4

Reference:

A-5-1 Performance Management

Interrogatory:

a) Page 3 Band/Tribal Council Meetings: The target for this initiative is to meet with the Band or Tribal Council at least eight times per year. In 2016 and 2017, 13 and 17 meetings, respectively, were achieved. Please explain the need for additional meetings in these years compared to the three previous years.

b) Page 5 Environmental Management System ("EMS") Objectives and Achievements: The target for acceptable performance is the completion of 80% of planned deliverables. Please explain how the 80% was derived.

c) Page 5 Reducing Residential Arrears: Please provide the results for 2017 and the current target. Please discuss if Remotes will be tracking this metric for the years 2018 to 2022. If not, please explain.

d) Page 7 Health & Safety Mandatory Training: Please provide the data for 2017. Given the trend for the metric is declining since 2013 please explain the rationale to drop this metric.

Response:

a) The need for increased meeting with Band/Tribal councils has been driven by a notable increased interest in renewable projects, independent power authority service discussion related largely to the Watay project, and high impact customer related projects such as upgrades.

b) The 80% is established based on the historical performance of meeting Environmental Management System ("EMS") Objectives and Achievements of our business since 2002. On an annual basis this target is discussed and reviewed during the management review as well as confirmed annually in early Q1 once Objectives and Achievements have been finalized. The 20% shortfall allows for some flexibility for supervisors and managers to effectively manage their programs, overall Objectives and Achievements, and allows for changing needs and business requirements. Missed Objectives and Achievements, still deemed relevant and applicable are carried over to the next year.

c) Remotes experienced a 26% reduction in its total energy arrears for 2017. This metric is no longer tracked as a result of the overall success in reducing the total energy arrears to an acceptable level.

d) This metric is no longer tracked. Instead 2017 training focused on specific courses and skill shortfalls identified, to ensure that priority training is performed and risks are limited.

VECC - Interrogatory # 5

Reference:

A-5-1 Page 9 Operational Excellence

Interrogatory:

a) Please explain how Remotes sets annual targets for its reliability performance.

b) Please provide the SAIDI and SAIFI targets for 2018 to 2022.

a) Remotes indicates that SAIDI performance in 2016 and 2017 reflects adjustments for major events. Please provide the adjustments made for major events in 2016 and 2017.

Response:

a) Remotes sets its annual targets for reliability based on its five year historical performance.

b) Based on historical results, The SAIDI and SAIFI targets including loss of supply for 2018 are:
SAIDI 11.26
SAIFI 13.24

c) SAIDI performance in 2016 was not adjusted for major events. Please see I-02-12, Attachment 1 MED for the internal scorecard adjustments made in 2015 and 2017.

VECC - Interrogatory # 6

Reference:

A-5-1 Page 13 Major Project Milestones

Interrogatory:

Preamble: Remotes identifies the milestones of one major project a year and sets the timelines and budget for the project accordingly. Remotes then monitors how well the project stays on track according to these milestones and documents any deficiencies.

a) For each of the projects listed in Table 1, please provide the cost and schedule for each milestone; budget versus actual to show how each project tracked to each milestone.

b) Please explain the nature of the efficiencies that have been introduced and realized in subsequent projects and the resulting savings.

Response:

a)

		Budget (in $K)	Actual (in $K)
2013	Sandy Lake G3	1,624	1,431
2014	Lansdowne House C	1,083	1,215
2015	Fort Severn C	3,639	3,176
2016	Bearskin B	1,515	1,226
2017	Kingfisher B,C	5,700	5,646

Milestones were deliverable by date, not by budget.

Below is an example of the milestones from the Kingfisher Lake project.

Month	Milestone
January	1. Preliminary estimate 2. Conceptual design
	3. Long lead items ordered 4. Detailed Project Plan developed
March	5. Design substantially complete 6. BOM complete
June	7. Installation of C Unit
August	8. Commissioning of C Unit

	9. Installation of transformers
September	10. Commissioning of transformers & switchgear
November	11. Installation of B unit
December	12. Turnover meeting with Operations and Maintenance 13. On Budget
January 2018	14. Project completion

b) The efficiencies include:
   1) better detailed project planning and staging;
   2) better execution resulting from the more detailed plans;
   3) more efficient procurement of materials, especially with long lead times;
   4) efficiencies in shipping material, handling, storage and construction;
   5) adopting more effective practices (i.e.the use of piers in place of concrete);
   6) engineering designs that incorporate more readily available equipment for erection; and
   7) standardized drawing standards for generator controls has reduced design time.

The savings are in two places, the difference between the Actual and Budget and the reduction in budget amounts as efficiencies become embedded in the business.

VECC - Interrogatory # 7

Reference:

A-5-1 Attachment 1 Page 5

Interrogatory:

a) Please provide the updated scorecard for 2017 to reflect year end results.

Response:

a) Please see I-02-13.

VECC - Interrogatory # 8

Reference:
A-5-2 Page 5 Reliability Performance

Interrogatory:
a) Please provide the SAIDI and SAIFI results for 2017.

b) Please provide CAIDI results for the years 2012 to 2017.

c) Please provide the SAIDI and SAIFI results for the years 2013 to 2017 excluding Major Event Days, Loss of Supply and Scheduled Outages.

Response:
a) Please see 1-02-12 Service Quality Indicators for the updated SAIDI and SAIFI results.

b) Remotes notes that it has not had any major event days using the IEEE standard.
CAIDI results per year are as follows:
2013 – 0.76
2014 – 0.61
2015 – 1.13
2016 – 0.97
2017 – 0.89

c) SAIDI and SAIFI excluding scheduled outages and loss of supply are as follows:
2013 SAIDI – 1.52 SAIFI – 1.31
2014 SAIDI – 3.67 SAIFI – 2.47
2015 SAIDI – 6.21 SAIFI – 2.86
2016 SAIDI – 5.00 SAIFI – 2.58
2017 SAIDI – 4.18 SAIFI – 2.08

VECC - Interrogatory # 9

Reference:

A-5-2 Reliability Performance Pages 9 to 19

Interrogatory:

a) For each of the years 2012 to 2017, please provide a breakdown of defective equipment by sub-cause (equipment type) and show the contribution to number of customers interrupted and customer hours of interruption for each defective equipment sub-cause.

b) Please confirm storm interruptions are recorded under the adverse weather cause code.

c) Please define the Adverse Environment cause code.

d) Please provide the total number of outages for each of the years 2012 to 2017.

e) Please confirm that every outage results in a customer interruption. If not, please explain and provide the number of outages in part (d) that resulted in a customer interruption.

Response:

a) Defective equipment by sub-cause (equipment type) is not tracked, so a breakdown cannot be provided.

b) Confirmed. Adverse weather includes customer interruptions resulting storm events excluding outages associated with lightning or tree contacts.

c) The Adverse Environment Code includes customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flowing. Remotes includes house fires in this category, as there are limited fire-fighting resources in its communities, and operators generally need to take a community-wide generation outage to disconnect the electricity service and make conditions safe for emergency responders as operators are not qualified to disconnect live services. Both the initial outage (the fire) and the response (community-wide outage) are mapped to the Adverse Environment Code.

d) Total outages including loss of supply by year are as follows:
2012 - 291
2013 – 342
2014 – 290
2015 – 250
2016 – 293
2017 – 259

e) Yes. Each outage results in a customer interruption. Outages of less than one minute are excluded.

VECC - Interrogatory # 10

Reference:

A-7-2 Page 5

Interrogatory:

a) Please provide a list and description of all audits undertaken since 2013 related to Remotes.

b) Please provide a list and description of planned audits related to Remotes.

Response:

a) On the health, safety and environment side, Remotes has had an integrated management system in place since 2006 in which annual compliance and system audits are conducted and evaluated and compared to ISO and OHSAS standards by an external registrar.

Relating to financial results, the Internal Control Certification Team tests controls for the month end close reporting process for Remotes. They started testing controls for the Remotes LAR provision process in 2017. This is an ongoing process and will continue into 2018 and beyond.

b) Refer to response a).

VECC - Interrogatory # 11

Reference:

A-7-4 Page 3

Interrogatory:

a) Please provide the number of Interim Review of Variance (IROV) prepared for each of the years 2013 to 2017.

b) Please provide the total cost variance and schedule variance associated with the all of IROVs (amended business cases) for each of the years 2013 to 2017.

c) Please provide the number of projects cancelled per year for each of the years 2013 to 2017.

Response:

a) Remotes had a total of 21 Interim Review of Variances (IROV's) for the years 2013 to 2017, of which 13 related to a schedule change and 8 related to a cost variance. The majority of the schedule changes relate to projects that are contingent on receipt of funds from INAC.

Year	# of IROV's
2013	5
2014	10
2015	2
2016	2
2017	2

b)

Interim Review of Variance's 2013-2017

Year	Project Number	Description	Cost	Schedule	Scope change	Cost Variance	Agreed In-Service Date	Current In-Service Date
2013	700013132	Weagmow Tank Farm		x			Nov-12	May-13
2013	RMGCA5003	Kasabonika Wind Turbine Installati	x	x	x	317,000	Aug-12	Jul-13
2013	700013000	Scada & PLC	x	x	x	195,000	Feb-12	Jun-13
2013	700009232	BTL Windmill Refurbishment		x			Oct-13	Nov-14
2013	700009567	Hillsport Tank Farm Improvements	x	x	x	147,000	Aug-13	Jun-14
2014	700018532	Bearskin Water Well		x			Sep-13	Sep-14
2014	700018394	Weagamow Garage		x			Oct-13	Oct-14
2014	700019915	Bisco Water Well		x			Dec-13	Sep-14
2014	RMGCA6012	Fort Severn DGS Upgrade		x			Mar-13	Dec-20
2014	RMGCA6013	Big Trout Lake DGS Upgrade		x			Mar-13	Dec-20
2014	RMGCA6007	Weagamow DGS Upgrade		x			Dec-13	Dec-20
2014	RMGCA6014	Kasabonika Lake DGS Upgrade	x	x		246,000	Jan-12	Mar-15
2014	700022793	Fort Severn Garage		x			Sep-14	Oct-15
2014	700018394	Weagamow Garage		x			Oct-14	Oct-15
2014	700018625	Bisco Drawing Conversion	x	x		285,000	Dec-13	Nov-14
2015	700023033	Sultan Hydel Rebuild	x	x		30,000	Oct-14	Jun-15
2015	700023033	Sultan Hydel Rebuild	x	x		225,000	Jun-15	Oct-15
2016	RMGCA6007	Weagamow DGS Upgrade	x	x	x	1,676,000	Dec-20	Feb-17
2016	700022793	Fort Severn Garage		x			Oct-15	Oct-17
2017	700009805	Kingfisher Lake Upgrade		x			Sep-17	Feb-18
2017	700032368	Kingfisher Garage		x			Nov-17	Sep-18

c) There were no projects cancelled during 2013-2017. When INAC funding is available, Remotes defers projects, instead of cancelling them. Those projects will then fall into the bucket of change in completion dates.

VECC - Interrogatory # 12

Reference:

B1-1-1 Page 11

Interrogatory:

a) Please explain the steps Remotes undertook to respond to limited interest in each of the following CDM programs and how the decision to discontinue the program was made: Community Conservation Pilot Program, Energy Conservation Youth Camps, Community Conservation Competitions, Commercial Lighting Retrofit and Rebate-Fridge Round-up.

Response:

a) Community Conservation Program – In the effort to drive interest, Remotes heavily promoted this program for a number of years by:
   - Sending letters to Chief and Council on a yearly basis reminding them of the program, its availability and its benefits to the community
   - Meeting with community leadership specifically to discuss this program
   - Presenting whenever possible at various conferences
   - Attending tradeshows and speaking to leadership as well as community members
   - Engaging other groups such as Tribal councils to assist with the promoting the program
   - Publishing articles in various newsletters, newspapers and bill inserts
   - Piggybacked on programs offered by the OPA/IESO

   Additionally Remotes supported the program by:
   - Spending one on one time with participating communities on a regular basis in order to engage with community members.
   - Train energy advisors and follow-up with them on a weekly basis.
   - Discuss progress or concerns with community leadership as required.
   - Engage outside agencies when possible to help support participating communities.
   - Fund all aspects of the program including wages and required products.

   Energy Conservation Youth Camps - In the effort to drive interest, Remotes heavily promoted this program for a number of years by:

- Sending letters to Chief and Council on a yearly basis reminding them of the program, its availability and its benefits to the community
- Meeting with community leadership specifically to discuss this program
- Presenting whenever possible at various conferences
- Attending tradeshows and speaking to leadership as well as community members
- Engaging other groups such as Tribal councils to assist with the promoting the program
- Publishing articles in various newsletters, newspapers and bill inserts
- Developing a partnership with a well-known and respected Children's Educational Group to promote and deliver the program
- Worked specifically with same group to develop Remotes specific curriculum
- Personally worked with all groups to ensure arrangements have been made and paid for even when participating communities did not live up to their obligations.
- Visited community during each event to ensure the program meets our deliverables and get feedback from the teachers, participants and community leaders.

<u>Community Conservation Competitions</u> – Note In the effort to drive interest, Remotes heavily promoted this program for a number of years by:

- Sending letters to Chief and Council on a yearly basis reminding them of the program, its availability and its benefits to the community
- Meeting with community leadership specifically to discuss this program
- Presenting whenever possible at various conferences
- Attending tradeshows and speaking to leadership as well as community members
- Engaging other groups such as Tribal councils to assist with the promoting the program
- Publishing articles in various newsletters, newspapers and bill inserts
- Communicated on a regular basis the status of the results, promoting accomplishments and encouraging more engagement as required.

Note this program was primarily promoted to those actively participating or that had participated in the Community Conservation Program. Only one community participated.

The decision to discontinue the above programs was made due to limited interest/uptake by communities and because communities indicated a preference to work on renewable

energy projects, which were seen to have a more direct benefit and which also dovetailed with programs initiated by the IESO and NRCan/INAC on community energy planning.
Commercial Lighting Retrofit – Note that Remotes promoted this program in the beginning as noted above. In the effort to continue driving interest, Remotes continues to promote this program by:

- Sending letters to Chief and Council on a yearly basis reminding them of the program, its availability and its benefits to the community
- Meeting with community leadership specifically to discuss this program when the opportunity is presented or requested
- Engaging other groups such as Tribal councils to assist with the promoting the program
- Encourages communities to tap into this program with doing other projects in the community as a positive add on.
- When engaged by a customer to Remotes works closely to assist in the collection of data, data analysis, dialogue with suppliers, electricians etc. and advice for product selection.

Rebate-Fridge Round-up – Note this program was initially created in partnership with the Northwest Company. The Round-up portion had to be in partnership between the NWCo. as well as the participating community. Not all communities had a good working relationship with the NWCo and the NWCo stopped promoting due to lack of volume, making it not cost effective for them.

As a result, Remotes reworked the rebate portion of the program which in now called the Mail-In Rebate. Remotes became an Energy Star member and actively promotes the Energy Star brand as part of the programs. Additional to these Remotes continues to promote this program as with the others. Once or twice a year Remotes also heavily promotes the program through bill inserts including an application for and instructions to participate.

This year Remotes has plans to Promote Energy Star day using this program as a tool.

VECC - Interrogatory # 13

Reference:

B-1-1 Page 12

Interrogatory:

a) Figure 1-7 shows the CDM savings for the years 2012 to 2015. Please explain the higher CDM savings in 2014. Please provide the CDM savings in 2016 and 2017.

Response:

a) There was a spike in 2014 because of a long and focussed effort to promote the program to communities and Band Councils throughout 2012 and 2013. In 2015, a similar program was offered by the IESO/OPA and it became difficult to attract communities to participate in Remotes' program. Please see I-02-33 for information on CDM savings in 2016 and 2017.

VECC - Interrogatory # 14

Reference:

B1-1-1

Interrogatory:

a) Page 20 Table 2-4: The cost savings commence in 2013 for four initiatives and 2015 for the fifth initiative. Are there any new cost saving initiatives in 2018?

b) Page 24 Resource Availability: Please provide the percentage of the capital plan undertaken by internal resources versus external resources for each of the years 2013 to 2017 and the forecast for 2018.

c) Please discuss if there are costs savings associated with utilizing external resources compared to internal resources and provide the percentage savings.

d) Page 24: Please provide the percentage of the capital budget that was executed as planned for each of the years 2013 to 2017.

e) Page 67 Figure 3-5 Asset Condition Assessment: Please provide a schedule that quantifies the number of assets in very poor, poor, fair, good, and very good condition by asset type.

f) Please provide a schedule that sets out the asset categories, the population of each asset category and the quantity of each asset type proposed for replacement for each of the years 2018 to 2022.

g) Page 70 Table 3-7 Forecast Engine Hours: For each of the generation units listed, please provide the threshold/limit of the number of hours that each unit is expected to operate.

h) Page 102: From Remotes perspective, please explain why 32% of customers are unsure about ways to improve service to customers.

Response:

a) There are no further costs savings anticipated in 2018.

b) Capital Plan completion:

	Actual					Plan
	2013	2014	2015	2016	2017	2018
Internal - Regular Employees	49.8%	56.1%	59.8%	62.4%	57.0%	57.0%
External - Casual	50.2%	43.9%	40.2%	37.6%	43.0%	43.0%

c) Yes, there cost savings associated with using operators and meter readers from the local communities instead of internal resources. Those cost savings are provided in Appendix A.

d) Percentage of capital budget executed as planned:

	2013	2014	2015	2016	2017
Gross Capital	70.3%	70.8%	112.1%	105.8%	82.5%

e) Please refer to DSP pages 67-82 for a breakdown number of assets in very poor, poor, fair, good, and very good condition by asset type. They are summarized in each section by asset type.

f) Table 0-1: Summary of the ACA for Poles

Emergency	Replace Within 5 Years	No Replacement Within 5 Years
0	115	3,871

*115 poles are planned to be replaced over the next 5 years.

Table 0-2: Summary of the ACA Results for Distribution Transformers

VP	P	F	G	VG
79	181	597	248	33

* Distribution Transformers are replaced on an as required basis. The ACA above reflects asset age. However, all transformers remain in service if they continue to operate as intended.

	Diesel Generators (59)	Hydroelectric Generators (3)	Wind Turbines (4)	Station Transformers (47)
2018	0	0	0	0
2019	1	0	0	0
2020	2	0	0	0
2021	5	0	0	0
2022	1	0	0	0

g) Threshold/Limit for Unit Operation Hours:

		Replace at (hrs)
ARMSTRONG	A	60000
ARMSTRONG	B	60000
ARMSTRONG	C	60000
BEARSKIN	A	60000
BEARSKIN	B	60000
BEARSKIN	C	126000
BIG TROUT	A	60000
BIG TROUT	B	60000
BIG TROUT	C	126000
BIG TROUT	T1	60000
BISCOTASING	A	60000
BISCOTASING	B	60000
BISCOTASING	C	60000
DEER LAKE	A	126000
DEER LAKE	B	60000

DEER LAKE	**C**	60000
FORT SEVERN	**A**	126000
FORT SEVERN	**B**	60000
FORT SEVERN	**C**	126000
GULL BAY	**A**	60000
GULL BAY	**B**	60000
GULL BAY	**C**	60000
HILLSPORT	**A**	60000
HILLSPORT	**B**	60000
KASABONIKA	**A**	126000
KASABONIKA	**B**	126000
KASABONIKA	**C**	60000
KINGFISHER	**A**	60000
KINGFISHER	**B**	126000
KINGFISHER	**C**	60000
LANSDOWNE	**A**	60000
LANSDOWNE	**C**	60000
LANSDOWNE	**D**	126000
MARTEN FALLS	**A**	126000
MARTEN FALLS	**B**	60000
MARTEN FALLS	**C**	60000
OBA	**A**	60000
OBA	**B**	60000
OBA	**C**	60000
SACHIGO	**A**	60000
SACHIGO	**B**	60000
SACHIGO	**C**	126000
SANDY LAKE	**G1**	126000
SANDY LAKE	**G2**	126000
SANDY LAKE	**G3**	126000

SANDY LAKE	**G4**	126000
SULTAN	**A**	60000
SULTAN	**B**	60000
WAPEKEKA	**A**	126000
WAPEKEKA	**B**	60000
WAPEKEKA	**C**	60000
WEAGAMOW	**A**	60000
WEAGAMOW	**B**	60000
WEAGAMOW	**C**	60000
WEBEQUIE	**G1**	60000
WEBEQUIE	**G2**	126000
WEBEQUIE	**G3**	126000

h) The question about service improvement is an open-ended question to see what particular service improvements matter to customers that may not be covered off by other questions. Remotes assumes that customers may feel their views are reflected in their previous responses.

Appendix A: Total Cost Savings and %

Table - Total Cost Savings and %

	Historical ($)				**Forecast ($)**					
Cost Savings	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Costs - External Resources	1,373,355	1,378,955	1,447,666	1,424,998	1,464,483	1,464,812	1,465,314	1,501,870	1,502,254	1,502,798
Costs - Internal Resources	11,224,158	12,079,070	12,301,066	12,644,049	12,597,833	12,676,234	12,755,418	12,835,395	12,916,171	12,997,754
Total Cost Savings	**9,850,804**	**10,700,115**	**10,853,400**	**11,219,052**	**11,133,350**	**11,211,422**	**11,290,105**	**11,333,525**	**11,413,917**	**11,494,956**
% of Total Cost Savings	**717%**	**776%**	**750%**	**787%**	**760%**	**765%**	**770%**	**755%**	**760%**	**765%**

VECC - Interrogatory # 15

Reference:

B1-1-1 Appendix A

Interrogatory:

a) Please provide a priority ranking for each material investment in 2018.

Response:

a) The priority ranking for each material investment in 2018 is:

	Priority
New Customer Connections & Service Upgrades	2
Distribution System Improvements	9
Big Trout Lake A Generator Replacement	4
Generator Overhauls	1
Diesel Plant Civil Improvements	7
SCADA & PLC Replacements	5
Big Trout Lake and Wapekeka Connection and Upgrade	3
Sandy Lake Upgrade	6
Weagamow DGS Upgrade	8

VECC - Interrogatory # 16

Reference:

C1-1-1 Page 3 Table 2

Interrogatory:

a) Please provide the budget versus actual in-service additions for the years 2016 to 2017.

Response:

a) In-service additions (in $K):

	2016	2017
Budget	$5,900	$3,606
Actual	$4,656	$2,094
Variance	-$1,244	-$1,512

VECC - Interrogatory # 17

Reference:
D1-1-2 Generation OM&A

Interrogatory:

a) Table 1: Please provide a breakdown of Generation Maintenance between planned and unplanned maintenance.

b) Please provide the number of trouble reports for the years 2013 to 2017 and forecast for 2018.

c) Please provide the number and type of equipment or component failures for the years 2013 to 2017 and forecast for 2018.

d) Please explain the maintenance cycles of diesel engines, plant and auxiliary systems, buildings and tank farms and renewable energy and provide the number of units maintained under each category.

e) Please explain why higher maintenance of engines, auxiliary and plant systems and renewable energy maintenance is required in 2018 compared to other years.

Response:

a)

Generation Maintenance (in $K)

Category	**Board Approved**	**Historic (Actual)**				**Bridge**	**Test**
	2013	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Planned Maintenance	4,826	6,971	8,614	7,499	8,138	9,761	9,972
Unplanned Maintenance	1,187	1,677	1,318	1,111	1,436	1,631	1,668
Total	6,012	8,648	9,932	8,610	9,574	11,392	11,640

b) Trouble is reported from a wide number of sources, operators, field staff, outage reporting on the SCADA and at weekly trade meetings. Generation Maintenance does not currently have a single integrated data base to track the number of trouble reports per year.

c) A variety of auxiliary equipment was replaced over the time period 2013 -2017. There are both planned replacements and unplanned replacements. Component failures are predominately unplanned activities. The unplanned work is primarily replacing malfunctioning equipment including variable speed motor drives on cooling and ventilation system, leak detection equipment, bulk fuel level sensors, secondary heat piping replacement, battery replacements, fire system replacements, SCADA computer and screen replacements, generator breaker replacements, primary coolant hoses, secondary coolant pumps, exhaust mufflers, manual and automatic valves, fuel system controls and generator controls replacement. Other equipment modifications allowing for better voltage regulation and generator synchronization and fuel filtering and metering improvements was also done under unplanned work. Exact quantities of items replaced are not tracked and available. The forecast for 2018 is based on historic levels of failures in auxiliary equipment.

d) Generator maintenance follows the manufactures' recommendations based on Operated Hours. Maintenance is performed at hourly intervals of 500 hours. The procedure performed is determined by the total Operated Hours since new or the last major overhaul. There are 59 diesel generators.

Station auxiliary systems are checked annually; however a few systems are checked on a semi-annual basis (i.e. Shoulderblade Falls, fire systems). There are 20 stations.

Tank farms and renewable generation is maintained annually. There are 19 tank farms and 4 sites have renewable generation (2 wind and 2 hydro-electric). The 20 stations buildings are annually inspected and maintained as required.

e) Higher maintenance of engines will result from specific engines proving to require more periodic adjustment than was expected. Auxiliary and plant systems have increased costs due to failing and aging SCADA/PLC equipment, bulk tank level sensors and generator controls. Additional renewable energy maintenance is required in 2018 compared to other years due to work on failed governor controls.

VECC - Interrogatory # 18

Reference:

D1-1-2 Page 11 Table 5 Total Cost of Fuel

Interrogatory:

a) Please provide Table 5 for the years 2013 to 2017.

Response:

a) Table 5 is provided below.

Table 5
Total Cost of Fuel

Category	Board Approved	Historic (Actual)					Bridge	Test
	2013	2013	2014	2015	2016	2017	2017	2018
Fuel Efficiency (kWh/litre)	3.56	3.61	3.62	3.44	3.56	3.58	3.41	3.42
Total litres of fuel issued (in KL)	15,668	17,284	17,517	17,492	17,361	17,308	18,038	18,203
Average delivered cost per litre ($)	$1.536	$1.479	$1.477	$1.329	$1.363	$1.485	$1.468	$1.516
Total Cost of Fuel (in $K)	$24,067	$25,568	$25,869	$23,250	$23,669	$25,695	$26,485	$27,600

VECC - Interrogatory # 19

Reference:
D1-1-3 Distribution OM&A

Interrogatory:
a) Table 1: Please provide a further breakdown of Distribution Maintenance costs (2013 to 2018) that includes but is not limited to the following categories: planned maintenance, unplanned maintenance, trouble calls and metering.

b) Please explain the increase in Distribution Maintenance costs in 2018 compared to 2016.

c) Please provide the number of trouble calls for each of the years 2013 to 2017 and the forecast for 2018.

d) Please provide the forestry and right-of-way maintenance budget versus actual costs for the years 2013 to 2017 and provide the unit accomplishments per year.

e) Please provide the forestry and right-of-way maintenance budget for 2018 and the forecast unit accomplishments.

f) Please provide a summary of the planned maintenance activities, units maintained and the corresponding cycles.

g) Please provide the type and number of equipment failures for each of the years 2013 to 2017.

h) Please explain the increase in higher planned forestry activities in 2017.

Response:

a) The table is provided below:

Table 1

Distribution Maintenance in OM&A (in $K)

Category	**Board Approved**	**Historic (Actual)**					**Bridge**	**Test**
	2013	**2013**	**2014**	**2015**	**2016**	**2017**	**2017**	**2018**
Trouble Response	818	402	462	613	546	534	510	533
Distribution Minor Maintenance	571	598	805	895	861	800	928	969
Forestry Services	1,174	313	392	549	262	134	448	457
Metering	116	95	135	160	112	109	122	128
Other	0	-9	5	-1	-1	-7	0	0
Distribution Maintenance	**2,679**	**1,399**	**1,799**	**2,216**	**1,780**	**1,570**	**2,008**	**2,087**

b) The increase for 2016 to 2018 for Distribution Maintenance is broken down in the above chart. Notable variances include the increase in distribution minor maintenance and forestry services.

c) Trouble calls relating to distribution outages range from 90 to 158, average 116 over the period noted. Partial power outages and trouble calls assisting generation related outages are not included. In 2018, we would expect similar trouble calls as the previous periods.

d) Please refer to IR # I-02-32.

e) Please refer to IR # I-02-32.

f) Planned maintenance includes corrective and preventative line maintenance. The Distribution System Code requires that all local distribution companies patrol their distribution lines on a five-year cycle, to identify structural problems, damaged equipment and components that may cause a power interruption, as well as any hazards such as leaning poles, damaged equipment enclosures and vandalism. Preventative maintenance includes maintenance that is primarily cyclical in nature, including maintenance of equipment (load brake switches, electronic switches), as a means of reducing unplanned outages. Planned maintenance also reflects corrective and preventative line maintenance as identified during off-cycle patrols, trouble calls, operators, customers or 22/04. Many smaller and less critical components do not have scheduled or planned cycles, and are fixed or replaced when required. Air brake and viper switches are maintained on a three-year cycle.

g) The number and type of equipment failures are not tracked.

h) The higher planned forestry activities in 2017 reflects a proposed return to historical levels in an effort to address the 2015 and 2016 forestry work not performed.

VECC - Interrogatory # 20

Reference:
D1-1-3 Page 2

Interrogatory:
Preamble: Remotes indicates that unplanned maintenance is reactive due to external factors such as storms, variability in equipment deterioration and random equipment failures.

a) Please confirm the cost to repair equipment/component failures is part of the capital budget.

b) Does Remotes track when unplanned maintenance is undertaken on each asset within its data management systems?

Response:
a) Items that are repaired or replaced due to equipment/component failures are part of the capital budget, provided the existing capitalization thresholds and rules have been met.

b) No. Hydro One Remotes does not track O&M spending at the asset level.

VECC - Interrogatory # 21

Reference:

D1-1-4 Customer Care OM&A

Interrogatory:

a) Please explain the increase in Customer Care costs in 2018.

Response:

a) The cost increase noted is inflationary related to increased flight costs required for collections, unionized labour costs and contracted meter reading costs. As well, the number of customers served by Remotes continues to increase. Incremental improvements in the customer care program are also necessary in order to maintain our high customer satisfaction levels. Forecasted amounts are in-line with previous years.

Category	**Board Approved**	**Historic (Actuals)**				**Bridge**	**Test**
	2013	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Customer Care	1,855	2,844	1,906	1,733	1,897	1,857	1,939

VECC - Interrogatory # 22

Reference:

D1-5-1 Page 3

Interrogatory:

a) With respect to payroll obligations, please explain how the overtime component within payroll obligations is derived.

b) In the Technician example provided, please provide the $ amount of overtime included and show how it is derived.

c) Please explain how Remotes determines its annual overtime budget and how actuals are tracked.

Response:

a) No overtime is included in the payroll obligations shown in D1-05-01, Table 1. When overtime is worked, a higher Remotes Communities Technician Rate is charged out to allocate the additional wages paid.

b) The payroll obligations for Remote Communities Technician ($70) do not include an overtime component.

c) The annual overtime budget is determined through the business planning process. Overtime is planned to make the best use of staff when they are on site. Transportation costs from flying back and forth to site are more costly than overtime. Departmental managers are consulted to provide an estimate of their staffing needs including overtime hours. The budget for overtime hours is based on a review of historical data and adjusted for the upcoming work plan. Reports on actual overtime worked are prepared by Finance and reviewed by management on a monthly basis.

VECC - Interrogatory # 23

Reference:

D1-5-1 Page 4

Interrogatory:

a) Please show the calculation of the 2018 Non-Labour Administration Costs ($13) that is based on historical trends and other factors.

b) Please show the calculation of the 2018 Non-Project, Administration and Support Services Labour ($81) that is based on historical trends and current company initiatives.

Response:

a) Calculation of administrative non-labour component in Remote Communities Technician (RCT) rate:

Administrative Non-Labour Costs	$627,965	**(a)**
Estimated RCT Direct Labour Hours	47,195	**(b)**
Administrative Non-Labour Cost / Hr	$13	**(a) / (b)**

b) Calculation of 2018 non-project, administration and support services labour:

All Labour Costs included in RCT Rate	$7,112,570	**(a)**
Estimated RCT Direct Labour Hours	47,195	**(b)**
Total Labour Costs/Hr	$151	**(c) = (a) / (b)**
RCT Payroll Obligations	$70	**from below (f)**
Non-Project, Administration, Management and Support Services Labour	$81	**(c) - (f)**

Estimated RCT Labour Costs	$4,638,623	**(d)**
Estimated RCT Hours Worked	65,995	**(e)**
RCT Payroll Obligations / Hr	$70	**(f) = (d) / (e)**

VECC - Interrogatory # 24

Reference:

Ex D1-3-1

Interrogatory:

a) Page 1: Please provide the percentage of work performed by regular resources.

b) Page 2: Please provide the number of eligible retirements and actual retirements for the years 2013 t0 2017 and the forecast for 2018.

Response:

a) Percentage of total hours worked:

	2013	2014	2015	2016	2017
Regular	78.9%	77.6%	79.5%	80.2%	78.9%
Casual	21.1%	22.4%	20.5%	19.8%	21.1%

b) The table is provided below. Eligible retirees include all individuals eligible for early or normal retirement. The 2018 forecast is undetermined at this time.

	ACTUAL					PLAN
	2013	2014	2015	2016	2017	2018
Employees Eligible to Retire	10	7	8	11	11	14
Retirements	3	1	0	2	2	

VECC - Interrogatory # 25

Reference:

Ex D2-3-2

Interrogatory:

a) Please add a column to the table to show Last Rebasing Year 2013 Board Approved.

Response:

a) The table is provided below.

Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	BA-2013	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Opening Balance		$ 43,483	$ 45,212	$ 45,939	$ 41,113	$ 43,497	$ 48,385
Generation Operations							
Sustainment Projects - Operations	$ 3,477	-$ 326	-$ 11	$ 222	-$ 53	$ 468	$ 80
Environment	$ 1,096	$ 59	-$ 35	-$ 145	$ 74	-$ 7	$ 21
Sustainment Projects - Operations	$ 24,066	$ 1,501	$ 302	-$ 2,618	$ 420	$ 2,816	$ 1,115
Other Power Supply Expenses	$ 1,980	-$ 1,980	$ -	$ -	$ 61	-$ 61	$ -
Generation Maintenance							
Sustainment Projects - Gx Maintenance	$ 5,340	$ 2,439	$ 991	-$ 970	$ 902	$ 1,343	$ 229
Safety Improvements	$ 393	$ 67	$ 173	-$ 296	-$ 187	$ 386	$ -
RET Improvements	$ 48	-$ 36	-$ 6	$ 7	-$ 6	$ 7	$ -
Environmental Improvements	$ 78	-$ 2	-$ 52	$ 152	$ 38	-$ 118	$ 2
Engineering Investigations	$ 153	$ 167	$ 179	-$ 215	$ 217	$ 199	$ 17
Distribution Maintenance							
Distribution Sustainment	$ 2,980	-$ 1,517	$ 415	$ 535	-$ 423	$ 128	$ 84
Billing and Collecting							
Customer Care	$ 1,903	$ 1,161	-$ 1,331	-$ 1,104	$ 1,247	$ 16	$ 108
Community Relations							
Community Relations	$ 751	-$ 231	$ 34	-$ 263	-$ 153	$ 241	-$ 75
Administrative and General							
Shared Services and Other Admin Costs	$ 1,157	$ 282	$ 102	-$ 224	$ 170	-$ 323	$ 177
External Costs	$ 61	$ 145	-$ 34	$ 93	$ 77	-$ 207	$ -
Closing Balance	$ 43,483	$ 45,212	$ 45,939	$ 41,113	$ 43,497	$ 48,385	$ 50,143

VECC - Interrogatory # 26

Reference:

Ex D2-5-2 Appendix 2-K

Interrogatory:

a) What does the category temporary staff include?

b) Are part-time staff and casual staff included under temporary staff? If not please explain.

c) Which category do co-op students and summer students fall under?

d) Please recast Appendix 2-K to show executive, management, non-union, union, and temporary FTEs and overtime and incentive pay.

e) Please provide the number of work hours by year for the years 2013 to 2018.

f) Please provide a list of the new positions added since 2013 by year and include the function and rationale for the position.

g) Please provide the allocation of employee costs between OM&A and Capital for the years 2013 to 2017 and forecast for 2018.

Response:

a) The category "temporary staff" does not exist on Appendix 2-K. Costs are categorized as management and non-management on this schedule.

b) See response to a)

c) Co-op students and summer students are non-management.

d)

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2013- Board Approved	Last Rebasing Year - 2013- Actual	2014 Actuals	2015 Actuals	2016 Actuals	2017 Bridge Year	2018 Test Year
Number of Employees (FTEs including Part-Time and Casual Employees) [1]							
Management	5.0	5.0	5.0	3.0	5.0	5.0	5.0
Union - Regular [2]	43.0	43.0	42.0	45.0	46.0	46.0	46.0
Union - Temporary [3]		4.0	4.6	2.1	2.5	1.7	1.7
Union - Casual		6.4	7.1	8.1	8.3	7.6	7.6
Total	**48.0**	**58.3**	**58.7**	**58.2**	**61.8**	**60.3**	**60.3**
Total Salary and Wages including overtime and incentive pay							
Management	$ 740,430	$ 704,673	$ 741,678	$ 558,677	$ 803,740	$ 819,814	$ 819,814
Union - Regular & Temporary	$ 5,026,714	$ 5,375,739	$ 5,362,936	$ 5,705,876	$ 5,884,365	$ 5,934,201	$ 5,984,490
Union - Casual		$ 973,414	$ 1,069,956	$ 1,056,804	$ 1,184,316	$ 1,196,159	$ 1,208,121
Total	**$ 5,767,145**	**$ 7,053,826**	**$ 7,174,570**	**$ 7,321,357**	**$ 7,872,420**	**$ 7,950,174**	**$ 8,012,424**
Total Benefits (Current + Accrued) 4							
Management	$ 104,355	$ 126,978	$ 152,154	$ 130,301	$ 141,716	$ 172,429	$ 175,678
Union - Regular, Temporary & Casual	$ 737,645	$ 897,564	$ 1,061,168	$ 954,580	$ 1,071,015	$ 1,080,038	$ 1,095,638
Total	**$ 842,000**	**$ 1,024,542**	**$ 1,213,322**	**$ 1,084,881**	**$ 1,212,731**	**$ 1,252,468**	**$ 1,271,315**
Total Compensation (Salary, Wages, & Benefits)							
Management	$ 844,785	$ 831,651	$ 893,832	$ 688,978	$ 945,455	$ 992,243	$ 995,492
Union - Regular, Temporary & Casual	$ 5,764,360	$ 7,246,716	$ 7,494,060	$ 7,717,260	$ 8,139,696	$ 8,210,398	$ 8,288,248
Total	**$ 6,609,145**	**$ 8,078,368**	**$ 8,387,892**	**$ 8,406,238**	**$ 9,085,151**	**$ 9,202,641**	**$ 9,283,740**

Note:

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

[2] Board Approved amounts from Last Rebasing Year (2013) did not include Casual Employees.

[3] Temporary employees provide coverage for regular positions (ie sick leave and maternity leave)

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

e) Total Hours Worked:

	Actual					Plan
	2013	2014	2015	2016	2017	2018
Total Hours	129,917	132,786	134,091	135,271	140,022	138,996

f) 3 additional regular staff resources were hired where Remotes could not secure casual staff to complete the work program. Staff resources were required to 1) establish a fire certification program for its stations as required for regulatory compliance and to complete the program approved by the Board in 2013; 2) an additional Operations Officer was required to improve safety and reliability training and support for local operators; and 3) as indicated in Exhibit B, Section 4.4, page 108, to hire a staff member with specialized information technology, networking and programming skills required to complete necessary SCADA and PLC projects.

g) Allocation of employee costs between OM&A and Capital:

	Actual					Plan
	2013	2014	2015	2016	2017	2018
OM&A	76%	78%	71%	72%	69%	81%
Capital	24%	22%	29%	28%	31%	19%

OSLP - Interrogatory # 1

Reference:

Exhibit A-03-02 Page 6 of 6

Interrogatory:

"In 2003, Remotes developed and adopted an Emission Reduction Strategy and submitted an application and Action Plan for Reducing Greenhouse Gases to the Environment Canada Voluntary Challenge Registry (now known as "Clean Start"). Remotes continues to report, monitor and reduce its emissions."

a) Please provide a summary of the Remotes performance against this strategy.
b) Please provide a summary of annual GHG emissions since 2013.

Response:

Remotes CleanStart Reports are accessible to the public on the following website: https://www.csaregistries.ca/cleanstart/projectinfo_e.cfm?No=801. The most up to date report is 2016 and has been filed.

a) Remotes continues to reduce their emissions intensity year to year even with growing consumption demands from our customers. The following tables illustrate Remotes' historical direct GHG emissions which have remained relatively static even with increased demand. The second table illustrates Remotes' historical direct GHG emissions and gross emissions intensities since 1990 which are on a continual decline.

Figure 2: Historical Direct GHG Emissions

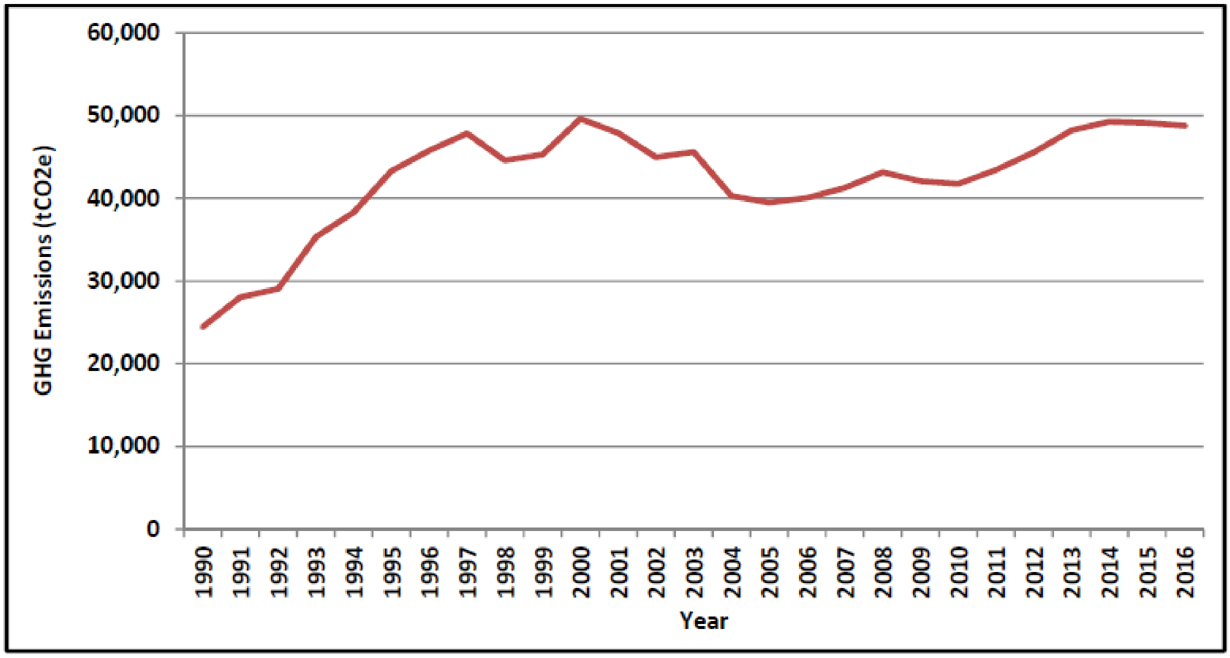
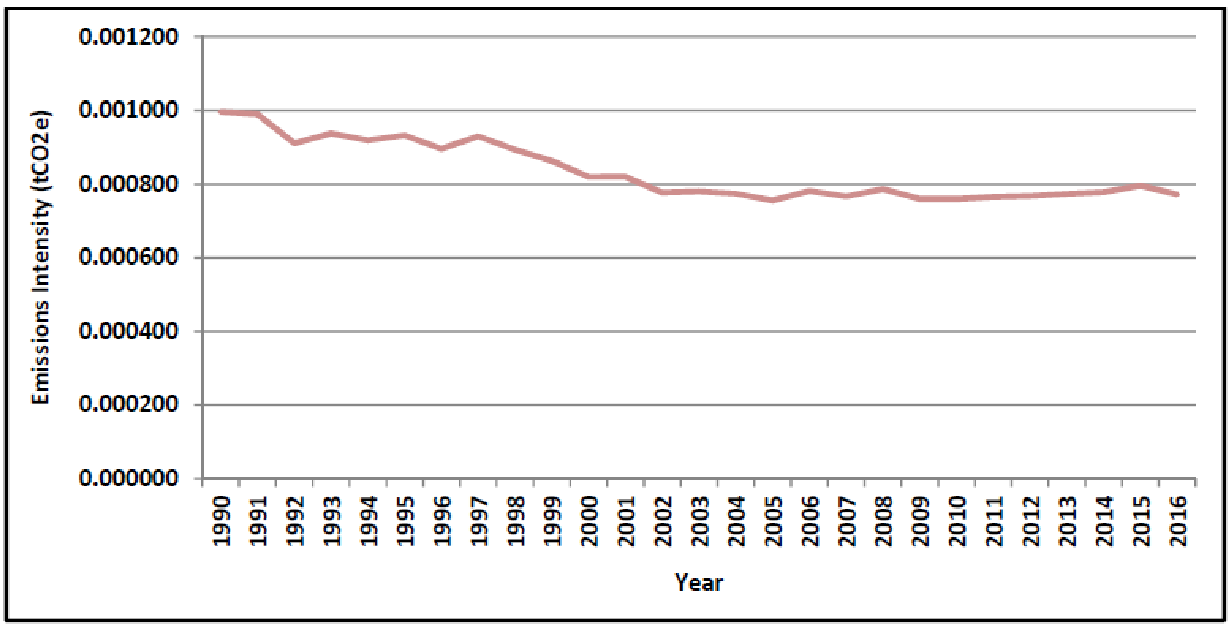


Figure 3: Historical Gross Emission Intensities



b) Annual emissions since 2013 can be seen here:

Year	Diesel Generation (kWh)	GHG Emissions (tCO_2e)	Gross Emission Intensity (tCO_2e/kWh)
2013	62,372,035	48,220	0.000773
2014	63,344,724	49,266	0.000778
2015	61,696,965	49,124	0.000796
2016	63,193,956	48,773	0.000772

OSLP - Interrogatory # 2

Reference:

Exhibit A-03-02 Attachment 1 Page 1 of 3

Interrogatory:

Remotes has indicated it involves First Nations in its business as employees, contractors, local operators and meter readers.

a) Please provide the total number for each of the following: employees, local operators and meter readers.
b) How does Remotes actively recruit First Nations?
c) Please provide the total number of First Nations employed for each of the above categories.
d) Does Remotes have any First Nations employment targets? If so, please provide an assessment of actual performance since 2013 vs these targets.
e) Why is First Nations employment not tracked as a key performance indicator in the scorecard?

Response:

a)

Employees (2017 FTEs)	60.3
Operators	37
Meter Readers	18

b) As a subsidiary of Hydro One, Remotes benefits from and participates in programs established by Hydro One to attract and retain First Nation employees. Hydro One has an active program to recruit First Nation employees through job fairs and has established a First Nation scholarship that also offers First Nation students the opportunity to apply for developmental work terms within Hydro One, including Remotes. Remotes staff have participated in Hydro One’s Indigenous Network Circle, which was created to help retain First Nation staff members who have been successfully recruited to Hydro One.

c) The total number of individuals who self-identify as First Nations is as follows:

Employees	5
Operators	28
Meter Readers	14

d) Remotes does not have any First Nation employment targets.

e) Since Remotes does not have any First Nation employment targets, it is not tracked as a key performance indicator.

OSLP - Interrogatory # 3

Reference:

Exhibit A-03-02 Attachment 1 Page 2 of 3

Interrogatory:

The Remotes business plan states the Provincial Government has received requests from Cat Lake, Pikangikum and Wunnumin to join Remotes' service territory.

a) What steps are required from Remotes in order to take over service in Pikangikum First Nation?
b) What is the timing to complete each one of these steps?
c) Does Remotes see any risks of not being able to take over service by the anticipated commissioning of the distribution line?
d) Have any other communities requested to join Remotes' service territory?

Response:

a) Remotes wrote to Pikangikum First Nation in April, 2016 noting that a new generation station or a completed connection to the provincial grid would be required for Remotes to take over service to the community of Pikangikum. The letter also included the following requirements:

    1) An agreement would need to be made among and set out each of Remotes', Pikangikum's and INAC's roles and the principles that would guide that relationship. For example, Remotes would agree to serve the community under the same terms and conditions and at the same rates as our other customers. INAC would agree to continue to fund capital under its capital programs or notify us if those programs change. Pikangikum would need to agree to allow Remotes to do its work, including collections of overdue accounts.

    2) Remotes and the Electrical Safety Authority would need to inspect the distribution assets in the community to ensure they meet standards. Some capital investment, to ensure that the assets can be operated safely, may be required. These investments would be made by the First Nation, with support from INAC.

    3) Most of the distribution assets and the generation assets in the community which were owned by Ontario Hydro and were retained by Ontario Electricity Financial Corporation (the statutory continuation of Ontario Hydro by virtue of Section 54(1) of the *Electricity Act, 1998*) ("OEFC") in 1999. These assets must be formally

transferred to Remotes as part of the agreement. OEFC, which is the legal continuation of Ontario Hydro, would need to relinquish any permits and agreements related to Ontario Hydro's occupation of the Reserve and must have a full release from the First Nation and from INAC in order to formally transfer legal title to the assets to Remotes.

4) Remotes would transfer the generation site (including the existing generating station) to the First Nation following the OEFC transfer referenced above.

5) The First Nation and the First Nation LDC would need to transfer any distribution assets that have been built since the First Nation and the First Nation LDC commenced serving the community to Remotes.

6) The First Nation would need to ensure that all permits required related to the assets have been obtained.

7) The First Nation would need to update the Environmental Site Assessment Report that was worked on during the initial discussions in 2011 and 2012.

8) The agreement would need to include a time line for the First Nation to decommission the existing generating station.

9) A time line for the remediation of the diesel site would need to be included and a remediation plan and funding share would need to be agreed to by the First Nation and Remotes.

10) The provincial government would need to amend Ontario Reg. 199/02 "Hydro One Inc." to add Pikangikum to the list of communities that Remotes is allowed to serve.

11) The provincial government would need to amend Ontario Reg. 442/01 to allow the customers in Pikangikum to benefit from the Rural or Remote Electricity Rate Protection ("**RRRP**") program.

12) Together, Remotes and the First Nation would need to apply to the OEB for approval of the purchase and sale of the community distribution assets owned by the First Nation and/or First Nation LDC to Remotes (Section 86 of the OEB Act). No Section 86 approval is required for the transfer of assets from OEFC to Remotes.

13) The OEB would need to approve the transfer and amend Remotes' licence for Remotes to be able to serve the community.

14) INAC and the First Nation would need to issue a Section 28(2) permit to Remotes. This would include a Section 28(2) permit being issued to Remotes for the distribution assets in the community.

b) Timing to complete these steps depends on the active involvement of all the parties. In the case of Pikangikum, most of the issues between the parties have been negotiated. Once the agreement is completed and signed, a request can be made to the Minister of Energy for the required Regulatory changes to allow Remotes to provide service to the community. The request to the OEB to amend Remotes licence would follow those Regulatory changes. These steps would be expected to take 6 months to 1 year.

c) Remotes expects that it will be in a position to take over service to the community of Pikangikum when the new line to the community is completed. Remotes notes that at the time this application was prepared, the estimated date to take over service was in 2019.

d) Yes, besides Pikangikum, Cat Lake and Wunnumin Lake, five Independent Power Authorities that are involved in the Watay project have written to the Minister of Energy to request service from Remotes: Muskrat Dam, Wawakapewin, Keewaywin, North Spirit Lake and Poplar Hill. Remotes assumes that once a federal/provincial funding agreement is finalized for the Wataynikaneyap project, that discussions on agreements for service to these communities would be negotiated. Remotes notes that because so many of the distribution assets and generation assets used to serve Pikangikum were never legally transferred to the First Nation by Ontario Hydro, the Pikangikum agreement is more complex than would be required for a new community. Finally, in addition to the communities involved in the Watay project, the community of Weenusk/Peawanuck, which is not considered a candidate for grid connection, also wrote the Minister of Energy to request service from Remotes. No discussions are currently underway with Weenusk.

OSLP - Interrogatory # 4

Reference:
Exhibit A-03-03 Page 2 of 3

Interrogatory:
How many REINDEER Program applications are active with Remotes? How many contracts are expected to be signed in 2018?

Response:
On average we have 3-5 projects under review, development or application at a given time. Since this program is fundamentally based on the actions of other parties as well as provincial and federal funding programs it would be difficult to forecast in future periods. Hydro One Remotes continues to support the connection of renewable projects and remains hopeful that the progress made to date will continue.

OSLP - Interrogatory # 5

Reference:

Exhibit A-03-03 Attachment 1 Page 1 of 3

Interrogatory:

Remotes has indicated that the REINDEER Program Contracts will be terminated when the distribution system is connected to the transmission grid.

a) How many existing contracts will be impacted assuming the Wataynikaneyap Transmission Project is completed by 2023?
b) What steps are being taken by Remotes to work with the First Nations, project owners, and the IESO to mitigate these impacts?

Response:

a) "Stand Alone" REINDEER projects would be cancelled after grid connection as these projects are settled based on the avoided cost of diesel fuel. Net metering projects are expected to remain in place. There are currently no "Stand Alone" projects in service in communities expected to be grid connected, so cancellation of contracts is not expected.

b) Remotes has clearly identified this issue upfront in the REINDEER program documents and the corresponding contracts, so First nations and project owners are well aware of these risks. Other than initial identification and discussion, Remotes has not actively taken on any strategies to mitigate these impacts, as it is outside our operating mandate and connection to the transmission grid is not imminent. As described above in a), we are not expecting any contract cancellations.

OSLP - Interrogatory # 6

Reference:

Exhibit A-04-01 Page 2 of 6

Interrogatory:

Remotes has indicated that from time-to-time, it holds community meetings with end-use customers. Please provide a list of community meetings since 2013.

Response:

The number of community meetings is not specifically tracked.

OSLP - Interrogatory # 7

Reference:

Exhibit A-04-01 Page 2 of 6

Interrogatory:

Remotes has indicated it has a Customer Advisory Board (CAB) that usually meets twice a year.

a) Is there a Terms of Reference or guiding documents for the CAB? If so, please provide.
b) How are Board members selected?
c) How many Board members are from Remotes First Nations customers?
d) Since 2013, please provide the number of meetings per year held with the CAB along with the participation rate (number of Board members present vs total number of Board members) for each meeting.

Response:

a) Please see Attachment 1.

b) Board members are selected by Hydro One Remote Communities.

c) 5 of the 6 members are from First Nation communities.

d) 2013 – 2 meetings, 6 CAB members, 100% attendance at each meeting
2014 – 2 meetings, 5 CAB members, 80% attendance and 100% attendance
2015 – 2 meetings, 6 CAB members, 83% attendance at each meeting
2016 –1 meeting, 6 CAB members 100% attendance
2017 – 0 No meetings were held in 2017

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HYDRO ONE REMOTE COMMUNITIES INC. CUSTOMER ADVISORY BOARD

CHARTER

Revised 2012

Hydro One Remote Communities Inc. Customer Advisory Board Charter

1. INTRODUCTION

a. Background

Hydro One Remote Communities Inc. ("Hydro One Remotes") established a Customer Advisory Board (" CAB") to assist the company in being aware of and sensitive to the needs and situations of its customers. This forum will allow various representatives from across the service area to participate in a forum where they can offer advice and recommendations to Remotes on a range of generation, distribution, customer and policy issues.

b. Purpose

This document is intended to guide the activities of the Hydro One Remotes' CAB. It communicates the expectations and processes for the members and the role of Hydro One Remotes' staff and management. It is expected that all parties will abide by the terms outlined within this document.

2. OVERVIEW

a. Mandate

The mandate of the CAB is to review information presented by the company and to offer advice and suggestions about what possible impacts the generation/ distribution policies, procedures and/or other planned services may have on the service area and/or consumer population. Although the unique experiences of each member and of each community is valued, all members of the CAB are representatives of the entire service area and not representatives from a specific community. While all advice and suggestions will be considered by Hydro One Remotes, all final decisions will remain the full responsibility of Hydro One Remotes' Management.

b. Code of Business Conduct

A Hydro One Remotes employee is expected to abide by the company's Code of Business Conduct. Similar to other Hydro One Boards, the Hydro One Remotes CAB is a component of the company's business and as such there is an expectation that members will also comply with the Code of Business Conduct. To support this expectation all CAB members will receive an orientation to the Code of Business Conduct and will be provided with a copy of the document for routine reference.

c. Confidentiality/Media and Public Relations

At times confidential information may be disclosed and/or media or public relation requests may be requested. To protect all parties from potential liability exposure, members will be informed by Hydro One Remotes that the information to be discussed is confidential. If a member feels they cannot agree to keep the information confidential, they will declare themselves in a conflict of interest and will not participate in the discussion. Members must also agree to the use of their names to promote the Advisory Board before Hydro One Remotes will disclose their names publicly.

d. Composition

The composition of the CAB is designed to be representative of Hydro One Remotes' overall customer base.

To ensure that group manageability is maintained, representation will be limited to a maximum of eight representatives, including:

- One residential customer from the Road/Rail service area;
- One service/business customer from the Road/Rail service area;
- Three air access residential First Nation customers;
- One air access service/business customer; and
- Two additional representatives.

In order to achieve a diversity of views within the Advisory Board, Hydro One Remotes will endeavor to recruit members with a diversity of experience and views from as wide a range of communities as possible.

e. Benefits

Participation in the Hydro One Remotes CAB is voluntary and advisory in nature.

Membership will offer customers and Hydro One Remotes the opportunity to work together to share their ideas and offer valuable input and advice regarding the issues and policies that have the potential to impact the customer and/or Hydro One Remotes.

Customer representatives will have the opportunity to:

- Have a voice and influence on the development and implementation of specific Hydro One Remotes policies and procedures;
- Offer consumer insights regarding customer, community and service area related matters that Hydro One Remotes faces; and

- Gain insight and in depth knowledge of the operations of Hydro One Remotes.

Hydro One Remotes will have the opportunity to:

- Receive suggestions and ideas pertaining to its services that come directly from the customers' perspective;
- Increase their understanding and sensitivity to the needs and situations of their customers;
- Consider opportunities for the delivery of improved and more cost effective service; and
- Strengthen its overall relationship with its customers.

3. MEMBERSHIP

a. Recruitment

The following process will be applied for the recruitment of all new CAB members:

i) An advertisement in Wawatay News, Hydro One Remotes’ newsletter or a standard poster size advertisement mailed to each community for posting in public locations, and/or recommendations from Hydro One Remotes staff or from CAB members.

ii) Interested applicants will be asked to prepare a letter of interest.

iii) All candidates must reside or work in a community serviced by Hydro One Remotes

iv) Candidates will be selected by Hydro One Remotes and will be invited to participate in an interview.

v) In selecting members, Hydro One Remote Communities will be mindful of the diversity of communities within its service territory and will attempt to recruit members from a broad range backgrounds, interests and communities.

vi) Once selection is finalized successful candidates will receive an orientation package including a welcome letter and the date, time and location for the meeting.

b. Term

i) The standard membership term will be twenty-four consecutive months (2 Years).

ii) Membership terms will be extended based on mutual interest and consent.

iii) Replacement planning will be discussed and take place as required.

c. Vacancies

If a member resigns, or is unable to fulfill their duties Hydro One Remotes may appoint a new member.

d. Delegates

There will be no alternate delegates appointed to the CAB. Only confirmed members will attend meetings. This ensures continuity of the discussions and recommendations made at prior meetings.

e. Membership List A membership list will be maintained by Hydro One Remote Communities Inc.

f. Termination Clause

Hydro One Remote Communities Inc. reserves the right to terminate and/or disband the Customer Advisory Board. Notice of termination shall be provided to all members and First Nation Leadership in writing and shall include an explanation for the termination decision.

4. MEETING PROCEDURES - GENERAL

a. Number and Duration of Meetings

Advisory Board Meetings will consist of at least one face to face meeting per year. The additional meetings may include face to face meetings and/or teleconference meetings.

b. Meeting Schedule

Meetings will be held during the year as agreed by CAB members and Hydro One Remotes.

c. Location

Face-to-face meetings will normally take place in Thunder Bay.

d. Notice

Notice will be provided by Hydro One Remotes at least one month before each meeting. Meeting notices will be distributed in writing and follow up telephone calls will be made to verify attendance.

e. Discussion Topics

While the majority of discussion topics will be selected by Hydro One Remotes there will be regular opportunity for CAB members to bring forward discussion topics on matters that are relevant to the services provided by Hydro One Remotes. Meeting topics will be included with all meeting notices.

f. Meeting Materials

Pre-reading and other relevant materials will be distributed to Hydro One Remote Communities Inc. CAB members prior to each meeting when possible. All materials will be designed with the intent to educate and/or inform members on the key issues to be discussed.

g. Allowable Expenses

All reasonable out of pocket expenses incurred by members to travel to and from all scheduled meetings will be reimbursed by Hydro One Remotes according to the following guidelines:

i. All travel arrangements (air, rail) will be coordinated directly by Hydro One Remotes and details will be provided to CAB members as part of their meeting package.

ii. If alternative travel arrangements are necessary, prior approval must be received in writing from Hydro One Remotes at least two weeks prior to the scheduled meeting.

iii. If no prior approval is received the CAB member will be responsible for costs incurred.

iv. Individuals traveling by car will be reimbursed according to Hydro One Remotes Mileage Reimbursement Policy.

v. Lunches for all full day meetings will be arranged on site and costs will be covered by Hydro One Remotes. CAB members who wish to have lunch off site will be responsible for costs incurred.

vi. Where necessary, accommodations will be booked and direct billed to Hydro One Remotes for those individuals requiring an overnight stay. If reasonable travel arrangements are made that do not support an overnight stay, and the CAB member wishes to stay, he/she will be responsible for any costs incurred.

vii. Breakfast and dinner will be reimbursed, breakfast at $8.25, dinner at $20.00, and lunch (when not provided) at $11.25. Receipts or missing receipt forms are required.

5. MEETING PROCESS

a. Meeting Agenda

To support consistency the following standard agenda will be used:

1. Opening Prayer
2. Welcome and introductions
3. Review and approval of agenda
4. Review and approval of minutes from previous meeting
5. Update from Hydro One Remote Communities Inc.
6. New Business Items
7. General Discussion/Recommendations
8. Next meeting date and location
9. Closing Prayer

b. Chairperson

i. All meetings will be chaired by Hydro One Remotes.

c. Minutes

i. Minutes will be taken by a Hydro One Remotes employee.

ii. Minutes will be distributed to all members at least one month before the next meeting as part of the distribution package.

iii. Hydro One Remotes CAB members will approve all minutes at the following meeting.

d. Process for Preparing Suggestions for Hydro One Remotes

All members of the CAB understand that any suggestions brought forward are subject to review and final approval by Hydro One Remotes Management. To support the formulation of suggestions the following process will be applied:

i. Discussion items will be presented by knowledgeable Hydro One Remotes staff representative of the service area, i.e. Distribution, Collections, and Generation Rates etc.

ii. Such presentations shall include but not be limited to the following:

- Item to be discussed,
- What type of advice/suggestion is needed (i.e. impact analysis, suggested improvements etc.),
- Background information,
- Statistical information if relevant,
- Timelines for implementation if relevant, and
- Any other relevant information to support the formulation of a response by the CAB members.

iii. CAB members will have the opportunity to ask questions regarding the information presented.

iv. CAB members will be asked to share their perspective by responding to questions similar to the following:

  - What do you think will be the positive impacts on the customer, the community, and Hydro One Remotes service area overall? Why?
  - What do you think will be the negative impacts on the customer, the community, and Hydro One Remotes service area overall? Why?
  - What do you think Hydro One Remote Communities Inc. can do to maximize the positive impacts?
  - What do you think Hydro One Remotes can do to minimize the negative impacts?
  - What is (are) your suggestions(s) to Hydro One Remotes?

e. Communication and Feedback – From Hydro One Remotes

i. All submissions prepared by the CAB will be brought forward to Hydro One Remotes Management for review and approval.

ii. If approved for implementation, Hydro One Remotes will offer regular updates on progress.

iii. If not approved for implementation Remotes will prepare and/or present a formal response to the CAB including an explanation about why the recommendation was not accepted and what will be done with the recommendations made.

f. Other

It is anticipated that the CAB will evolve over time and as such, other roles, responsibilities, task forces and/or sub-committees may be required to support the overall operations and activities of the CAB. These alternative requirements and/or activities will be identified and discussed routinely as part of the meeting process.

OSLP - Interrogatory # 8

Reference:

Exhibit A-04-01 Page 5 of 6

Interrogatory:

Remotes noted earlier in the application that, in order to reach the largest number of customers in its service territory, Remotes requested that notice of this Application be published in English, Cree, Oji Cree and Ojibway. In terms of engagement with end use customers:

a) Which community engagement materials are translated into the local languages? If none, how could Remotes utilize translated engagement materials and what would be the estimated cost?
b) Are translators utilized at community engagement activities with end users? If not, what is the estimated cost for the use of translators at community engagement activities with end use customers?

Response:

a) None of the written materials related to engagement were translated into local languages. Remotes does not have an estimate of the cost to translate the written materials as these materials were prepared for meetings with customers fluent in English.

b) Translation for the community engagement activities outlined in the schedules under Exhibit A, Tab 4 and in section 4.1.6 of the DSP was not required as the end-use customers at these meetings were fluent in English.

OSLP - Interrogatory # 9

Reference:

Exhibit A-04-01 Attachment 1 Page 1 of 5

Interrogatory:

In the "Customer Engagement Activities Summary":

a) Why is there no reference or summary of engagement with end use customers?
b) Why is there no reference to the "Opiikapawiin Services LP, Hydro One Remote Communities Inc., and Ontario Energy Board Watay Community Workshop?
c) For both of these, please provide a list of customer needs and preferences identified through this engagement. What actions will be taken to respond to identified needs and preferences?

Response:

a) All of the customer engagement activities referenced in Exhibit A-04-01 Attachment 1, were with end-use customers. In fact, all of the schedules included in Exhibit A Tab 4 document various engagement activities with end use customers.

b) The Opiikapawinn Services Meeting, Hydro One Remote Communities and Ontario Energy Board Watay Community Workshop discussions were summarized by one of the Tribal Councils and is included in the DSP as Appendix B. Exhibit A, Tab 4, Schedule 2 sets out the verbatim meeting notes from this two-day workshop are included in Exhibit A, Tab 4, Schedule 2.

c) The two-day workshop was a single meeting. The impact of the customer preferences identified in this meeting is outlined in Section 2.3 of the DSP.

OSLP - Interrogatory # 10

Reference:

Exhibit A-04-01 Attachment 2 Page 16 of 59

Interrogatory:

In reference to the community question around having someone available at Remotes customer service that speaks the language.

Does Remotes have someone available through the customer hotline who speaks Cree, Oji Cree and/or Ojibway. If no, what are the barriers and costs to providing such a service in at least one of those Indigenous languages?

Response:

No. Our customer hotline representatives do not speak Cree, Oji Cree and/or Ojibway.

Securing a contract translator is possible, but of limited value to have someone available for the few times required. In general, English speaking representatives (Band office or relatives) will contact our office, on an elder's behalf if translation services are required.

OSLP - Interrogatory # 11

Reference:
Exhibit A-04-01 Attachment 2 Page 25 of 59

Interrogatory:
Does Remotes have a full time staff dedicated to First Nations relations? If not, what would be the cost for such a position?

Response:
Remotes does not have a full-time employee, but the service is provided by Hydro One Networks Inc. for a fee of $66,000 as part of an Affiliate Agreement. The cost to create a new position at Hydro One Remotes is estimated at $150,000 including salary and benefits (based on wages for similar positions at Hydro One Networks). Program costs would be additional. All of Remotes' staff are tasked with building relationships with customers, including First Nations. All of Remotes staff have taken training and courses regarding the history, social and political realities of Indigenous peoples in Canada, and have taken part in courses regarding the historic and current factors that influence relationships with Indigenous communities in Ontario. Staff have also participated in training on creating effective working relationships and relationship building practices. Remotes is concerned that tasking a single individual with accountability for relationships would not support an improvement to the overall customer experience and could potentially degrade existing relationships.

OSLP - Interrogatory # 12

Reference:

Exhibit A-04-01 Attachment 2 Page 35 of 59

Interrogatory:

In reference to the following customer feedback provided to Remotes: "Late payment charge: 19.5% on an annual basis is too high and the time frame that kicks in is too short with 20 days. To consider with 60 days' time frame and to be tied to borrowing rates/user rate fees and not market-based rates."

a) What metrics and statistics are used to track late payment charges? How do these metrics compare to industry comparables?
b) For residential customers from 2013 - 2017, please provide an annual summary of total revenue from late payment charges and percentage of revenue from late payment charges. How does this compare to industry comparables?
c) What is required for Remotes to provide better late payment charge terms to its residential customers?

Response:

a) Remotes tracks the late payment charges monthly and reports with other revenue. Our late payment charges are similar to other LDC's and are within the rules as outlined in the distribution system code. We are not aware how we compare to the industry as to amounts earned through late payment charges.

b) The chart as follows lists the late payment charges for the years 2014 to 2017. The data is not available for all of 2013 due to the reporting that was available under the old Customer Information System. In 2014 there was a suspension of the late payment charges for part of the year resulting in lower revenues when compared to other years. As stated above we are not aware of how we compare to the industry.

Late Payment Charges - Residential Customers (in $K)

Historic Years				
	2014	**2015**	**2016**	**2017**
Energy Late Payment -Residential	27	118	111	113
% of Revenue from Residential Energy Late Payment Charges	0.08%	0.39%	0.36%	0.35%

c) For Remotes to provide better late payment charges to customers either an increase to RRRP or to customer rates would be required. In addition, there would be a cost to program the change in the billing system.

OSLP - Interrogatory # 13

Reference:

Exhibit A-04-01 Attachment 2 Page 35 of 59

Interrogatory:

How do connection charges for Remotes compare to connection charges at Hydro One Networks?

Response:

Remotes does not believe that its connection charges can be compared to Networks, which has a connection component recovered through its distribution rates. Remotes does not include the costs of connection component in its customer rates or RRRP requirement. Under the Electrification Agreements, INAC is responsible for funding changes to the distribution system associated with load growth, including connections. Connection charges are calculated based on the actual cost to connect, including materials, labour and transportation.

OSLP - Interrogatory # 14

Reference:

Exhibit A-04-01 Attachment 2 Page 58 of 59

Interrogatory:

What additional investments would be required for Remotes generators to act as backup power once the communities are connected by Wataynikaneyap Power?

Response:

The existing diesel generation stations are designed to operate as prime power generation stations that have a diesel generator running continuously. If they are to be converted to stand-by generation stations, additional insulation and heating for the building and equipment will need to be installed and maintained. Modifications to the stations' protection and main breaker/station service will need to be made to allow the grid to supply station service and heating safely. Also, some consideration should be given to the amount of fuel storage that will be maintained at a station. Investment in the remote reporting of equipment status to the Grid Control Center and revenue metering will need to be installed at this facility.

OSLP - Interrogatory # 15

Reference:

Exhibit A-04-01 Attachment 3 Page 5 of 29

Interrogatory:

With regards to the customer service survey goals and methodology:

a) Was the survey offered in any other language than English?
b) Were the communities (through Chief & Council) or the Community Advisory Board involved in the design and methodology of the survey?
c) Are the survey results presented to Chief & Council and the Community Advisory Board? If so, what was the feedback?
d) Has Remotes considered any other survey delivery methods?

Response:

a) The survey company Remotes uses employs indigenous callers who are able to speak English and indigenous language(s). Remotes is not aware of any customers requesting the survey in any language other than English.

b) Remotes has undertaken customer surveys since 2004. The Customer Advisory Board has offered input into previous survey questions and the current questions reflect their input. Communities, through Chief and Council, were not asked for input into the survey questions.

c) The survey is primarily for Remotes' use, to get feedback from customers. Previous survey results have been presented to the Customer Advisory Board. In 2011, CAB feedback included: improvements to meter reader training and tools; why were customers in Webequie less satisfied with reliability; concern about high bills. In 2013, the CAB were primarily interested in the reasons for improved satisfaction, as results were very high that year. In 2015, Remotes focussed the discussion on ways to improve customer knowledge of various programs (i.e. LEAP, conservation). The 2017 results have not been presented to the CAB.

d) Remotes has considered different delivery methods. In 2003/2004, Remotes hired a contractor to mail surveys in English and the local First Nation Language to customers and hired individuals who would encourage customers to complete the surveys and who would pick up completed surveys and mail in envelope. These individuals were offered a flat fee for each survey received from the community they were responsible for. The project was more costly than a telephone survey and had disappointing results in terms of customer response. Remotes looked into on line surveys in 2013 and at that time, it was not clear how many customers were active on the internet and how an online survey could be confined to Remotes' service territory. Based on the results from the 2017 survey, an on line survey will be considered as a potential alternative for the 2019 survey.

OSLP - Interrogatory # 16

Reference:

Exhibit B-01-01 Page 24 of 481

Interrogatory:

Remotes has indicated that there is a lack of skilled trades contract resources living in the communities and there are very few contractors who work in them.
What steps are being taken to support development of skilled trades in the communities?

Response:

Remotes employs and provides training to plant operator/agents that live in the community.
Skills training includes:

- Minor generator maintenance procedures for changing oil and filters.
- Maintenance inspection procedures.
- Control of the station, i.e. start stop generators.
- Spill and other emergency response.
- Fuelling operations.
- Waste management.
- Safety and environmental responsibilities.

Remotes also employs and provides training to local meter readers that live in the community. Training includes:

- Meter identification
- Meter reading and data collection
- Account verification and documentation
- Theft of power, meter damage, etc.
- Safety and environmental responsibilities

Remotes also employs occasional labourers. The training and oversight provided would be specific to the job at hand.

OSLP - Interrogatory # 17

Reference:

Exhibit B-01-01 Page 28 of 481

Interrogatory:

There is a recommendation to employ someone in the community to assist with customer service issues.

a) Has this been considered? If not, what are some options to increase local customer service representation in the communities?
b) In what ways could local customer representation save costs and improve customer service?

Response:

a) The recommendation of employing someone in the community to assist with customer service issues has been considered, but given the small number of customers in each community and the infrequency of service requests, establishing a community customer service liaison in each community would be of limited value. Unfortunately, there is not enough work within each community to drive the need for a dedicated local customer service rep.

b) Customer service costs would be much higher. Remotes currently employs two Customer Service Representatives to serve 21 communities. Increased supervisory/contractor oversight costs would also be involved.

OSLP - Interrogatory # 18

Reference:

Exhibit B-01-01 Page 87 of 481

Interrogatory:

Remotes has indicated that, as per the Order-in-Council from the Provincial Government, 16 remotes communities may be connected to the transmission system. Nine of these communities are presently served by Remotes and at least two more communities are expected to be served by Remotes in the future.

a) Has Remotes altered or scaled down its investments in anticipation of these connections?
b) If so, how would its key performance indicators be impacted if the communities are not connected or are delayed in being connected?
c) If so, how would this be communicated to impacted customers?
d) Does Remotes typically make major investment decisions based on external projects that are still in the planning stages?

Response:

a) Generation: There are two drivers for investment in generation, load/capacity increase and renewal.
   Capacity increase planning timelines are customer driven and sometimes as short as a one year planning cycle. As the grid line date for connection becomes clearer, the date will likely impact upgrade decisions.
   Renewal decisions are driven by cost, reliability and safety. Generator Operate Hours vary from year to year and are forecast annually. The planning cycle for this work can be as little as 2 years. As the grid line date for connections becomes clearer, we will update the plan.

b) Not scaled down yet.

c) Changes that impact capacity increase timelines are made with community leadership involvement and DISC (INAC). Meetings are held with the community leadership and when possible with the community. Grid connection timelines are part of the considerations by the community.
   We expect that changes/scaling down the renewal decisions would be communicated with the community leadership and DISC.

d) Remotes has modified major investment decisions based on projects like the Watay grid connection. We have utilized the existing facilities infrastructure when increasing the capacity of plants rather than all new construction. The Wapekeka- KI tie line and station capacity increase is one example of these modified decisions.

OSLP - Interrogatory # 19

Reference:

Exhibit G1-05-01 Page 5

Interrogatory:

Remotes has provided a definition of Standard A customers and has noted several exceptions. How were these exceptions determined?

Response:

These exceptions are set out in the Rural or Remote Rate Protection Regulation (O.Reg 442/01).