REQUESTOR NAME	**VECC**
INFORMATION REQUEST ROUND NO:	**# 1**
TO:	**Wellington North Power Inc. (WNP)**
DATE:	**June 7, 2012**
CASE NO:	**EB-2011-0249**
APPLICATION NAME	**2012 Cost of Service Electricity Distribution Rate Application**

RATE BASE

1. Reference: Exhibit 2, Tab 5, Schedule 6

a) Please provide the amounts spend on office renovations and office equipment for each year 2008, 2009, 2010 and 2011 and that proposed for 2012.

<u>Wellington North Power Inc. – Response</u>

a. The table below summarizes the amounts that Wellington North Power Inc. has spent on office renovations and office equipment between the years of 2008 and 2011, together with the forecast for 2012 Test Year:

Year	Amount Spent	Forecast
2008	$9,938	
2009	$4,351	
2010	$50,650	
2011	$25,769	
2012		**$334,000**
	$90,708	**$334,000**

It should be noted that the proposed forecast for the 2012 Test Year is:

- A forecast view;
- Subject to recommendations from structural engineers and architects, as explained in WNP' application as well as subsequent updates included in Interrogatories responses.
- Subject to approval of WNP's rate application request in order to fund some / all of the required renovations.

The table below itemizes what the amounts have been spent on in 2008, 2009, 2010 and 2011 together with the proposed items for the 2012 Test Year:

Year	Description	Amount Spent
2008	Building and fixture renovations Project was scoped to replace ceiling tiles, added support beams to floor in front office and crawl space, remove walls, redirect heat ducts, install ceiling, flooring, shelving in storage area and repairing to drywall.	$9,170
2008	Office Equipment - Project was to purchase a conference call phone	$768
2009	Lighting Retrofit in middle-office and back-office of main building	$2,930
2009	Security System Upgrade - installation of upgrade site alarm	$565
2009	Battery Backups for computer terminals	$856
2010	Office Storage Space	$2,125
2010	Repairs to Shop Roof (Arthur Shop)	$12,960
2010	New Office Furniture	$2,667
2010	Postage/Stuffing Machine	$32,898
2011	Photocopier - Replace existing older model	$6,495
2011	Building Upgrades - replacing drywall, installing receptacles, repairing floor	$10,268
2011	Office Furniture - Replacement of office furniture	$5,606
2011	Barrier Free Drawings - building drawings to assess access to/from building	$3,400
2012	Shop addition - Add 2 bays to the existing building to allow conversion of the west-side shop for office space	$200,000
2012	Building Renovations - Accessibility (Front Entrance), Close in Stairway to Operations, Washroom Alterations and Flooring for Health & Safety of Employees	$40,000
2012	Garland Canada (Watertight) - Roof Replacement - replace roof as leaking	$66,000
2012	Installation of Security Cameras - Front counter, Rear Entrance, Yard for security and safety	$4,000
2012	Replacement of HP 8100 Laser Printer - Purchased in 1999 and concerned unit will fail. This printer is used for all customer bill printing	$9,500
2012	Replace Existing Board Room Table - Table has mould, may be emitting mould spores	$2,500
2012	West Shed Insulation, heating and new garage doors to be able to use for trucks and storage	$12,000

2. Reference: Exhibit 1, Tab 2, Schedule 5, page 49

a) Please clarify whether the one person noted as being dedicated to MDM/R activity is doing only this work for the next four years.

Wellington North Power Inc. – Response

a. WNP wishes to clarify that the one person currently dedicated to MDM/R activity is not solely dedicated to these duties for the next four years.

   This individual has been 100% dedicated resource involved with the testing and implementation of MDM/R prior to WNP transition to Time-of-Use (TOU) pricing. WNP transferred to TOU on January 31, 2012.

   Currently this individual is committed to resolving post-implementation activities and data management. As MDM/R queries reduce and become less complex, this individual will spend some of their time focusing on other billing activities. However, they will still be responsible for ongoing daily troubleshooting of meter readings and MDM/R issues as well as meter data file transfers.

3. Reference: Exhibit 2, Tab 1, Schedule 1, page 177

a) Please restate Table 2.2 on a CGAAP basis showing any IFRS adjustment separately**.**

Wellington North Power Inc. – Response

a. Although Wellington North Power Inc. was directed to file its Cost of Service application in MIFRS, the company is deferring its transition to the International Financial Reporting Standards (IFRS), until such time as it is mandate for Rate Regulated Entities. Therefore, there is no requirement to update Table 2-2 because the 2012 Test Year, in principle, under CGAAP or MIFRS is the same. There were no adjustments for the change in the current obligation, or the regulatory treatment of the obligation.

As the LDC has deferred its transition to IFRS, there is no change in the current obligation, or the regulatory treatment of the obligation. These amounts have not been incorporated anyway in the revenue requirement.

At the time of transition to IFRS, Wellington North Power Inc. will follow the guidelines and direction from the Ontario Energy Board Uniform System of Accounts for Electricity Distributors, the International Accounting Standards Board, (IASB) the Accounting Standards Board of Canada (AcSB) and the advice of the company's external auditor.

From January 2012, WNP did adjust its depreciation typical useful life periods, as recommended by the Kinectrics Study commissioned by the OEB (The Asset Depreciation Study for the OEB by Kinectrics Inc. (dated July 8, 2010 – Report No.: K-418033-RA-001-R000) that has been circulated by the OEB for LDC use.). The adjusted depreciation periods are shown in WNP's application in Exhibit 2, Tab 3, Schedule 1 – Table 2-15, page 205.

WNP has no change in its capitalization accounting policy, as it did not capitalize indirect costs or administrative burden.

WNP has updated Table 2-2 to reflect 2011 actual data, as per table below:

Description	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Gross Fixed Assets	$9,096,307	$9,767,059	$10,181,113	$10,569,965	$12,143,669	$12,616,728
Accumulated Depreciation	$5,125,858	$5,173,881	$5,334,026	$5,780,372	$6,476,586	$6,627,125
Net Book Value	$3,970,449	$4,593,179	$4,847,087	$4,789,593	$5,667,083	$5,989,603
Average Net Book Value	$3,970,449	$4,077,379	$4,720,133	$4,818,340	$5,228,338	$5,828,343
Working Capital	$7,864,103	$7,905,245	$7,962,966	$9,389,759	$10,539,218	$12,303,351
Working Capital Allowance	$1,179,615	$1,185,787	$1,194,445	$1,408,464	$1,580,883	$1,845,503
Rate Base	$5,150,064	$5,263,166	$5,914,578	$6,226,804	$6,809,221	$7,673,846

4. Reference: Exhibit 2, Tab 51, Schedule 1, page 177-178

a) WNP states that the percentage rate base changes year-on-year is consistent with the exception of 2010. However, the growth in fixed assets between 2010 and 2011 was almost 14%. Please explain this variation. Please quantify the portion of 2011 asset growth that was attributable to smart meter investments.

Wellington North Power Inc. – Response

a. The table below illustrates the Rate Base values and Closing Fixed Asset balances for the period 2008 onwards, based upon the information submitted with WNP's application.

Rate Base Analysis

	2008 OEB Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Rate Base	$5,150,064	$5,263,166	$5,914,578	$6,226,804	$6,809,221	$7,673,846
$ Variance compared to previous year			$651,412	$312,226	$582,417	$864,625
Rate Base % change Year-on-Year			12%	5%	9%	13%
$ Change From 2008 OEB Approved Value		$113,102	$764,514	$1,076,739	$1,659,156	$2,523,781
$ Yearly Variance since 2008 OEB Approved				$538,370	$553,052	$630,945
% Change From 2008 OEB Approved Value		2.20%	14.84%	20.91%	32.22%	49.00%
% Yearly Variance since 2008 OEB Approved				10.45%	10.74%	12.25%
Gross Fixed Assets (Closing Balance)	$9,096,307	$9,767,059	$10,181,113	$10,569,965	$12,143,669	$12,616,728
% Change to previous Years			4%	4%	15%	4%

As noted by the Intervenor, in 2010 WNP's Rate Base grew by 5% compared to 2009.

In 2010, Gross Fixed Assets value did not increase in value at the same rate as prior or latter years. The reason for this is two-fold:

- During 2010, the LDC continued to invest funds and resources for Smart Meter implementation and roll-out to achieve the directive issued by the Minister of Energy (July 14, 2004).

- Wellington North Power Inc. was required to pay for its' Smart Meter expenditures before being able to draw funds from the financing institution. As a result of this, the LDC needed to carefully manage its cash-flow and actively made the decision to reduce the amount of money allocated to capital projects for 2010. (The LDC did not limit any capital spending to projects that could have jeopardized the safety, reliability and/or service of its distribution system.)

As noted by the Intervenor and demonstrated in the above table, the Fixed Asset growth between 2010 and the 2011 Bridge Year was 14%. This growth was exacerbated because:

- In its application in the 2011 Bridge Year, WNP included the value of assets attributed with Smart Meters;
- Prior to 2011, the fixed asset values attributed with Smart Meters was not included in WNP's asset base and therefore not included in the LDC's 2010 Rate Base (i.e. the 2011 Bridge Year is the first year that WNP realized Smart Meters asset values in its Rate Base)
- As illustrated in Exhibit 2, Tab 3, Schedule 1 Table 2-16, illustrated the change in Fixed Asset costs for each year with supporting narrative explaining about the addition of Smart Meter Assets in the 2011 Bridge Year. Below is a summary of this information:

	Cost					
Year Ending	Opening Balance	Additions	Disposals	Closing Balance	$ Change to Prior Year	% Change to Prior Year
2008	$ 8,365,897	$1,435,546	$ (34,384)	$ 9,767,059		
2009	$ 9,767,059	$ 673,123	$(259,069)	$10,181,113	**$ 414,054**	**4.24%**
2010	$ 10,181,113	$ 421,750	$ (32,898)	$10,569,965	**$ 388,852**	**3.82%**
2011 Projection	$ 11,550,307	$ 597,297	$ (3,935)	$12,143,669	**$1,573,703**	**14.89%**
2012 Projection	$ 12,143,669	$ 983,803	$ 510,744	$12,616,728	**$ 473,059**	**3.90%**

The following observations can be made for the above table:

- 2010 Closing Balance ($10,569,965) and 2011 Opening Balance ($11,507,635) has a variance of $937,669. This is due to the Bridge Year Opening Balance including Smart Meter Costs, specifically;

o Smart Meters	$577,899	+
o Smart Meter Computer Soft/Hardware	$359,770	
Total	$937,669	

As part of Wellington North Power Inc.'s 2012 Cost-of-Service rate application, it is requesting recovery of Smart Meter costs which is described in Exhibit 10. In addition, the LDC is also requesting Smart Meters to be included in the company's Rate Base and Revenue Requirement for 2012 and onwards.

The table below illustrates the Smart Meter information that was incorporated into WNP's 2011 Bridge Year:

	Smart Meter Opening Balance	Smart Meter Additions in 2011
Smart Meters	$577,899	$2,323
Smart Meters Hardware	$114,618	$3,064
Smart Meters Software	$245,153	$35,958
	$937,669	**$41,345**

The table below shows the proportion of the 2011 Test Year Fixed Asset Opening Balance and Additions that were related to Smart Meter assets:

Fixed Asset Open **(before** Smart Meters included)	$10,569,965
Smart Meter Asset inclusion	$937,669
Fixed Asset Opening Balance (**after** Smart Meters included)	$11,507,635
Proportion attributed to Smart Meters	8.15%
Fixed Asset Additions in 2011 (not Smart Meter related)	$589,488
Smart Meter Asset Additions in 2011	$41,345
Total Fixed Additions (excl. Contributions & Grants)	$630,833
% of 2011 Additions related to Smart Meters	6.55%

5. Reference: Exhibit 2, Tab 2, Schedule 1, page 187

a) How many customers of WNP customers are served by distribution assets owned by Hydro One?

b) What amounts did WNP pay Hydro One to service load transfer customers in 2010, 2011 and forecast for 2012?

Wellington North Power Inc. – Response

a) The table below illustrates how many WNP customers are served by assets owned by Hydro One

b) The table below illustrates payments between Hydro One and WNP together with WNP's forecast for 2012.

It should be noted that in 2012, the one MicroFIT customer is anticipated to transfer to WNP. The MicroFIT asset was supplied and installed by WNP.
In its forecasting, WNP has applied 75% of 2011 generation data for 2012 as it is expected that this transfer could happen in Quarter 4 of the Test Year. WNP is currently working with Hydro One and the customer regarding the transfer.

In its forecasting for Customer Class Usage, WNP has applied the percentage change between the years of 2011 and 2012 that was derived Weather Normalization modeling technique as discussed in Exhibit 2.

WNP's Long-Term Load Forecast summary:

Long-Term Load Transfers:

Wellington North Power Inc. Billed Hydro One:			Customer Class Calculated Usage including Loss			Number of Customers		
	Billed Year	Amount Billed	Residential	General Service <50 kW	microfit	Residential	General Service <50 kW	MicroFIT
Jan 1 to December 31, 2007	2008	$18,866.66	71,420	116,259		3	2	
Jan 1 to December 31, 2008	2009	$12,835.67	75,352	50,533		3	2 finaled	
Jan 1 to December 31, 2009	2010	$9,088.80	85,055			3	0	
Jan 1 to December 31, 2010	2011	$8,390.50	69,232			3	0	0
Jan 1 to December 31, 2011	2012	$8,585.96	64,153			3	0	0
2012 Forecast	2013	$8,350.00	63,896			3	0	0

To calculate the forecast, applied the same % change as per Weather Normalization model

Hydro One Billed Wellington North Power Inc.	Billed Year	Amount Billed	Residential	General Service <50 kW	microfit	Residential	General Service <50 kW	MicroFIT
Jan 1 to December 31, 2007	2008	$8,043.98	31,288	62,189		2	3	
Jan 1 to December 31, 2008	2009	$11,103.91	48,548	75,555		2	3	
Jan 1 to December 31, 2009	2010	$12,916.61	37,042	102,103		2	3	
Jan 1 to December 31, 2010	2011	$10,772.35	75,488	31,908	(5,552)	4	1	1
Jan 1 to December 31, 2011	2012	$10,931.63	73,093	33,541	(16,370)	4	1	1
2012 Forecast	2013	$10,800.00	72,801	33,206	(12,278)	4	1	0

To calculate the forecast, applied the same % change as per Weather Normalization model

To calculate the forecast, applied the same % change as per Weather Normalization model

1 x MicroFIT customer is wants to transfer from Hydro One to WNP. WNP working with Hydro One. Forecasted this will happen in Q3 of 02012, therefore calculated 3/4 of year generation credit

6. Reference: Exhibit 2, Tab 4, Schedule 1, page 210

On April 12, 2012 the OEB issued revised guidelines for working capital reducing the default value (i.e. not supported by a lead/lag study) from 15 to 13% of the cost of power and controllable costs for 2013 cost of service filings.

a) Please explain why in light of the late filing why WNP believes that it should apply a 15% amount rather than the new value established by the Board.

b) Does WNP bill all its customers on a monthly basis?

Wellington North Power Inc. – Response

a. Wellington North Power Inc. believes that 15% working capital allowance should be applied on the principles of:
   - Applying 15% is consistent with other LDC 2012 Cost-of-Service applicants. Through being consistent, this may assist the OEB and Intervenors when reviewing WNP's revenue requirement and bill impact information and comparing this to similar LDC's who have also filed for 2012 rates.
   - WNP have adhered to the guidelines and filing requirements that were issued by the OEB, (Chapter 2 of the Filing Requirements for Transmission and Distribution Applications June 22, 2011). Section 2.5 – Exhibit 2 – Rate Base, page 17 onwards describes working capital allowances approaches , and in particular:
     - Section 2.5.1.4 – Allowance for Working Capital:
       "The applicant may take one of two approaches for calculation of its allowance for working capital: (1) the 15% allowance approach; or (2) the filing of a lead/lag study."
       WNP did not file a lead/lag study and adopted the 15% allowance approach in its application as guided by the OEB;
     - In the application of "the15% Allowance Approach is calculated to be 15% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General)."
       In its application, WNP applied the 15% to the Cost of Power and controllable expenses as directed by the OEB;
     - Page 19 of this document states:
       "Cost of Service Applications for the 2013 Rate Year
       The Board informs distributors that 2012 will be the final year for which the 15% Allowance Approach will be allowed as a default value. The Board is reviewing the possibility of requiring distributors to file lead/lag studies for the purpose of establishing the working capital allowance for the 2013 rate year."

WNP is a 2012 Cost-of-Service applicant and is applying for the 2012 (not 2013) Rate Year.
Despite submitting its' 2012 Cost of Service application late, the OEB has not guided the LDC to divert from the methodology or principles that were issued in the Chapter 2 of the Filing Requirements for Transmission and Distribution Applications - June 22, 2011.

- On April 12, 2012, the OEB issued a letter entitled ***"Re: Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications – Allowance for Working Capital"***
  In this letter the following points are of particular interest:

  "Section 2.5.1.4 of the Filing Requirements notes the following:

  > *Cost of Service Applications for the 2013 Rate Year*
  > The Board informs distributors that 2012 will be the final year for which the 15% Allowance Approach will be allowed as a default value. The Board is reviewing the possibility of requiring distributors to file lead/lag studies for the purpose of establishing the working capital allowance for the 2013 rate year"……
  > Based on the results of WCA studies filed with the Board in the past few years, the Board has determined that the default value going forward will be 13% of the sum of cost of power and controllable expenses. This default value will be <u>applicable to 2013 rate applications</u> and beyond……
  > The Board therefore revises section 2.5.1.4 of the Filing Requirements, specifically the 15% Allowance Approach to establish a 13% Allowance Approach as the new default value. The following revised excerpt of section 2.5.1.4 is effective immediately for <u>2013 cost of service applications</u>:
  >
  > > The Applicant may take one of two approaches for the calculation of its allowance for working capital: (1) the 13% allowance approach; or (2) the filing of a lead/lag study."

  WNP has reviewed the letter issued by the OEB to all distributors dated April 12, 2012 and concludes that the change to 13% working capital allowance is effective to <u>2013 rate applications and beyond</u>, not 2012. The letter <u>does not</u> make reference to amending the 2012 rate application working capital allowance methodology for those LDC's that were delayed in submitting their 2012 Cost of Service application.

b. WNP can confirm, the LDC bills all of its customers on a monthly basis

7. Reference: Exhibit 2, Tab 5, Schedule 6, page 251

a) Please provide the reference to the Ministry of Energy requirement to "graphically present Smart Meter consumption data".

b) What is the total amount (software, hardware and OM&A) that is being spent to meet this requirement in 2012, 2013 and 2014?

Wellington North Power Inc. – Response

a. Wellington North Power Inc. has included some points below from the Minister of Energy directive to the Ontario Energy Board:

- Consider measures by which and conditions under which customer can have access to full meter data in real time and assign such access to third parties

- A smart meter must be capable of being read remotely and the meter system must be capable of providing customer feedback on energy consumption and data updated no less than daily.

- Stand-alone customer feedback (providing immediate feedback, such as usage, pricing or spending data, to customer by way of customer display or interface.

RECEIVED

JUL 1 6 2004

CHAIR ONTARIO
ENERGY BOARD

Minister of Energy

Hearst Block, 4th Floor
900 Bay Street Toronto
ON M7A2E1 Tel.:
4163276715 Fax:
4163276754

JUL 1 4 2004

Mr. Howard Wetston
Chair
Ontario Energy Board
2300 Y onge Street, 26th Floor
Toronto, Ontario
M4P 1 E4

Dear Mr. Wetston:

Enclosed is a copy of a Minister's Directive issued under Section 27.1 of the *Ontario Energy Board Act,* 1998 recently approved by the Lieutenant Governor in Council. The Order in Council is dated June 23, 2004. The Directive requires the Board to develop and, upon approval by the Minister of Energy, implement a plan to achieve the government's objectives for the deployment of smart electricity meters. The Directive requires the Board to provide its completed implementation plan to the Minister of Energy no later than February 15, 2005.

In conjunction with the development of its implementation plan, the Directive also requires the Board to examine the need for and effectiveness of time of use rates for non-commodity charges - in addition to season/time-based standard supply service commodity rates the Board is already in a position to establish - to complement the implementation of and maximize the benefits of smart meters.

I would appreciate the Board proceeding to take the appropriate steps to implement the attached Directive.

Sincerely,

Original signed by

Dwight Duncan
Minister

Enclosure

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit:

WHEREAS the Government of Ontario has established targets for the installation of 800,000 smart electricity meters by December 31, 2007 and installation of smart meters for all Ontario customers by December 31, 2010.

AND WHEREAS it is desirable, through the installation of smart meters, to manage demand for electricity in Ontario in order to make more efficient use of the current supply of electricity and to reduce the province's reliance on external sources.

AND WHEREAS it is desirable that the installation of smart meters in accordance with the aforementioned targets be facilitated and supported by a regulatory framework.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.1 of the *Ontario Energy Board Act, 1998* to promote energy conservation, energy efficiency and load management.

NOW THEREFORE the Directive attached hereto is approved.

Recommended: ______________________ **Minister of Energy**

Concurred: ______________________ **Chair of Cabinet**

Approved and Ordered JUN 2 3 2004 **Date**

______________________ **Lieutenant Governor**

O.C./Décret 1411/2004

OICNA-10285

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

The Government of Ontario has established targets for the installation of 800,000 smart electricity meters by December 31, 2007 and installation of smart meters for all Ontario customers by December 31, 2010.

In order to meet these targets and to maximize the resulting benefits, I, Dwight Duncan, Minster of Energy, hereby direct the Ontario Energy Board (the "Board") under section 27.1 of the *Ontario Energy Board Act, 1998* as follows:

1. By February 15, 2005 the Board shall develop and provide to the Minister of Energy an implementation plan for the achievement of the Government of Ontario's smart meter targets. Full implementation will commence upon the Minister's approval of the Board's plan.

2. During the development of its plan, the Board shall consult with stakeholders to:

    - identify and review options for the achievement of the smart meter targets
    - identify potential barriers to rapid deployment of smart meters and address how those barriers can be mitigated
    - address competitiveness in the provision and support of smart meters, including consideration of third party providers
    - identify and address technical requirements as set out in paragraphs 5 and 6 of this Directive and additional functionality as set out in paragraph 7
    - consider the establishment of common requirements in the office and support operations of distributors in relation to smart meters, including requirements for compatibility, and for billing and reporting
    - consider measures by which and conditions under which customers can have access to full meter data in real time and assign such access to third parties
    - identify and address regulatory mechanisms for the recovery of costs, taking into account the cost savings and other benefits that will be realized (for example, timely access to detailed system usage data) by the installation of smart meters
    - examine the need for and potential effectiveness of the introduction of non-commodity time of use rate structures as a means to complement the implementation of smart meters
    - identify and address other issues as the Board deems advisable.

3. In conjunction with its implementation plan, the Board shall also address the need for and potential effectiveness of the introduction of non-commodity time of use rate structures as a means to complement the implementation of smart meters and maximize the benefits of smart meters.

4. In the implementation plan, priority shall be given to installation of smart meters in new homes and for customers with a demand of 50 kilowatts or more. The Board may authorize the commencement of installation of smart meters for customers with a demand of 50 kilowatts or more as soon as it deems advisable without further report to the Minister. The Board may also establish other implementation priorities, including different priorities for different distributors, to optimize the opportunities for and benefits of deploying smart meters.

5. The Board's plan shall identify mandatory technical requirements for smart meters and associated data systems in accordance with the following criteria:

   - A smart meter must be able to measure and indicate electrical usage during prespecified time periods
   - A smart meter must be adaptable or suitable, without removal of the meter, for seasonal and time of use commodity rates, critical peak pricing, and other foreseeable electricity rate structures.
   - A smart meter must be capable of being read remotely and the metering system must be capable of providing customer feedback on energy consumption with data updated no less than daily.

6. Recognizing the additional capability and flexibility of bi-directional communication, the Board's plan shall identify mandatory technical requirements for bi-directional communication, except in those circumstances where the Board finds the options available are impractical.

7. In developing its plan, the Board shall consider and identify additional functionality for smart meters, on either a mandatory or optional basis. Functionality to be considered includes:
   - stand-alone customer feedback (providing immediate feedback, such as usage, pricing or spending data, to the customer by way of customer display or interface)
   - load control capabilities that can be utilized either by the distributor or the customer
   - capability of multi-meter readings (for example, gas and water metering in addition to electricity metering)
   - any other functionality the Board deems advisable.

8. The Board may establish different technical requirements and functionalities for different customer groups.

(Minister of Energy) (Date)

b. The table below illustrates WNP's projections of Capital Expenditures that the LDC believes are required to fully comply meet this requirement.

It should be noted that in the table below, WNP has included Capital Expenditures for initiatives that can be "partly" attributed to this requirement. These include server upgrades and replacement in 2014 to provide the capacity to store current and historical data. In addition, this includes the purchase and installation of a separate server that consumer's can access that will store only consumer data to mitigate the risk of an individual accessing sensitive / secure information.

Year	Project Ref:	Name	Description	Justification	Estimated Cost	Fully Attributable Cost
2012	2012-021	Harris Computer Software (CIS)	E-Care	Customers are required to have access to smart meter consumption	$23,500	Yes
2012	2012-022	Web Presentment/Software	Mandated by Minister of Energy	Customers are required to have access to smart meter consumption	$50,000	Yes
2013	-	No planned projects			$0	
2014	2014-008	WNP Internal Server	Upgrade Server Hardware	Replace existing server that was purchased in 2009 and is five years old Purchase a separate smaller capacity server to store "customer-only" data	$25,000	Partly
2014	2014-010	Smart Meter Server replacement	Replace server serving Elster Smart Meters	Current servers installed in 2008/2009 and will need replacing to take advantage of latest technology & efficiencies	$40,000	Partly
				Total	**$138,500**	

8. Reference: Exhibit 2, Tab 7, Schedule 1, page 268

a) Please explain the meaning of the term "Total Customer Interruptions" in Tables 2-81 – through 2-84 (and similarly in Tables 2-85 and 2-86).

b) Please explain why in Table 2-81 for the year 2010 the indices show a figure of 2.22 for SAIFI, but figures of zero for SAIDI and CAIDI.

c) Please confirm that Table 2-85 to 2-88 show reliability indices net of loss of supply from Hydro One (i.e. confirm this is the meaning of "loss supply adjusted").

d) If this is confirmed, please explain why for the year 2010 CAIDI is 0.03 for WNP alone (loss supply adjusted Table 2-85), but zero when one includes Hydro One supply interruptions (loss including supply loss Table 2-81).

Wellington North Power Inc. – Response

a) "Total Customer Interruptions" is the total number of interruptions that occurred during the year (e.g. 100 customers interrupted two times = 100 x 2 = 200) Interruption is defined as there is no power to the customer

b) The table below illustrates WNP's Service Reliability Indices for 2010 *(note this is not Loss of Supply Adjusted)*.

Month	Total Customer Hours of Interruptions *(e.g. 15 mins interruption for 200 customers = 0.25 x 200 = 50 hours of interruption)*	Total Customer Interruptions *(e.g. 100 customers interrupted 2 times = 2 x 100 = 200 customers interrupted)*	Total No. of Customers *(i.e. total customers served within month in the LDC service territory)*	System Average Interruption Duration Index (SAIDI)	System Average Interruption Frequency Index (SAIFI)	Customer Average Interruption Duration Index (CAIDI)
January	3	1	3,612	0.00083	0.00028	3.00000
February	0	0	3,613	0.00000	0.00000	0.00000
March	1	12	3,615	0.00028	0.00332	0.08333
April	1	8	3,608	0.00028	0.00222	0.12500
May	2	182	3,618	0.00055	0.05030	0.01099
June	6	2,743	3,629	0.00165	0.75586	0.00219
July	1	2,598	3,629	0.00028	0.71590	0.00038
August	3	2,480	3,628	0.00083	0.68357	0.00121
September	0	0	3,625	0.00000	0.00000	0.00000
October	0	0	3,622	0.00000	0.00000	0.00000
November	0	0	3,623	0.00000	0.00000	0.00000
December	0	0	3,645	0.00000	0.00000	0.00000
	Total Customer Hours of Interruptions	Total Customer Interruptions	Average No. of Customers	Total SAIDI	Total SAIFI	Total CAIDI
Total	**17**	**8,024**	**3,622.25**	**0.00469322**	**2.21519774**	**0.00211864**

The calculations that were used are:

$$\text{SAIFI} = \frac{\text{Total \# of customer interruptions}}{\text{Total \# of customers}} = \frac{8024}{3{,}622.25} = 2.21519774$$

$$\text{CAIDI} = \frac{\text{Total \# of hours of interruption}}{\text{Total \# of interruptions}} = \frac{17}{8024} = 0.002211864$$

$$\text{SAIDI} = \frac{\text{Total \# of hours of interruption}}{\text{Total \# of customers}} = \frac{17}{3{,}622.25} = 0.00469322$$

In Table 2-81 for SAIDI and CAIDI, there were two decimal places shown. The table on the previous page has been updated to show eight decimal places. The reason for SAIDI and CAIDI being low indices score are due to only 17 hours of "Total Customer Hours of Interruptions" for the whole year.

c) WNP can confirm that Table 2-85 to 2-88 in Exhibit 2, Tab 7, Schedule 1 show Service Reliability Indices that are Loss Supply adjusted (i.e. customer interruptions due to an outage that occurs upstream of WNP's distribution system.)

d) The table below shows the "Loss Supply" Customer Average Interruption Duration Index (CAIDI) for 2010, with yearly indices of 0.03, calculated by:

$$\text{CAIDI} = \frac{\text{Total \# of hours of interruption}}{\text{Total \# of interruptions}} = \frac{5}{155} = 0.03225806$$

Month	Adjusted Customer Hours of Interruptions *(e.g. 15 mins interruption for 200 customers = 0.25 x 200 = 50 hours of interruption)*	Total Customer Interruptions *(e.g. 100 customers interrupted 2 times = 2 x 100 = 200 customers interrupted)*	Total No. of Customers *(i.e. total customers served within month in the LDC service territory)*	Customer Average Interruption Duration Index (CAIDI)
January	0	0	3,612	0.00
February	0	0	3,613	0.00
March	0	0	3,615	0.00
April	1	8	3,608	0.13
May	0	0	3,618	0.00
June	3	145	3,629	0.02
July	0	0	3,629	0.00
August	1	2	3,628	0.50
September	0	0	3,625	0.00
October	0	0	3,622	0.00
November	0	0	3,623	0.00
December	0	0	3,645	0.00
	Adjusted Customer Hours of Interruptions	Adjusted Customer Interruptions	Average No. of Customers	Total CAIDI
Total	**5**	**155**	**3,622.25**	**0.03**

The Loss Adjusted CAIDI is higher because of the smaller numbers involved in the calculations, namely:

- Loss Adjusted CAIDI = 5/155 = 0.03225806
- Not Loss Adjusted CAIDI = 17/8024 = 0.00211864

The Loss Adjusted CAIDI shows, that compared to the non-Loss Adjusted CAIDI, there were fewer customer interruptions affecting fewer customer, which as a ratio could be shown as:

- Loss Adjusted CAIDI = 155/5 = 1:31
- Not Loss Adjusted CAIDI = 8024/17 = 1:472

Therefore, as the Non-Loss Adjusted has a higher divisible number (i.e. 8024) the indices result is lower.

LOAD FORECAST AND REVENUE OFFSETS

9. Reference: Exhibit 3, Tab 1, Schedule 1, page 329, Table 3-0

a) The total revenues for both "2012 Test at Current Rates" and "2012 Test at Proposed Rates" are the same. Please review and revise the Table as necessary.

<u>Wellington North Power Inc. – Response</u>

a. The table below is an updated version of Table 3-30 from WNP's application in Exhibit 3, Tab 1, Schedule 1 and also includes 2011 actual data.
The "Other Revenue" for "2012 Test at Current Rates" and "2012 Test at Proposed Rates" are identical values because is Wellington North Power is proposing to maintain the current amounts applied for the Specific Service Charges which have been previously approved by the OEB (as illustrated in Table 3-31 in Exhibit 3, Tab3 , Schedule 2.

Summary of Operating Revenue Table	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2009 Actual	2010 Actual	2012 Test at Current Rates	2012 Test at Proposed Rates	2011 Actual
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Distribution Revenue								
Residential	851,679	806,376	(45,303)	875,796	865,808	867,143	1,172,408	902,621
GS < 50 kW	290,734	219,253	(71,481)	294,035	289,627	290,017	396,406	308,694
GS 50 - 999 kW	290,734	266,713	(24,021)	374,212	333,145	282,658	306,179	329,632
GS 1,000 - 4,999 kW	218,697	141,075	(77,622)	186,098	199,619	185,400	310,884	197,514
Sentinel Lights	7,220	4,421	(2,799)	9,583	10,542	8,037	2,571	10,534
Street Lighting	48,741	22,889	(25,852)	62,062	65,742	65,692	89,762	70,811
Unmetered Scattered Loads	2,394	442	(1,952)	221	248	106	156	215
Total	**1,710,199**	**1,461,168**	**(249,031)**	**1,802,007**	**1,764,731**	**1,699,052**	**2,278,366**	**1,820,021**
% of Total Revenue	90.49%	87.73%		82.60%	90.91%	91.64%	93.63%	93.42%
Other Distribution Revenue								
Late Payment Charges	18,034	18,614	580	20,947	20,833	26,047	26,047	26,047
Specific Service Charges	54,450	61,681	7,231	65,097	58,820	57,043	57,043	45,870
Other Distribution Revenue	107,210	80,579	(26,631)	76,761	54,642	54,537	54,537	60,733
Other Income and Expenses	0	43,489	43,489	216,839	42,262	17,321	17,321	(4,531)
Total	**179,694**	**204,363**	**24,669**	**379,642**	**176,558**	**154,947**	**154,947**	**128,119**
% of Total Revenue	9.51%	12.27%		17.40%	9.09%	8.36%	6.37%	6.58%
Grand Total:	**1,889,893**	**1,665,531**	**-224,362**	**2,181,649**	**1,941,289**	**1,854,000**	**2,433,315**	**1,948,142**

It should be noted, and as per Exhibit 1, Tab 3, Schedule 3 in WNP's application, that in the 2009 Fiscal Year, the Net Income of $492,913 was over-stated by $192,195.30. During 2009, a 5,000 kVA transformer owned by Wellington North power Inc. was struck by lightning and replaced the asset in 2010 using insurance proceeds of $192,195. This amount was not "revenue" but proceeds received as a result of a natural disaster and therefore the actual revenue for 2009 is:

Net Income for 2009	$492,913
Less; Insurance Proceeds:	<u>$192,195</u>
Realized Net Income for 2009	**$300,178**

10. Reference: Exhibit 3, Tab 2, Schedule 1, page 331

a) Please provide the regression model equations estimated for the individual customer classes and the associated adjusted R-squared values.

Wellington North Power Inc. – Response

a. The tables over the following pages below illustrate the regression model equations and associated adjusted R-squared values for each customer class.

It should be noted that:

- Based on the low R square values, Wellington North Power Inc. concluded using the equation resulting from the individual rate class regression analysis would not be satisfactory for forecasting purposes; and
- Using each customer class purchase data, WNP is not confident that this data accurately reflects a calendar month. For instance:
  - For the period of January 1st to January 31st, there could be data from December and possibly February, depending upon meter reading dates and meter reading cycle.
  - Different customer classes could have different meter reading cycles;
  - Furthermore, not each meter reading cycle would reflect the same number of days of consumption each month.
- In summary, WNP does not have consumed without losses data for calendar monthly periods by customer class. Instead, and as described in WNP's application, the LDC used the aggregated Wholesale kWh loss data that reflects consumption on a complete calendar monthly period (i.e.1st to 28th / 30th / 31st) that reflects that is available.

A copy of the results and the data used has been uploaded to the RESS site:
(Filename: WellingtonNorth_IR_Responses_Aeepndix_June12)

Residential Customer Class - Regression Equations and Adjusted R-Square:

SUMMARY OUTPUT RESIDENTIAL:

Regression Statistics	
Multiple R	88.58%
R Square	78.47%
Adjusted R Square	77.38%
Standard Error	204905.22
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	1.20894E+13	3.02235E+12	71.98435599	1.44537E-25
Residual	79	3.31691E+12	41986150415		
Total	83	1.54063E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	316902.391	885877.272	0.358	0.722	-1446392.181	2080196.963	-1446392.181	2080196.963
Heating Degree Days	1744.365	119.414	14.608	0.000	1506.678	1982.053	1506.678	1982.053
Cooling Degree Days	3127.756	848.341	3.687	0.000	1439.177	4816.336	1439.177	4816.336
Number of Days in Month	12407.222	29739.384	0.417	0.678	-46787.541	71601.985	-46787.541	71601.985
Number of Peak Hours	2693.220	1383.277	1.947	0.055	-60.123	5446.563	-60.123	5446.563

General Service <50 kW Customer Class - Regression Equations and Adjusted R-Square:

SUMMARY OUTPUT GENERAL SERVICE <50kW

Regression Statistics	
Multiple R	78.39%
R Square	61.45%
Adjusted R Square	59.49%
Standard Error	93519.09
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	1.1012E+12	2.753E+11	31.47789779	1.12726E-15
Residual	79	6.9092E+11	8745819615		
Total	83	1.79212E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-5828.331	404315.870	-0.014	0.989	-810598.927	798942.264	-810598.927	798942.264
Heating Degree Days	557.386	54.501	10.227	0.000	448.905	665.867	448.905	665.867
Cooling Degree Days	1433.070	387.184	3.701	0.000	662.400	2203.741	662.400	2203.741
Number of Days in Month	12272.258	13573.105	0.904	0.369	-14744.331	39288.847	-14744.331	39288.847
Number of Peak Hours	1418.288	631.330	2.247	0.027	161.657	2674.918	161.657	2674.918

General Service 50-999 kW Customer Class - Regression Equations and Adjusted R-Square:

SUMMARY OUTPUT GENERAL SERVICE 50-999 kW

Regression Statistics	
Multiple R	56.68%
R Square	32.12%
Adjusted R Square	28.69%
Standard Error	203396.67
Observations	84

ANOVA

	df	SS	MS	F	Significance F
Regression	4	1.54675E+12	3.86688E+11	9.347026182	3.08494E-06
Residual	79	3.26825E+12	41370206367		
Total	83	4.815E+12			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-78118.798	879355.278	-0.089	0.929	-1828431.666	1672194.070	-1828431.666	1672194.070
Heating Degree Days	645.525	118.535	5.446	0.000	409.588	881.462	409.588	881.462
Cooling Degree Days	1679.243	842.095	1.994	0.050	3.095	3355.391	3.095	3355.391
Number of Days in Month	40613.163	29520.438	1.376	0.173	-18145.797	99372.123	-18145.797	99372.123
Number of Peak Hours	2004.299	1373.093	1.460	0.148	-728.773	4737.372	-728.773	4737.372

General Service 1000-4999 kW Customer Class - Regression Equations and Adjusted R-Square:

SUMMARY OUTPUT GENERAL SERVICE 1000-4999 kW

Regression Statistics	
Multiple R	21.00%
R Square	4.41%
Adjusted R Square	-0.43%
Standard Error	441227.71
Observations	84

ANOVA

	df	SS	MS	F	Significance F
Regression	4	7.09611E+11	1.77403E+11	0.911243678	0.461641559
Residual	79	1.53799E+13	1.94682E+11		
Total	83	1.60895E+13			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	798500.669	1907582.430	0.419	0.677	-2998447.115	4595448.453	-2998447.115	4595448.453
Heating Degree Days	-263.719	257.137	-1.026	0.308	-775.538	248.099	-775.538	248.099
Cooling Degree Days	-145.723	1826.754	-0.080	0.937	-3781.785	3490.340	-3781.785	3490.340
Number of Days in Month	63375.530	64038.585	0.990	0.325	-64090.083	190841.143	-64090.083	190841.143
Number of Peak Hours	496.049	2978.645	0.167	0.868	-5432.796	6424.894	-5432.796	6424.894

Streetlights Customer Class - Regression Equations and Adjusted R-Square:

SUMMARY OUTPUT STREETLIGHTS

Regression Statistics	
Multiple R	80.87%
R Square	65.40%
Adjusted R Square	63.65%
Standard Error	6857.96
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	7024479908	1756119977	37.33911741	1.65861E-17
Residual	79	3715499664	47031641.31		
Total	83	10739979572			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	58599.488	29649.379	1.976	0.052	-416.123	117615.099	-416.123	117615.099
Heating Degree Days	35.885	3.997	8.979	0.000	27.930	43.841	27.930	43.841
Cooling Degree Days	10.290	28.393	0.362	0.718	-46.225	66.805	-46.225	66.805
Number of Days in Month	-1020.233	995.346	-1.025	0.308	-3001.419	960.953	-3001.419	960.953
Number of Peak Hours	77.375	46.297	1.671	0.099	-14.777	169.526	-14.777	169.526

Sentinel Lights Customer Class - Regression Equations and Adjusted R-Square:

SUMMARY OUTPUT SENTINEL LIGHTS

Regression Statistics	
Multiple R	46.45%
R Square	21.57%
Adjusted R Square	17.60%
Standard Error	371.19
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	2993935.493	748483.8733	5.432268425	0.000646145
Residual	79	10884997.09	137784.7733		
Total	83	13878932.58			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-3299.343	1604.801	-2.056	0.043	-6493.619	-105.067	-6493.619	-105.067
Heating Degree Days	0.486	0.216	2.245	0.028	0.055	0.916	0.055	0.916
Cooling Degree Days	2.185	1.537	1.422	0.159	-0.874	5.244	-0.874	5.244
Number of Days in Month	148.565	53.874	2.758	0.007	41.331	255.798	41.331	255.798
Number of Peak Hours	5.539	2.506	2.211	0.030	0.552	10.527	0.552	10.527

Unmetered Scattered Load Customer Class - Regression Equations and Adjusted R-Square:

SUMMARY OUTPUT UNMETERED SCATTERED LOAD

Regression Statistics	
Multiple R	21.62%
R Square	4.67%
Adjusted R Square	-0.15%
Standard Error	4150.55
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	66715893.23	16678973.31	0.968185282	0.429758663
Residual	79	1360936709	17227046.95		
Total	83	1427652602			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-9648.542	17944.276	-0.538	0.592	-45365.730	26068.646	-45365.730	26068.646
Heating Degree Days	3.594	2.419	1.486	0.141	-1.220	8.409	-1.220	8.409
Cooling Degree Days	25.069	17.184	1.459	0.149	-9.134	59.273	-9.134	59.273
Number of Days in Month	104.968	602.399	0.174	0.862	-1094.078	1304.013	-1094.078	1304.013
Number of Peak Hours	30.358	28.020	1.083	0.282	-25.414	86.129	-25.414	86.129

11. Reference: Exhibit 3, Tab 2, Schedule 1, pages 332-336

a) Did WNPI attempt (pages 332-333) to perform any regression analyses that included economic indicators (e.g., local employment, GDP, etc.) as an explanatory variable? If yes, please provide the results.

b) Please explain how (page 335) the purchased energy values for each month were adjusted to remove the usage for the three specific customers. In particular, what allowance (if any) was made for the losses associated with the sales to these customers?

c) The text on page 336 states that the reduction in billed kWh between 2010 and 2011 can be attributed to the General Service 1,000 – 4,999 customer class. However, an inspection of Table 3-5 indicates that this class makes only a very small contribution to the reduction, less than that for the Residential, GS<50 or GS 50-999 classes. Please reconcile.

d) Also, please explain why the total sales to GS 1,000-4,999 only decline by less than 500,000 kWh in 2011 versus 2010 when the sales to the three automotive customers in the class are projected to decline by over 1,000,000 kWh (per Table 3-15).

Wellington North Power Inc. – Response

a. WNP did perform regression analysis for its total customer portfolio which included the following variables:

		Scenarios			Variables Used in Power Purchase Load Model					
Scenario Model	"R" Sq Result	Adjusted 2009 Purchased Load data?	Included 2011 Actual data	Sensitive customers removed (GS 1000 - 4999kW customers removed)	HDD days	CDD Days	No. of Days in Month	No. Of Peak Hours	Real Ontario GDP	Number of Customers
A3	72.65%	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes

A summary of the variables used is shown below:

Variable	Reason	Source
Weather data - Heating degree days	Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled	Data source from Owen Sound / Collingwood station
Weather data - Cooling degree days		
Real Ontario GDP	Historic view and forecasted view of economic growth, decline and/or stability	Real gross domestic product (GDP) for Ontario (1988 to 2006: 2003 and 2008 Ontario; Economic Outlook and Fiscal Review, Ontario Ministry of Finance, 2007 to 2011: 2010; Ontario Budget March 25, 2010, Ontario Ministry of Finance)
Number of days in the month	Identifies seasonal peaks and less/more days in calendar months	
Number of peak hours	Number of peak hours (16* number of business days in any given month, excluding weekends and holidays)	
Number of customers	Takes into account purchase load requirements subject to customer number growth, decline or stability	Wellington North Power Inc.'s historical analysis.

The results of this regression analysis are shown below:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	85.24%
R Square	72.65%
Adjusted R Square	70.52%
Standard Error	379676.4512
Observations	84

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	2.94857E+13	4.91429E+12	34.09050685	9.04057E-20
Residual	77	1.10999E+13	1.44154E+11		
Total	83	4.05856E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-6194359.185	3178362.266	-1.949	0.055	-12523286.915	134568.546	-12523286.915	134568.546
Heating Degree Days	2802.129	224.083	12.505	0.000	2355.923	3248.334	2355.923	3248.334
Cooling Degree Days	6520.593	1584.600	4.115	0.000	3365.251	9675.935	3365.251	9675.935
Real Ontario GDP	27734.017	17898.303	1.550	0.125	-7906.057	63374.091	-7906.057	63374.091
Number of Days in Month	118041.076	55248.052	2.137	0.036	8028.150	228054.001	8028.150	228054.001
Number of Peak Hours	7397.098	2571.791	2.876	0.005	2276.008	12518.189	2276.008	12518.189
Number of Customers	803.900	916.948	0.877	0.383	-1021.976	2629.776	-1021.976	2629.776

A spreadsheet containing the data tested, regression equation and results has been provided. This has been uploaded on to the OEB's RESS site with the file name below:
(Filename: WellingtonNorth_IR_Responses_Appendix_June12)

b. For each of the three "sensitive" customers, WNP used the meter reading data for each month. This data is available through the company's CIS system and an external data provider (Utili-Smart). The monthly totals of each "sensitive" customer data was deducted from the total wholesale Purchased Load with Loss data:

Purchased Load (Wholesale) kWh including Losses	**less**	"Sensitive" Customers Purchase Load with Losses	**Equals**	Adjusted Purchase Load with Losses

WNP the applied the Loss Adjusted factor of 1.0699 to the monthly meter reading data to create a billed with loss value for each customer.
The loss factor of 1.0699 has been consistent over the past six years as illustrated in Exhibit 8, Tab 8, Schedule 2, table 8-14. Table 8-14 shows Wellington North Power Inc. calculated of the Total and Distribution loss factor based on the average Wholesale and Retail kWh for a six year period from 2005 to 2010.

c. WNP has reviewed this statement and concurs with the Intervenor comment. This is illustrated in the table below.

Billed Energy by Rate Class								
Year	Residential	General Service < 50kW	General Service 50 - 999 kW	General Service 1,000 - 4,999 kW	Streetlights	Sentinel Lights	Unmetered Scattered Load	**Total**
Energy (kWh)								
2004	24,384,437	12,478,963	22,994,865	28,467,921	727,714	38,904	101,904	89,194,708
2005	25,217,181	12,036,675	23,752,850	30,363,260	728,596	39,379	101,904	92,239,845
2006	25,227,824	11,886,853	24,784,448	30,857,138	731,832	38,909	101,877	93,628,881
2007	25,023,794	11,930,026	24,233,832	33,212,587	727,707	38,081	82,586	95,248,613
2008	25,142,788	11,678,034	25,169,769	30,725,657	748,942	36,606	19,284	93,521,080
2009	25,158,787	11,573,828	20,973,876	27,961,217	738,099	33,138	7,536	86,446,481
2010	25,200,723	11,323,787	20,890,084	37,885,731	720,757	31,636	9,732	96,062,450
2011	24,400,666	10,729,163	19,937,405	37,393,947	716,131	30,417	6,213	93,213,943
2012	24,526,192	10,553,093	19,595,187	38,290,749	711,588	29,247	3,967	93,710,023
2011 compared to 2010 Change of Billed Energy by Rate Class								
2011	-3.28%	-5.54%	-4.78%	-1.32%	-0.65%	-4.01%	-56.63%	-3.06%

d. As illustrated in the table above and noted by the Intervenor, General Service 1,000-4999 kW billed kWh for the 2011 Bridge Year's forecast to reduce by 491,783 kWh (as per table 3-5)
   In its application in Table 3-15 of Exhibit 3, Tab2, Schedule 1, for the sensitive customers, the 2011 Bridge Year compared to 2011 shows a reduction of 1,210,210 billed kWh.

   WNP would like to clarify the following points that support the above rationale:

   - Table 3-15 illustrates the three "sensitive" customers billed kWh forecast for 2011 Bridge Year and 2012 Bridge Year, using the methodology described beneath this table.
   - WNP would like to highlight that this is a forecast and made the decision to use the average of 2004-2010 actual data, excluding 2009 year, to create the forecast. As eluded to in its application, WNP believe that these customers are more sensitive to economic conditions compared to other customers in this class. WNP believed that the Japanese Tsunami of March 2011 would have an impact with these three manufacturing companies and made the decision to forecast billed kWh using the methodology described in its application.
   - These three automotive manufacturing companies are component suppliers to Japanese car manufacturers. Following the Japanese tsunami of March 11, 2011, the car companies of Nissan and Toyota in particular closed their operational plants for a prolonged period of time. Consequently, these three automotive manufacturing companies reduced their production schedules, hours of operations and working shift patterns. Shift patterns were reduced from three shifts to two shifts for the remaining days of March and most, if not all, of April 2011. This supports WNP's decision to "hold" the billed kWh forecast using the methodology described in its application.
   - Table 3-5 includes <u>all</u> customers within the class of GS 1,000 – 4,999kW. Therefore as the billed kWh for the three "sensitive" is forecasted to reduce, there will be an off-setting by other customers in this class who are experiencing growth. Evidence of this is the CPI indicator which is showing an inflation rate of 2.25% for the first four months of 2012.

12. Reference: Exhibit 3, Tab 2, Schedule 1, pages 338-341 & Appendix 3A

a) Does the purchase data shown in Appendix 3A (2nd column) include or exclude the sales to the three automotive customers?

b) What loss factor (page 338, 2nd bullet) was used to adjust the purchased energy forecast to produce billed energy? Please explain how this loss factor was determined.

c) Table 3-14 shows predicted purchases for 2012 (excluding the 3 specific customers) of 75,059,199. Table 3-15 indicates that the 2012 purchases attributable to the 3 specific customers are 26,394,130 kWh – for a total of 101,453,329 kWh. Please confirm that this is the purchased energy value associated with the 94,614,023 billed kWh for 2012 shown in Table 3-20.

Wellington North Power Inc. – Response

a. WNP confirms that the purchase data shown in Appendix 3A (2nd column) excludes the sales to the three automotive customers.

b. WNP the applied the Loss Adjusted factor of 1.0699.
The loss factor of 1.0699 has been consistent over the past six years as illustrated in Exhibit 8, Tab 8, Schedule 2, table 8-14. Table 8-14 shows Wellington North Power Inc. calculated of the Total and Distribution loss factor based on the average Wholesale and Retail kWh for a six year period from 2005 to 2010.

c. WNP can confirm that the Intervenors comment (*Reference 12c*) is correct, as per summary table below:

	2012 Test Year Predicted Purchases (kWh)	Reference
All WNP customers excluding 3 sensitive customers	75,059,199	Table 3-14
3 sensitive customers	26,394,130	Table 3-15
Total Predicted Purchases	**101,453,329**	
Forecast Billed kWh prior to CDM Adjustment	**94,614,023**	Table 3-20

13. Reference: Exhibit 3, Tab 2, Schedule 1, pages 343-348

a) Provide a table that sets out for 2009, 2010 the following:
- The actual purchases for each year (excluding the kWh attributed to the three specific automotive customers – per Table 3-14)
- The actual HDD and CDD values for each year
- The "weather normal" HDD and CDD values for each year (as defined by WNPI)
- The HDD and CDD coefficients per WNPI's regression model
- The weather normal adjustment for each year based on the product of a) the HDD and CDD coefficients and b) the differences between the actual and "weather normal" values for HDD and CDD respectively.
- The estimated "weather normal purchases" calculated by adjusting actual purchases by the values calculated in the preceding bullet.

b) What was the actual average billed kWh per customer for these three specific customers for 2011 (see Table 3-15)?

c) Please explain why (in Table 3-15) different loss factors were used for forecasting 2011 and 2012 predicted purchases for the 3 specific customers.

Wellington North Power Inc. – Response

a. As requested, WNP has used the methodology described and the table below summarizes the output:

		A	B	C	D	E	F	G	H	I	J	
									F*(D-B)	G*(E-C)	A+H+I	J-A
			Actual		Weather Normal		Coefficients		Weather Normal Adjustment			
Year	Month	Actual Purchases	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	Weather Normal Purchases	Variance
2009	Jan	7,391,553	816.5	0.0	816.5	0.0			-	-	7,391,553	0
	Feb	6,382,454	620.1	0.0	620.1	0.0			-	-	6,382,454	0
	Mar	6,590,037	556.5	0.0	556.5	0.0			-	-	6,590,037	0
	Apr	5,694,696	352.0	0.5	352.0	0.5			-	-	5,694,696	0
	May	5,229,715	232.5	2.8	232.5	2.8			-	-	5,229,715	0
	Jun	5,369,116	98.2	16.9	98.2	16.9			-	-	5,369,116	0
	Jul	5,288,185	21.5	26.6	21.5	26.6			-	-	5,288,185	0
	Aug	5,739,569	20.0	69.1	20.0	69.1			-	-	5,739,569	0
	Sep	5,417,984	75.8	10.7	75.8	10.7			-	-	5,417,984	0
	Oct	6,096,676	296.5	0.0	296.5	0.0			-	-	6,096,676	0
	Nov	6,171,735	351.5	0.0	351.5	0.0			-	-	6,171,735	0
	Dec	7,187,686	619.0	0.0	619.0	0.0			-	-	7,187,686	0
2010	Jan	7,343,340	725.8	0.0	725.8	0.0			-	-	7,343,340	0
	Feb	6,539,527	625.3	0.0	625.3	0.0			-	-	6,539,527	0
	Mar	6,459,810	485.0	0.0	485.0	0.0			-	-	6,459,810	0
	Apr	5,603,257	265.0	3.0	265.0	3.0			-	-	5,603,257	0
	May	5,757,226	139.0	20.7	139.0	20.7			-	-	5,757,226	0
	Jun	5,683,543	51.7	21.9	51.7	21.9			-	-	5,683,543	0
	Jul	6,025,352	7.7	136.0	7.7	136.0			-	-	6,025,352	0
	Aug	6,165,214	6.0	129.8	6.0	129.8			-	-	6,165,214	0
	Sep	5,702,200	93.2	26.8	93.2	26.8			-	-	5,702,200	0
	Oct	6,032,362	238.8	0.0	238.8	0.0			-	-	6,032,362	0
	Nov	6,433,663	410.0	0.0	410.0	0.0			-	-	6,433,663	0
	Dec	7,232,578	668.7	0.0	668.7	0.0	2872.45273	5638.77866	-	-	7,232,578	0
2011	Jan	7,467,524	777.5	0.0	721.8	0.0			(160,037)	-	7,307,487	-160,037
	Feb	6,794,516	645.3	0.0	653.4	0.0			23,349	-	6,817,865	23,349
	Mar	7,168,803	610.8	0.0	565.5	0.0			(130,204)	-	7,038,599	-130,204
	Apr	5,870,756	334.7	0.0	336.2	0.8			4,186	4,430	5,879,372	8,616
	May	5,663,513	175.6	14.1	199.4	9.4			68,364	(26,583)	5,705,294	41,782
	Jun	5,588,002	58.4	20.7	51.4	45.8			(20,230)	141,694	5,709,466	121,464
	Jul	6,163,969	0.7	139.9	10.0	93.2			26,796	(263,089)	5,927,676	-236,293
	Aug	6,240,041	2.7	88.2	14.5	81.8			33,936	(36,330)	6,237,647	-2,394
	Sep	5,830,412	72.3	21.2	67.2	30.9			(14,732)	54,535	5,870,215	39,803
	Oct	6,203,366	223.0	2.8	239.5	6.8			47,437	22,716	6,273,519	70,153
	Nov	6,371,649	336.2	0.0	403.8	0.0			194,301	-	6,565,950	194,301
	Dec	7,022,209	555.3	0.0	633.8	0.0			225,447	-	7,247,656	225,447
											Variance Total	195,986

A spreadsheet containing the data from the above table has been provided. This has been uploaded on to the OEB's RESS site with the file name below:
(Filename: WellingtonNorth_IR_Responses_Appendix_June12)

b. The table below includes 2011 Billed kWh actual data for the three specific customers:

Year	Total Billed (kWh)	Average Billed kWh per customer (Total Billed / 3 customers)
2004	20,831,385	6,943,795
2005	25,428,234	8,476,078
2006	25,642,352	8,547,451
2007	26,300,386	8,766,795
2008	23,661,505	7,887,168
2009	19,493,387	6,497,796
2010	25,825,024	8,608,341
2011	27,252,309	9,084,103

c. In its application in Exhibit 8, Tab 8, Schedule 2, Wellington North Power Inc. calculated the Total and Distribution loss factor based on the average Wholesale and Retail kWh for a six year period from 2005 to 2010. The output from this analysis indicated that the Secondary Metered Customer Total Loss factor for 2012 is 1.0723%. WNP applied this Loss factor in its Load Forecast and Bill Impact calculations for 2012 Test Year.

Below is a copy of the table that was shown in Exhibit 8, Tab 8, Schedule 2 (table 8-14) which summarizes how WNP derived 2012 Total Loss Factor:

	2005	2006	2007	2008	2009	2010	6 Year Total
"Wholesale" kWh (IESO) **Qty at the Meter** *(A)*	95,916,378	96,449,458	98,554,351	97,205,281	90,335,536	99,218,944	
"Wholesale" kWh (GEN) *(B)*	-	-	-	-	-	-	
Net "Wholesale" kWh (A)-(B) *(C)*	**95,916,378**	**96,449,458**	**98,554,351**	**97,205,281**	**90,335,536**	**99,218,944**	**577,679,948**
Retail kWh (Distributor) **Qty at the Meter** *(D)*	92,239,845	93,628,881	95,248,613	93,521,080	86,446,481	96,062,450	**557,147,350**
	-	-	-	-	-	-	-
Net "Retail" kWh (D) *(F)*	**92,239,845**	**93,628,881**	**95,248,613**	**93,521,080**	**86,446,481**	**96,062,450**	
							6 Yr Average
Distribution Loss Factor [(C)/(F)] *(G)*	1.0399	1.0301	1.0347	1.0394	1.0450	1.0329	**1.0370**
Supply Facility Loss Factor *(H)*	1.0340	1.0340	1.0340	1.0340	1.0341	1.0342	**1.0340**

Total Utility Loss Adjustment Factor:	**LAF**	
Supply Facility Loss Factor:	**1.0340**	*(6 yr average of 2005 - 2010)*
Distribution Loss Factor:	**1.0370**	*(6 yr average of 2005 - 2010)*
Total Loss Factor:		
Secondary Metered Customer:		
Total Loss Factor - Secondary Metered Customer < 5,000kW:	**1.0723**	
Total Loss Factor - Secondary Metered Customer > 5,000kW:	n/a	
Primary Metered Customer:		
Total Loss Factor - Primary Metered Customer < 5,000kW:	**1.0616**	
Total Loss Factor - Primary Metered Customer > 5,000kW:	n/a	

14. Reference: Exhibit 3, Tab 2, Schedule 1, page 349

Preamble: The Board's draft CDM Guidelines (EB-2012-0003) would require LDCs to track actual CDM savings against the savings incorporated the approved load forecast by customer class.

a) Please provide the most recent progress report from the OPA regarding WNPI's 2011 CDM achievements. Based on this report, is it reasonable to assume that WNPI will achieve the projected CDM savings in 2011 of 452,000 kWh?

b) What 2012 CDM programs is WNPI currently participating in? If the 1st quarter OPA CDM report for 2012 is available, please provide.

c) For purposes of future LRAM calculations (see Preamble), please break the 2012 CDM kWh savings down by customer class and, for those classes billed on a kW basis, provide the associated kW CDM savings.

Wellington North Power Inc. – Response

a. Wellington North Power Inc. has included the Ontario Power Authority 2011 results. Unfortunately, Power Authority did not begin to release programs until June of 2011. Some of the 2011-2014 provincial programs were not ready for rollout until later that same year.

The delay in the start of the programs impacted the utility's ability to begin customer conservation initiatives before August of 2011.

Wellington North Power Inc. did not receive the 2011 PAB (Program Administration Budget) funding for the programs until the end of December, 2011. With no funding for marketing and advertising until the end of December, the company could not cover the cost of these programs, as this would be view as cross subsidization. Therefore Wellington North Power's energy savings for 2011 are disappointing.

Wellington North Power's energy savings realized in 2011 was 109,701 kWhs and 14 kW.

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Ontario Power Authority Q4 2011 Conservation & Demand Management Status Report

January 1, 2011 to December 31, 2011

Wellington North Power Inc.

2011 At a Glance

The following tables show progress to OEB targets first: following the OPA reporting practice of 1 year persistence for demand response and second: assuming demand response remains in your territory until 2014 .

Unverified 2014 Peak Demand Savings Target Achieved (%):	1.6%
Unverified 2011-2014 Cumulative Energy Target Achieved (%):	9.7%

Assuming Demand Response resources remain in your territory until 2014:		Standing:
Unverified 2014 Peak Demand Savings Target Achieved (%):	1.6%	71 of 77
Unverified 2011-2014 Cumulative Energy Target Achieved (%):	9.7%	66 of 77

Message from the Vice President

The OPA Conservation team is pleased to provide the Q4 2011 CDM Status Report. Province-Wide programs are showing success and we are well positioned to meet our 2011-14 targets, thanks to the efforts of the OPA and you, the LDCs. A "Standing" column has been included in this report (in the table above) which reflects your position based on the percent of target achieved. This is based on preliminary results and is intended to provide you with a snapshot of how your LDC is performing relative to the others in the province.

We have achieved 80% of our 2011 Province-Wide programs peak demand savings forecast - more data will be available as projects progress through the final stages of approval. We will continue to update preliminary 2011 data (which will be reflected in the "Program-to-Date" columns) until the results are verified later this year.

We invite you to continue to look for opportunities to improve this report to meet your needs and welcome your suggestions. Additionally, if you are having any concerns with roll-out or have a particular success to share, please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca.

- Andrew Pride
Vice President, Conservation
Ontario Power Authority

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About this Report:

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not incl. Ontario Energy Board (OEB) approved CDM programs or other conservation efforts undertaken by an LDC).
- Unverified quarterly results discounted using forecasted net-to-gross ratios. Once full Evaluation, Measurement & Verification (EM&V) occurs in the following year, results will be identified as final (verified).
- Data presented in this report represents program activity (i.e. projects completed, appliances picked up) completed on or before December 31, 2011 and received and entered into the OPA processing systems as per the dates specified in table 5.
- Updates to the previous quarter's participation due to more data availability.

Future reports will contain:

- More data for the Home Assistance Program
- *peaksaver* PLUS preliminary results representing all participants that are enrolled in *peaksaver* PLUS.
- Full, bar-code specific 2011 Coupon and Bi-Annual Retailer Event data (Retailers have until March 31, 2012 to submit coupons redeemed in 2011 to the OPA).Results are currently provincially allocated; once bar-code specific data is gathered, results can be attributed to a particular LDC. Data will be available to LDCs once retailers have submitted the coupons and QA/QC by the OPA is undertaken.

New this quarter based on LDC feedback:

- Demand response is now reported only in the "YTD Incremental" column. This value represents the total demand response under contract in your LDC territory as of the end of the current reporting period.
- The allocation methodology used to attribute non-bar code specific coupon redemptions from the Instant Coupon Booklet and Bi-Annual Retailer Event to each LDC was updated to reflect each LDC's proportion of the average 2008 and 2009 residential throughput as per the OEB yearbook.
- Table 5 on the final page of this report is intended to assist the LDC in reconciling internal data sources with the data contained in this report by communicating: **1.** The date in which the OPA considers savings to 'start'; **2.** At what point the data becomes available to the OPA; **3.** The date in which the data was collected for reporting purposes; **4.** The expected probability and magnitude of updates to the data as more information becomes available.

Reporting Methodology (Quarterly, Unverified results):

The OPA's policy on reporting preliminary results for prescriptive measures (i.e. standard technologies and items) is to determine the activity (i.e. appliances collected, projects completed, coupons redeemed, etc.) in the most detail possible and multiply these values by Prescriptive Input Assumptions (PIAs) and net-to-gross (NTG) ratios that were used to forecast the programs if available.

*Preliminary Net Savings = Activity * Gross per unit PIA * Net-to-gross ratio*

For engineered or custom projects, the calculated savings from each participant worksheet are summed and then multiplied by the forecasted net-to-gross ratio used for program planning purposes.

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2011-2014 Summary

2011 Quarter 4 *January 1, 2011 to December 31, 2011*

This section provides a portfolio level view of net peak demand savings and net energy savings procured through Tier 1 programs to date.

Table 1 presents preliminary net peak demand savings results from 2011 to date by implementation period. This table also presents the net annual peak demand savings that are expected to persist through to 2014 from program activity completed to date. Please note that demand response 1 and 3 have a persistence of 1 year.

Table 1: Net Peak Demand Savings at the End-User Level (MW)

#	Implementation Period	Annual			
		2011	2012	2013	2014
1	2011 - Reported - Quarter 1	0.35	0.00	0.00	0.00
2	2011 - Reported - Quarter 2	0.35	0.00	0.00	0.00
3	2011 - Reported - Quarter 3	0.00	0.00	0.00	0.00
4	2011 - Reported - Quarter 4	0.00	0.00	0.00	0.00
5	2012				
6	2013				
7	2014				
Annual Reported (Unverified)		0.01			
Annual Final (Verified)		n/a			
Unverified Net Annual Peak Demand Savings in 2014:					0.01
2014 Annual CDM Capacity Target:					0.93
Unverified 2014 Peak Demand Savings Target Achieved (%):					1.6%

Table 2 presents preliminary net annual energy savings results from 2011 to date by implementation period. This table also presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date.

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual				Cumulative
		2011	2012	2013	2014	2011-2014
1	2011 - Reported - Quarter 1	0.02	0.02	0.02	0.02	0.07
2	2011 - Reported - Quarter 2	0.03	0.02	0.02	0.02	0.10
3	2011 - Reported - Quarter 3	0.03	0.03	0.03	0.03	0.11
4	2011 - Reported - Quarter 4	0.04	0.04	0.04	0.04	0.16
5	2012					
6	2013					
7	2014					
Annual Reported (Unverified)		0.11				
Annual Final (Verified)		n/a				
Unverified Net Cumulative Energy Savings 2011-2014:						0.44
2011-2014 Cumulative CDM Energy Target:						4.52
Unverified 2011-2014 Cumulative Energy Target Achieved (%):						9.7%

ONTARIO POWER AUTHORITY

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2011-2014 Summary

2011 Quarter 4 *January 1, 2011 to December 31, 2011*

Figure 1 presents unverified net annual peak demand savings achieved and expected persistence through to 2014 for program activity completed to date. The 2014 annual peak demand savings target as per OEB is also presented.

Figure 1: Net Peak Demand Savings (MW)

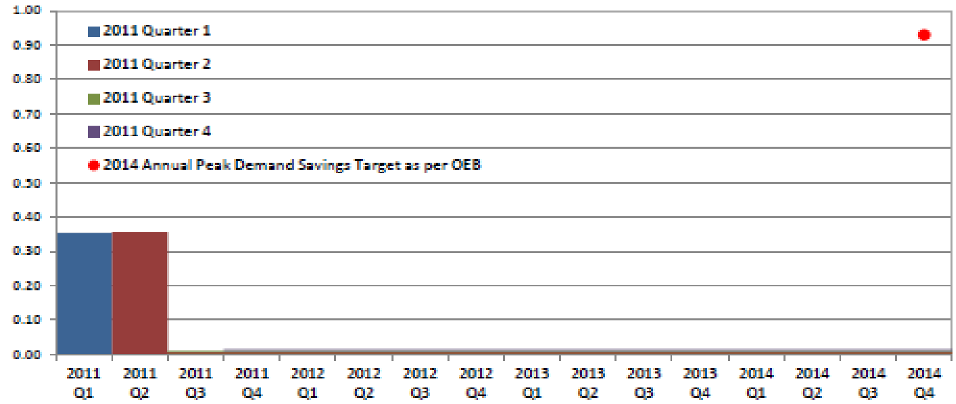
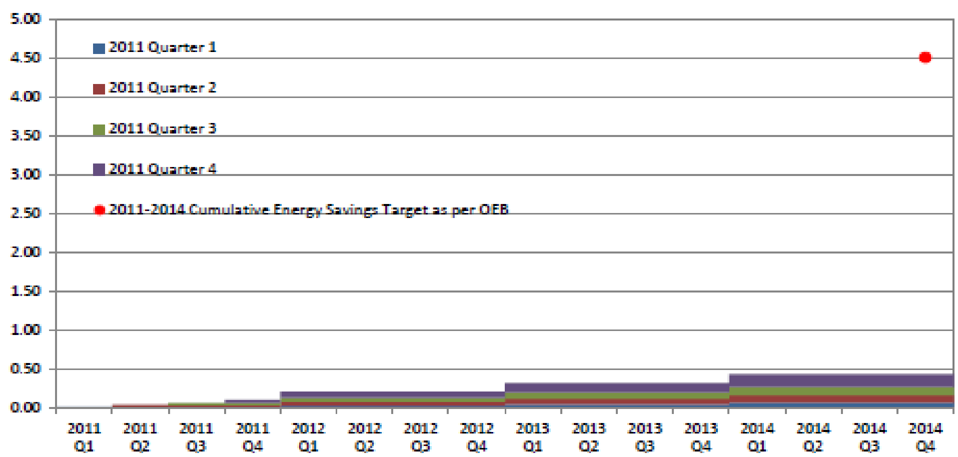


Figure 2 presents unverified net cumulative energy savings achieved including expected persistence to 2014 from program activity completed to date. The 2011-2014 cumulative energy savings target as per OEB is also presented.

Figure 2: Net Cumulative Energy Savings (GWh)



ONTARIO POWER AUTHORITY

Table 3: Wellington North Power Inc. Initiative and Program Level Savings

Shaded areas indicate data is not yet available

All results are NET and presented at the end-user level

#	Initiative	Activity			Net Peak Demand Savings (kW)			Net Energy Savings (kWh)		
		Unit	Incremental (Current Quarter)	Program-to-Date (2011-to-Date):	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: unverified annual savings in 2014	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: unverified cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	14	56	1	4	4	7,683	29,786	119,145
2	Appliance Exchange	Appliances	0	1	0	0	0	0	168	671
3	HVAC Incentives	Equipment	0	4	0	1	1	323	2,338	9,351
4	Conservation Instant Coupon Booklet	Coupons	57	91	0	0	0	4,500	7,184	28,735
5	Bi-Annual Retailer Event	Coupons	124	213	0	1	1	7,620	13,715	54,860
6	Retailer Co-op	Items	0	0	0	0	0	0	0	0
7	*peaksaver* extension	Devices	0	0	0	0	0	0	0	0
8	Midstream Electronics	Items				not in market				
9	Midstream Pool Equipment	Items				not in market				
10	Residential New Construction	Houses	0	0	0.00	0.00	0.00	0	0	0
Consumer Program Total					1	6	6	20,125	53,190	212,762
Business Program										
11	Equipment Replacement Incentive	Projects	0	1	0	1	1	0	1,511	6,043
12	Direct Installed Lighting	Projects	1	2	2	3	3	15,801	24,923	99,691
13	Direct Service Space Cooling	Equipment				not in market				
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	0	0	0	0	0	0	0
16	*peaksaver* extension	Devices	0	0	0	0	0	0	0	0
17	Demand Response 1	Facilities		0		0	0		0	0
18	Demand Response 3	Facilities		0		0	0		0	0
Business Program Total					2	4	4	15,801	26,434	105,734
Industrial Program										
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	0	0	0	0	0	0	0	0
23	Demand Response 1	Facilities		0		0	0		0	0
24	Demand Response 3	Facilities		0		0	0		0	0
Industrial Program Total					0	0	0	0	0	0
Home Assistance Program										
25	Home Assistance Program	Units	0	0	0	0	0	0	0	0
Home Assistance Program Total					0	0	0	0	0	0
Pre-2011 Programs completed in 2011										
25	Electricity Retrofit Incentive Program	Projects	0	0	0	0	0	0	0	0
26	High Performance New Construction	Projects	0	0	1	4	4	3,894	30,077	120,308
27	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
28	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total					1	4	4	3,894	30,077	120,308
OPA-Contracted Province-Wide Portfolio Total					4	14	14	39,820	109,701	438,804

Table 4: Province-Wide Initiative and Program Level Savings

Shaded areas indicate data is not yet available

All results are NET and presented at the end-user level

#	Initiative	Activity: Unit	Activity: Incremental (Current Quarter)	Activity: Program-to-Date (2011-to-Date):	Net Peak Demand Savings (kW): Incremental (Current Quarter)	Net Peak Demand Savings (kW): YTD Incremental (2011-to-Date)	Net Peak Demand Savings (kW): Program-to-Date: unverified annual savings in 2014	Net Energy Savings (kWh): Incremental (Current Quarter)	Net Energy Savings (kWh): YTD Incremental (2011-to-Date)	Net Energy Savings (kWh): Program-to-Date: unverified cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	15,019	56,035	1,194	4,333	4,333	7,716,329	28,872,984	115,491,936
2	Appliance Exchange	Appliances	0	4,715	0	479	479	0	604,709	2,418,836
3	HVAC Incentives	Equipment	7,397	56,127	1,717	12,512	12,512	1,134,038	17,784,401	71,137,602
4	Conservation Instant Coupon Booklet	Coupons	90,106	144,467	269	468	468	7,114,454	11,358,484	45,433,938
5	Bi-Annual Retailer Event	Coupons	195,529	337,358	374	791	791	12,047,863	21,685,594	86,742,376
6	Retailer Co-op	Items	0	152	0	0	0	0	41	162
7	*peaksaver* extension	Devices	10	18,435	8	14,352	14,352	156	287,033	1,148,132
8	Midstream Electronics	Items				not in market				
9	Midstream Pool Equipment	Items				not in market				
10	Residential New Construction	Houses	5	5	0.04	0.04	0.04	557	557	2,227
Consumer Program Total					3,561	32,934	32,934	28,013,397	80,593,802	322,375,209
Business Program										
11	Equipment Replacement Incentive	Projects	243	944	1,845	8,223	8,223	7,170,097	37,650,286	150,601,145
12	Direct Installed Lighting	Projects	2,422	18,667	1,546	10,407	10,407	11,414,663	77,311,193	309,244,770
13	Direct Service Space Cooling	Equipment				not in market				
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	0	0	0	0	0	0	0
16	*peaksaver* extension	Devices	0	121	0	201	201	0	4,029	16,117
17	Demand Response 1	Facilities		0		0	0		0	0
18	Demand Response 3	Facilities		145		21,390	0		667,368	667,368
Business Program Total					3,391	40,222	18,832	18,584,760	115,632,876	460,529,401
Industrial Program										
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	35	179	439	1,636	1,636	2,056,245	7,800,798	31,203,192
23	Demand Response 1	Facilities		0		0	0		0	0
24	Demand Response 3	Facilities		125		67,276	0		699,670	699,670
Industrial Program Total					439	68,912	1,636	2,056,245	8,500,468	31,902,862
Home Assistance Program										
25	Home Assistance Program	Units	494	494	1	1	1	18,047	18,047	72,188
Home Assistance Program Total					1	1	1	18,047	18,047	72,188
Pre-2011 Programs completed in 2011										
25	Electricity Retrofit Incentive Program	Projects	29	483	397	5,079	5,079	1,441,254	19,451,459	77,805,835
26	High Performance New Construction	Projects	28	220	650	4,723	4,723	4,306,415	33,266,180	133,064,719
27	Toronto Comprehensive	Projects	27	576	1,559	13,774	13,774	13,405,628	83,570,866	334,283,463
28	Multifamily Energy Efficiency Rebates	Projects	0	110	0	1,886	1,886	0	7,218,883	28,875,534
Pre-2011 Programs completed in 2011 Total					2,606	25,461	25,461	19,153,297	143,507,388	574,029,551
OPA-Contracted Province-Wide Portfolio Total					9,998	167,529	78,863	67,825,747	348,252,582	1,388,909,212

saveONenergy

Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Final Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported Savings: savings achieved that are based on reported activity and forecasted savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Table 5: Data Qualifiers for Initiatives currently in market

For Example: Preliminary results for Retrofit are reported in this quarter if a project is completed on or before Dec. 31, 2011 and had the iCON status "Approved for payment by LDC" or "Released for Payment" as of Jan. 20, 2012. There is a high probability that there are more results coming in for this initiative.

Initiative	Savings 'start' Date	Data Available	As of:	Updates:
Consumer Program				
Conservation Instant Coupon Booklet	Invoice date from coupon clearinghouse	Once data is submitted to the OPA by retailers	Dec. 21, 2011	High
Bi-Annual Retailer Event				
Appliance exchange initiative	Event date		Dec. 16, 2011	Low
Retailer co-op activities	Will vary by specific project	Varies by specific project	Dec. 31, 2011	Low
Appliance Retirement	Pick-up date	When database is queried	Jan. 11, 2012	Moderate
HVAC Incentives	Installation date	Customers submit rebate and invoices are processed	Oct. 31, 2011	High
peaksaver extension	Device installation date	Upon payment to LDC	Jan. 26, 2012	Moderate
New construction	Project completion	Preliminary Billing Report issued to LDC	Jan. 2, 2012	Low
Home Assistance Program				
Home Assistance Program	Project Completion Date	TBD	Jan. 23, 2012	High
Business (Commercial & Institutional) Program				
Direct Installed Lighting	Project Completion Date	Work-order: invoiced, approved and paid to LDC	Dec. 1, 2011	High
Equipment Replacement Incentive		"Approved for Payment by LDC" or "Released for Payment" status on iCON	Jan. 20, 2012	High
Process & Systems Upgrades			Jan. 20, 2012	Low
Building Commissioning		Upon payment to LDC	Jan. 20, 2012	Moderate
New Construction		Upon payment to LDC	Jan. 20, 2012	Low
peaksaver extension	Device installation Date	Upon payment to LDC	Jan. 26, 2012	Moderate
Demand Response (DR1, DR3)	Facility is available under contract	Facility under contract with aggregator	Dec. 31, 2011	Low
Pre-2011 Projects Completed in 2011				
High Performance New Construction	Project Completion Date	Upon payment to LDC	Jan. 16, 2012	High
Electricity Retrofit Incentive Program			Jan. 13, 2012	High
Multifamily Energy Efficiency Rebates			Nov. 2011	Low
Toronto Comprehensive			Jan. 11, 2012	High
Industrial Program				
Equipment Replacement Incentive	Project Completion Date	"Approved for Payment by LDC" or "Released for Payment" status on iCON	Jan. 20, 2012	High
Process & System Upgrades	In Service Date		Jan. 20, 2012	Low
Monitoring & Targeting	2nd year Report	Report submitted	Jan. 20, 2012	Low
Demand Response (DR1, DR3)	Facility is available under contract	Facility available under contract	Dec. 31, 2011	Low
Energy Manager	Quarterly Report Date	Report submitted quarterly	Jan. 20, 2012	Low

b. Wellington North Power Inc. is participating in the provincially coordinated Ontario Power Authority programs, to reduce customer energy consumption. The company has had a booth area home shows, held conservation information sessions for general service customers and is meeting with general service customers to perform facility audits to assist them, in reducing their monthly energy use. The equipment for the *peaksaver* PLUS program has not been approved at the time of this response. Once approved Wellington North Power will be able to enroll customers in the program.

Below are the provincial programs Wellington North Power is participating in:

- saveONenergy Fridge & Freezer Pickup
- saveONenergy Heating & Cooling Incentive
- saveONenergy Coupon Event
- *peaksaver* PLUS
- Retrofit Program
- High Performance New Construction
- HVAC Incentive Program
- Small Business Lighting
- Energy Audits
- saveONenergy Home Assistance Program

The OPA report for Wellington North Power's energy savings Q1 2012 are inserted below:

saveONenergy

Ontario Power Authority
Conservation & Demand Management Status Report

Q1 2012 Preliminary Results Update to March 31, 2012

Wellington North Power Inc.

Unverified LDC Tier 1 Progress Performance at a Glance

Table 1 shows unverified progress to target using two scenarios:

Scenario 1: Aggregation of LDC achievement in energy efficiency (EE)and demand response (DR) initiatives using the current DR reporting policy of 1 year persistence. This scenario is used on pages 4 - 7.

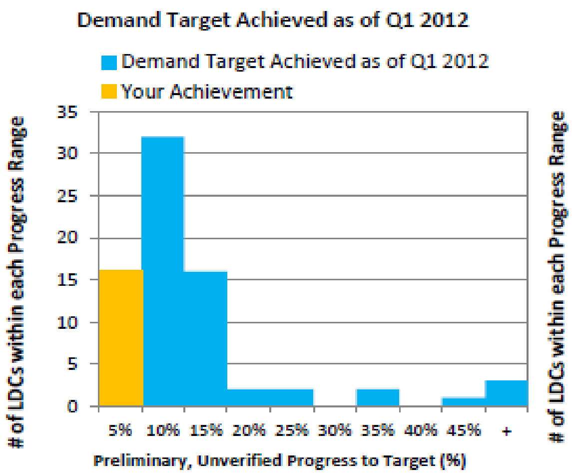
Scenario 2: Aggregation of LDC acheivement in EE and DR initiatives using alternate assumption that DR customers contribute to the program until 2014, including participant acheivement to date. Scenario 2 is used on this page only.

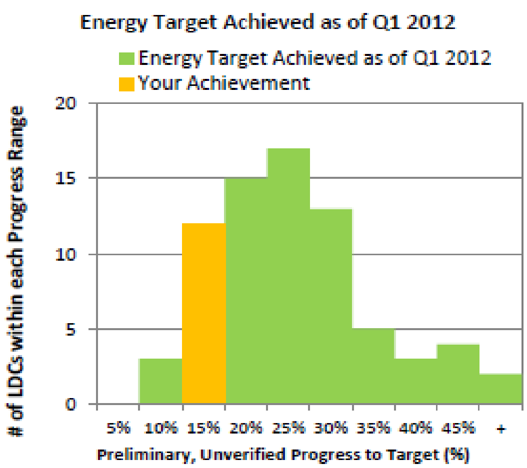
Table 1: Unverified Progress to Targets

Unverified Progress to Targets	Scenario 1	Scenario 2	
	% of Target Achieved	% of Target Achieved	Rank (of 77)
Net Annual Peak Demand Savings in 2014	3.3%	3.2%	70
2011-2014 Net Cumulative Energy Savings	14.0%	13.9%	65

Figures 1 & 2 shows a histogram with all LDCs' unverified performance towards their OEB targets and where your LDC performance is in relation to the LDC community. The golden lines show your progress towards peak demand and energy targets, respectively.

Figures 1 & 2: LDC Position in Relation to Entire LDC Community





For Example: there are 3 LDCs that have achieved between 5 and 10% of their OEB cumulative energy target using scenario 2.

Message from the Vice President

Q1 2012 was an exciting quarter for the OPA and LDCs. Customer participation in the saveONenergy programs continues to gain momentum. 25 LDCs have achieved over 25% of their cumulative energy target in Q1 2012 compared to only 9 in Q4 2011! To further build the capability of the LDC community and innovative program delivery, please share your success stories so others can learn and build from your best practices.

Through the effective collaboration continuing into Q1 2012 the OPA and LDCs have begun to incorporate additional tools and greater flexibility to deliver more customer centric programs. We anticipate the resulting improvements will further drive customer participation - encouraging a culture of conservation across the province. We look forward to continuing to work with the LDCs to bring these customized program ideas forward.

Congratulations on another successful quarter. We invite you to contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca with any questions or potential opportunities regarding this report.

Sincerely,

- Andrew Pride
Vice President, Conservation
Ontario Power Authority

About this Report

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not incl. Ontario Energy Board (OEB) approved CDM programs or other LDC conservation efforts).
- Unverified quarterly results discounted using forecasted net-to-gross ratios. Once full Evaluation, Measurement & Verification (EM&V) occurs in the following year, results will be identified as final (verified).
- Program activity data (i.e. projects completed, appliances picked up) completed on or before March 31, 2011 and received and entered into the OPA processing systems as per the dates specified in Table 6.
- Updates to the previous quarter's participation due to more data availability.
- *Assumption of 1 year persistance used to inform the remainder of this report

Future reports will contain:

- More data for the Home Assistance Program
- Preliminary results for **peaksaver PLUS™** representing participants that have signed a Participant Agreement will appear

New this quarter based on LDC feedback:

- Demand response is now reported in both the "YTD Incremental" and "YTD Incremental (2012-to-Date)" columns. These values represent the total demand response under contract in your LDC territory as of the end of the current reporting period.
- Assumptions have been updated to reflect findings from 2010 Evaluations and consultation with the Consumer, Business, and Industrial Work Groups. A document containing the net-to-gross ratio assumptions that will be used in 2012 preliminary, unverified reporting is available on the iCON Portal under "Other Program Materials." The item is called: "Reporting tools." OPA will continue to populate this folder with information to help LDCs understand reporting assumptions and policies.

2011-2014 Summary: Net Peak Demand Savings Achieved (MW)

This section provides a portfolio level view of net peak demand savings procured through Tier 1 programs to date.

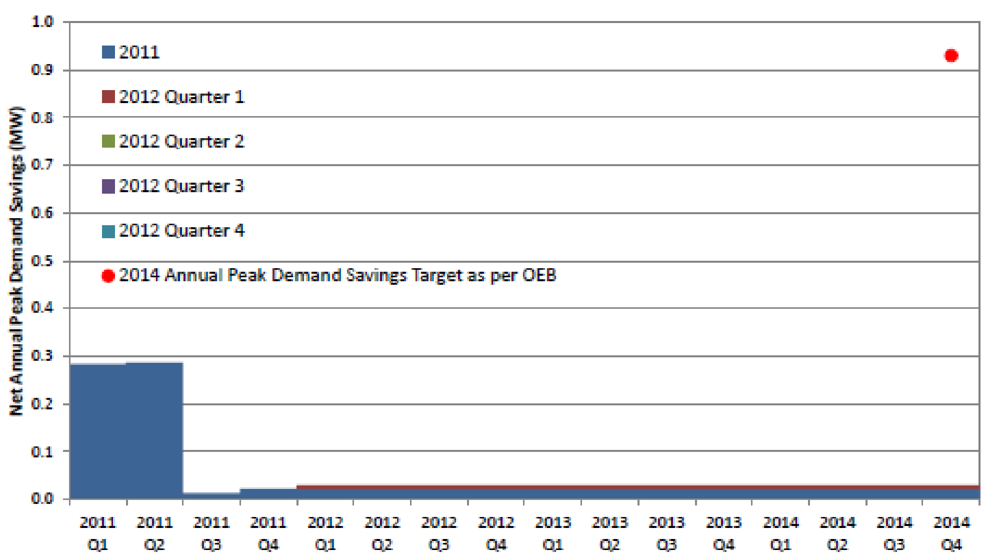
Table 2 presents preliminary net peak demand savings results from 2011 to date listed by implementation period. This table also presents the net annual peak demand savings that are expected to persist through to 2014 from program activity completed to date. Please note that Demand Response 1 and 3 have a persistence of 1 year in the table and figure below.

Table 2: Net Peak Demand Savings at the End-User Level (MW)

#	Implementation Period	Annual			
		2011	2012	2013	2014
1	2011 - Reported	0.02	0.02	0.02	0.02
2	2012 - Reported - Quarter 1		0.01	0.01	0.01
3	2012 - Reported - Quarter 2				
4	2012 - Reported - Quarter 3				
5	2012 - Reported - Quarter 4				
6	2013				
7	2014				
Annual Reported (Unverified)		0.02	0.03		
Annual Final (Verified)		n/a	n/a		
Unverified Net Annual Peak Demand Savings in 2014:					0.03
2014 Annual Peak Demand Savings Target as per OEB:					0.93
Unverified 2014 Peak Demand Savings Target Achieved (%):					3.3%

Figure 3 presents a visual summary of the information contained in Table 2.

Figure 3: Net Peak Demand Savings (MW)



2011-2014 Summary: Net Energy Savings Achieved (GWh)

This section provides a portfolio level view of net energy savings procured through Tier 1 programs to date.

Table 3 presents preliminary net annual energy savings results from 2011 to date by implementation period. This table also presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date.

Table 3: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual				Cumulative
		2011	2012	2013	2014	2011-2014
1	2011 - Reported	0.12	0.12	0.12	0.12	0.48
2	2012 - Reported - Quarter 1		0.05	0.05	0.05	0.16
3	2012 - Reported - Quarter 2					
4	2012 - Reported - Quarter 3					
5	2012 - Reported - Quarter 4					
6	2013					
7	2014					
Annual Reported (Unverified)		0.12	0.17			
Annual Final (Verified)		n/a	n/a			
Unverified Net Cumulative Energy Savings 2011-2014:						0.63
2011-2014 Cumulative Energy Savings Target as per OEB:						4.52
Unverified 2011-2014 Cumulative Energy Target Achieved (%):						14.0%

Figure 4 presents a visual summary of the information contained in Table 3.

Figure 4: Net Cumulative Energy Savings (GWh)

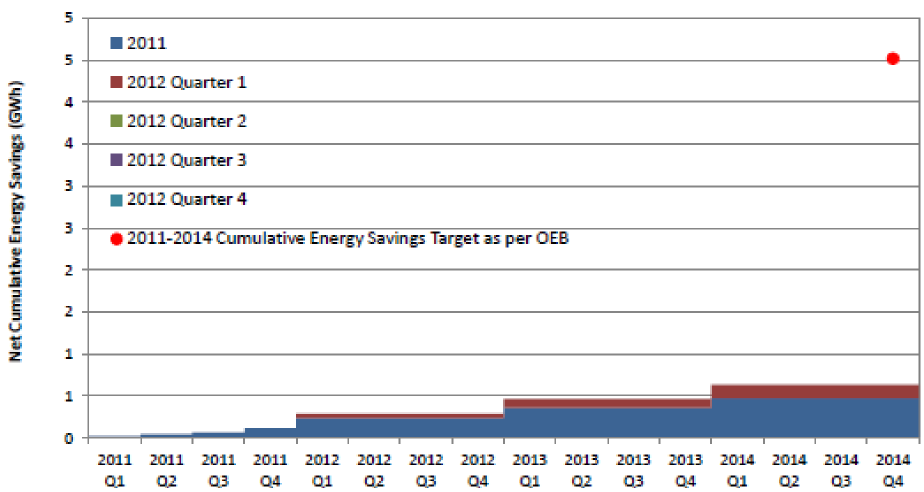


Table 4: Wellington North Power Inc. Initiative and Program Level Savings

All results are NET and presented at the end-user level

#	Initiative	Activity			Net Peak Demand Savings (kW)			Net Energy Savings (kWh)		
		Unit	Incremental (Current Quarter)	Program-to-Date (2011-to-Date):	Incremental (Current Quarter)	YTD Incremental (2012-to-Date)	Program-to-Date: unverified annual savings in 2014	Incremental (Current Quarter)	YTD Incremental (2012-to-Date)	Program-to-Date: unverified cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	8	64	1	1	5	4,800	4,800	147,226
2	Appliance Exchange	Appliances	0	1	0	0	0	0	0	181
3	HVAC Incentives	Equipment	4	30	1	1	7	1,707	1,707	48,283
4	Conservation Instant Coupon Booklet	Coupons	0	112	0	0	0	0	0	28,138
5	Bi-Annual Retailer Event	Coupons	0	252	0	0	0	0	0	49,702
6	Retailer Co-op	Items	0	0	0	0	0	0	0	0
7	peaksaver® extension	Devices	0	0	0	0	0	0	0	0
8	Midstream Electronics	Items			not in market					
9	Midstream Pool Equipment	Items			not in market					
10	Residential New Construction	Houses	0	0	0.00	0.00	0	0	0	0
Consumer Program Total					**2**	**2**	**13**	**6,506**	**6,506**	**273,530**
Business Program										
11	Equipment Replacement Incentive	Projects	0	1	0	0	0	0	0	4,511
12	Direct Installed Lighting	Projects	11	13	5	5	7	35,990	35,990	178,873
13	Direct Service Space Cooling	Equipment			not in market					
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	0	0	0	0	0	0	0
16	peaksaver® extension	Devices	0	0	0	0	0	0	0	0
17	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
18	Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Business Program Total					**5**	**5**	**8**	**35,990**	**35,990**	**183,384**
Industrial Program										
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	0	0	0	0	0	0	0	0
23	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
24	Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Industrial Program Total					**0**	**0**	**0**	**0**	**0**	**0**
Home Assistance Program										
25	Home Assistance Program	Units	0	0	0	0	0	0	0	0
Home Assistance Program Total					**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011										
25	Electricity Retrofit Incentive Program	Projects	0	0	0	0	0	0	0	0
26	High Performance New Construction	Projects	0	0	2	2	9	9,789	9,789	177,811
27	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
28	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total					**2**	**2**	**9**	**9,789**	**9,789**	**177,811**
OPA-Contracted Province-Wide Portfolio Total					**8**	**8**	**30**	**52,285**	**52,285**	**634,725**
Unverified Savings Target Achieved:							3.3%			14.0%

Table 5: Province-Wide Initiative and Program Level Savings

All results are NET and presented at the end-user level

#	Initiative	Activity			Net Peak Demand Savings (kW)			Net Energy Savings (kWh)		
		Unit	Incremental (Current Quarter)	Program-to-Date (2011-to-Date):	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: unverified annual savings in 2014	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: unverified cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	7,188	63,258	662	662	5,618	4,073,618	4,073,618	138,629,181
2	Appliance Exchange	Appliances	0	4,152	0	0	185	0	0	1,179,214
3	HVAC Incentives	Equipment	12,353	102,735	2,702	2,702	21,342	4,261,812	4,261,812	127,297,206
4	Conservation Instant Coupon Booklet	Coupons	0	201,500	0	0	388	0	0	49,225,347
5	Bi-Annual Retailer Event	Coupons	0	397,676	0	0	637	0	0	78,587,230
6	Retailer Co-op	Items	0	152	0	0	0	0	0	98
7	peaksaver® extension	Devices	0	17,825	0	0	9,982	0	0	1,568,600
8	Midstream Electronics	Items			not in market					
9	Midstream Pool Equipment	Items			not in market					
10	Residential New Construction	Houses	1	6	0.01	0.01	0.05	123	123	2,597
Consumer Program Total					3,364	3,364	38,151	8,335,553	8,335,553	396,489,473
Business Program										
11	Equipment Replacement Incentive	Projects	426	3,644	2,071	2,071	12,095	7,999,750	7,999,750	233,373,113
12	Direct Installed Lighting	Projects	3,283	19,053	1,701	1,701	7,794	12,503,959	12,503,959	266,707,290
13	Direct Service Space Cooling	Equipment			not in market					
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	381	0	0	20	0	0	319,108
16	peaksaver® extension	Devices	0	112	0	0	72	0	0	2,903
17	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
18	Demand Response 3	Facilities	149	145	17,253	17,253	0	536,415	536,415	1,070,310
Business Program Total					21,024	21,024	19,981	21,040,124	21,040,124	501,472,725
Industrial Program										
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	82	785	733	733	4,832	3,508,356	3,508,356	91,723,489
23	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
24	Demand Response 3	Facilities	132	125	53,447	53,447	0	555,851	555,851	1,115,587
Industrial Program Total					54,180	54,180	4,832	4,064,207	4,064,207	92,839,076
Home Assistance Program										
25	Home Assistance Program	Units	166	671	0	0	1	39,667	39,667	258,809
Home Assistance Program Total					0	0	1	39,667	39,667	258,809
Pre-2011 Programs completed in 2011										
25	Electricity Retrofit Incentive Program	Projects	0	953	0	0	9,962	0	0	235,219,415
26	High Performance New Construction	Projects	57	317	2,108	2,108	10,100	10,827,160	10,827,160	196,665,067
27	Toronto Comprehensive	Projects	0	735	0	0	12,651	0	0	300,325,644
28	Multifamily Energy Efficiency Rebates	Projects	0	110	0	0	1,798	0	0	27,506,630
Pre-2011 Programs completed in 2011 Total					2,108	2,108	34,510	10,827,160	10,827,160	759,716,757
OPA-Contracted Province-Wide Portfolio Total					80,676	80,676	97,475	44,306,711	44,306,711	1,750,776,840
Unverified Savings Target Achieved:							7.3%			29.2%

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Table 6: Data Qualifiers for Initiatives Currently In-Market & Likelihood of Additional Data

Initiative	Savings 'start' Date	Data Available	As Of:	Additional Data
Consumer Program				
Conservation Instant Coupon Booklet	Invoice date from coupon clearinghouse	Once data is submitted to the OPA by retailers	Apr. 13, 2012	High
Bi-Annual Retailer Event				
Appliance exchange initiative	Event date		Apr. 19, 2012	Low
Retailer co-op activities	Will vary by specific project	Varies by specific project	Apr. 15, 2012	Low
Appliance Retirement	Pick-up date	When database is queried	Apr. 26, 2012	Moderate
HVAC Incentives	Installation date	Customers submit rebate and invoices are processed	Apr. 16, 2012	Moderate
peaksaver extension	Device installation date	Project Completion Report uploaded to the iCON Portal	Apr. 23, 2012	Moderate
New construction	Project completion	Preliminary Billing Report issued to LDC	Apr. 19, 2012	Low
Business (Commercial & Institutional) Program				
Direct Installed Lighting	Project Completion Date	Work-order: invoiced, approved and paid to LDC	Feb. 29, 2012	High
Equipment Replacement Incentive		"Approved for Payment by LDC" or "Released for Payment" status on iCON	Apr. 18, 2012	High
Process & Systems Upgrades			Apr. 20, 2012	Low
Building Commissioning		Upon payment to LDC	Apr. 23, 2012	Moderate
New Construction		Upon payment to LDC	Apr. 23, 2013	Moderate
peaksaver extension	Device installation Date	Upon payment to LDC	Apr. 23, 2012	Moderate
Demand Response (DR1, DR3)	Facility is available under contract	Facility under contract with aggregator	Apr. 11, 2012	Low
Industrial Program				
Equipment Replacement Incentive	Project Completion Date	"Approved for Payment by LDC" or "Released for Payment" status on iCON	Apr. 18, 2012	High
Process & System Upgrades	In Service Date		Apr. 20, 2012	Low
Monitoring & Targeting	2nd year Report	Report submitted	Apr. 20, 2012	Low
Demand Response (DR1, DR3)	Facility is available under contract	Facility available under contract	Apr. 11, 2012	Low
Energy Manager	Quarterly Report Date	Report submitted quarterly	Apr. 20, 2012	Low
Home Assistance Program				
Home Assistance Program	Project Completion Date	Data sent to OPA by LDC	Apr. 19, 2012	High
Pre-2011 Projects Completed in 2011				
High Performance New Construction	Project Completion Date	From delivery agent, quarterly (results currently allocated)	Apr. 20, 2012	High
Electricity Retrofit Incentive Program		Upon payment to LDC	Apr. 15, 2012	High
Multifamily Energy Efficiency Rebates			Nov. 2011	Low
Toronto Comprehensive			Apr. 15, 2012	High

For Example: Preliminary results for Retrofit are reported in this quarter if a project is completed on or before Dec. 31, 2011 and had the iCON status "Approved for payment by LDC" or "Released for Payment" as of Jan. 18, 2012. There is a high probability that there are more results coming in for this initiative.

Reporting Methodology (Quarterly, Unverified results)

Over the last quarter, LDC and OPA members of the Reporting Work Group have been working on communicating reporting policies and procedures to the LDC community. There are now several resources for your use including: Reporting Policy & FAQ Document, LDC Consumer Program Tracking Tool (both of which available on the iCON Portal in "Other Program Materials" in the "Reporting Tools" folder), and several webinars available at the following link: http://www.snwebcastcenter.com/custom_events/opa-20111781/site/index.php

Notes:

- Table 6 is intended to assist the LDC in reconciling internal data sources with the data contained in this report by communicating:
  1. The date in which savings are considered to 'start';
  2. At what point the data becomes available to the OPA;
  3. The date in which the data was collected for reporting purposes; and
  4. The expectated probability and magnitude of updates to the data as more information becomes available.
- OPA will query iCON CRM for Retrofit data on the Wednesday, 2 weeks following the end of the calendar quarter. If you would like to have the ability to align the projects included in quarterly reports with your records, please run a query on the same day.

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Final Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported Savings: savings achieved that are based on reported activity and forecasted savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

c. Below is the breakdown of the Q1 2012 kWh CDM savings by customer class for consumers billed on kWh and kW:

Conservation Program Results - 2012 Q1			
Customer Class		kWh Energy Savings Q 1	Net Peak Demand Savings kW
Resident		16,295	
General Service < 50 kW		35,990	
General Service >50 - 999 kW			2
General Service >1000-4999 kW		-	-
		52,285	2

15. Reference: Exhibit 3, Tab 2. Schedule 1, page 352

a) The text at the bottom of the page acknowledges the trend analysis used by other distributors in forecasting kW/kWh ratios. The text states that WNPI used the historical average. However, Table 3-24 shows the trended values for 2011 and 2012. Please confirm whether WNPI used an average or trended kW/kWh ratio and explain why.

Wellington North Power Inc. – Response

a. WNP can confirm that it used the Trend approach in forecasting the kW / kWh ratios. The figure of 0.2772% was calculated by applying the Trend forecasting technique. The table below shows the summary of the data used.

To calculate 0.2772% 2012, the formula was:

=trend(select data percentages highlighted below for years 2004 to 2011 inclusive)

General Service 1,000 - 4,999 kW			
	kW	kWH	
2004	82,224	28,467,921	0.2888%
2005	87,633	30,363,260	0.2886%
2006	91,294	30,857,138	0.2959%
2007	70,180	33,212,587	0.2113%
2008	68,718	30,725,657	0.2236%
2009	73,937	27,961,217	0.2644%
2010	85,226	37,885,731	0.2250%
2011			0.2903%
2012			0.2772%

WNP applied the trended method because this technique can assist with identifying an underlying pattern of behaviour in a time series which would otherwise be partly or nearly completely hidden if simply applying an “average”.

16. Reference: Exhibit 3, Tab 3, Schedule 2, page 359

a) Please provide the actual 2011 Other Operating Revenue by the accounts shown in Table 3-30.

b) Where in Table 3-30 are the SSS Administration Fee Revenues included?

c) Please explain why, in 2012, Expenses from Non-Utility Operations exceed Revenues from Non-Utility Operations.

Wellington North Power Inc. – Response

a. The table below has been updated to reflect 2011 actual data:

Summary of Other Distribution Revenue							
Expense Description	2008 Board Approved	2008 Actual	Variance from 2008 Board Approved	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Other Distribution Revenue							
4082-Retail Services Revenues	7,312	7,565	253	7,944	8,591	7,521	8,679
4084-Service Transaction Requests (STR) Revenues	193	156	(38)	118	221	157	199
4210-Rent from Electric Property	32,886	36,281	3,395	34,597	30,617	30,334	27,267
4090- Electric Services Incidental to Energy Sales	11,487	20,194	8,707	11,901	0	0	0
4325-Other Electric Revenues	14,482	2,945	(11,537)	9,278	2,681	38,286	26,527
4330-Costs & Expenses of Merchandising & Jobbing		0		(510)	(1,024)	(29,237)	(21,928)
4225-Late Payment Charges	18,033	18,614	581	20,947	20,833	26,047	26,047
4235-Miscellaneous Service Revenues	54,450	61,681	7,231	65,097	58,820	45,870	57,043
4350-Losses from Disposition of Future Use Utility Plant	0	0	0	0	0	0	0
4355-Gain on Disposition of Utility and Other Property	0	20,100	20,100	233,782	16,713	134	0
4360-Loss on Disposition of Utility and Other Property	0	0	0	0	0	0	0
4375- Revenues from Non-Utility Operations	126,864	131,943	5,079	236,469	134,925	138,883	141,661
4380-Expenses from Non-Utility Operations	(80,962)	(96,880)	(15,918)	(252,966)	(122,267)	(136,532)	(139,262)
4385-Non-Utility Rental Income	0	9,473	9,473	0	0	0	0
4390-Miscellaneous Non-Operating Income	4,673	0	(4,673)	(8,569)	150	880	150
4405-Interest and Dividend Income	20,197	(21,147)	(41,344)	8,123	12,742	24,621	14,773
Sub-Total	**209,615**	**190,925**	**(18,689)**	**366,209**	**163,001**	**146,964**	**141,155**
4080-Distribution Services Revenue- SSS Admin Fee	21,795	13,438	(8,357)	13,433	13,557	13,673	13,792
Total	**231,409**	**204,363**	**(27,046)**	**379,642**	**176,558**	**160,637**	**154,947**
Specific Service Charges	54,450	61,681	7,231	65,097	58,820	45,870	57,043
Late Payment Charges	18,033	18,614	581	20,947	20,833	26,047	26,047
Other Distribution Revenues	88,155	80,579	(7,576)	76,761	54,642	60,733	54,537
Other Income and Expenses	70,772	43,489	(27,283)	216,839	42,262	27,987	17,321
Total	**231,409**	**204,363**	(27,046)	**379,642**	**176,558**	**160,637**	**154,947**

b. Table 3-30 in WNP's application incorrectly showed the values for the 2012 Year and should have reflected the numbers highlighted in the table above. This table now includes 2011 actual data:

c. When gathering information for this IR, Wellington North Power discovered some errors had been made during 2008, 2009 and 2011 regarding the Ontario Power Authority payments and expenses and the water and sewer expense.

The Water / Sewer billing and collection services provided to the municipality, is billed month at $2.25 per customer per bill. This revenue is allocated to account 4375 Non-Utility Operations Revenue. An offsetting journal entry is done to allocate expenses to 4380 Non-Utility Operations Expenses, for stationary, postage, mailing equipment, water meter reading and staff processing time from account 5315 Billing and account 5320 Collecting. As shown below, Wellington North Power has explained the incorrect allocation of transaction within 4375 and 4380.

<u>2008</u> – funds moved to the Balance Sheet should have been $122,468.30 instead of the $119,352.44 a difference of $3,115.86. Water and sewer expenses were understated in 2008 by approximately $24,822.43. The revenue over expense for water and sewer billing should have been approximately 7.7% or $7,124.70.

<u>2009</u> – funds moved to the Balance Sheet should have been $102,030.43 instead of the $126,100.00 a difference of $24,069.57.

<u>2010</u> – adjustments were completed to correct the errors in the OPA amounts in 2008 and 2009. The amounts were reallocated to correct the OPA payments and expenses as shown in the table below.

<u>2011</u> – water and sewer expense was overstated by $5,210.53.

The table below shows the <u>correct</u> allocation for 4375 and 4380.

Account	Name	2008		2009		2010		2011
			Should have been: Move unused $122,468.30 to Balance sheet		Should have been: Move unused $102,030.43 to Balance sheet		Move unused $170,196.50 to Balance Sheet, which included the corrections for	
4375	OPA Payment	39,414.61		162,225.96		44,027.04		34,742.53
4375	Water & Sewer Revenue	92,528.68		98,312.81		90,897.89		104,140.33
4380	OPA Expense	(39,414.61)		(162,225.96)		(44,027.04)		(34,742.53)
4380	Water & Sewer Expense	(60,581.55)		(90,740.44)		(78,240.22)		(101,789.04)
Total		31,947.13		7,572.37		12,657.67		2,351.29
	Moved to balance sheet	119,352.44		Moved to Balance sheet	126,100.00			106,999.57
	Should have moved to BS	(122,468.30)		Should have moved to BS	(102,030.43)		W/S Expense	(101,789.04)
	Expense Understated -	(3,115.86)		OPA Payment Understated -	24,069.57		overstated	5,210.53
	Corrected in 2010			Corrected in 2010				

OPERATING COSTS

17. Reference: Exhibit 4, Tab2, Schedule 1, page 382

a) The evidence at paragraph h) states that an hourly cost per hour is established for six shared vehicles. Who are these vehicles shared with?

b) Does WNP have an affiliate relationship with any other company?

c) What services to WNP provide to Township of Wellington North or the Township of Southgate?

<u>Wellington North Power Inc. – Response</u>

a. These vehicles are owned and operated by Wellington North Power Inc. They are shared by employees and utilized only by Wellington North Power Inc.

b. No, Wellington North Power does not have an affiliate relationship with any other company.

c. Wellington North Power Inc. works with the Township of Wellington North and Township of Southgate with respect to the removal of tree branches in the vicinity of overhead power lines in the company's service area. In these situations, Wellington North Power Inc. provides the bucket truck and experienced linemen required to complete the work of trimming around power lines and the respective Townships provide the ground crew and equipment required to remove the resulting brush.

   Wellington North Power Inc. provides water and sanitary sewer billing and collection services to the Township of Wellington North for which Wellington North Power Inc. charges $2.25 per bill per month. Wellington North Power does not provide any water and sanitary sewer billing and collection services to the Township of Southgate.

18. Reference: Exhibit 4, Tab 2, Schedule 1, page 387

a) What are the fees paid to CHEC and the EDA in each of 2008 through 2012 (forecast)?

b) Please clarify Appendix 2-L to show the total costs incurred by RSL for the services and the amount paid by the affiliates (Utilities and Services) for these services and/or the total costs incurred by Utilities or Services and the amounts paid by RSL for the services.

Wellington North Power Inc. – Response

a. The table below illustrates the fees to CHEC and the EDA together with a forecast for the 2012 Test Year:

	2008	2009	2010	2011	2012
CHEC	$4,354	$15,000	$15,750	$16,950	$16,950
EDA	$7,102	$7,193	$7,508	$8,339	$8,814

b. WNP can confirm that it has no affiliates.
This question does not relate to Wellington North Power Inc. and the LDC assumes it is relevant only to the LDC referred to in the IR.

19. Reference: Exhibit 4, Tab 2, Schedule 3, Tables 4-5 to 4-9

a) Please explain why there has been no forecast decrease in meter expenses (Account 5065) notwithstanding the complete replacement of meters in the past two years.

Wellington North Power Inc. – Response

a. Wellington North Power Inc. continues to have meter expense allocated to account (5065) Meter Expense. Only low volume customers, residential and GS <50 kW were moved to smart meters. Wellington North Power must read and maintain the GS >50-999 kW and the GS >1000-4999 meters to ensure they are reverified, tested and have a current seal date to meet Measurement Canada regulation.

20. Reference: Exhibit 4, Tab 2, Schedule 3, Tables 4-5 to 4-9

a) Please breakdown and compare, account 5310, the 2008 actual meter reading expense ($56,220) to a breakdown of the forecast 2012 meter expenses ($60,198).

Wellington North Power Inc. – Response

a. The table summarizes Account 5310 2008 Actual data versus the 2012 Test Year forecast:

Account 5310	2008 Actual	Account 5310	2012 Forecast Actual
Payroll Burden	$10,815	Payroll Burden	$11,062
Outside Services Employed	$24,720	Outside Services Employed	$25,460
Outside Labour	$16,454	Outside Labour	$8,545
Inside Labour	$4,231	Inside Labour	$7,425
		Software Maintenance	$3,560
		WAN Maintenance	$4,146
Actual Total	$56,220	Actual Total	$60,198

The following comments can be made about the above table to explain the variance between 2008 and 2012 Test Year forecast:

- In April 2011, a Customer Service Representative was hired at the LDC. This was an additional position and was required to assist with more complex billing and collection activities, which were needed in order to have two employees trained on doing billing requests to the IESO, validation of hourly meter reading versus historic monthly reads, trouble shooting meter communication issues and to cover vacation and sick days. In the past, meters were read 12 times a year for each customer as opposed to the new technology that requires 8,760 readings per year.
  This contributes to the increase in Inside Labour and Payroll Burden costs incurred in 2012.

- WNP anticipate that the cost for Meter Reading Expense will increase somewhat in 2011 and 2012 as a result of increased meter data validation functions, meter communication troubleshooting and the move to Time-of-Use pricing.

- WNP retains the services of Utilismart for settlement. Nightly Utilismart reads Wellington North Power's wholesale metering points and the company's over 1000-4999 kW interval customers and match with the hourly spot market price. This information is then downloaded to our CIS system for billing. This contributes to the Outside Services Employed expense and reflects the increase in service costs.

- In the 2012 Test Year, it is forecasted that there will be an increase which correlates to the other cost driver of Smart Metering, namely to ensure the verification of smart meter data, it is necessary that the meter reader records two full cycles of each new meter installed to ensure the proper operations of smart meters.

- In sheet I7.2 "Meter Reading" in the Cost Allocation model (Exhibit 7), Wellington North Power Inc has provided a view of meter reading effort against using Residential with a score of "1" as a benchmark (as prescribed by the OEB). The LDC believes that meter reading and meter data validation requires more time and expertise for the complex meters, which also have more reading dials and multiple data channels. Such complex meters are used by the General Service >50-999kW and General Service >1000-4999kW which have been allocated a score of 3.00 and 4.00 respectively. For GS<50kW, a score of "1.5" was used as the LDC monitors both kVA demand and kWh readings for these customers to determine whether they qualify to move into the GS>50kW class.
  This contributes to the variation in meter reading expenses for the 2012 Test Year compared to 2008.

- WNP has included Software Maintenance costs and WAN Maintenance costs in account 5310 in the 2012 Test Year. As per its application, WNP has requested that Smart Meters and associated costs are transferred from Accounts 1555 and 1556 into the appropriate expense accounts, including Account 5310. These Maintenance costs did not exist in 2008 and also contribute to the variation between this year and the 2012 Test Year

21. Reference: Exhibit 4, Tab 2, Schedule 3, Tables 4-5 to 4-9

a) Please provide the actual bad debt expense (account 5335) for 2011 and the first quarter of 2012.

Wellington North Power Inc. – Response

a. Wellington North Power Inc's Bad Debt expense (account 5335) for 2011 was $11,699
At the time of responding to this question, there have been no adjustments made for bad debt account for Quarter 1 of 2012. This is because the LDC is continuing to pursue all aged debt that relates to Quarter 1 billing activities. When the company is doing their yearend process, accounts in arrears are reviewed to determine which are uncollectable and allocated to bad debt expense.

22. Reference: Exhibit 4, Tab 2, Schedule 3, Tables 4-8 (Account 5315)

a) Please provide a breakdown of the actual 2011 customer billing costs (account 5315) and compare and contrast those amounts with the 2012 forecast costs.

Wellington North Power Inc. – Response

a. The table below shows the attributes that contribute to Account 5315 – Customer Billing:

Breakdown of 5315 Account:		
GL No.	**GL Description:**	**Description**
1-5315-5300-510-150	B&C - Cust Billing - Inside Lab	Inside Labour to prepare, validate and execute monthly billing
1-5315-5300-510-400	B&C - Cust Billing - Subcontractors	UtiliSmart (3rd party agent fees)- settlement provider for interval customers
1-5315-5300-510-500	B&C - Cust Billing - Expenses	Costs incurred for paper, postage, printer and material for postage machine
1-5315-5300-510-505	B&C - Cust Billing - Training	-
1-5315-5300-510-510	B&C - Cust Billing - Prof Services	Aegisys (3rd party agent fees - Disaster Recovery provider)- for nightly system back-up; Harris system upgrades to billing program

For account 5315, the table below shows the 2011 actual data as well as the 2012 Test Year values that were submitted in WNP's application:

GL No.	GL Description:	2011 Actual	2012 Forecast
1-5315-5300-510-150	B&C - Cust Billing - Inside Lab	$55,314	$37,449
1-5315-5300-510-400	B&C - Cust Billing - Subcontractors	$43,863	$28,950
1-5315-5300-510-500	B&C - Cust Billing - Expenses	$17,821	$12,750
1-5315-5300-510-505	B&C - Cust Billing - Training	$0	$0
1-5315-5300-510-510	B&C - Cust Billing - Prof Services	$23,240	$19,000
	Total	**$140,238**	**$98,149**

The following observations can be made about the above table:

- Inside Labour:
  WNP have forecasted that Inside Labour costs in the 2012 Test Year will be lower than 2011. In 2011, the LDC was preparing for the transition to Time-of Use pricing which attracted overtime costs and system upgrades.
  Wellington North Power Inc. transferred to TOU pricing on January 31, 2012. In Quarter 1 of 2012, the LDC has encountered system and data issues resulting in some system costs (Professional Services) and overtime expenses (Inside Labour). However, the LDC believes that now TOU has

been implemented, there should be minimal overtime costs incurred for the remainder of 2012.

Expenses:

WNP is forecasting in 2012 to spend less on materials than in 2011. As part of TOU rollout, Wellington North Power initiated customer education for TOU rates throughout the third and fourth quarter of 2011. This was done by flyers, special mailings and website event banner. There were addition costs for TOU shadow billing testing, the LDC incurred additional costs in printing “test” bills to validate the data and check the bill-lay-out. These costs will not exist in 2012.

Professional Services:

As part of TOU testing, the LDC incurred system upgrade costs. Post-implementation of TOU pricing, there have been some further system upgrades that have been required to address new data issues.

As mentioned previously, the LDC anticipates that now TOU pricing has been implemented, there should be less system costs incurred for the remainder of 2012.

23. Reference: Exhibit 4, Tab 2, Schedule 4, page 424

a) Please update the 2011 CPI inflation rate for actual rate as reported by Statistics Canada.

b) What assumption has WNP used for inflation in years 2008, 2009 and 2010 in its analysis of cost increases?

c) What 2012 forecast rate of inflation has WNP used in this application? When was this forecast last updated? If later than end of year 2011 please update this forecast.

Wellington North Power Inc. – Response

a. The table below shows the 2011 CPI inflation rate as reported by Statistics Canada.

	CPI
Jan-11	2.3
Feb-11	2.2
Mar-11	3.3
Apr-11	3.3
May-11	3.7
Jun-11	3.1
Jul-11	2.7
Aug-11	3.1
Sep-11	3.2
Oct-11	2.9
Nov-11	2.9
Dec-11	2.3
Average 2011 CPI	2.917

Source: http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ46a-eng.htm

b. In Wellington North Power Inc's application, Table 4-2 in Exhibit 4, Tab 2, Schedule 2 showed the year-over-year change itemized by each of the OMA components. WNP also provided a view of the published inflation rate for that particular year.
Illustrated below is a copy of Table 4-2:

Copy of Table 4-2 from Exhibit 4, Tab 2, Schedule 2:

2009 versus 2008:	2008 Actual $	2009 Actual $	Variance $	Variance %
Operations	277,177	242,297	(34,880)	-13%
Maintenance	170,399	209,605	39,206	23%
Billing & Collecting	230,806	257,652	26,846	12%
Community Relations	2,830	8,270	5,440	192%
Administrative and General	507,572	430,642	(76,930)	-15%
Total OM&A Expenses	**1,188,784**	**1,148,466**	**(40,318)**	**-3.4%**
Inflation Rate	*2.3706%*	(source : www.rateinflation.com)		
2010 versus 2009:	2009 Actual $	2010 Actual $	Variance $	Variance %
Operations	242,297	239,492	(2,805)	-1%
Maintenance	209,605	182,571	(27,034)	-13%
Billing & Collecting	257,652	264,248	6,596	3%
Community Relations	8,270	2,834	(5,435)	-66%
Administrative and General	430,642	565,006	134,364	31%
Total OM&A Expenses	**1,148,466**	**1,254,152**	**105,686**	**9.2%**
Inflation Rate	*0.2989%*	(source : www.rateinflation.com)		
2011 Bridge Year versus 2010:	2010 Actual $	2011 Bridge $	Variance $	Variance %
Operations	239,492	307,367	67,875	28%
Maintenance	182,571	223,089	40,518	22%
Billing & Collecting	264,248	369,768	105,521	40%
Community Relations	2,834	5,661	2,826	100%
Administrative and General	565,006	659,928	94,922	17%
Total OM&A Expenses	**1,254,152**	**1,565,813**	**311,661**	**24.9%**
Inflation Rate	*1.7775%*	(source : www.rateinflation.com)		
2012 Test Year versus 2011 Bridge Year:	2011 Bridge $	2012 Test $	Variance $	Variance %
Operations	307,367	286,141	(21,226)	-7%
Maintenance	223,089	247,516	24,427	11%
Billing & Collecting	369,768	355,363	(14,405)	-4%
Community Relations	5,661	6,804	1,143	20%
Administrative and General	659,928	706,848	46,920	7%
Total OM&A Expenses	**1,565,813**	**1,602,671**	**36,859**	**2.4%**
Inflation Rate	*2.9614%*	*(Jan-Aug)*	(source : www.rateinflation.com)	

c. Wellington North Power Inc. staff based forecasts for the 2011 Bridge Year and 2012 Test Year using the most accurate information available at the time together with sharing of knowledge and experience from employees. Each account was reviewed individually to project future costs. For instance, insurance and fuel costs have increased more than one percent annually since 2008, therefore the forecast was approximately 3 percent. Some costs such as payroll was already known, because although the company is non-union there is an Employee

Working Agreement for January 1, 2008 to December 31, 2010 and January 1, 2011 to December 31, 2013. A copy of the Wellington North Power Inc. Employee Working Agreement, have been filed as Appendices in the Board staff interrogatories.

Wellington North Power Inc. estimated inflationary increases for its OM&A budget using the rate of the yearly average posted CPI inflation. For the 2012 Test Year, Wellington North Power Inc. has used the average between January 2011 to June 2011 Bridge year rates which equates to an inflation rate of 3.0% as derived from the Canada CPI off the website www.statcan.gc.ca and http://www.bankofcanada.ca/.

According to www.rateinflation.com, the first four months of 2012, the Canadian CPI rate is 2.25% as per table below.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	Average
2012	2.46%	2.62%	1.93%	2.00%										2.25%
2011	2.35%	2.16%	3.29%	3.28%	3.70%	3.10%	2.74%	3.08%	3.17%	2.90%	2.89%	2.30%	2.95%	
2010	1.86%	1.58%	1.40%	1.84%	1.39%	0.96%	1.83%	1.74%	1.92%	2.44%	2.00%	2.35%	1.78%	
2009	1.07%	1.43%	1.24%	0.35%	0.09%	-0.26%	-0.95%	-0.78%	-0.86%	0.09%	0.96%	1.32%	0.30%	
2008	2.19%	1.81%	1.35%	1.70%	2.23%	3.13%	3.39%	3.49%	3.40%	2.60%	1.97%	1.16%	2.37%	

WNP feels that there is little benefit in revising / updating its forecast, as the 2012 inflation rate of 2.25% versus WNP's 2011 actual of 2.4%.

24. Reference: Exhibit 4, Tab 2, Schedule 3, page 411 & page 425

a) Please reconcile the reported $207,999 in regulatory costs for the 2012 test year shown at Table 4-9 with the proposed recovery of regulatory costs of $106,201 shown at Table 4-12.

Wellington North Power Inc. – Response

a. In its application, WNP requested recovery of $207,999 per year within its rates. However, this value is incorrect because the one-time costs should be recovered over the four-year period until the next Cost-of-Service application is due.

Therefore, the Regulatory Expenses in Account 5655 for the 2012 Test Year have been reduced from $207,999 to $106,201.

		Annual recovery of costs in Rates			
	2012 Test Year	2012	2013	2014	2015
On-Going Costs	$72,268	$72,268	$72,268	$72,268	$72,268
One-time Costs	$135,731	$33,933	$33,933	$33,933	$33,933
Total	$207,999	$106,201	$106,201	$106,201	$106,201
		one-time costs of $135,731 divided by 4 years			

The above change has contributed to the reduction of OM&A expenses by over $100,000 in the 2012 Test Year, which in-turn has also reduced the revenue deficiency.

25. Reference: Exhibit 4, Tab 2, Schedule 6, page 427

a) Please provide the most recent OM&A cost per customers and FTEE for WNP's cohort of utilities as defined by the OEB.

Wellington North Power Inc. – Response

a. The table on the following page illustrates the most recent (OEB Yearbook 2010) OM&A cost per customers and FTEE for Group 2 Cohorts, which includes Wellington North Power.

Notes:

- The number of customers is defined as and consists of the following classes:
    - Residential;
    - General Service <50kW;
    - General Service >50kW; and
    - Unmetered Scattered Loads
- To calculate number of FTEE, WNP took the number of customers and divided by the cost per customers;
- Source used: Ontario Energy Board - 2010 Yearbook
- In 2010, WNP was in Group 2 Cohorts.

A spreadsheet containing the information shown in the table has been provided. This has been uploaded on to the OEB's RESS site with the file name below:
(Filename: WellingtonNorth_IR_Responses_Appendix_June12)

Group 2 - Cohorts	Number of Customers	Number of FTEE	Cost Per Customer
Atikokan Hydro Inc.	11,612	16	$744.69
Bluewater Power Distribution Corporation	35,945	125	$287.35
Brant County Power Inc.	9,717	27	$361.27
Brantford Power Inc.	38,100	189	$201.44
Burlington Hydro Inc.	64,354	296	$217.65
Cambridge and North Dumfries Hydro Inc.	50,951	271	$188.26
Cooperative Hydro Embrun Inc.	1,977	8	$241.50
E.L.K. Energy Inc.	11,205	60	$185.93
Enersource Hydro Mississauga Inc.	195,894	807	$242.63
EnWin Utilities Ltd.	85,643	339	$252.91
Espanola Regional Hydro Distribution Corporation	3,321	11	$311.73
Essex Powerlines Corporation	28,333	146	$194.46
Fort Erie - Eastern Ontario Power (CNP)	15,654	45	$345.63
Fort Frances Power Corporation	3,780	11	$350.99
Guelph Hydro Electric Systems Inc.	50,828	261	$194.82
Haldimand County Hydro Inc.	21,049	65	$325.37
Halton Hills Hydro Inc.	20,919	99	$210.67
Hearst Power Distribution Company Limited	2,734	9	$299.76
Horizon Utilities Corporation	237,638	1,438	$165.24
Hydro One Networks Inc.	1,203,030	2,645	$454.77
Hydro Ottawa Limited	303,748	1,654	$183.67
Innisfil Hydro Distribution Systems Limited	14,789	56	$265.75
Kenora Hydro Electric Corporation Ltd.	12,272	40	$307.79
Kingston Hydro Corporation	27,102	122	$222.78
Lakeland Power Distribution Ltd.	9,480	30	$311.46
London Hydro Inc.	148,468	728	$203.97
Midland Power Utility Corporation	6,926	26	$267.26
Milton Hydro Distribution Inc.	29,326	153	$191.91
Newmarket - Tay Power Distribution Ltd.	33,026	163	$202.84
Niagara Peninsula Energy Inc.	51,513	197	$262.02
Niagara-on-the-Lake Hydro Inc.	7,902	35	$224.50
Norfolk Power Distribution Inc.	18,986	73	$259.72
Oakville Hydro Electricity Distribution Inc.	63,337	360	$175.79
Orangeville Hydro Limited	11,414	49	$234.52
Orillia Power Distribution Corporation	13,014	40	$325.24
Oshawa PUC Networks Inc	53,019	316	$167.61
Ottawa River Power Corporation	10,547	48	$221.70
Parry Sound Power Corporation	3,396	9	$359.27
Peterborough Distribution Incorporated	35,396	195	$181.82
PowerStream Inc.	328,408	1,909	$172.00
PUC Distribution Inc.	32,886	124	$264.30
Rideau St. Lawrence Distribution Inc.	5,866	21	$282.71
Sioux Lookout Hydro Inc.	2,763	6	$426.09
St. Thomas Energy Inc.	16,421	81	$203.23
Thunder Bay Hydro Electricity Distribution Inc.	49,979	201	$248.69
Tillsonburg Hydro Inc.	6,764	20	$330.22
Veridian Connections Inc.	113,493	622	$182.51
Wasaga Distribution Inc.	12,094	67	$180.81
Waterloo North Hydro Inc.	52,453	275	$190.70
Welland Hydro-Electric System Corp.	21,624	98	$221.07
Wellington North Power Inc.	**3,616**	**10**	**$348.98**
Westario Power Inc.	22,070	113	$195.13
Whitby Hydro Electric Corporation	40,059	179	$223.49
Woodstock Hydro Services Inc.	15,208	65	$234.68

26. Reference: Exhibit 4, Tab 2, Schedule 7, page 427

a) Please provide WNP's cost for transition to IFRS in years 2011, 2012, and 2013

Wellington North Power Inc. – Response

a. The table below illustrates the actual costs incurred to date (June 2012) by Wellington North Power Inc. for transition to IFRS:

2011	
Consulting Fees - BDO	40,265.98
Employee Training	458.78
Total Costs Incurred	**40,724.76**
2012	
Consulting Fees - BDO	2,500.00
Total Costs Incurred to Date	**2,500.00**

It should be noted that

- Although Wellington North Power Inc. was directed to file its Cost of Service application in MIFRS, the company is deferring its transition to the International Financial Reporting Standards (IFRS), until such time as it is mandate for Rate Regulated Entities. Therefore there is no change in the current obligation, or the regulatory treatment of the obligation. At the time of transition to IFRS, Wellington North Power Inc. will follow the guidelines and direction from the Ontario Energy Board Uniform System of Accounts for Electricity Distributors, the International Accounting Standards Board (AcSB) and the advice of the company's external auditor.
- Based upon the above comment, WNP anticipates to incur further IFRS transition costs (e.g. consultancy and training expenses, IS system and training costs) when the LDC does migrate from CGAPP to IFRS.

27. Reference: Exhibit 4, Tab 2, Schedule 10, page 451

a) Please update Table 4-24 (Overview of Employee Compensation) to show 2008 Board approved 2008 Actuals, 2009 Actuals and the amount of total compensation capitalized in each year.

Wellington North Power Inc. – Response

a. The table below shows the 2008, 2009 :2010 and 2011 Bridge Year actual data:

Description	Last Rebasing Year 2008	Historical Year 2009	Historical Year 2010	Bridge Year 2011	Test Year 2012
Number of Employees (FTEs including Part-Time)					
Executive	5.0	5.0	6.0	6.0	6.0
Management	2.0	2.0	2.0	3.0	3.0
Non-Union	8.5	8.5	8.5	8.5	10.5
Union					
Total	15.5	15.5	16.5	17.5	19.5
Number of Part-Time Employees					
Executive					
Management					
Non-Union	0.5	0.5	0.5	0.5	0.5
Union					
Total	0.5	0.5	0.5	0.5	0.5
Total Salary and Wages					
Executive	$ 32,900	$ 32,812	$ 148,752	$ 150,493	$ 145,059
Management	$ 256,097	$ 265,416	$ 203,797	$ 327,540	$ 322,826
Non-Union	$ 320,123	$ 360,937	$ 347,348	$ 472,433	$ 501,255
Union	$ -				
Total	$ 609,120	$ 659,165	$ 699,898	$ 950,466	$ 969,140
Current Benefits					
Executive			$ 893	$ 1,079	$ 7,845
Management	$ 1,694	$ 2,117	$ 832	$ 3,151	$ 15,720
Non-Union	$ 1,824	$ 2,472	$ 2,053	$ 3,613	$ 31,301
Union					
Total	$ 3,518	$ 4,589	$ 3,778	$ 7,843	$ 54,865
Total Compensation (Salary, Wages, & Benefits)					
Executive	$ 32,900	$ 32,812	$ 149,645	$ 151,572	$ 152,903
Management	$ 257,791	$ 267,533	$ 204,630	$ 330,691	$ 338,546
Non-Union	$ 321,947	$ 363,409	$ 349,401	$ 476,046	$ 532,556
Union	$ -		$ -	$ -	$ -
Total	$ 612,638	$ 663,754	$ 703,676	$ 958,308	$ 1,024,005
Compensation - Average Yearly Base Wages					
Executive	$ 6,580	$ 6,562	$ 24,792	$ 25,082	$ 24,176
Management	$ 128,048	$ 132,708	$ 101,899	$ 109,180	$ 107,609
Non-Union	$ 37,662	$ 42,463	$ 40,864	$ 55,580	$ 47,739
Union					
Total	$ 39,298	$ 42,527	$ 42,418	$ 54,312	$ 49,699
Compensation - Average Yearly Overtime					
Executive	$ -	$ -	$ -	$ -	$ -
Management	$ 5,267	$ -	$ -	$ 1,490	$ 3,667
Non-Union	$ 2,135	$ 2,549	$ 3,853	$ 6,577	$ 2,841
Union					
Total	$ 7,401	$ 2,549	$ 3,853	$ 8,067	$ 6,507
Compensation - Average Yearly Compensation					
Executive	6,580.00	6,562.40	24,940.88	25,261.93	25,483.88
Management	128,895.28	133,766.53	102,314.87	110,230.35	112,848.72
Non-Union	37,876.18	42,754.02	41,105.98	56,005.37	50,719.59
Union					
Total	39,525.04	42,822.85	42,647.02	54,760.47	52,513.08
Total Compensation	$ 612,638	$ 663,754	$ 703,676	$ 958,308	$ 1,024,005

The table below shows the Total compensation capitalized in each year

2008	2009	2010	2011
$124,106	$120,677	$143,385	$117,359

28. Reference: Exhibit 4, Tab 2, Schedule 10, 11 page 463

Since 2008 WNP has increased its FTE by 25%.

a) Please explain what incremental roles and responsibilities have occurred since 2010 which require the addition of two administrative positions.

b) Please explain the need for an incremental linesman.

c) Is 19.5 WNP long-term FTE requirement or are any existing positions expected to be retired between 2012 and 2015?

Wellington North Power Inc. – Response

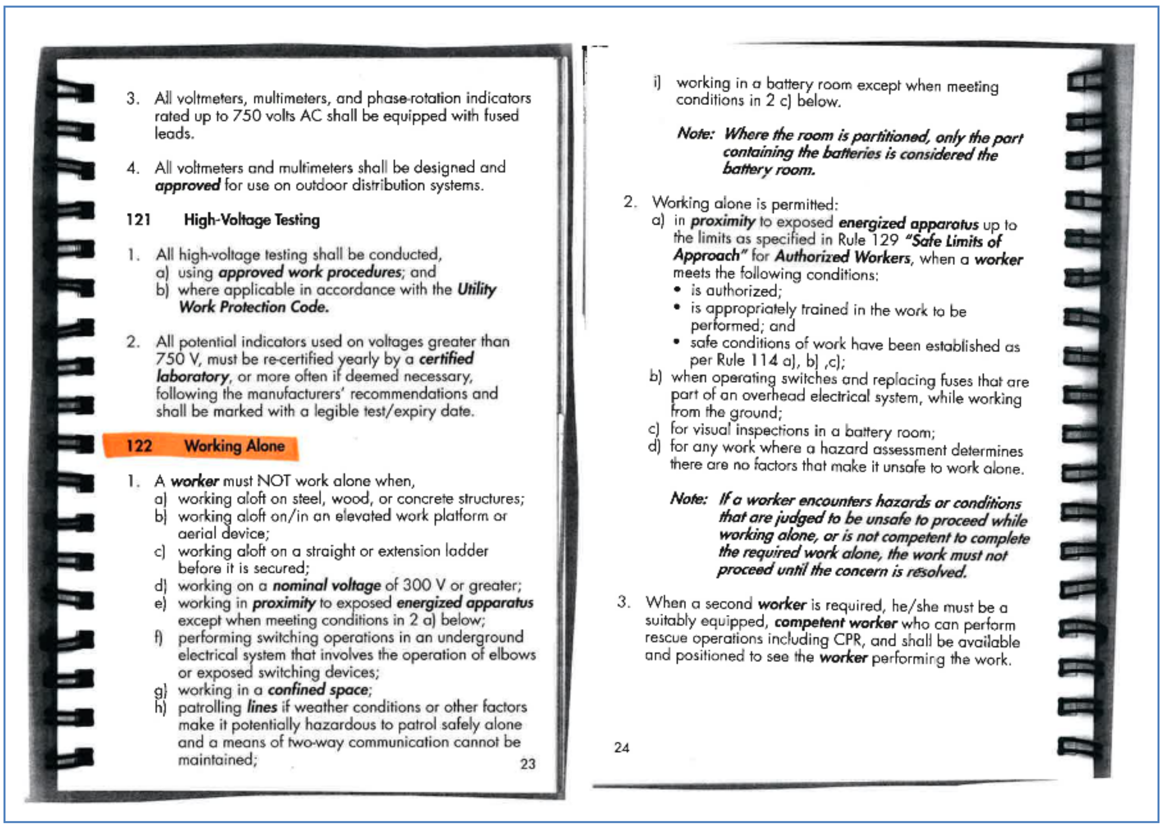
a. The current requirements of the Green Energy Act has increased the workload of Wellington North Power Inc., whether we consider the increased workload of planning and designing for renewable generation or monthly settlement of generation supplier bills; the Green Energy Act impacts all aspects of Wellington North Power's business. The Green Energy Plan as proposed by Wellington North Power supports the addition of a clerical support staff for operations, as detailed within our application. This clerical support staff member will be charged with assisting the Manager of Operations in completing the necessary documentation to run the operations department. This will include, but is not limited to, the monitoring of the Ontario Power Authority's website for renewable projects, creating and organizing the documentation that support renewable energy projects as well as secretarial work associated with assisting our customers with Green Energy related inquiries.

To summarize the incremental roles and responsibilities:

- Green Energy Act activities
- Increased emphasis on health and safety
- Increased reporting requirements to regulatory agencies
- Increase documentation required for construction activities

b. Wellington North Power Inc. is committed to replacing its aging distribution assets in a planned and co-ordinated manner to ensure long-term system reliability and performance. The asset management plan and capital budget forecast to complete this work is significant and in order for Wellington North Power Inc. to complete this work is a safe and efficient manner, an additional lineman is required.

The Electrical Utility Safety Rules establish the legal framework in Ontario for what is acceptable safe work practices while working on high voltage equipment. Within the rulebook, Rule #122 is titled “Working Alone”. This rule details the conditions when workers are able to work alone as well as when a worker must not work alone. WNP have taken an excerpt from the rulebook below for reference:



3. All voltmeters, multimeters, and phase-rotation indicators rated up to 750 volts AC shall be equipped with fused leads.

4. All voltmeters and multimeters shall be designed and **approved** for use on outdoor distribution systems.

121 High-Voltage Testing

1. All high-voltage testing shall be conducted,
   a) using **approved work procedures**; and
   b) where applicable in accordance with the ***Utility Work Protection Code.***

2. All potential indicators used on voltages greater than 750 V, must be re-certified yearly by a ***certified laboratory***, or more often if deemed necessary, following the manufacturers' recommendations and shall be marked with a legible test/expiry date.

122 Working Alone

1. A **worker** must NOT work alone when,
   a) working aloft on steel, wood, or concrete structures;
   b) working aloft on/in an elevated work platform or aerial device;
   c) working aloft on a straight or extension ladder before it is secured;
   d) working on a **nominal voltage** of 300 V or greater;
   e) working in **proximity** to exposed **energized apparatus** except when meeting conditions in 2 a) below;
   f) performing switching operations in an underground electrical system that involves the operation of elbows or exposed switching devices;
   g) working in a ***confined space***;
   h) patrolling **lines** if weather conditions or other factors make it potentially hazardous to patrol safely alone and a means of two-way communication cannot be maintained;

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   i) working in a battery room except when meeting conditions in 2 c) below.

   Note: Where the room is partitioned, only the part containing the batteries is considered the battery room.

2. Working alone is permitted:
   a) in **proximity** to exposed **energized apparatus** up to the limits as specified in Rule 129 ***"Safe Limits of Approach"*** for **Authorized Workers**, when a **worker** meets the following conditions:
      - is authorized;
      - is appropriately trained in the work to be performed; and
      - safe conditions of work have been established as per Rule 114 a), b) ,c);
   b) when operating switches and replacing fuses that are part of an overhead electrical system, while working from the ground;
   c) for visual inspections in a battery room;
   d) for any work where a hazard assessment determines there are no factors that make it unsafe to work alone.

   Note: If a worker encounters hazards or conditions that are judged to be unsafe to proceed while working alone, or is not competent to complete the required work alone, the work must not proceed until the concern is resolved.

3. When a second **worker** is required, he/she must be a suitably equipped, **competent worker** who can perform rescue operations including CPR, and shall be available and positioned to see the **worker** performing the work.

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Taken from Electrical Utility Safety Rules - Revised 2009.

Towards that end, with an aggressive planned capital program for the coming years and in the interest of being able to maintain and operate the distribution system while completing this capital work, an extra lineman will be required. An additional lineman will provide human resource flexibility within the operations department.

c. To clarify, the FTE requirements is 14.5 (not 19.5 as per Intervenor's question). Wellington North Power Inc. will have up to three retirements occur within a three year horizon. Of those expected retirements, two will be experienced lineman. The immediate addition of a lineman and/or apprentice is required to ensure the safe transition between the retiring lineman and the next generation lineman. It is expected that with future workload requires the fourth journey person / line technician sought in our application will be permanent, full-time, position at Wellington North Power. The third foreseeable retirement is Wellington North Power Inc.'s current President and CEO.

29. Reference: Exhibit 4, Tab 2, Schedule 10, page 451

a) Table 4-24 showing the overview of employee compensation does not show the same amounts as the equivalent categories in Tables 4-25 and 4-26. For example in Table 4-24 the Total Salary and Wages for the Management category in 2010 is $200,976. For the same category and year Table 4-26 shows a regular management salary of $298,457. Please reconcile the differences in these tables.

Wellington North Power Inc. – Response

a. The tables below are updated to reconcile as well as including 2011 actual data:

2008 Employee Compensation					
Description	**Board**	**Management**	**Operations**	**Admin**	**Total**
Paid Vacation	$ -	$ 13,115	$ 11,400	$ 3,406	$ 27,921
Allow Taxable	$ -	$ -	$ -	$ -	$ -
Taken In-Lieu	$ -	$ -	$ -	$ -	$ -
Allow Non-Taxable	$ -	$ -	$ -	$ -	$ -
Retro Pay	$ -	$ -	$ -	$ 658	$ 658
Retro OT	$ -	$ -	$ -	$ 4	$ 4
Regular Salary	$ -	$ 228,950	$ 161,082	$ 114,820	$ 504,852
Overtime	$ -	$ 10,533	$ 16,540	$ 1,603	$ 28,677
Standby	$ -	$ 3,498	$ 10,610	$ -	$ 14,109
Taxable Benefit	$ -	$ 1,694	$ 1,261	$ 563	$ 3,518
Gross Pay	**$ 32,900**	**$ 257,791**	**$ 200,893**	**$ 121,055**	**$ 612,638**
Deductions:					
C.P.P.	$ 464	$ 6,148	$ 6,148	$ 5,137	$ 17,897
OMERS	$ -	$ 18,689	$ 13,373	$ 5,382	$ 37,443
Income Tax	$ -	$ 63,954	$ 45,152	$ 18,644	$ 127,750
E.I.	$ -	$ 2,133	$ 2,133	$ 1,941	$ 6,208
INS.	$ -	$ 1,694	$ 1,261	$ 563	$ 3,518
CSB'S	$ -	$ 16,760	$ 7,384	$ 70	$ 24,214
Total Deductions	**$ 464**	**$ 109,377**	**$ 75,451**	**$ 31,737**	**$ 217,029**
Additions:					
Expenses	$ 2,805	$ 6,123	$ 1,993	$ 2,416	$ 13,337
Net Pay	**$ 35,241**	**$ 154,536**	**$ 127,435**	**$ 91,734**	**$ 408,946**

2009 Employee Compensation

Description	Board	Management	Operations	Admin	Total
Paid Vacation	$ -	$ 12,400	$ 11,745	$ 5,776	$ 29,921
Allow Taxable	$ -	$ -	$ -	$ -	$ -
Taken In-Lieu	$ -	$ -	$ 4,756	$ 191	$ 4,947
Allow Non-Taxable	$ -	$ -	$ -	$ -	$ -
Retro Pay	$ -	$ -	$ -	$ -	$ -
Retro OT	$ -	$ -	$ -	$ -	$ -
Regular Salary	$ -	$ 253,015	$ 172,795	$ 134,038	$ 559,848
Overtime	$ -	$ -	$ 17,255	$ 4,409	$ 21,664
Standby	$ -	$ -	$ 9,972	$ -	$ 9,972
Taxable Benefit	$ -	$ 2,117	$ 1,517	$ 955	$ 4,589
Gross Pay	**$ 32,812**	**$ 267,533**	**$ 218,039**	**$ 145,370**	**$ 663,754**
Deductions:					
C.P.P.	$ 473	$ 6,356	$ 6,356	$ 6,117	$ 19,301
OMERS	$ -	$ 19,509	$ 13,791	$ 7,773	$ 41,073
Income Tax	$ 900	$ 65,469	$ 47,734	$ 22,666	$ 136,768
E.I.	$ -	$ 2,195	$ 2,195	$ 2,305	$ 6,695
INS.	$ -	$ 2,117	$ 1,517	$ 955	$ 4,589
CSB'S	$ -	$ 18,200	$ 7,384	$ 910	$ 26,494
Total Deductions	**$ 1,373**	**$ 113,846**	**$ 78,977**	**$ 40,725**	**$ 234,921**
Additions:					
Expenses	$ 2,458	$ 7,778	$ 1,734	$ 5,025	$ 16,994
Net Pay	**$ 33,897**	**$ 161,464**	**$ 140,796**	**$ 109,670**	**$ 445,828**

2010 Employee Compensation

Description	Board	Management	Operations	Admin	Total
Paid Vacation	$ 6,420	$ 9,250	$ 12,945	$ 5,284	$ 33,899
Allow Taxable	$ -	$ 1,850	$ 1,850	$ -	$ 3,700
Taken In-Lieu	$ -	$ -	$ 1,296	$ -	$ 1,296
Allow Non-Taxable	$ -	$ 650	$ 650	$ -	$ 1,300
Retro Pay	$ -	$ 1,045	$ -	$ 592	$ 1,637
Retro OT	$ -	$ -	$ -	$ 105	$ 105
Regular Salary	$ 101,035	$ 197,422	$ 143,597	$ 138,004	$ 580,058
Overtime	$ -	$ -	$ 12,753	$ 20,000	$ 32,753
Standby	$ -	$ -	$ 10,272	$ -	$ 10,272
Taxable Benefit	$ 893	$ 1,725	$ 1,313	$ 739	$ 4,671
Gross Pay	**$ 142,332**	**$ 211,943**	**$ 184,676**	**$ 164,725**	**$ 703,676**
Deductions:					
C.P.P.	$ 2,533	$ 6,260	$ 5,244	$ 6,044	$ 20,082
OMERS	$ 8,329	$ 8,595	$ 11,815	$ 6,410	$ 35,149
Income Tax	$ 29,553	$ 50,963	$ 43,779	$ 27,432	$ 151,726
E.I.	$ 747	$ 2,208	$ 1,832	$ 2,299	$ 7,086
INS.	$ 893	$ 1,725	$ 1,313	$ 739	$ 4,671
CSB'S	$ 5,200	$ 13,000	$ 7,384	$ 910	$ 26,494
Total Deductions	**$ 47,256**	**$ 82,752**	**$ 71,367**	**$ 43,834**	**$ 245,207**
Additions:					
Expenses	$ 6,952	$ 4,334	$ 740	$ 4,424	$ 16,449
Net Pay	**$ 102,028**	**$ 133,525**	**$ 114,049**	**$ 125,315**	**$ 474,918**

Bridge Year: 2011 Actual Employee Compensation					
Description	**Board**	**Management**	**Operations**	**Admin**	**Total**
Paid Vacation	$ 13,034	$ 19,421	$ 16,027	$ 5,679	$ 54,161
Taken In-Lieu	$ -	$ 1,143	$ 2,678	$ 482	$ 4,303
Retro Pay	$ 739	$ 2,833	$ 2,213	$ 2,728	$ 8,514
Retro OT	$ -	$ -	$ 927		$ 927
Regular Salary	$ 136,719	$ 299,673	$ 205,185	$ 170,016	$ 811,592
Overtime	$ -	$ 4,470	$ 20,386	$ 35,521	$ 60,377
Standby	$ -		$ 10,592		$ 10,592
Taxable Benefit	$ 1,079	$ 3,151	$ 2,112	$ 1,500	$ 7,843
Gross Pay	**$ 151,572**	**$ 330,691**	**$ 260,119**	**$ 215,926**	**$ 958,308**
Deductions:					
C.P.P.	$ 2,375	$ 11,450	$ 6,653	$ 7,681	$ 28,158
OMERS	$ 9,957	$ 18,966	$ 19,187	$ 11,924	$ 60,033
Income Tax	$ 34,099	$ 75,262	$ 59,793	$ 40,007	$ 209,161
E.I.	$ 787	$ 4,115	$ 2,360	$ 2,849	$ 10,112
INS.	$ 1,079	$ 3,151	$ 2,112	$ 1,500	$ 7,843
CSB'S	$ 5,200	$ 4,440	$ 7,384	$ 910	$ 17,934
Total Deductions	**$ 53,496**	**$ 117,385**	**$ 97,489**	**$ 64,871**	**$ 333,241**
Net Pay	**$ 98,076**	**$ 213,306**	**$ 162,630**	**$ 151,056**	**$ 625,068**

Employee Costs

Description	Last Rebasing Year 2008	Historical Year 2009	Historical Year 2010	Bridge Year 2011	Test Year 2012
Number of Employees (FTEs including Part-Time)					
Executive	5.0	5.0	6.0	6.0	6.0
Management	2.0	2.0	2.0	3.0	3.0
Non-Union	8.5	8.5	8.5	8.5	10.5
Union					
Total	15.5	15.5	16.5	17.5	19.5
Number of Part-Time Employees					
Executive					
Management					
Non-Union	0.5	0.5	0.5	0.5	0.5
Union					
Total	0.5	0.5	0.5	0.5	0.5
Total Salary and Wages					
Executive	$ 32,900	$ 32,812	$ 148,752	$ 150,493	$ 145,059
Management	$ 256,097	$ 265,416	$ 203,797	$ 327,540	$ 322,826
Non-Union	$ 320,123	$ 360,937	$ 347,348	$ 472,433	$ 501,255
Union	$ -				
Total	$ 609,120	$ 659,165	$ 699,898	$ 950,466	$ 969,140
Current Benefits					
Executive			$ 893	$ 1,079	$ 7,845
Management	$ 1,694	$ 2,117	$ 832	$ 3,151	$ 15,720
Non-Union	$ 1,824	$ 2,472	$ 2,053	$ 3,613	$ 31,301
Union					
Total	$ 3,518	$ 4,589	$ 3,778	$ 7,843	$ 54,865
Total Compensation (Salary, Wages, & Benefits)					
Executive	$ 32,900	$ 32,812	$ 149,645	$ 151,572	$ 152,903
Management	$ 257,791	$ 267,533	$ 204,630	$ 330,691	$ 338,546
Non-Union	$ 321,947	$ 363,409	$ 349,401	$ 476,046	$ 532,556
Union	$ -		$ -	$ -	$ -
Total	$ 612,638	$ 663,754	$ 703,676	$ 958,308	$ 1,024,005
Compensation - Average Yearly Base Wages					
Executive	$ 6,580	$ 6,562	$ 24,792	$ 25,082	$ 24,176
Management	$ 128,048	$ 132,708	$ 101,899	$ 109,180	$ 107,609
Non-Union	$ 37,662	$ 42,463	$ 40,864	$ 55,580	$ 47,739
Union					
Total	$ 39,298	$ 42,527	$ 42,418	$ 54,312	$ 49,699
Compensation - Average Yearly Overtime					
Executive	$ -	$ -	$ -	$ -	$ -
Management	$ 5,267	$ -	$ -	$ 1,490	$ 3,667
Non-Union	$ 2,135	$ 2,549	$ 3,853	$ 6,577	$ 2,841
Union					
Total	$ 7,401	$ 2,549	$ 3,853	$ 8,067	$ 6,507
Compensation - Average Yearly Compensation					
Executive	6,580.00	6,562.40	24,940.88	25,261.93	25,483.88
Management	128,895.28	133,766.53	102,314.87	110,230.35	112,848.72
Non-Union	37,876.18	42,754.02	41,105.98	56,005.37	50,719.59
Union					
Total	39,525.04	42,822.85	42,647.02	54,760.47	52,513.08
Total Compensation	$ 612,638	$ 663,754	$ 703,676	$ 958,308	$ 1,024,005

COST OF CAPITAL

30. Reference: Exhibit 5, Tab 1, Schedule 1, page 689

a) Please explain why WNP is seeking a different long-term debt rate than the Board approved rate.

Wellington North Power Inc. – Response

a. For the 2012 Test Year, Wellington North Power Inc., applied the Cost of Capital parameter rates issued by the OEB on March 2, 2012, the "*Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012*" document, the average cost of capital is illustrated in the table below:

Weighted Average Cost of Capital using 2012 Rates			
	Deemed Portion	Effective Rate	Average Cost of Capital
Long-Term Debt	56.00%	4.42%	2.47%
Short-Term Debt	4.00%	2.08%	0.08%
Return on Equity	40.00%	9.12%	3.65%
Regulatory Rate of Return	**100.00%**		**6.20%**

The table above shows the Long-Term Debt Effective rate of 4.42%. This is 0.01% higher than the rate published in the "Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012" document. The reason for this variance is due the LDC securing an interest rate of 4.42% for its Smart Meter Loan which in-turn is driving up the Weighted Debt Cost Rate for 2012.

RATE DESIGN

31. Reference: Exhibit 8, Tab 1, Schedule 2, page 722

a) Is the fixed-variable split for the GS 50-999 class (Table 8.6) based on variable revenues net of (i.e. less) the transformer ownership allowance? If not, please recalculate the split and the resulting rates using the net variable revenues.

Wellington North Power Inc. – Response

a. In Exhibit 8, Tab1, Schedule 3, Table 8.6 the fixed-variable split for the General Service 50-999 kW class is **not** based on variable revenues net of the transformer ownership allowance.

The table below illustrates the recalculated split and resulting rate based upon variable revenues net of the 2012 transformer ownership allowance:

Customer Class	Total Base Rev Requirement	Variable Revenue Proportion	Transformer Allowance	2012 Volume	Unit	Proposed Volumetric Charge
Residential	$ 1,172,408	39.30%	$ -	24,515,702	kWh	$ 0.0188
GS < 50 kW	$ 396,406	43.65%	$ -	10,548,580	kWh	$ 0.0164
GS 50 - 999 kW	$ 306,179	56.02%	$ 13,915	50,418	kW	$ 3.6781
GS 1,000 - 4,999 kW	$ 310,884	57.66%	$ -	85,443	kW	$ 2.0981
Sentinel Lights	$ 2,571	59.58%	$ -	80	kW	$ 19.0385
Street Lighting	$ 89,762	16.77%	$ -	1,925	kW	$ 7.8215
Unmetered Scattered Loads	$ 156	31.18%	$ -	3,967	kWh	$ 0.0123
TOTAL	**$ 2,278,366**					

32. Reference: Exhibit 8, Tab 2, Schedule 1, page 726

a) Please update the proposed Retail Transmission Rates using the approved 2012 Uniform Transmission Rates.

Wellington North Power Inc. – Response

a. The Retail Transmission Rates using the approved 2012 Uniform Transmission Rates have been updated as per table below:

Wellington North Power Inc. - - CoS

Uniform Transmission Rates	Unit	Effective January 1, 2010	Effective January 1, 2011	Effective January 1, 2012
Rate Description		Rate	Rate	Rate
Network Service Rate	kW	$ 2.97	$ 3.22	$ 3.57
Line Connection Service Rate	kW	$ 0.73	$ 0.79	$ 0.80
Transformation Connection Service Rate	kW	$ 1.71	$ 1.77	$ 1.86

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2010	Effective January 1, 2011	Effective January 1, 2012
Rate Description		Rate	Rate	Rate
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective January 1, 2010	Effective January 1, 2011	Effective January 1, 2012
Rate Description		Rate	Rate	Rate
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ 0.0470	$ 0.0470
RSVA Transmission connection – 4716 – which affects 158	kW	-$ 0.0250	-$ 0.0250	-$ 0.0250
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ 0.0580	$ 0.0580
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	-$ 0.0750	-$ 0.0750
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ 0.0050	$ 0.0050

Applying the above updated Uniform Transmission Rates, there is no change to the Final 2012 RTS Rates for Wellington North Power Inc compared to the LDC's application, as per table 8-7 in Exhibit 8, Tab 2, Schedule 1.

A model which includes the updated 2012 Uniform Transmission Rates has been provided. This has been uploaded on to the OEB's RESS site with the file name below:
(Filename: 2012_RTSR_Adjustment_Work_Form1)

33. Reference: Exhibit 8, Tab 7, Schedule , page 733

a) Please outline the basis for WNPI's forecast 2012 Low Voltage charges (i.e., $145,889.78).

b) Please provide an alternative forecast of WNPI's 2012 Low Voltage charges based on the following calculation:
- WNPI's actual 2011 LV Charges (from Hydro One) times
- The ratio of WNPI's actual 2011 power purchases / WNPI's forecast 2012 power purchases per Exhibit 3.

Wellington North Power Inc. – Response

a. WNP is an embedded distributor with Hydro One and is subject to Low Voltage charges. The LDC allocated the low voltage costs by customer class based on the similar allocation of the retail transmission connection rates to develop percentage of allocation of the total Low Voltage charges for the customer classes.

The 2012 Low Voltage figure of $145,889 was forecasted by:
- Compared the percentage change for Hydro One's Transmission Connection Rate between the years of 2012 to 2011. This was an increase of 2.449%.
- Applied a similar increase of 2.449% to WNP's 2011 LV charge to provide a forecasted LV charge of $145,792.14.

Below is a summary of the calculations that were applied:

Customer Class	Hydro One's Transmission - Connection Rate 2011	Hydro One's Transmission - Connection Rate 2012	% Change between 2012 to 2011	2011 LV Charge	Forecasted 2012 LV Charge
Residential	$ 0.0037	$0.0038	2.449%	$142,307	$145,792
General Service < 50 kW	$ 0.0031	$0.0032	2.449%		
General Service 50 to 999 kW	$ 1.2399	$1.2703	2.449%		
General Service 1,000 to 4,999 kW	$ 1.3593	$1.3926	2.449%		
Street Lighting	$ 0.9586	$0.9821	2.449%		
Sentinel Lighting	$ 0.9786	$1.0026	2.449%		
Unmetered Scattered Load	$ 0.0031	$0.0032	2.449%		

b. Using the methodology described, set-out below is the Alternative LV Forecast for 2012 Test Year.

Applying this methodology, the 2012 Test Year LV Forecast would reduce by $17,318.43.

	Common ST Lines A/C: 0239768006	LVDS	Common ST Lines A/C2711620005	
Jan-11	$4,834.00	$602.17	$3,393.06	
Feb-11	$4,758.82	$551.09	$3,384.82	
Mar-11	$4,413.99	$495.36	$3,339.23	
Apr-11	$4,767.95	$490.49	$3,350.05	
May-11	$6,045.20	$431.20	$4,413.88	
Jun-11	$5,567.16	$385.71	$4,358.12	
Jul-11	$6,179.84	$437.14	$4,750.48	
Aug-11	$6,114.56	$387.69	$4,762.72	
Sep-11	$5,510.72	$458.90	$4,507.04	
Oct-11	$5,821.48	$506.37	$4,641.68	
Nov-11	$6,377.72	$630.98	$4,798.08	
Dec-11	$6,549.77	$690.30	$4,882.75	**Total:**
2011 Hydro One LV Charges to WNP	**$66,941.21**	**$6,067.40**	**$50,581.91**	**$123,590.52**
Actual LV Charge from Hydro One	$123,591			
2011 Actual Purchases / 2012 Forecasted Purchases (kWh)	105,542,005 / 101,453,329	=	1.0403	
Alternative LV Forecast	$123,591	x	1.0403	**$128,571.35**
LV Forecast as per WNP's Application				**$145,889.78**
Variance (Alternative Forecast less WNP's application LV Forecast)				**($17,318.43)**

34. Reference: Exhibit 8, Tab 8, Schedule 2, page 736

a) Please explain the significant increase in the loss factor for 2009 relative to other years.

b) Given that 2009 is a noted anomaly (per Exhibit 3); would it not be reasonable to exclude 2009 from the determination of the loss factor? If not, why not?

Wellington North Power Inc. – Response

a. The change in the Loss factor for 2009 can be attributed to the reduced Purchased Load volumes as a result of the Global economic recession that started in September 2008. As per WNP's application, exhibit 3, Tab 2, Schedule 1, Table 3-1, the LDC observed that:

> "Upon running the Power Purchase Model using the loaded data described and the variables, the 'R' square result was 76.22%. Wellington North Power Inc. believes that this result is not acceptable and upon investigating the model and data inputs, Wellington North Power Inc. observed that the Purchase Load data in 2009 was significantly lower compared to other years…….The underlying contributing factor for the lower 2009 Purchase Load volume is due to the Global Economic recession that started in September 2008. Within Wellington North Power Inc.'s customer base there are three automotive manufacturing companies that, due to the recession, altered their production, hours of operations and working shift pattern at the end of 2008 and start of 2009. It has been observed by Wellington North Power Inc. that it has taken until early 2011 for these customers to have resumed to "normal" consumption patterns."

In addition to the above explanation, the table below shows:

- Difference between Wholesale kWh versus Retail kWh, with 2009 showing the most significant variance of all years; and
- Wholesale kWh and Net kWh variance year-over-year:

	2007	2008	2009	2010
Wholesale less Net kWH variance:	3,305,738	3,684,201	3,889,055	3,156,495
Wholesale kWh variance to prior year:	2,104,893	(1,349,070)	(6,869,745)	8,883,408
Net kWh variance to prior year:	1,619,732	(1,727,533)	(7,074,599)	9,615,969

Furthermore, in 2009, WNP observed the lowest On-Load Peak Demand Factor as illustrated in the table below:

	On Peak Load Factor
2006	87.35%
2007	87.92%
2008	87.28%
2009	**86.54%**
2010	87.43%
2011	87.24%

In summary, the above points illustrate that WNP customers were consuming less electricity during 2009 and, with a lower the On-Peak Load, the distribution system was less efficient compared to previous and subsequent years.

b. Excluding 2009 from the determination of the loss factor and applying a five-year average (2005 – 2010), the recalculated Distribution Loss Factor and Supply Loss factor are represented in the table below:

	2005	2006	2007	2008	2009	2010	5 Year Total
"Wholesale" kWh (IESO) **Qty at the Meter** *(A)*	95,916,378	96,449,458	98,554,351	97,205,281	90,335,536	99,218,944	
"Wholesale" kWh (GEN) *(B)*	-	-	-	-	-	-	
Net "Wholesale" kWh (A)-(B) *(C)*	**95,916,378**	**96,449,458**	**98,554,351**	**97,205,281**	**90,335,536**	**99,218,944**	**487,344,412**
Retail kWh (Distributor) **Qty at the Meter** *(D)*	92,239,845	93,628,881	95,248,613	93,521,080	86,446,481	96,062,450	**470,700,869**
	-	-	-	-	-	-	-
Net "Retail" kWh (D) *(F)*	**92,239,845**	**93,628,881**	**95,248,613**	**93,521,080**	**86,446,481**	**96,062,450**	
							5 Yr Average
Distribution Loss Factor [(C)/(F)] *(G)*	1.0399	1.0301	1.0347	1.0394	1.0450	1.0329	**1.0354**
Supply Facility Loss Factor *(H)*	1.0340	1.0340	1.0340	1.0340	1.0341	1.0342	**1.0340**

Total Utility Loss Adjustment Factor:	**LAF**	
Supply Facility Loss Factor:	**1.0340**	*(5 yr average of 2005 - 2010, excluding 2009)*
Distribution Loss Factor:	**1.0354**	*(5 yr average of 2005 - 2010, excluding 2009)*
Total Loss Factor:		
Secondary Metered Customer:		
Total Loss Factor - Secondary Metered Customer < 5,000kW:	**1.0706**	
Total Loss Factor - Secondary Metered Customer > 5,000kW:	n/a	
Primary Metered Customer:		
Total Loss Factor - Primary Metered Customer < 5,000kW:	**1.0599**	
Total Loss Factor - Primary Metered Customer > 5,000kW:	n/a	

Using the above method, the LDC's 2012 forecasted Secondary Metered Customer Total Loss factor reduces from 1.0723 (as per application) to 1.0706.

35. Reference: Exhibit 8, Tab 10, Schedule 1, pages 753 and 757

a) Based on the most recent 12 months of billing data please indicate the number of Residential customers whose average monthly use falls into each of the following consumption ranges:
- 0-250 kWh
- >250-500 kWh
- >500-800 kWh
- >800 – 1,500 kWh
- >1,500 kWh

b) Please provide the Residential bill impact calculations (per page 753) for Residential customers with 500 kWh of monthly use and 250 kWh of monthly use.

Wellington North Power Inc. – Response

a. Using the last 12 months of billing data (June 2011 to May 2012 inclusive), the number of Residential customers whose average monthly use falls into each of the following consumption ranges is:

Consumption Range	Count of Residential Customers
0-250 kWh	191
>250-500 kWh	770
>500-800 kWh	1,056
>800 – 1,500 kWh	844
>1,500 kWh	154
Total:	3,015

b. The Residential Bill impact for a customer with a monthly use of 500 kWh is:

		Consumption	500 kWh							
			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
1	Monthly Service Charge		$ 13.8800	1	$ 13.88	$ 18.7700	1	$ 18.77	$ 4.89	35.23%
2	Smart Meter Rate Adder		$ 2.5000	1	$ 2.50	$ 0.6787	1	$ 0.68	-$ 1.82	-72.85%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)		$ 0.1500	1	$ 0.15	$ -	1	$ -	-$ 0.15	-100.00%
5	Distribution Volumetric Rate		$ 0.0139	500	$ 6.95	$ 0.0188	500	$ 9.40	$ 2.45	35.25%
6	Low Voltage Rate Adder		$ 0.0016	500	$ 0.80	$ 0.0018	500	$ 0.89	$ 0.09	10.88%
7	Volumetric Rate Adder(s)			500	$ -		500	$ -	$ -	
8	Volumetric Rate Rider(s)			500	$ -		500	$ -	$ -	
9	Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
10	LRAM & SSM Rate Rider		$ 0.0004	500	$ 0.20	$ -	500	$ -	-$ 0.20	-100.00%
11	Deferral/Variance Account Disposition Rate Rider		-$ 0.0058	500	-$ 2.90	-$ 0.0081	500	-$ 4.07	-$ 1.17	40.26%
12	Stranded Meter Rate Rider				$ -	$ 1.1490	1	$ 1.15	$ 1.15	
13					$ -			$ -	$ -	
14	Mitigation Rider				$ -		800	$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 21.58**			**$ 26.82**	**$ 5.24**	**24.27%**
17	RTSR - Network		$ 0.0053	534.929	$ 2.84	$ 0.0054	535.85	$ 2.91	$ 0.08	2.69%
18	RTSR - Line and Transformation Connection		$ 0.0037	534.929	$ 1.98	$ 0.0038	535.85	$ 2.03	$ 0.05	2.63%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 26.39**			**$ 31.76**	**$ 5.37**	**20.33%**
20	Wholesale Market Service Charge (WMSC)		$ 0.0052	534.929	$ 2.78	$ 0.0052	535.85	$ 2.79	$ 0.00	0.17%
21	Rural and Remote Rate Protection (RRRP)		$ 0.0013	534.929	$ 0.70	$ 0.0011	535.85	$ 0.59	-$ 0.11	-15.24%
22	Special Purpose Charge			534.929	$ -		535.85	$ -	$ -	
23	Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	0.00%
25	Energy		$ 0.0684	534.929	$ 36.58	$ 0.0807	535.85	$ 43.24	$ 6.66	18.21%
26	Smart Metering Charge (IESO)	monthly			$ -	$ 0.8100	1	$ 0.81	$ 0.81	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 70.20**			**$ 82.93**	**$ 12.73**	**18.14%**
29	HST		13%		$ 9.13	13%		$ 10.78	$ 1.66	18.14%
30	**Total Bill (including Sub-total B)**				**$ 79.33**			**$ 93.71**	**$ 14.38**	**18.13%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 7.93**	-10%		**-$ 9.37**	**-$ 1.44**	**18.16%**
32	**Total Bill (including OCEB)**				**$ 71.40**			**$ 84.34**	**$ 12.94**	**18.12%**
33	**Loss Factor (%)**	**Note 1**	6.99%			7.17%				

The Residential Bill impact for a customer with a monthly use of 250 kWh is:

		Consumption	250 kWh							
			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
1	Monthly Service Charge		$ 13.8800	1	$ 13.88	$ 18.7700	1	$ 18.77	$ 4.89	35.23%
2	Smart Meter Rate Adder		$ 2.5000	1	$ 2.50	$ 0.6787	1	$ 0.68	-$ 1.82	-72.85%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)		$ 0.1500	1	$ 0.15	$ -	1	$ -	-$ 0.15	-100.00%
5	Distribution Volumetric Rate		$ 0.0139	250	$ 3.48	$ 0.0188	250	$ 4.70	$ 1.23	35.25%
6	Low Voltage Rate Adder		$ 0.0016	250	$ 0.40	$ 0.0018	250	$ 0.44	$ 0.04	10.88%
7	Volumetric Rate Adder(s)			250	$ -		250	$ -	$ -	
8	Volumetric Rate Rider(s)			250	$ -		250	$ -	$ -	
9	Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
10	LRAM & SSM Rate Rider		$ 0.0004	250	$ 0.10	$ -	250	$ -	-$ 0.10	-100.00%
11	Deferral/Variance Account Disposition Rate Rider		-$ 0.0058	250	-$ 1.45	-$ 0.0081	250	-$ 2.03	-$ 0.58	40.26%
12	Stranded Meter Rate Rider				$ -	$ 1.1490	1	$ 1.15	$ 1.15	
13					$ -			$ -	$ -	
14	Mitigation Rider				$ -		800	$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 19.06**			**$ 23.71**	**$ 4.65**	**24.42%**
17	RTSR - Network		$ 0.0053	267.464	$ 1.42	$ 0.0054	267.925	$ 1.46	$ 0.04	2.69%
18	RTSR - Line and Transformation Connection		$ 0.0037	267.464	$ 0.99	$ 0.0038	267.925	$ 1.02	$ 0.03	2.63%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 21.46**			**$ 26.18**	**$ 4.72**	**21.98%**
20	Wholesale Market Service Charge (WMSC)		$ 0.0052	267.464	$ 1.39	$ 0.0052	267.925	$ 1.39	$ 0.00	0.17%
21	Rural and Remote Rate Protection (RRRP)		$ 0.0013	267.464	$ 0.35	$ 0.0011	267.925	$ 0.29	-$ 0.05	-15.24%
22	Special Purpose Charge			267.464	$ -		267.925	$ -	$ -	
23	Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	250	$ 1.75	$ 0.0070	250	$ 1.75	$ -	0.00%
25	Energy		$ 0.0684	267.464	$ 18.29	$ 0.0807	267.925	$ 21.62	$ 3.33	18.21%
26	Smart Metering Charge (IESO)	monthly			$ -	$ 0.8100	1	$ 0.81	$ 0.81	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 43.49**			**$ 52.30**	**$ 8.81**	**20.25%**
29	HST		13%		$ 5.65	13%		$ 6.80	$ 1.14	20.25%
30	**Total Bill (including Sub-total B)**				**$ 49.14**			**$ 59.09**	**$ 9.95**	**20.25%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 4.91**	-10%		**-$ 5.91**	**-$ 1.00**	**20.37%**
32	**Total Bill (including OCEB)**				**$ 44.23**			**$ 53.18**	**$ 8.95**	**20.24%**
33	**Loss Factor (%)**	**Note 1**	6.99%			7.17%				

DEFERRAL AND VARIANCE ACCOUNTS

36. Reference: Exhibit 4, Tab 2, Schedule 10, page 451

a) Table 4-24 showing the overview of employee compensation does not to show the same amounts as the equivalent categories in Tables 4-25 and 4-26 which appear later in the evidence. For example in Table 4-24 the Total Salary and Wages for the Management category for 2010 is $200,976. For the same category and year in Table 4-26 show the regular salary of $298,457. Please reconcile these tables.

Wellington North Power Inc. – Response

a. Please see Wellington North Power's response to Reference 29.

SMART METERS

37. Reference: Exhibit 10, Tab 2, Schedule 1, pages 787/ 806

WNP states that it proposes to charge residential and general service customers the same amount to recover stranded meter costs because it does not have sufficient information to allocate these costs among the classes.

a) Is it WNP's experience that a residential meter is less costly than general service meters? What is WNP's estimate of the cost difference?

b) Is it WNP's experience that a residential meter is less costly to install than a general service meter? What is WNP's estimate of the cost difference?

c) Based on WNP's experience of purchasing and installing meters prior to 2010, is not possible to develop a proxy allocator based on the average cost in 2010 (or earlier) to purchase and install a residential meter and a general service <50 meter.

d) Based on estimated cost differences between the capital and OM&A (installation) cost of residential and general service meters please provide develop an alternative stranded meter rate rider.

Wellington North Power Inc. – Response

a. Regarding Stranded meters, WNP has the estimated cost of purchasing a mechanical meter as per table below:

	Mechanical Meter Cost	Installation Cost	Material & Installation Cost
Residential	$50	$100	$150
General Service < 50kW	$300	$300	$600

b. Regarding Stranded meters, WNP has the estimated cost of installing a mechanical meter as per table above:

c. Based upon the information available, WNP has constructed the following model:

	Mechanical Meter Cost	Installation Cost	Material & Installation Cost	Weighting Ratio
Residential	$75	$100	$175	23%
General Service < 50kW	$300	$300	$600	77%
			$775	

	Customer Numbers	Weighting Ratio
Residential	3,160	87%
General Service < 50kW	489	13%
	3,649	

	Residential	General Service <50 kW
Customer Number weighting	87%	13%
Purchase & Install weighting	23%	77%
Allocator	**55%**	**45%**

Net Book Value Segregated by Rate Class:	Residential	GS <50 kW	Total
	$109,865	$91,367	**$ 201,233**
Number of Metered Customers:	3,160	489	**3,649**
Rate Rider to Recover Stranded Meter Costs:	**$0.7243**	**$3.8966**	
Recovery period (years):	**4**	**4**	

WNP has attempted to provide a weighting factor not only the purchase and installation of costs of mechanical meters, but also the number of customers in each class. The LDC is looking for fairness and equitably to both classes in seeking for the recovery of the Net Book Value that WNP is requesting disposition of, calculated at $201,233 as at December 31, 2012.

The approach applied by WNP was:

- Use the purchase and install cost information to create a meter cost weighting ratio for each class;
- Use the customer numbers for each calls to create a customer number weighting ratio for each class;
- There are two weighting variables (meter cost and customer numbers). Calculate the ratio for these variable to create one ratio that can be used to distribute the NBV between two classes
- Applying the above technique, the table above shows that Residential customers are allocated $109,869 and General Service < 50kW customers are allocated $$91,367.
- Dividing these allocated values by the number of customers in each class and selecting a recovery period of 4 years, the table above shows the Rate Rider amount that each customer would pay every month.

d. As illustrated in the above table in part (c), WNP has attempted to be equitable to both rate classes by using customer numbers together with OM&A and capital costs.

   This is another view compared to the proposal put forward in WNP Cost of Service application.

   The LDC is interested to learn of other methodologies that Board Staff and/or Intervenors can share that ensure that both rate classes are treated fairly and equally.

*****End of Document*****