Ottawa River Power Corporation
Exhibit 2
Response to Interrogatories

2-Staff-7 Ref: Exhibit 2, p. 18 – 26 of 58 and Appendix 2-AA

Please provide table 2-AA showing capital project by category from 2010 to 2016 in one table in aggregate, not separated by accounts. Please add a column showing actual capital expenditures for the 2015 bridge year up to December 31, 2015.

Response:

Ottawa River Power presents the following updated table 2-AA.

System Access	2010	2011	2012	2013	2014	2015 Prelim	2015 Bridge	2016 Test
New Services	$60,456	$38,124	$48,033	$43,112	$87,069	$66,783	$358,000	
Logan Subdivision - Ketch Construction	$7,240							
New Service on Minto St. - Beachburg	$2,372							
Line Extension 3 Fern Gully Lane Beachburg	$3,871							
Shepard St. Pump Station Upgrade	$0							
351 Matheson Dr - Townhouses	$3,880							
Blakely St Townhouses - Ryan Habraken Carpentry	$4,128							
Integrated Health Centre	$639							
Microfit Connection	$786	$1,224			$1,984	$8,238		
Beachburg Line Extension			$1,870					
Hydro One Networks - Walmart Tap	$43,897							
Enerdu - APT Service	$7,424	$13,959						
Ottawa Street		$78,197						
Patterson St - Line Extension		$27,821						
Equators Grind		$13,562						
Almonte Mews - Anne St - Townhouse project		$34,006	$1,096	$4,908	$2,250			
Noik @ Bell St - 12 Townhouses - Ken Siegel		$4,979						
375 Country St, - 18 Unit Apt.		$1,329						
Noik @ Bell St - 12 Townhouses - Ken Siegel			$3,078					
New Algonquin College		$56,370	$19,235					
Frank Neighbour Street Extension			$3,465					
Hyde Park Condominium - Jamieson St.		$8,026	$33,144					
Rondeau Electric Mackay St		$8,369	$18,558					
Crozier Electric.		$7,764	$4,825					
Holiday Inn Suites - Good Night Hotel Inc			$7,318					
LCBO - 1050 Pembroke St E - MARNAC Developement			$12,267					
Lakeridge Trail Phase Ph 2 Poleline Extension			$18,761					
CW Homes - 559 Nelson St - Townhomes			$1,210					
Noik Drive - 12 unit Apt					$1,333			
Poleline Extension - Fern Gulley Lane			$6,352					
Seigel Developement - Bell & Patricia St			$4,969	$92,905	$5,714			
Reginal Homes - Mill Run Phase 1A			$11,731	$62,547				
Creek Side Towns - Novatech Engineering				$7,793				
Everett St - 3 Unit Townhouse.				$340				
Watchorn Drive Line Extension				$34,122				
Vera Cres; Install 2 Polls - Jeff Johnson				$5,209				
Lowe Court - Beachburg				$6,150				
OPP Detachment - Install UG Primary XLPE Cable					$45,879			
Fibre - Install duct from SW16 to OPP Building					$1,370			
Watchorn U/G Line Extension - Load Transfer					$46,032			
Mill Run - Phase 1 B Developement					$102,940			
U/G Services - Townhouses - 329-339 Matheson Dr					$3,111			
New Gas Station - Almonte					$15,119			
Almonte - New Transformer Bank - Spring St Pumping Station					$16,174			
Install Transformer Bank - Stinson Paul Martin Drive					$8,060			
Rd Crossing - McKenzie St Development					$1,663			
Construct Line - Loadtransfer Cust. @ 68 Watchorn Rd					$1,733			
Meters	$10,436							
Transformers	$60,897	$75,699	$35,275	$45,858				
Conductors Residential Development								$20,500
Eight poles Residential Development								$17,500
Scattered Residential						$105,086	$152,650	$68,500
50 New Meters Scattered Residential								$10,500
Almonte Riverview ($139k) and Pembroke Golfview ($158k)								$70,650
Almonte Riverview ($139k)								$31,500
Riverfront Almonte Phase3								$10,700
Commerical Development						$25,839	$173,000	$100,500
Riverfront 60, Molly, Almonte appt, Florence, Elgin, Joseph, Taylor, Golfview, Nelson								$75,000
Pembroke Golfview ($158k)								$19,000
Golfview Phase1 78 Townhomes 9 singles Meters								$14,000
Almonte Riverview ($139k) and Pembroke Golfview ($158k)								$62,500
TOTAL SYSTEM ACCESS	**$206,026**	**$369,429**	**$231,185**	**$302,942**	**$340,430**	**$205,947**	**$683,650**	**$500,850**

System Renewal	2010	2011	2012	2013	2014	2015 Prelim	2015 Bridge	2016 Test
Minor Capital Betterments	$40,487	$38,367	$133,915	$73,057	$101,577	$105,811	$235,820	
Energy Retrofit at Substation 1			$4,460					
Farm St @ Almonte Lane Relocation	$10,242							
Ottawa Street	41856	$23,776						
Sub-Station 1 in Almonte Rebuild	$135,131							
River Road - Bus Betterment	$599							
Replace Poles/Secondary Transformer - Craig St	$8,388							
Remove Lines - Bell St. and Angus Campbell Drive	$120,941							
Morris St - Extension	$7,100							
Quarry Road - City Yard	$7,861							
Replace Pole & Transfer Backlot - 498 Cecelia St	$724							
Install Transformer - 40 Watchorn Rd Beachburg	$3,428							
Florence St. 44KV Airbrake Switch	$35,692							
Replace NRTC 35' with ORPC 40' Pole - 59 Robertson Rd	$1,908							
Moffat St. Betterment 623 to 698	$34,863							
Alexander St. Rebuild	$9,242	$62,486						
Beachburg Road Line Upgrade	$24,142	$59,798						
Substation 4 -Pole Storage Building	$31,317							
Line Upgrade - Laurier Ave		$15,759						
Ellis Avenue Line Upgrade		$13,734						
Replace Feeder Cables in Substation #3		$20,479						
Cassidy's Transfer Service Upgrade Warehouse 1001 Mackay St		$1,332						
Substation 4 Storage Building		$27,438						
Fraser St. Reconductoring			$307	$89,235	$52,559			
Maple St. Reconductoring			$65,353	$135				
Martin St. Betterment			$64	$92,321	$86,625			
Pole Replacement on Coolidge - Fire - Behind 247 Mackenzie			$3,499					
Replace Poles & Reconductor - Pemb W & Renfrew St			$11,567	$10,975				
Replace 44 KV Pole - Angus Campbell Dr			$10,508					
Repole 44Kv Line From Superior Elec To Quarry			$87,080	$6,638				
Install Transformer at Mikes Garage in Killaloe			$1,495					
Mackay St - 44 KV Ecress Sub #4				$71,871				
Beachburg Fire - 1888 Beachburg Rd (15 KVA Transformer)				$8,444				
Replace 3 44 KV Poles McKenzie St				$14,435				
Replace Defective UG Riser Pole - 240 Reynolds Ave					$3,516			
Almonte 44 KV Betterment Hwy 15 to Sub #2					$61,735			
Robertson Rd Rebuild - Beachburg					$64,971			
Install 35" Guy Stub Pole Anchor & Transfer - 968 Reynolds A					$768			
Replace Transformer 75 Kva to 50 Kva - 386 Morris St					$6,019			
Reroute Primary - International Drive					$14,206			
Reconductor McGee St With 4/0 / 1/0 Bus					$16,986			
Install OH 120V Secondary - Bell St					$1,854			
Replace 2 Poles & Transfer @ Cameron St					$4,834			
Reinsulate 15 KV Line - Bennet & Julien St					$8,967			
Fraser St - 5 KV -Convert to Armless Construction					$3,690			
Install 44 KV Switches - 260 Fraser St					$3,575			
Install 2 45' Poles - John St @ Ryan St Killaloe					$3,973			
Upgrade Secondary Conductor - Everett St					$2,989			
Substation 7 - New Batteries		$10,250	$1,717					
Substation 1 in Almonte - Completion		$34,006						
Killaloe Reclosure			$24,875					
Substation 2				$40,093				
Sub 3& 6 Ground Grid					$20,936			
Install Spun Bus Second. -Ryan St Killaloe						$ 27,224		
Pembroke Substations						$ 112,831	$ 44,500	$ 29,000
Scattered pole replacement						$ 51,630	$ 75,500	$ 46,000
misc Related line betterments						$ 27,864		$ 14,200
Fisher Street to Trafalgar Related line betterments								$ 14,200
Sub 4 behind Remi auto Related line betterments								$ 11,700
Conductors Related to line betterments						$ 37,377		$ 44,500
407 pole and 129 Pad mounts								$ 15,000
transformers related to Scattered pole replacement								$ 9,500
Transformers Related to line betterments								$ 10,000
Meters						$ 40,524	$ 49,500	
TOTAL SYSTEM RENEWAL	**$513,921**	**$307,425**	**$344,841**	**$407,204**	**$459,781**	**$403,262**	**$ 405,320**	**$ 194,100**

System Service	2010	2011	2012	2013	2014	2015 Prelim	2015 Bridge	2016 Test
Replace Collectors in Almonte With Pole Mount Colle					$12,216			
Install New Viper Mount Reclosure - Mill St Killaloe					$40,437	$ 25,997	$ 40,000	
SUB 2 - Rebuild					$135,296			
Subs 2 & 3 - Inspection and Testing - Almonte					$28,828			
Almonte Sub 2 & 3						$ 37,851	$ 30,000	
Substation 6						$ 35,025	$ 32,000	
44 kV MS-2 to river xcing								$ 58,100
Arc Flash, Load flow, Loss and short circuit								$ 86,000
44 kV MS-2 to river xcing								$ 27,100
MS 2 Feeder Cable 2F2								$ -
Almonte Sub 2 Feeders								$ 24,300
Almonte Sub 3 Feeders								$ 18,500
Almonte Sub 3 Feeders								$ 14,300
Electronic Protective relays								$ 16,500
Scada upgrade								$ 45,000
Scada Survalent								$ 78,000
Sub 6 Fencing								$ 12,000
Sub 6 Grounding								$ 50,000
Sub 2 Control building								$ 38,000
Almonte MS-1								$ 7,000
TOTAL SYSTEM SERVICE	**$0**	**$0**	**$0**	**$0**	**$216,777**	**$ 98,874**	**$ 102,000**	**$ 474,800**

General Plant	2010	2011	2012	2013	2014	2015 Prelim	2015 Bridge	2016 Test
Building Accesibility	$14,386	$5,349						
Communication Equipment	$5,658		$1,574		$2,148	$17,644	$1,200	$1,200
Computer Hardware	4747	$8,336	$5,308	$28,127	$10,557	$7,982	$10,000	$10,000
Doors for Garage				$11,963				
Front Office Washroom			$12,844					
Garage Work					$12,989			
Heat Exchanger			$7,424					
Accessible washroom, new shower area and men's washroom and lunch room area				$40,459				
Measurement and Testing Equipment				$30,697				
Men's Wshrm Accessability					$11,740			
Miscellaneous Small Tools	$2,335	$5,114	$12,399	$6,273	$39,977	$14,101	$10,000	$10,000
New Front Entrance - Accessibility Entrance			$29,979					
New Roof		$8,830						
Office Furniture	$5,883	$2,572		$1,388	$3,337	$2,737	$5,000	$8,000
Overhead Walkway between Buildings				$41,323				
Pave between buildings			$4,100					
Renovate downstairs washroom		$4,428						
Roof Repair			$5,813					
Scada Computer and System Upgrade	$64,230		$4,116		$611	$12,050	$15,500	
Software - CIS, Harris		$4,500		$46,620	$28,560	$18,666	$34,000	$10,000
Software - Finance, Mapping	$1,585				$12,407			$9,000
Software - Other	$1,050	$4,148						
Third Octet	$7,109							
Transportation Equipment	$277,695	$28,088	$145,403	$55,916	$58,879	$33,246	$36,000	$300,000
Transportation Equipment				$401,326			$25,000	$28,000
Doors for Stores							$10,000	
Fire Alarm							$38,000	
Garage Roof							$20,000	
Garage floor							$13,000	
Office façade							$25,000	
Service Department Renovations						$10,151		
TOTAL GENERAL PLANT	**$384,678**	**$71,365**	**$228,960**	**$664,092**	**$122,327**	**$116,577**	**$242,700**	**$376,200**
TOTAL EXPENDITURES	**$1,104,625**	**$748,219**	**$804,985**	**$1,374,238**	**$1,139,315**	**$824,660**	**$1,433,670**	**$1,545,950**

2-Staff-8
Ref: Exhibit 2, p. 18 – 26 of 58 and Appendix 2-AA

Appendix 2-AA shows capital expenditures of $108K in system renewal. Please reconcile with the amount of $194K shown in appendix 2-AB of the DSP.

Response:

Ottawa River Power corrected Appendix 2-AA. The total column was not summing the individual projects. This now reconciles to $194K as shown in Appendix 2-AB of the DSP.

2-Staff-9 Pacing and Distribution Rate Impacts

The Applicant's annual capital spending since the last COS year (2010) has been about 32.5% or $378,950 greater that the amount the Board approved in its 2010 decision.

a) In its annual capital planning and implementation for the years 2010 to 2016 did the applicant take into account the cumulative impact its capital expenditures would have on rates in 2016?

Response:

Ottawa River Power did take the cumulative impact its capital expenditures has on its rates. In the 2010 Cost of Service application $1.2M was approved in annual capital expenditures not including capital contributions. This equates to a total of $7.6M from 2010 until 2015. Actual capital expenditures for this period were only $6M.

b) What changes ensued from these considerations?

Response:

Ottawa River Power does understand the importance of rate impacts to its customers. All measures are considered when planning its capital expenditures. With fleet purchases necessary for its large trucks these are timed to mitigate bill impacts.

Distribution System Plan

Ref: Exhibit 2, p. 47 – DSP – Section 5.4.1 Capital Expenditures

ORPC provided a DSP for the years 2015-2019. Since this application is for the 2016 test year, please explain why the DSP was not extended to cover a 5 year period from 2016 to 2020 inclusively.

Response:

The DSP was created in 2014 for the 2015 rate application. We will be creating the DSP to cover 20 years with a rolling 5 year project. Currently we are completing our Asset Assessment tools and this data will be utilized to develop a robust Asset Management System.

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, p. 5.

At the reference, ORPC states: “Two substations will require upgrading in the next 10 years and the addition of a new substation is planned for future growth beyond 2020.”

a) Please identify any costs associated with the two planned substation upgrades included in the present capital expenditure forecast.

Response:

The Pembroke Substation # 3/7 ($97k) has been upgraded in 2015 and the Pembroke Substation #6 (2015 completed $26k and $62k in 2016) will be upgraded in 2016.

b) Please identify any costs associated with the planned new substation included in the present capital expenditure forecast.

Response:

The new substation is for Almonte. We have included the following projects in the present capital expenditure list;

1. 2015 GIS and DESS software ($30k)
2. 2016 Load study ($20k)
3. 2018 Station design ($73k)
4. 2019 Land acquisition final design ($115k)

2-Staff-11

Ref: Exhibit 2, p. 47 – DSP Section 5.2.1: Distribution System Plan Overview, p. 15.

At the reference, ORPC states: "ORPC intends to adopt a "just-in-time" asset replacement approach, under which assets will be replaced on a proactive manner, as they approach their high probability of failure zone of their lifecycle. ORPC's strategy is to replace end-of-life assets under planned and coordinated circumstances, as opposed to under emergency or after hour's circumstances which add unnecessary risk and expense."

a) Please quantify the anticipated annual incremental cost of adopting the new asset replacement approach.

Response:

The asset evaluation will be completed with existing resources and tools. The inspection activities will be completed as part of our existing Testing, Inspection and Maintenance plan. ORPC will not transition from its present Maintenance Mode to its planned "just in time" Rebuild Mode, until all the tools needed for such implementation are developed and operational to avoid replacing assets prematurely. Incremental costs include GIS mapping $20k.
ORPC will attempt to monetize the savings to be achieved in its OM&A and incremental annual capital cost over the 5-year planning period for each asset group, as it moves from a Maintenance Mode to a proactive Capital Rebuild Mode

b) Please show how the incremental cost of adopting the new asset replacement approach will be distributed between the four expenditure categories.

Response:

The adopting of the new tools will be capitalized in the General Plant Category under a project to be completed in 2015.

2-Staff-12

Ref: Exhibit 2, p. 47 – DSP Section 5.2.2: Co-ordinated Planning with Third Parties, *Regional Planning Consultations*, p. 17.

At the reference, ORPC states: "At the time of preparing this DS Plan, the Regional Infrastructure Planning initiative is still in the early stages of development and as such many of the elements of the planning process have not yet been implemented. As per the "Integrated Planning Requirements – Part 1: regional Infrastructure Planning", the transition and implementation to Regional Infrastructure Planning (RIP) is expected to take four (4) years."

a) Does ORPC expect that the regional planning process will impact the investments identified in this DSP?

Response:

Currently we expect no impacts on investments identified in the DSP. The Ottawa area study which includes Almonte has been completed and neither projects nor modifications to our DSP are required.
The preliminary Plan (released for review January 25th, 2016) for the Renfrew region (which covers Beachburg, Killaloe and Pembroke) has been completed and it also has not identified any issues that require capital investments.

However, the OEB Regional Planning and Cost Allocation Review EB-2016-0003 may conclude that the cost allocation of Upstream transmission improvements be shared amongst distributors in the Region.

b) If yes to a), please quantify the expected impacts.

Response:
N/A

2-Staff-13

Ref: Exhibit 2, p. 47 – DSP Section 5.2.2: Co-ordinated Planning with Third Parties, *Consultations with Municipal Planning Office*, p. 19.

At the reference, ORPC states: "ORPC is currently aware of two significant development projects being coordinated through the Planning Office of Pembroke and Almonte for the 2015 planning horizon."

a) Are the *"two significant development projects"* expected to impact the forecast capital expenditures identified in this DSP?

Response:

No impacts on forecasted capital expenditures are expected as these projects are identified in the System Access and System Renewal budgets for the planning horizon.

b) If yes to a), please quantify any costs associated with these developments that will be borne by ORPC ratepayers.

Response:

N/A

2-Staff-14

Ref: Exhibit 2 p. 47 – DSP Section 5.2.3.5: System Reliability and Performance, *Overall System Performance [Table]*, p. 30.

Including loss of service from HONI (Code 2)	SAIDI	3.20	1.21	10.69	3.31	3.97	1.74
	SAIFI	2.87	1.40	6.01	2.25	3.04	3.99
	CAIDI	1.11	0.86	1.78	1.47	1.30	0.44
Excluding Loss of service from HONI (Code 2)	SAIDI	2.66	0.71	2.39	1.69	0.91	1.24
	SAIFI	2.10	0.79	1.43	1.08	0.81	0.79
	CAIDI	1.27	0.89	1.67	1.57	1.13	1.57

a) Please describe the major causes of fluctuations in the SAIDI metric excluding loss of service from HONI over the period 2009 to 2014.

Response:

Type of Outage	Scheduled		Defective equipment		Adverse Weather		Total		Average
Year	# events	Total hrs	# events	Total hrs	# events	Total hrs	Events	Total hrs	Outages/#events
2009	13	6,946	20	3,496	14	43,914	47	54,356	1,157
2010	9	330	9	2,940	8	2,078	26	5,349	206
2011	6	1,334	21	8,332	7	2,514	34	12,180	358
2012	18	10,826	13	3,903	11	2,502	42	17,230	410
2013	16	8,503	11	795	14	14,034	41	23,332	569
2014	22	1,834	17	9,448	3	1,442	42	12,725	303

A summary of the outages are totaled in the above table and described below. The 2010 outage statistics confirm the low SAIDI (0.71) was due to the low number of outages (26) and the low average outage duration (1.12 hrs).
High SAIDI exist for the years 2011 and 2014 and was due to defective equipment which included two pole fires and one underground cable failure.
Adverse weather in 2009 and 2013 was the cause of the SAIDI result.
Although the 2013 SAIDI result is not abnormally high, the major outages recorded were due to weather and scheduled outages in Almonte to connect new subdivisions and services.

b) Please describe the HONI events that caused the high SAIDI and SAIFI results, with particular focus on 2011.

Response:

The table below highlights the major outages in 2011that skewed the SAIDI results. The outages were related to “Loss of Supply” with the majority of outages due to various seasonal storms.

Date	Location	Code / Sub Code		# Customers Affected	Duration (Hours)		Notes
January-17-11	Killaloe	2-Loss of Supply		375	2.08		
February-18-11	Pembroke	2-Loss of Supply	High Winds	7145	0.52		Trees on line
February-18-11	Killaloe	2-Loss of Supply	HONI	375	3.00		High Winds
April-10-11	Killaloe	2-Loss of Supply	Fire	375	6.25		Pole fire
April-28-11	Beachburg	2-Loss of Supply	High Winds	469	2.80		
April-28-11	Pembroke	2-Loss of Supply	High Winds	7145	1.75		Trees on line
May-24-11	Killaloe	2-Loss of Supply	HONI	384	2.40		
July-17-11	Pembroke	2-Loss of Supply	HONI	7145	8.58		Storm & HONI Maintenance
July-17-11	Killaloe	2-Loss of Supply	HONI	375	8.58		Storm & HONI Maintenance
July-17-11	Beachburg	2-Loss of Supply	HONI	469	8.58		Storm & HONI Maintenance
October-30-12	Killaloe	2-Loss of Supply	HONI	375	2.00		Planned outage by HONI
October-31-12	Killaloe	2-Loss of Supply	HONI	375	1.50		
November-01-12	Killaloe	2-Loss of Supply	HONI	375	1.37		
November-06-12	Killaloe	2-Loss of Supply	HONI	375	2.00		Insulator replacement at stn

c) Has ORPC consulted with HONI to identify ways to mitigate the poor performance metric results caused by the HONI loss of service events?

Response:

ORPC communicates regularly with the Key Account representative at Hydro One to discuss operational issues including poor performance metrics. Also, our issues are reported while completing the “Needs Screening Report” as required for the Regional Infrastructure Planning.

d) If yes to c), please describe the mitigating actions that have been taken, or that are planned.

Response: Examples of mitigating actions completed by HONE;

1. Protocol was created to reduce the duration of outages in Killaloe.
2. Upgrading of Pembroke TS completed in 2014
3. Upgrading of Cobden TS completed in 2015
4. Coordinated planned outages in 2015
5. Breaker modifications in Almonte feeder completed in 2015

2-Staff-15

Ref: Exhibit 2, p. 47 – DSP Section 5.3: Asset Management Process, p. 37.

At the reference, ORPC states: “An asset’s health is based on its relative age compared to industry established life expectancies (Kinetric’s Report), as well as information that quantifies its operating capacity. Assessing age and operating load allow for the probability of failure to be assigned. Based on this approach, ORPC will develop a profile of the order in which assets are expected to fail, categorized by asset type. The year during which an asset is expected to fail due to exceeding its failure risk tolerance is called its “Adjusted End-of Life” (AEOL). The AEOL profile of assets drives ORPC’s pace of capital reinvestment needs for sustainment or development activities (also referred to as asset lifecycle management).”

a) Please confirm that ORPC intends to assess the condition of its assets by
   i. Comparing individual asset ages against average actuarial values taken from the Kinectrics Report.

Response:

Yes ORPC intends to assess the condition of its assets by comparing individual asset ages against average actuarial values taken from the Kinectrics Report.

   ii. Comparing actual asset loading against calculated capacity.

Response:

Ottawa River Power will compare actual asset loading against calculated capacity.

b) Is the approach described in this section an interim process that will be superseded once ORPC has collected adequate asset condition information to determine the risk of asset failure?

Response:

The life expectancy adjustments are currently performed based on the judgment and expertise of knowledgeable staff. ORPC plans to develop a more definitive set of criteria that underpin life expectancy adjustments in future iterations of the process.

ORPC operates under a low cost philosophy with the objective of balancing necessary distribution system maintenance and reinvestment, and providing customers with a safe and reliable supply of electricity at the lowest possible rates. ORPC has taken a “just-in-time” asset replacement approach, under which assets will be replaced on a proactive manner, as the assets approach their high probability of failure, as established by ORPC’s asset management process. ORPC’s strategy is to replace end-of-life assets under planned and coordinated circumstances, as opposed to under emergency or afterhours circumstances which add unnecessary risk and expense.

c) Please describe ORPC’s asset condition assessment and testing approaches, including frequency of testing for different asset classes such as poles and transformers.

Response:

ORPC currently performs visual inspection and has completed drill testing on poles. Visual inspections record detailed information about the pole, the attached hardware and any other relevant information. This information is used in conjunction with the drill test to prioritize pole replacement, hardware replacement or to create new designs that will integrate with the present configuration. Drill assessment is a non-destructive testing method using an International Distribution Network (IML) Resistograph drill which measures the density or resistivity of the wood against the drill bit. The drill test provides an overall indication of rot, void, and solid wood thickness that can be used to calculate the remaining strength of the pole. The planned inspection schedule calls for the inspection of 1/3 of the poles annually. The OEB minimum inspection for poles requires that they be inspected in urban areas at a maximum interval of 3 years and in rural areas at a maximum interval of 6 years. In addition to the pole inspection program ORPC poles are being inspected during normal patrol to meet the OEB requirements. Currently, the inspections are being completed and the records are being stored in an ESRI database.

Pole Material Broken or Loose Guying, Max Pole Circumference Pole Age Ground Wire Missing or not Intact, Min Pole Circumference, Preservative Pole, Leaning or Twisting, External Damage Hole Width, Crossarm, Condition, Signs of Fire/Lighting/Arcing, External Damage Hole Depth, Transformer Standard, Comments, Insect Infestation, Drill Orientation, Porcelain Insulator, Vegetation Growth, Max External Decay, Width Pole Top, Condition Debris or Bird's Nesting, Max Internal Decay Width, Shell Condition, Cut-out Switch, Minimum Remaining Shell Width, Wood Pecker Damage, Sound Test, Interpretation of Test Result, Inline Switch, Overall Visual and Sound Remarks.

ORPC visually inspects transformers every three years under the Overhead Visual Inspection and Underground Visual Inspection Programs and Record and follow-up on any complaints received from customers. The inspection of transformers includes:
In addition to visual inspection OHL covers all of its transformers in its annual infra-red inspections. These inspections look for hot spots on transformers and their primary/secondary connections.
Polemount Transformers:

- Paint condition and corrosion
- Phase indicators and unit numbers match operating map
- Leaking oil
- Flashed or cracked insulators
- Contamination/discolouration of bushings
- Ground lead attachments
- Damaged disconnect switches or lightning arresters
- Ground wire on arresters unattached
- Padmount Transformers:
- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta bolt in place or damage
- Grading changes
- Access changes (Shrubs, trees etc.)
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Lid Damage, missing bolts, cabinet damage
- Cable connections
- Ground connections
- Nomenclature
- Animal nests/damage
- General Condition

<u>Transformer Maintenance</u>

ORPC performs maintenance on any transformers which are identified by either visual or infra-red inspection as needing work. This work may include replacement of connections if found to be hot, painting or replacement of unit if leaking.

2-Staff-16

Ref: Exhibit 2, p. 47 – DSP Section 5.3.1: Asset Management Process Overview (Step 2), p. 40.

At the reference, ORPC states: “The output of this step is a populated asset register that contains all pertinent attribute and condition data. The populated asset register enables data analysis to be performed on individual assets or on asset groups or classes.”

a) Has ORPC assembled an asset register that includes condition assessments for all its assets?

Response:

ORPC has an asset register as part of the ESRI GIS software. The asset register in ESRI includes the result of Condition assessments. However, pole year, transformer age, and asset condition parameters are not currently included in the database and need to be updated as soon as the asset assessment is completed.

Comments:					Table1-1 Useful Life Values for Fully Dressed Wood Poles					
Oldest poles 35 yrs					Asset	Usefull Life				
Rebuild from 1975 - 1985					Componentization	MUL	**TUL**	MUL		
Pole replacement program continued every year throughout history.					Pole	35	**45**	75		
Experienced Bad Pole Batches - premature failure due to inefficient treatment										
Majority of ORPC Poles - Wood 45' Class 3										
		IFRS Additions								
1	2	77	3	4	5	6	7	8	9	10
ID_NUMBI	OWNEI	ORPC_INS	POLE_CONIF	MAN	MATERIAL	HEIGHT	Pole Class	CONDITION	PRIM_CON	SEC_COND
?	ORPC	2009	STANDARD	2009	WOOD	45	3	NEW	3X1	
? EP	ORPC	2009	STUB/GUY	2009	WOOD	40	3	NEW	NONE	
AP0010	ORPC	2008	STANDARD	2008	WOOD	45	3	NEW	1X1	NONE
AP0011	ORPC		STANDARD	1993	WOOD	45	3	GOOD	1X1	NONE
AP0012	ORPC		STANDARD	1993	WOOD	45	3	GOOD	1X1	SINGLE PHASE

b) If NO to a), when does ORPC expect to have assembled an asset register that includes condition assessments for all of its assets?

Response:

ORPC intends to complete the complete asset assessment by the end of 2017. The Testing, Inspection and Maintenance cycle is 3 years for most assets with the exception of Substations (which is every 4 years and we initiated in 2014).

2-Staff-17

Ref: Exhibit 2, p. 47 – DSP Section 5.3.1: Asset Management Process Overview (Step 3), p. 41.

At the reference, ORPC states: "The resulting end-of-life estimations are referred to as "Adjusted End-of-Life" (AEOL) projections. The AEOL value profile for asset classes essentially generates a listing that reflects ORPC's best guess as to the order in which assets will fail.

The life expectancy adjustments are currently performed based on the judgment and expertise of knowledgeable staff. ORPC plans to develop a more definitive set of criteria that underpin life expectancy adjustments in future iterations of the process.

The AEOL profile for each asset class is updated annually to incorporate the latest available inspection, condition testing and performance data results. The end-of-life profile of assets allows ORPC to focus on the portion of assets that require special attention over the planning horizon. In other words, it allows ORPC to focus its attention on the assets that demand attention.

With ORPC's replacement cost data available at the asset level, ORPC is able to quickly and easily generate high level cost projections for long range planning purposes"

a) Does ORPC plan to replace assets (such as poles) based solely on age?

Response:

No. The asset process defines the AEOL by factors such as Asset Statistics (Age), Asset Failure rates, Impact on Health and Safety & Environment, Customer Service (Reliability), Inspection Data and failure rates.

b) Is the Adjusted End-of Life (AEOL) used to determine which assets will be replaced, or is it only used to assemble budgets for expected replacement costs over the planning period? Please explain.

Response:

The AEOL is used for both, which assets will be replaced and to assemble budgets. The AEOL will be "fine-tuned" as more asset information is gathered in the coming years.

2-Staff-18

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *Poles*, p. 82.

At the reference, ORPC states: "Wood poles installed 50 years ago during the expansion and electrification across Pembroke service area are now approaching end of life. Approximately 35% of the poles installed exceed the TUL as mentioned in the Kinectrics report. To help ensure reliability and public safety, ORPC plans to replace 50 wood poles in 2015"

a) Are the 50 poles being replaced because they have exceeded the actuarial life estimate given in the Kinectrics Report, or because their conditions have been assessed and determined to be unacceptable?

Response:

ORPC set the target of replacing 50 poles from asset information that was gathered in 2014. ORPC gathered the asset condition information prior to the retirement of the Lines Supervisor who had the majority of historical information of the pole inventory.

2-Staff-19

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *<u>Poles</u>*, p. 82.

At the reference, ORPC states: "Poles which are deemed to be at the end of their useful service life due to excessive deterioration have been estimated at approximately 25 poles per year. It is also important to note that wood poles frequently (on average five per year) fail prematurely, due to sudden devastating damage incurred by external influence such as wood peckers, snow ploughs or pole fires."

a) ORPC has stated that it intends to replace 50 wood poles in 2015. Does ORPC expect to reduce the number of annual pole replacements to 25 after the year 2015?

Response:

The 25 poles mentioned are to be added to the 50 wood poles. The 25 poles are being replaced in response to emergency situations versus proactive replacement.

2-Staff-20

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *Pole Inspection*, p. 83.

At the reference, ORPC states: “With 4300 poles in our distribution system, more than 1,500 poles will need to be replaced in the next 10 years. The Typical Useful Life of a wood pole is approximately 45 years. ORPC recommends a replacement rate on average of 125 poles a year in to keep pace, which represents 2.90% of the entire population of distribution poles. Increase in the amount of poles replaced will reduce the risk of having poles in a critical or poor condition.”

a) Please reconcile ORPC's plan to replace 125 poles per year with the statement in Section 5.3.2: Overview of Assets Managed, Poles, p. 82 - "Poles which are deemed to be at the end of their useful service life due to excessive deterioration have been estimated at approximately 25 poles per year."

Response:

ORPC recommends a replacement rate of 125 poles per year, however without statistics such as failure mode, failure rate, etc., ORPC is comfortable in stating that we are able to replace 100 poles per year as shown herein. 50 poles due to age +25 poles due to excessive deterioration and +25 poles due to unforeseen (fire, vehicles, etc)

Using a degradation model developed for wood poles, it was assumed that the number of poles replaced annually will be maintained at 100 on average until the end of 2020, at which point the number of replacements will be standardised. Based on future analysis, it may be seen that an increase of replacements annually would be required to manage failures while bringing the number of poles in critical and poor condition to an acceptable level. The impact of different replacement policies will impact the number of failed poles that have reached end of life and/or degraded to 60% or less of the required design strength. The actual failure of the pole is contingent on it being stressed by external forces approaching or equal to these maximal design conditions. The 50 replacement level is based on an assumed 100% program efficiency, that is to say only the oldest and poorest condition poles are replaced first. This level of program efficiency does not occur in practice, rather as areas are targeted for replacement, all poles within 5-10 years of end-of-life within the affected area are replaced. This approach allows for financial efficiencies, and reduced customer inconvenience, over the piece-meal approach of only replacing poles currently at end-of-life. It is estimated that the replacement program is typically around 50% efficient, that is, 50% of the poles that are projected to fail annually are able to be replaced in a planned fashion. If the annual planned replacements exceed this value the remaining planned replacements are assumed to be the oldest poles in the system. In order to achieve the results as the 100% efficiency pole replacement program, 130 poles annually may be required at 50% efficiency. Based on this analysis it is recommended that roughly 100 poles annually be targeted for replacement in order to achieve the desired results. If increases in pole replacements are deferred it will result in a potential increase in pole failures, but also increased replacement requirements in the future to achieve the same results. For example, if increase in pole replacements is deferred until 2025 the number of annual pole replacements required to achieve the same result as increasing the number of pole replacements to 125 in 2020, may be 175.

Replacement of less than 100 poles annually will be challenging from a resource perspective. The alternative will not only introduce organizational risk due to the potential for pole failures but it will also stress the available resources as the estimated labour requirements for planned and unplanned pole replacement work will increase. With the proposed planned program, unplanned pole replacements are anticipated to be reduced hence a more efficient labour resource. Conversely, with a higher annual replacement policy, unplanned replacements will account for a lower % of the available labour resource. A planned labour approach allows for the program to be scaled from year to year and contractor resources to be brought in to assist in the replacement program. With the replace at failure approach, the majority of replacements would require the use of internal resources. In addition, the unplanned work would not be divided evenly between years as shown. Plant failure trends show that as the average annual number of pole failures increase, the unplanned replacement labour requirement would be anticipated to fluctuate.

2-Staff-21

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *Pole Capital [Table]*, p. 84.

At the reference, ORPC states: "ORPC estimates that it may require approximately 500 poles replaced to sustain the existing population of 4,299 over the current planning cycle. Wood pole replacements have been identified as having a significant impact on the DS Plan."

ORPC Pole replacement schedule	
2011	25
2012	25
2013	25
2014	25
2015	100
2016	100
2017	100
2018	100
2019	100
2020	100

a) Please reconcile the planned replacement of 100 poles shown year in the table above, with the replacement of 125 poles per year discussed in Section 5.3.2: Overview of Assets Managed, Pole Inspection, p. 83 and the replacement of 25 poles per year reaching end of service life discussed in Section 5.3.2: Overview of Assets Managed, Poles, p. 82.

Response:

See previous response

2-Staff-22

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *Transformer Capital*, p. 88.

At the reference, ORPC states: "The age distribution of the population of the 1583 pole mounted transformers is not evenly distributed. The population has high positive skew, and as such, approximately 61% (972 transformers) will require replacement over the first half of the lifecycle period (over the next 20 years)."

a) How many pole mounted transformers does ORPC plan to replace during each forecast year?

Response:

Year	1 Phase Pad Mounted	1 Phase Pad Mounted Transformer Replacement Cost	3 Phase Pad Mounted	3 Phase Pad Mounted Transformer Replacement Cost	Pole Mounted Transformers	Pole Mounted Transformer Replacement Cost	Spare	Spare Transformer Replacement Cost	Total #	Total Cost
2015	1	$12,000	0	$-	4	$19,200	4	$28,400	**9**	**$59,600**
2016	1	$12,000	1	$22,000	10	$48,000	3	$21,300	**15**	**$103,300**
2017	1	$12,000	1	$22,000	10	$48,000	3	$21,300	**15**	**$103,300**
2018	1	$12,000	1	$22,000	10	$48,000	3	$21,300	**15**	**$103,300**
2019	1	$12,000	1	$22,000	10	$48,000	3	$21,300	**15**	**$103,300**

b) What is the average cost of each transformer replacement?

Response:

The following table indicates the average cost of transformer replacements.

Single Phase Pad Mounted Transformer Cost Table			
Tx KVA	Estimated Tx Cost	Estimated Labour, Time & Other Material	Total Cost
15	$ 3,500	$ 5,536	$ 9,036
25	$ 4,000	$ 5,536	$ 9,536
37	$ 4,250	$ 5,536	$ 9,786
50	$ 4,500	$ 5,536	$ 10,036
75	$ 5,500	$ 5,536	$ 11,036
100	$ 6,000	$ 5,536	$ 11,536
150	$ 9,000	$ 5,536	$ 14,536
167	$ 10,000	$ 5,536	$ 15,536
333	$ 12,000	$ 5,536	$ 17,536

Three Phase Pad Mounted Transformer Cost Table			
Tx KVA	Estimated Tx Cost	Estimated Labour, Time & Other Material	Total Cost
112	$ 12,000	$ 9,106	$ 21,106
150	$ 12,500	$ 9,106	$ 21,606
225	$ 13,000	$ 9,106	$ 22,106
300	$ 13,500	$ 9,106	$ 22,606
350	$ 14,000	$ 9,106	$ 23,106
500	$ 16,000	$ 9,106	$ 25,106

Single Phase Polemounted Transformer Cost Table			
Tx KVA	Estimated Tx Cost	Estimated Labour, Time & Other Material	Total Cost
5	$ 1,400	$ 1,415	$ 2,815
10	$ 1,600	$ 1,415	$ 3,015
15	$ 1,800	$ 1,415	$ 3,215
25	$ 2,000	$ 1,415	$ 3,415
37	$ 2,500	$ 1,415	$ 3,915
50	$ 3,000	$ 1,415	$ 4,415
75	$ 4,500	$ 1,415	$ 5,915
100	$ 5,000	$ 1,415	$ 6,415
167	$ 9,000	$ 1,415	$ 10,415

c) Will ORPC's proposed transformer replacement program address the "skewed" transformer vintage, in other words, will replacements be staged to avoid replication of the same issue in the future?

Response:

Yes, it is our objective to ensure the replacements will be staged to avoid replication of the same issue in the future.

d) Does ORPC consider that there is high risk in operating a pole mounted transformer that has exceeded its Useful Life ("UL") but which otherwise has been evaluated as being in good operating condition?

Response:

No, ORPC does not consider that there is high risk in operating a pole mounted transformer that has exceeded its Useful Life ("UL"). The design and fabrication of these vintage transformers tends to allow the asset to exceed the UL. The steel core, copper wiring and other internal components result in a more robust transformer.
None the less, ORPC does take other factors in determining the End of Life other than age as shown below.

Customer Type	Impact_of_Failure	Special Consideration
Residential	Very High	Long Delivery Time
Hospital	High	No Suitable Spare
Institutional	Medium	Obsolete
Multiresidential Complex	Low	Overloaded
Commercial	Very Low	Environmental
Residential & Commercial	None	
Critical Customer Infrastructure	Asset Failed	

2-Staff-23

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *<u>Overhead Distribution Assets Optimization Policies and Practices</u>*, *Overhead Transformers*, p. 104.

At the reference, ORPC states: "ORPC does not refurbish overhead transformers and generally speaking transformers do not require maintenance. Historically transformers were run to failure, or alternately, were replaced in poorly accessible areas (back lot construction) at the same time that the wood poles to which they were mounted to were replaced. ORPC's new asset management approach is to transition to a just-in-time replacement approach, such that replacements are conducted under planned and coordinated circumstances, as opposed to under emergency repair circumstances. Factors that influence transformer replacements include the relative health of the transformer as determined by ORPC's asset management process, as well as the impact of failure. ORPC must ramp up its replacement program, beginning with replacements that are found to have the lowest health and highest impact of failure. ORPC's asset management process is utilized to prioritize the order in which individual transformers require replacing."

a) Has ORPC conducted a cost benefit analysis of changing from a "run-to-fail" to a "just-in-time" replacement program for overhead transformers?

Response:

No, ORPC has not conducted a cost benefit analysis, however we acknowledge that Industry practice and other LDC guidelines can serve us well.

The life expectancy adjustments are currently performed based on the judgment and expertise of knowledgeable staff. ORPC plans to develop a more definitive set of criteria that underpin life expectancy adjustments in future iterations of the process.

ORPC operates under a low cost philosophy with the objective of balancing necessary distribution system maintenance and reinvestment, and providing customers with a safe and reliable supply of electricity at the lowest possible rates. ORPC has taken a "just-in-time" asset replacement approach, under which assets will be replaced on a proactive manner, as the assets approach their high probability of failure, as established by ORPC's asset management process. ORPC's strategy is to replace end-of-life assets under planned and coordinated circumstances, as opposed to under emergency or afterhours circumstances which add unnecessary risk and expense.

b) If YES to a), please provide the results of the analysis.

Response:

N/A

c) What is the expected incremental annual capital cost of ORPC's transition to the proposed "just-in-time" replacement approach?

Response:

ORPC will not transition from its present Maintenance Mode to its planned "just in time" Rebuild Mode, until all the tools needed for such implementation are developed and operational to avoid replacing assets prematurely.

ORPC will attempt to monetize the savings to be achieved in its OM&A and incremental annual capital cost over the 5-year planning period for each asset group, as it moves from a Maintenance Mode to a proactive Capital Rebuild Mode

d) Will transformer condition be assumed by comparing asset age against the Kinectrics TUL, or will the asset condition be physically tested or evaluated?

Response:

ORPC does take other factors in determining the End of Life other than age as shown below. ORPC intends to perform further analyses to determine how available asset condition data affects the longevity of individual assets, including inspection results, condition testing results, asset performance data, employee expertise, root cause failure data from outage reports and known manufacturer defect information.

Customer Type	Impact_of_Failure	Special Consideration
Residential	Very High	Long Delivery Time
Hospital	High	No Suitable Spare
Institutional	Medium	Obsolete
Multiresidential Complex	Low	Overloaded
Commercial	Very Low	Environmental
Residential & Commercial	None	
Critical Customer Infrastructure	Asset Failed	

e) How does the transformer program correlate to the pole replacement program?

Response:

The asset management replacement process is similar to the pole replacement program.

2-Staff-24

Ref: Exhibit 2, p. 47 – DSP Section 5.4.1: Capital Expenditure Summary Plan, _Linking Investment Categories to Planning Process Outcomes_, *Planned System Access*, p. 110.

Capital Expenses as per OEB Categories 2015-2019

DESCRIPTION	2015	2016	2017	2018	2019
System Access	$500,850	$500,850	$452,200	$392,700	$392,700
System Renewal	$449,820	$194,100	$248,750	$193,200	$193,200
System Service	$270,800	$474,800	$345,849	$573,650	$293,200
General Plant	$212,200	$376,200	$255,200	$116,200	$134,200
TOTAL	$1,433,670	$1,545,950	$1,301,999	$1,275,5700	$1,013,300

At the reference, ORPC states: "Planned System Access investments are dedicated towards the upgrade of infrastructure for new customer connections. ORPC has planned for customer growth over the forecast period and as such, has allocated capital expenditures towards customer driven load expansions. A total of $ 500k has been allocated towards System Access expenditures, representing 45% of the total planned capital expenditures over the 2015 forecast period."

a) Given the relatively flat population growth and modest historical annual customer connection count, what is the basis for the high forecast levels of System Access expenditures as a proportion of overall capital investments?

Response:

Subdivision construction, construction resulting from zoning changes, etc. are very difficult to predict when they will be constructed. The budget includes $130k for Pembroke subdivisions and $130k for Almonte subdivisions
Approximately $120k of the proposed budget is for commercial development which correlates with strength in the local economy.
Also, $120k is for scattered residential development which is typical for our service area and is more expensive to connect per customer compared to a multi residential or subdivision.
Historically the budget was $410k and the actual spent was $290k/year for the period 2010 – 2014.

b) What portion of the system access costs are recovered through capital contributions and what is added to rate base in each of the 5 years?

Response:

Ottawa River Power estimates that approximately 30 to 40% of system access costs are recovered through capital contributions. The full amount of the contributions have been added to the rate base in each of the five years. ORPC confirms that its treatment of capital contributions will be consistent with direction as found in the Accounting Procedures Handbook.

2-Staff-25

Ref: Exhibit 2, p. 47 – DSP Section 5.4.1: Capital Expenditure Summary Plan, *Linking Investment Categories to Planning Process Outcomes*, *System Renewal*, p. 110.

At the reference, ORPC states: “System Renewal is by far the most dominant investment category demanding capital reinvestment. ORPC has to upgrade obsolete transformer station equipment and protection and historically has operated in a “Maintenance Mode”.

a) Please reconcile the above statement that System Renewal is the dominant investment category with the information provided showing that System Renewal expenditures will be lower than either System Access or System Service expenditures in almost all forecast years.

Response:

We reiterate the intent of the statement is to state/reflect the fact that the majority of the risk is related to future funding required on Renewal of the poles, transformer and substation assets. These critical assets are approaching the end of their typical useful service life and may pose a high risk of failure.

b) Given that forecast 2015 System Renewal expenditures of approximately $450,000 comprise just over 31% of total 2015 capital expenditures”, please explain the statement: "Approximately 45% of all planned capital expenditures over the 2015 forecast period are towards System Renewal”.

Response:

Clarification; Approximately 45% (more precisely 48%) of all planned capital expenditures (excluding System Access) over the 2015 forecast period are towards System Renewal.

2-Staff-26

Ref: Exhibit 2, p. 47 – DSP Section 5.4.1: Capital Expenditure Summary Plan, *Linking Investment Categories to Planning Process Outcomes*, *System Service*, p. 111.

At the reference, ORPC states: "System Service expenditures are largely driven by ORPC's desire to achieve operational objectives including; customer preference; maintaining/improving service reliability; and the elimination of potential safety hazards. Over the 2015 forecast period ORPC has committed a total of $270k towards the System Service category, which represents approximately 25% of total planned capital expenditures. Significant planned activities under this category include the installation of a fire barrier in 2017, a $15k Outage Management System in 2015, a total of $120k towards operational reliability improvements, and $115k towards eliminating safety hazards. The Outage Management System (OMS) will enable ORPC to respond to outages proactively, assist in pin-pointing equipment failures, offer improved oversight of the performance of ORPC's distribution system, as well as improve customer communication regarding outages. The elimination of identified safety hazards as well as strategic reliability improvements projects are also included in this category."

a) Please explain the causes driving the relatively large and year-to-year uneven expenditures in the System Service category over the forecast period.

Response:

There are many reasons for the uneven expenditures in the investment categories and they include; pacing and smoothing, Resource management and urgency. The previous management did not use the same interpretation of the definitions and trigger drivers for System Service in classifying the projects and most of the projects were included with System Renewal.

We attempted to smooth the overall capital investments which cause fluctuations in the investment categories. We also had to take in to account the availability of resources whether they are internal or external contractors.

Urgency

2016 is the time to complete safety studies (such as arc flash) and load flow studies. And the right time to complete safety deficiencies and recommendations from the studies and projects such as substation fencing and ground grid. Also in 2016 it is the right time to kick off Smart Grid initiatives with Scada to Almonte, Outage Management System and Electronic relays and reclosures.

2018 is the time to complete substation upgrades in advance of the proposed new substation in Almonte or upgraded MS2 which should be completed in 2020 and 2021.

- ***System service*** investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements

system service	expected changes in load that will constrain the ability of the system to provide consistent service delivery	– property acquisition – capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – line extensions
	system operational objectives: – safety – reliability – power quality – system efficiency – other performance/functionality	– protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – automation (new/upgrades) by device type/function – SCADA – distribution loss reduction

2015 Investment Category System Service							
14	109	Almonte Feeder MS-2 (2F1) conductor upgrades	1835	$43,500	$0.00	$0.00	MS 2 Feeder Cable 2F1
14	109	Almonte Feeder MS-2 (2F2) conductor upgrades	1835	$18,500	$0.00	$0.00	MS 2 Feeder Cable 2F2
51	108	Almonte Feeder Reclosing relay MS 2	1835	$24,300	$0.00	$0.00	Almonte Sub 2 Feeders
292	108	Almonte Feeder Reclosing relay MS 3	1835	$18,500	$0.00	$0.00	Almonte Sub 3 Feeders
552	223	Almonte MS- 3 fencing	1820	$18,000	$0.00	$0.00	Fencing and crushstone
532	220	Electronic Protective relays	1820	$16,500	$0.00	$0.00	
386	207	ESRI - mobile mapping	1925	$15,000	$0.00	$0.00	Lakeland Power
534	102	Outage Management	1980	$8,000	$0.00	$0.00	Locate faults and Voltage sensing devices
535	102	Outage Management	1980	$7,500	$0.00	$0.00	Collect metering points (collector near recloser) to display outage info
531	220	Overhead line Fault indicators	1835	$13,500	$0.00	$0.00	
405	103	Pembroke MS 3/7 Ground Grid	1820	$28,000	$0.00	$0.00	Sub 3 Grounding
407	103	Pembroke MS 6 Ground Grid	1820	$12,000	$0.00	$0.00	Sub 6 Grounding
206	103	Pembroke Substation MS 3/7 Fence	1820	$18,000	$0.00	$0.00	Sub 3 Fence
548	220	SCADA connections Almonte MS-1	1980	$7,000	$0.00	$0.00	Almonte MS-1
520	217	Substation design and engineering	1820	$22,500	$0.00	$0.00	Almonte Load Study and Substation feasability
	Total			**$270,800**	**$0.00**	**$0.00**	

2016 Investment Category System Service								
438	133	Almonte MS-2 44 kV conductor upgrades	1835	$58,100		$0.00	$0.00	44 kV MS-2 to river xcing
	219	Engineering Studies	1820	$86,000				Arc Flash, Load flow, Loss and short circuit
439	133	Almonte MS-2 44 kV pole upgrades	1830	$27,100		$0.00	$0.00	44 kV MS-2 to river xcing
14	109	Almonte Feeder MS-2 (2F2) conductor upgrades	1835	$0		$0.00	$0.00	MS 2 Feeder Cable 2F2
51	108	Almonte Feeder Reclosing relay MS 2	1835	$24,300		$0.00	$0.00	Almonte Sub 2 Feeders
292	108	Almonte Feeder Reclosing relay MS 3	1835	$18,500		$0.00	$0.00	Almonte Sub 3 Feeders
13	109	Almonte MS 3 feeder cables	1835	$14,300		$0.00	$0.00	Almonte Sub 3 Feeders
532	220	Electronic Protective relays	1820	$16,500		$0.00	$0.00	
529	16	Scada upgrade	1980	$45,000				
499	215	Outage Management System	1980	$78,000		$0.00	$0.00	Scada Survalent
281	105	Pembroke MS 6 Ground Grid	1820	$12,000		$0.00	$0.00	Sub 6 Fencing
649	105	Pembroke MS 6 Ground Grid	1820	$50,000		$0.00	$0.00	Sub 6 Grounding
415	213	Pembroke Substation MS 2	1808	$38,000		$0.00	$0.00	Sub 2 Control building
548	220	SCADA connections Almonte MS-1	1980	$7,000		$0.00	$0.00	Almonte MS-1
Total				**$474,800**		**$0.00**	**$0.00**	

2017 Investment Category System Service										
606	16	System Service	Scada upgrade	2017	1980	$45,000.00		$0.00	$0.00	Scout
609	104	System Service	Sub Battery	2017	1820	$11,350.00		$0.00	$0.00	Sub
273	118	System Service	44 Tie Line MS2 to MS3	2017	1830	$99,999.00		$0.00	$0.00	Rough
635	130	System Service	Sub 8 Firewall	2017	1820	$65,000.00		$0.00	$0.00	
398	214	System Service	SF6 Breaker	2017	1820	$108,000.00		$0.00	$0.00	
622	220	System Service	Electronic Protective relays	2017	1820	$16,500.00		$0.00	$0.00	
Total						$345,849.00				

2018 Investment Category System Service										
610	104	System Service	Sub Battery	2018	1820	$11,350.00		$0.00	$0.00	Sub
170	130	System Service	Sub 3 Vector Correction	2018	1820	$5,800.00		$0.00	$0.00	Labour and contracts
631	130	System Service	Sub 4 PT	2018	1820	$9,000.00		$0.00	$0.00	Re-locate PT to allow for 3 meter clearances
287	213	System Service	Pem Sub 2 Switchgear HV Switch	2018	1820	$228,000.00		$0.00	$0.00	Sub 2 HV swith and LV padmount
521	217	System Service	Substation design and engineering	2018	1820	$73,000.00		$0.00	$0.00	New Substation Design
623	220	System Service	Electronic Protective relays	2018	1820	$16,500.00		$0.00	$0.00	
620	223	System Service	Almonte MS-3 Rebuild	2018	1820	$230,000.00		$0.00	$0.00	Substation Rebuild, with new tx?
Total						$573,650.00				

2019 Investment Category System Service										
607	16	System Service	Scada upgrade	2019	1980	$47,500.00		$0.00	$0.00	Scout
399	214	System Service	SF6 Breaker	2019	1820	$108,000.00		$0.00	$0.00	
568	217	System Service	Substation design and engineering	2019	1830	$121,200.00		$0.00	$0.00	New Substation
624	220	System Service	Electronic Protective relays	2019	1820	$16,500.00		$0.00	$0.00	
Total						$293,200.00				

b) Please confirm that ORPC has categorized expenditures primarily driven by asset condition as System Renewal investments.

Response:

Yes ORPC confirms that expenditures primarily driven by asset condition are categorized as System Renewal investments. The trigger driver for the proposed investments correlates with triggers for System Service.

For example; Almonte MS3 upgrade could be classified System Renewal due to its trigger being age, but the recent condition assessment completed in 2014 did not highlight any deficiencies or concerns. The substation will need to be upgraded due to the existing load and future growth in the area.
Another example is the electromechanical relays. ORPC plans to install new solid state relays under the System Service due to the trigger being Smart Grid and reclosures functionality and not due to the age of the relays.

- ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

system renewal	assets/asset systems at end of service life due to: – failure – failure risk – substandard performance – high performance risk – functional obsolescence	– programs to refurbish/replace assets or asset systems; e.g: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)

2-Staff-27

Ref: Exhibit 2, p. 47 – DSP Section 5.4.4: Capital Expenditure Summary, *Criteria for Prioritizing Capital Projects [Table]*, p. 121.

Capital Project Name	2014	2015	2016	2017	2018	2019	Total
Fully Dressed Wood Pole Replacement Program	$34,000	$64,500	$64,500	$64,500	$64,500	$64,500	$322,500
Overhead & Pad-Mounted Transformer Replacement Program	$59,600	$59,500	$103,300	$103,300	$103,300	$103,300	$472,700
Conductors	$220,359	$60,200	$44,500	$14,000	$14,000	$14,000	$146,700
Fleet Vehicle Replacement Program	$49,066	$61,000	$300,000	$60,000	$60,000	-	$481,000
Scada		$18,000	$45,000	$45,000		$45,000	$153,000
Transformer Station – Power Transformer Fire Barrier				$65,000			$65,000
Information System	$35,425	$10,000			$26,000	$47,000	$83,000
Transformer Station - 44kV Breaker Replacement				$108,000		$108,000	$216,000
Engineering Studies			$86,000				$86,000
Outage Management System			$78,000				$78,000
44 KV tie Line Almonte				$100,000			$100,000
Substation upgrades	$84,000				$228,000		$228,000
Almonte Substation					$280,000		$280,000
Substation Design	$74,600				$73,000	$115,000	$188,000
Scattered Residential and Subdivisions	$203,500	$400,850	$400,850	$290,700	$290,700	$290,700	$1,673,800
Commercial	$108,370	$100,500	$100,500	$161,500	$91,500	$91,500	$545,500
2015 Misc. Small Capital Projects		$285,250					$285,250
2016 Misc. Small Capital Projects			$424,100				$424,100
2017 Misc. Small Capital Projects				$219,700			$219,700
2018 Misc. Small Capital Projects					$226,550		$226,550
2019 Misc. Small Capital Projects						$222,900	$222,900

a) Please categorize each of the above projects and programs by primary Capital Expenditure driver, i.e.: System Access, System Renewal, System Service or General Plant.

Response:

The above table is categorized in the following table:

Capital Project Name	Investmment Category	2014	2015	2016	2017	2018	2019	Total
Fully Dressed Wood Pole Replacement Program	System Renewal	$34,000	$64,500	$64,500	$64,500	$64,500	$64,500	$322,500
Overhead & Pad-Mounted Transformer Replacement Program	System Renewal	$59,600	$59,500	$103,300	$103,300	$103,300	$103,300	$472,700
Conductors		$220,359	$60,200	$44,500	$14,000	$14,000	$14,000	$146,700
Fleet Vehicle Replacement Program	General Plant	$49,066	$61,000	$300,000	$60,000	$60,000	-	$481,000
Scada	System Service		$18,000	$45,000	$45,000		$45,000	$153,000
Transformer Station – Power Transformer Fire Barrier	System Service				$65,000			$65,000
Information System	General Plant	$35,425	$10,000			$26,000	$47,000	$83,000
Transformer Station - 44kV Breaker Replacement	System Service				$108,000		$108,000	$216,000
Engineering Studies	System Service			$86,000				$86,000
Outage Management System	System Service			$78,000				$78,000
44 KV tie Line Almonte	System Service				$100,000			$100,000
Substation upgrades	System Service	$84,000				$228,000		$228,000
Almonte Substation	System Service					$280,000		$280,000
Substation Design	System Service	$74,600				$73,000	$115,000	$188,000
Scattered Residential and Subdivisions	System Access	$203,500	$400,850	$400,850	$290,700	$290,700	$290,700	$1,673,800
Commercial	System Access	$108,370	$100,500	$100,500	$161,500	$91,500	$91,500	$545,500
2015 Misc. Small Capital Projects			$285,250					$285,250
2016 Misc. Small Capital Projects				$424,100				$424,100
2017 Misc. Small Capital Projects					$219,200			$219,200
2018 Misc. Small Capital Projects						$226,550		$226,550
2019 Misc. Small Capital Projects							$222,900	$222,900

b) Please state if engineering cost of $86,000 are capitalized. If so, please indentify the related project.

Response:

The project is listed as project #219 in the below table under the System Service Category. The project is to complete safety studies (such as arc flash and short circuit) and load flow and line loss studies. An external engineering firm will be contracted to complete the studies.

2016 Investment Category System Service							
438	133	Almonte MS-2 44 kV conductor upgrades	1835	$58,100	$0.00	$0.00	44 kV MS-2 to river xcing
	219	Engineering Studies	1820	$86,000			Arc Flash, Load flow, Loss and short circuit
439	133	Almonte MS-2 44 kV pole upgrades	1830	$27,100	$0.00	$0.00	44 kV MS-2 to river xcing
14	109	Almonte Feeder MS-2 (2F2) conductor upgrades	1835	$0	$0.00	$0.00	MS 2 Feeder Cable 2F2
51	108	Almonte Feeder Reclosing relay MS 2	1835	$24,300	$0.00	$0.00	Almonte Sub 2 Feeders
292	108	Almonte Feeder Reclosing relay MS 3	1835	$18,500	$0.00	$0.00	Almonte Sub 3 Feeders
13	109	Almonte MS 3 feeder cables	1835	$14,300	$0.00	$0.00	Almonte Sub 3 Feeders
532	220	Electronic Protective relays	1820	$16,500	$0.00	$0.00	
529	16	Scada upgrade	1980	$45,000			
499	215	Outage Management System	1980	$78,000	$0.00	$0.00	Scada Survalent
281	105	Pembroke MS 6 Ground Grid	1820	$12,000	$0.00	$0.00	Sub 6 Fencing
649	105	Pembroke MS 6 Ground Grid	1820	$50,000	$0.00	$0.00	Sub 6 Grounding
415	213	Pembroke Substation MS 2	1808	$38,000	$0.00	$0.00	Sub 2 Control building
548	220	SCADA connections Almonte MS-1	1980	$7,000	$0.00	$0.00	Almonte MS-1
	Total			**$474,800**	**$0.00**	**$0.00**	

2-Staff-28

Ref: Exhibit 2, p. 47 – DSP Section 5.4.4: Capital Expenditure Summary, *Criteria for Prioritizing Capital Projects [Table]*, p. 123.

DESCRIPTION	2010	2011	2012	2013	2014
System Access	$206,026	$369,429	$231,185	$302,943	$340,430
System Renewal	$513,921	$307,425	$344,841	$407,204	$459,780
System Service	$0	$0	$0	$0	$216,819
General Plant	$384,678	$71,365	$228,960	$664,092	$181,206
TOTAL	$1,104,625	$748,219	$804,986	$1,374,239	$1,198,235

DESCRIPTION	2015	2016	2017	2018	2019
System Access	$500,850	$500,850	$452,200	$392,700	$392,700
System Renewal	$449,820	$194,100	$248,750	$193,200	$193,200
System Service	$270,800	$474,800	$345,849	$573,650	$293,200
General Plant	$212,200	$376,200	$255,200	$116,200	$134,200
TOTAL	$1,433,670	$1,545,950	$1,301,999	$1,275,700	$1,013,300

a) Please explain the departure from historical trends of the forecast expenditures in the System Access, System Renewal and System Service categories.

Response:

The difference in the system access category is Subdivision construction and construction resulting from zoning changes. These are very difficult to predict when they will be constructed. The budget includes $130k for Pembroke subdivisions and $130k for Almonte subdivisions. Approximately $120k of the proposed budget is for commercial development which correlates with strength in the local economy.
Also, $120k is for scattered residential development which is typical for our service area and is more expensive to connect per customer compared to a multi residential or subdivision. Historically the budget was $410k and the actual spent was $290k/year for the period 2010 – 2014.

System Renewal and System Service categories together are similar to historical years with, with the primary drivers being an aging distribution system and the necessity to upgrade this. The changes in general plant are a direct result of the timing of large trucks for the fleet.

b) Please explain the decrease in capital expenditures over the IRM term and describe the expected impact of this decrease on ROE.

Response:

The decrease in capital expenditures over the first portion of the IRM term was under the control of previous management. After 2013 they returned to normal levels. While Ottawa River Power acknowledges that O&M expenses were increased there was not a direct correlation between the two. O&M expenses were in line with CPI increases. Ottawa River Power believes the impact of this on ROE to be not of a material nature.

c) Please provide the capital: depreciation ratio over the five year period.

Response:

The capital to depreciation ratio over the five year period is as follows:

- 2010 1:0.84
- 2011 1:1.11
- 2012 1:0.98
- 2013 1:0.67
- 2014 1:0.78

2-Staff-29
Ref: Exhibit 2, p. 47 – Rate Base Trend, PDF p. 6

At the reference, ORPC states: “Under the new management, ORPC started the asset review portion of its Distribution System Plan in early 2014 which triggered a higher level of capital investment in its distribution system.”

a) Please describe the drivers of the increased level of capital additions in 2013, given that the asset review portion of ORPC's DSP was started in early 2014?

Response:

1. General Plant vehicles/rolling stock
    a. The major contributing factor to the increase is capital expenditures during 2013 was the replacement of a 1997 Double Bucket Truck for a cost of just over $400K.
    b. Two other vehicles over ten years old were also replaced for $57K.

2. System Renewal and System Service combined
    a. Substation #2 refurbishment (in the Pembroke service area) was started under new management adding $40K.
    b. Replacement of the 44KV line on Mackay St. in Pembroke added an additional $71K.

2-Staff-30

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, p. 6.

At the reference, ORPC states: "An analysis of load flow and load loss was completed in the 2005-2007 period. The analysis provided a system load study of which concluded that:

- Marginal implications were required to rebalance the system by changing individual load phase connections; and
- No additional options for loss reduction need be considered (e.g. increasing conductor size)."

a) How did ORPC determine that no additional options for loss reduction need to be considered?

Response:

Engineering concluded during the analysis (with the use of DESS software) that other options did exist that would require extensive capital investments and they also concluded that the investment should not be completed as they would affect the System reliability (Voltage Conversion). The existing system was designed in anticipation of load growth resulting from the demand of electric heat. Hence large transformers, large conductors combined with substation redundancy were incorporated into the distribution system.

ORPC intends to update the analysis in 2016 in utilizing real time data from the Smart meters. Although additional options for loss reduction were considered briefly (such as increasing conductor size), the costs would greatly outweigh any benefits that would accrue

b) Did ORPC conduct a cost-benefit analysis to investigate the economics of implementing any loss reduction projects? If NO, please explain.

Response:

Yes Ottawa River Power considering both the costs and benefits to determine if it was necessary to implement any loss reduction projects.

c) If yes to b), please provide more information.

Response:

When Ottawa River Power completed the analysis (with the use of DESS software) that other options did exist they determined that extensive capital investments would be necessary and they also concluded that the investment should not be completed as they would affect the System reliability (Voltage Conversion).

2-Staff-31

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, *Customer Statistics [Table]*, p. 13.

General Statistics	For the year ended December 31, 2012	For the year ended December 31, 2013	For the year ended December 31, 2014
Population Served	20,200	20,200	20,200
Municipal Population	20,200	20,200	20,200
Seasonal Population	-	-	-
Residential	9,136	9,250	9,298
General Service (<50 kW)	1,351	1,322	1,316
General Service (50-4999 kW)	146	146	146
Large User (>5000 kW)	-	-	-
Sub Transmission	-	-	-
Total Customers	**10,633**	**10,718**	**10,791**
Rural Service Area (sq. km)	-	-	-
Urban Service Area (sq. km)	35	35	35
Total Service Area (sq. km)	**35**	**35**	**35**
Overhead km of Primary Line		270	270
Underground km of Primary Line		25	25
Total km of Line		**295**	**295**
Total kWh Delivered (excluding losses)	188,134,284	188,547,051	186,751,366
Total Distribution Losses (kWh)	4,896,238	12,469,321	7,794,424
Total kWh Purchased	**193,030,522**	**201,016,372**	**194,545,791**
Winter Peak (kW)	35,963	36,856	43,158
Summer Peak (kW)	33,570	29,294	33,756
Average Peak (kW)	29,443	26,575	31,681
Capital Additions in 2012	$ 822,268	$ 1,336,555	$ 1,198,235
Full time equivalent number of employees	28	28	27

a) Was the exceptional winter peak in 2014 caused primarily by unusually cold weather?

Response:

During the RRR filing for 2014 it came to Ottawa River Power's attention that it had not been including the demand of its embedded generators but solely that of Hydro One. The embedded generation demand in 2014 was 11,038.

b) Please identify if there were other material drivers contributing to this peak demand.

Response:

See response to a)

c) Please identify and describe the key drivers for the 60% increase in capital additions from 2012 to 2013.

Response:

- The major contributing factor to the increase is capital expenditures during 2013 was the replacement of a 1997 Double Bucket Truck for a cost of just over $400K.
- Two other vehicles over ten years old were also replaced for $57K.
- Substation #2 refurbishment (in the Pembroke service area) was started in 2013 under new management adding $40K.
- Substation grounding was not completed in 2012
- Replacement of the 44KV line on Mackay St. in Pembroke added an additional $71K. to 2013. Project was planned for 2012
- Martin Street project and 44 kV conductor project in Almonte ($99k) was initiated but not completed until 2013.
- Very little residential construction completed in 2012

2-Staff-32

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, *Customer Statistics*, p. 14.

ORPC stated that "the institutional sector in particular has seen significant increases over the past five years, including the construction of a new 50,000 square foot medical centre in 2009, the construction of the new Algonquin College Waterfront Campus in 2011, and the current construction of a new 22,000 square foot Ontario Provincial Police headquarters."

a) Are any costs directly associated with the Ontario Provincial Police ("OPP") headquarters included in the present capital expenditure forecast?

Response:

No, the OPP project was completed in 2014 under System Access in the amount of $34k.

b) If so, please identify where the quantum of these expenditures.

Response:

N/A

2-Staff-33

Ref: Exhibit 2, p. 47 – DSP Section 5.1: General and Administrative Matters, *Customer Statistics*, p. 14.

Population projections are as follows:

- Total new residential construction in the planning period is expected to be approximately 38 units per year.
- Low density housing is expected to continue to account for the majority (60%) of housing completions. The demographic shifts anticipated in the population profile (aging of population), along with the natural pace of urban growth, suggest a gradual continued shift toward higher density housing demand in the City of Pembroke over the next three decades. It is expected that medium and high density housing will account for about 40% of the total residential construction in the future."

a) What is ORPC's average cost per residential connection?

Response:

The average cost per residential customer is approximately $6000.

b) If there is a material difference between the per unit connection costs for low, medium and high density housing, please provide the average connection costs per category.

Response:

Ottawa River Power does not have a large number of multi-unit complexes being constructed in its service territories. In the past year there were four units constructed. The average cost per customer in these cases range from 30% to 40% lower than the average residential connections with the one single apartment building being the lowest cost per customer at just over $1800

2-Staff-34

Ref: Exhibit 2, p. 47 – DSP Section 5.2.1: Distribution System Plan Overview, p. 16.

At the reference, ORPC states that “ORPC plans to expend significant effort in quantifying and characterizing its distribution system and general plant with the assistance of a Geographic Information System (GIS). ORPC has created an asset register that contains both quantitative data such as the age of individual assets. It is anticipated that we will enhance the asset register with key qualitative data, such as inspection and condition testing results including detailed asset information in the next two years. This enhancement will enable ORPC to project when individual assets are expected to reach the end of their useful service life, at which time the assets have a high probability of failure.”

a) Has ORPC established a mechanism to translate qualitative asset condition assessment information into replacement decisions?

Response:

Yes. The life expectancy adjustments are currently performed based on the judgment and expertise of knowledgeable staff. ORPC plans to develop a more definitive set of criteria that underpin life expectancy adjustments in future iterations of the process.

ORPC has an asset register as part of the ESRI GIS software. The asset register in ESRI includes the result of Condition assessments. However, pole year, transformer age, and asset condition parameters are not currently included in the database and need to be updated as soon as the asset assessment is completed.

Comments:					Table1-1 Useful Life Values for Fully Dressed Wood Poles					
Oldest poles 35 yrs					Asset	Usefull Life				
Rebuild from 1975 - 1985					Componentization	MUL	**TUL**	MUL		
Pole replacement program continued every year throughout history.					Pole	35	**45**	75		
Experienced Bad Pole Batches - premature failure due to inefficient treatment										
Majority of ORPC Poles - Wood 45' Class 3										
		IFRS Additions								
1	2	77	3	4	5	6	7	8	9	10
ID_NUMBI	OWNEI	ORPC_INS	POLE_CONF	MAN	MATERIAL	HEIGHT	Pole Class	CONDITION	PRIM_CON	SEC_COND
?	ORPC	2009	STANDARD	2009	WOOD	45	3	NEW	3X1	
? EP	ORPC	2009	STUB/GUY	2009	WOOD	40	3	NEW	NONE	
AP0010	ORPC	2008	STANDARD	2008	WOOD	45	3	NEW	1X1	NONE
AP0011	ORPC		STANDARD	1993	WOOD	45	3	GOOD	1X1	NONE
AP0012	ORPC		STANDARD	1993	WOOD	45	3	GOOD	1X1	SINGLE PHASE

The asset process defines the AEOL by factors such as Asset Statistics (Age), Asset Failure rates, Impact on Health and Safety & Environment, Customer Service (Reliability), Inspection Data and failure rates.

The AEOL is used to determine which assets will be replaced and to assemble budgets. The AEOL will be “fine-tuned” as more asset information is gathered in the coming years.

b) Does the capital expenditure forecast associated with this DSP incorporate the expected incremental costs of applying the new replacement methodology?

Response:

We anticipate completing the project in conjunction with our asset database information gathering exercise and with the capital expenditure as expected to update the ESRI software ($39k in 2015).

2-Staff-35

Ref: Exhibit 2, p. 47 / Tab 5 / Schedule 2 – DSP Section 5.2.3: Performance Measurement for Continuous Improvement [Table], p. 21.

Scorecard - Ottawa River Power Corporation

9/24/2014

Performance Outcomes	Performance Categories	Measures		2009	2010	2011	2012	2013	Trend	Target Industry	Target Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	98.60%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		99.40%	99.80%	99.80%	99.90%	99.90%		65.00%	
	Customer Satisfaction	First Contact Resolution									
		Billing Accuracy									
		Customer Satisfaction Survey Results									
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety [measure to be determined]									
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		2.66	0.71	2.39	1.59	0.91			at least within 0.71 - 2.66
		Average Number of Times that Power to a Customer is Interrupted		2.10	0.79	1.43	1.08	0.81			at least within 0.79 - 2.10
	Asset Management	Distribution System Plan Implementation Progress									
	Cost Control	Efficiency Assessment					3	3			
		Total Cost per Customer [1]		$452	$449	$457	$470	$505			
		Total Cost per Km of Line [1]		$32,140	$31,790	$34,703	$33,773	$32,410			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]				13.00%	13.00%	10.70%			1.61MW
		Net Cumulative Energy Savings (Percent of target achieved)				34.00%	60.00%	77.60%			8.57GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time						100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		3.66	3.29	2.70	2.32	1.54			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.74	0.74	0.73	0.72	0.73			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)			9.85%	9.85%	9.85%			
			Achieved			10.56%	11.60%	5.90%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings do not include any persisting peak demand savings from the previous years.

Legend:
up
down
flat
target met
target not met

a) What caused the step change in "Achieved Return" in 2013?

Response:

During 2013 Ottawa River Power had its first actuarial report completed. The difference between its previous accounting accrual and the actual number was $109,000 which was booked into account #5645. Without this ORPC would have achieved an ROE of 8.31%.

Additionally during 2013 Ottawa River Power hired a new president with an overlap of three months in wages and benefits. There were also recruitments costs.

2-Staff-36

Ref: Exhibit 2, p. 47 – DSP Section 5.2.3.1: Service Quality and Reliability Performance [Table], p. 22.

Service Quality Indicator	Minimum Standard	2009	2010	2011	2012	2013	2014
Connection of New Services – Low Voltage	90% or better	100	100	100	100	100	200
Connection of New Service – High Voltage	90% or better	n/a	n/a	n/a	n/a	n/a	n/a
Appointment Scheduling	90% or better	100	100	100	100	100	100
Appointments Met	90% or better	100	100	100	100	100	100

a) Please confirm if "Connection of New Services – Low Voltage" result of 200 for 2014 is a typo.

Response:

Ottawa River Power confirms that the result for 2014 Connection of New Services – Low voltage is a typo and should be replaced with 100.

2-Staff-37

Ref: Exhibit 2, p. 47 – DSP Section 5.2.3.5: System Reliability and Performance, *Killaloe Outage Performance*, p. 29.

On page 29, ORPC stated that "a Hydro One consultation was completed to determine if future improvements can be achieved. The installation of multiple remote operated switches was determined to be extremely costly and ORPC decided that the improvement not be completed at this time."

a) Please provide the cost estimates developed to determine the economic viability of installing "multiple remote operated switches".

Response:

Ontario Industry

SAIDI - Industry Annual	**8.80**	**4.27**	**7.10**	**3.96**	**3.44**	**7.19**	**3.99**

HONE estimate can be as little as $150k ($125k/switch + $25k study) to implement one remote operated switch. ORPC' s outage performance exceeds the Ontario average.

Hydro One email dated August 20th, 2013;

Good Morning Denis/Doug,
I've spoken with Ashley Lebel regarding the motorized switches for Killaloe. The project would likely have a fairly substantial price tag for the return.
As HONI is currently meeting the prescribed conditions of service we would require an agreement / feasibility study to come up with an estimate to determine the overall estimate (an agreement to create an estimate).
Having said this, there is some interest in facilitating this from our end but it would be entirely recoverable work (from HONIs perspective).
Regards,

Rob
Robert Wallenius
Customer Service Account Representative
Customer Business Relations - Hydro One
Phone) 416-345-6994
E-mail) robert.wallenius@hydroone.com
Fax) 416-345-5957

Hydro One email dated December 18th, 2013

Hi Denis,
A little more clarity with respect to our phone conversation.

if just the Cobden M6 went out in an isolated condition (only trouble call in province) controllers would look for feeder load transfers like we have to restore the power. This would likely occur within couple of hours.

However during a major storm this may not happen as fast, maybe ½ a day or more depending on how much trouble is going on.

So this will not happen automatically but it is our normal operating practice to restore load through existing feeder load studies.

I also spoke to Ashley regarding a ballpark cost for the study of motorized switching for Killaloe and he indicated that $25,000 would likely be a good figure. Note that it would be actual costs.

Merry Christmas,

Rob

Robert Wallenius
Customer Service Account Representative
Customer Business Relations - Hydro One
Phone) 416-345-6994
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2-Staff-38

Ref: Exhibit 2, p. 47 – DSP Section 5.2.3.6 a: Conservation and Demand Management, *kWh Savings*, p. 32.

On page 32, ORPC stated that “with the anticipated EERI project completions, the HAP program results, as well as the large HPNC project noted above (600,000 kWh), ORPC expects to meet its energy target of 9 GWh. A final report is to be released in September; whereby, the excluded savings will be included.”

a) Please provide the final report that was released in September 2015.

Response:

Ottawa River Power provides the final report attached

Message from the Vice President:

The IESO is pleased to provide the enclosed 2011-2014 Final Results Report. This report is designed to help populate LDC Annual Reports that will be submitted to the Ontario Energy Board (OEB) in September 2015.

2011-2014 Conservation Framework Highlights:

- LDCs have made significant achievements against dual energy and peak demand savings targets. Collectively, the LDCs have achieved 109% of the energy target and 70% of the peak demand target.
- Momentum has built as we transition to the Conservation First Framework. 2014 demonstrated an achievement of over 1 TWh of net incremental energy savings, positioning us well for average net incremental energy savings of 1.2 TWh required in the new framework to meet our 2020 CDM targets.
- Throughout the past framework, program results have become more predictable year over year as noted in the increasingly smaller variance between quarterly preliminary results and verified final results.
- Customer engagement continued to increase in both the Consumer and Business Programs. Between 2011 - 2014 consumers have purchased over 10 million energy efficient products through the saveONenergy COUPONS program. Customers in RETROFIT continue to declare a positive experience participating in the program with 86% likely to recommend.
- saveONenergy has seen a steady and significant increase in unaided brand awareness by 33% from 2011-2014
- Conservation is becoming even more cost-effective as programs become more efficient and effective. 2014 proved early investments in long lead time projects will pay off with the high savings now being realized in programs like PROCESS & SYSTEMS and RETROFIT. Within 4 cents per kWh, Conservation programs continue to be a valuable and cost effective resource for customers across the province.

The 2011-2014 Final Results within this report vary from the Draft 2011-2014 Final Results Report for the following reasons:

- Savings from Time of Use pricing are included in the Final Results Report. Overall the province saved 55 MWs from Time-of-Use pricing in 2014, or 0.73% of residential summer peak demand.
- Between August 4th and August 28th, the IESO and LDCs have worked collaboratively to reconcile projects from 2011-2014 Final Results Report to ensure every eligible project was captured and accurately reported.
- Verified savings from Innovation Fund pilots are also included for participating LDCs.

All results will be considered final for the 2011-2014 Conservation Framework. Any additional program activity not captured in the 2011-2014 Final Results Report will not be included as part of a future adjustment process.

Please continue to monitor saveONenergy E-blasts for future updates and should you have any other questions or comments please contact LDC.Support@ieso.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process and we look forward to the success ahead in the Conservation First Framework.

Sincerely,

Terry Young

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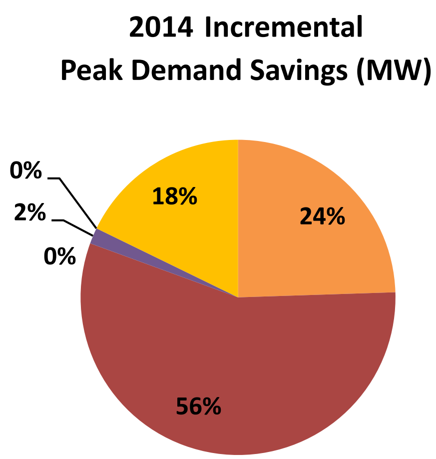
IESO-Contracted Province-Wide CDM Programs: 2011-2014 Final Results Report

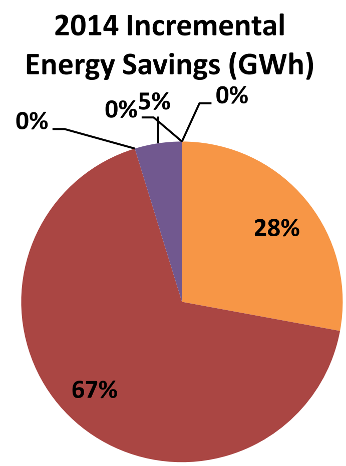
LDC: Ottawa River Power Corporation

Final 2014 Achievement Against Targets	2014 Incremental	2011-2014 Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	0.5	1.0	**62.6%**
Net Energy Savings (GWh)	1.8	9.4	**105.0%**

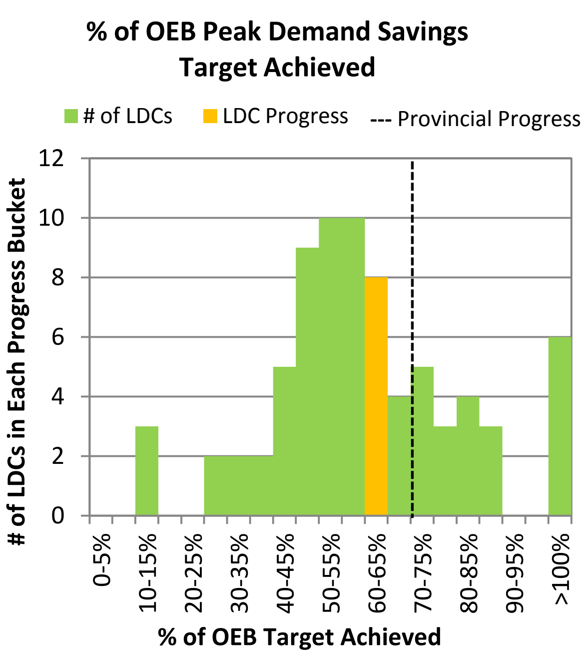
Unless otherwise noted, results are presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Achievement by Sector





Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)



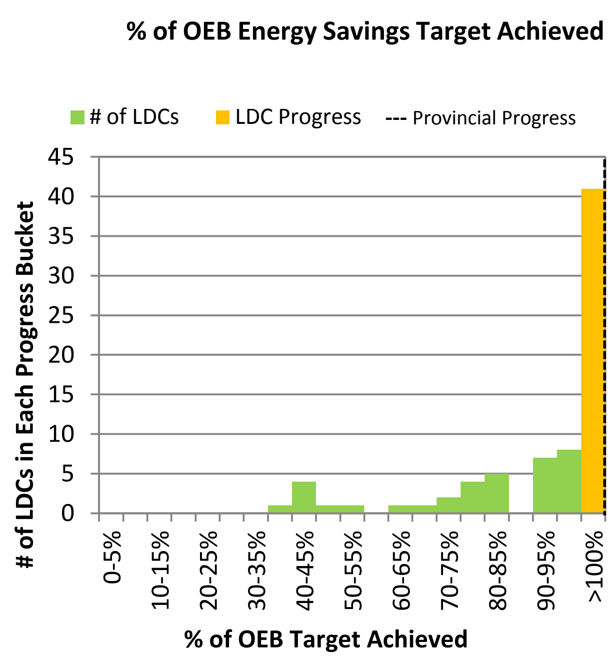


Table 1: Ottawa River Power Corporation Initiative and Program Level Net Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	92	146	64	59	6	8	4	4	39,179	56,155	26,275	25,409	22	402,939
Appliance Exchange	Appliances	16	5	11	12	2	1	2	2	1,896	1,251	4,064	4,433	6	22,909
HVAC Incentives	Equipment	104	103	108	134	49	24	25	33	96,849	44,321	45,706	62,853	131	674,623
Conservation Instant Coupon Booklet	Items	1,014	61	687	2,039	2	0	1	4	38,330	2,760	15,216	55,588	8	247,623
Bi-Annual Retailer Event	Items	1,880	2,094	1,865	9,525	3	3	2	16	58,017	52,873	33,917	242,637	24	701,158
Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	0	0	14	75	0	0	6	32	0	0	0	0	32	0
Residential Demand Response (IHD)	Devices	0	0	13	44	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Consumer Program Total						**62**	**37**	**40**	**91**	**234,271**	**157,360**	**125,178**	**390,920**	**224**	**2,049,252**
Business Program															
Retrofit	Projects	6	19	22	22	41	60	38	112	264,382	211,874	180,759	573,508	250	2,627,883
Direct Install Lighting	Projects	113	122	103	87	110	112	91	97	283,517	422,290	320,746	370,051	375	3,304,754
Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Construction	Buildings	0	1	0	0	0	0	0	0	0	0	0	0	0	0
Energy Audit	Audits	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Commercial Demand Response	Devices	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Business Program Total						**151**	**172**	**128**	**209**	**547,899**	**634,164**	**501,504**	**943,559**	**625**	**5,932,638**
Industrial Program															
Process & System Upgrades	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	0	1	0	0	0	0	0	0	0	0	0	0	0
Retrofit	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Industrial Program Total						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0	5	17	98	0	0	0	6	0	0	0	66,458	6	66,458
Home Assistance Program Total						**0**	**0**	**0**	**6**	**0**	**0**	**0**	**66,458**	**6**	**66,458**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2	0	0	0	4	0	0	0	15,726	0	0	0	4	62,903
High Performance New Construction	Projects	0	0	0	0	0	0	0	0	490	216	0	0	0	2,607
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total						**4**	**0**	**0**	**0**	**16,215**	**216**	**0**	**0**	**4**	**65,510**
Other															
Program Enabled Savings	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	66	0	0	0	0	66	0
LDC Pilots	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Total						**0**	**0**	**0**	**66**	**0**	**0**	**0**	**0**	**66**	**0**
Adjustments to 2011 Verified Results							**-11**	**0**	**0**		**-15,574**	**0**	**0**	**-12**	**-64,489**
Adjustments to 2012 Verified Results								**3**	**85**			**101,352**	**325,621**	**88**	**1,280,917**
Adjustments to 2013 Verified Results									**8**				**45,487**	**8**	**91,051**
Energy Efficiency Total						**217**	**209**	**163**	**341**	**798,386**	**791,740**	**626,683**	**1,400,938**	**893**	**8,113,858**
Demand Response Total (Scenario 1)						**0**	**0**	**6**	**32**	**0**	**0**	**0**	**0**	**32**	**0**
Adjustments to Previous Years' Verified Results Total						**0**	**-11**	**3**	**93**	**0**	**-15,574**	**101,352**	**371,107**	**83**	**1,307,480**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**217**	**198**	**172**	**466**	**798,386**	**776,166**	**728,034**	**1,772,045**	**1,008**	**9,421,337**
													Full OEB Target:	**1,610**	**8,970,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**62.6%**	**105.0%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 2: Adjustments to Ottawa River Power Corporation Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-49	5	5		-15	1	1		-28,452	2,344	2,553		-12	-101,673
Conservation Instant Coupon Booklet	Items	16	0	2		0	0	0		544	0	47		0	2,271
Bi-Annual Retailer Event	Items	162	0	0		0	0	0		4,310	0	0		0	17,242
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	0		0	0	0		0	0	0		0	0
Consumer Program Total						**-15**	**1**	**1**		**-23,598**	**2,344**	**2,600**		**-12**	**-82,160**
Business Program															
Retrofit	Projects	0	3	2		0	7	2		0	123,906	10,164		9	392,045
Direct Install Lighting	Projects	4	2	1		3	1	2		8,023	5,043	7,735		6	60,502
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	1	0		0	78	0		0	292,249	0		78	876,746
Energy Audit	Audits	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**3**	**86**	**4**		**8,023**	**421,198**	**17,899**		**93**	**1,329,293**
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	0	1		0	0	0		0	0	10,468		0	20,935
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**0**	**0**	**0**		**0**	**0**	**10,468**		**0**	**20,935**
Home Assistance Program															
Home Assistance Program	Homes	0	5	17		0	0	2		0	3,431	14,598		2	39,411
Home Assistance Program Total						**0**	**0**	**2**		**0**	**3,431**	**14,598**		**2**	**39,411**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0		0	0	0		0	0
High Performance New Construction	Projects	0	0	0		0	0	0		0	0	0		0	0
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Other															
Program Enabled Savings	Projects	0	0	0		0	0	0		0	0	0		0	0
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
LDC Pilots	Projects	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Adjustments to 2011 Verified Results						**-11**				**-15,574**				**-12**	**-64,489**
Adjustments to 2012 Verified Results							**88**				**426,972**			**88**	**1,280,917**
Adjustments to 2013 Verified Results								**8**				**45,564**		**8**	**91,051**
Total Adjustments to Previous Years' Verified Results						**-11**	**88**	**8**		**-15,574**	**426,972**	**45,564**		**83**	**1,307,480**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 3: Ottawa River Power Corporation Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a	n/a	0.51	0.46	0.42	0.42	1.00	1.00	n/a	n/a	0.52	0.47	0.44	0.44
Appliance Exchange	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	n/a	1.00	0.60	0.49	0.48	0.51	1.00	1.00	n/a	1.00	0.60	0.49	0.48	0.51
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.12	1.05	1.13	1.73
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.13	0.91	1.04	1.74	1.00	1.00	1.00	1.00	1.10	0.92	1.04	1.75
Retailer Co-op	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Business Program																
Retrofit	0.94	1.00	0.91	0.85	0.74	0.80	0.71	0.76	1.34	1.24	1.04	1.09	0.76	0.81	0.72	0.74
Direct Install Lighting	1.08	0.68	0.81	0.78	0.93	0.94	0.94	0.94	0.90	0.85	0.84	0.83	0.93	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
New Construction	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Energy Audit	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Monitoring & Targeting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Energy Manager	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Retrofit																
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	n/a	n/a	n/a	0.74	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.81	n/a	n/a	n/a	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.96	n/a	n/a	n/a	0.61	n/a	n/a	n/a	0.95	n/a	n/a	n/a	0.60	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50
Toronto Comprehensive	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Pilots	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Achievement Against CDM Targets

Results are recognized using current IESO reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenario 1). Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.2	0.2	0.2	0.2
2012 - Verified†	0.0	0.2	0.2	0.2
2013 - Verified†	0.0	0.0	0.2	0.2
2014 - Verified†	0.0	0.1	0.1	0.5
Verified Net Annual Peak Demand Savings Persisting in 2014:				**1.0**
Ottawa River Power Corporation 2014 Annual CDM Capacity Target:				**1.6**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**62.7%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	0.8	0.8	0.8	0.7	3.1
2012 - Verified†	0.0	0.8	0.8	0.8	2.3
2013 - Verified†	0.0	0.1	0.7	0.7	1.6
2014 - Verified†	0.0	0.3	0.37	1.8	2.5
Verified Net Cumulative Energy Savings 2011-2014:					**9.4**
Ottawa River Power Corporation 2011-2014 Annual CDM Energy Target:					**9.0**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**105.0%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146	20,952	22,563	3,299	2,011	1,433	1,617	23,005,812	13,424,518	8,713,107	9,497,343	8,221	159,100,415
Appliance Exchange	Appliances	3,688	3,836	5,337	5,685	371	556	1,106	1,178	450,187	974,621	1,971,701	2,100,266	2,973	10,556,192
HVAC Incentives	Equipment	92,748	87,540	96,286	113,002	32,037	19,060	19,552	23,106	59,437,670	32,841,283	33,923,592	42,888,217	93,755	447,009,930
Conservation Instant Coupon Booklet	Items	567,678	30,891	347,946	1,208,108	1,344	230	517	2,440	21,211,537	1,398,202	7,707,573	32,802,537	4,531	137,258,436
Bi-Annual Retailer Event	Items	952,149	1,060,901	944,772	4,824,751	1,681	1,480	1,184	8,043	29,387,468	26,781,674	17,179,841	122,902,769	12,389	355,157,348
Retailer Co-op	Items	152	0	0	0	0	0	0	0	2,652	0	0	0	0	10,607
Residential Demand Response	Devices	19,550	98,388	171,733	241,381	10,947	49,038	93,076	117,513	24,870	359,408	390,303	8,379	117,513	782,960
Residential Demand Response (IHD)	Devices	0	49,689	133,657	188,577	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	27	21	279	2,367	0	2	18	369	743	17,152	163,690	2,330,865	390	2,712,676
Consumer Program Total						**49,681**	**72,377**	**116,886**	**154,267**	**133,520,941**	**75,796,859**	**70,049,807**	**212,530,376**	**239,772**	**1,112,588,565**
Business Program															
Retrofit	Projects	2,828	6,481	9,746	10,925	24,467	61,147	59,678	70,662	136,002,258	314,922,468	345,346,008	462,903,521	213,493	2,631,401,223
Direct Install Lighting	Projects	20,741	18,691	17,833	23,784	23,724	15,284	18,708	23,419	61,076,701	57,345,798	64,315,558	84,503,302	73,304	604,196,658
Building Commissioning	Buildings	0	0	0	5	0	0	0	988	0	0	0	1,513,377	988	1,513,377
New Construction	Buildings	25	98	158	226	123	764	1,584	6,432	411,717	1,814,721	4,959,266	20,381,204	8,904	37,390,767
Energy Audit	Audits	222	357	589	473	0	1,450	2,811	6,323	0	7,049,351	15,455,795	30,874,399	10,583	82,934,042
Small Commercial Demand Response	Devices	132	294	1,211	3,652	84	187	773	2,116	157	1,068	373	319	2,116	1,916
Small Commercial Demand Response (IHD)	Devices	0	0	378	820	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	145	151	175	180	16,218	19,389	23,706	23,380	633,421	281,823	346,659	0	23,380	1,261,903
Business Program Total						**64,617**	**98,221**	**107,261**	**133,319**	**198,124,253**	**381,415,230**	**430,423,659**	**600,176,121**	**332,769**	**3,358,699,887**
Industrial Program															
Process & System Upgrades	Projects	0	0	5	10	0	0	294	9,692	0	0	2,603,764	72,053,255	9,986	77,260,782
Monitoring & Targeting	Projects	0	1	3	5	0	0	0	102	0	0	0	502,517	102	502,517
Energy Manager	Projects	1	132	306	379	0	1,086	3,558	5,191	0	7,372,108	21,994,263	40,436,427	8,384	95,324,998
Retrofit	Projects	433	0	0	0	4,615	0	0	0	28,866,840	0	0	0	4,613	115,462,282
Demand Response 3	Facilities	124	185	281	336	52,484	74,056	162,543	166,082	3,080,737	1,784,712	4,309,160	0	166,082	9,174,609
Industrial Program Total						**57,098**	**75,141**	**166,395**	**181,066**	**31,947,577**	**9,156,820**	**28,907,187**	**112,992,199**	**189,168**	**297,725,188**
Home Assistance Program															
Home Assistance Program	Homes	46	5,920	29,654	25,424	2	566	2,361	2,466	39,283	5,442,232	20,987,275	19,582,658	5,370	77,532,571
Home Assistance Program Total						**2**	**566**	**2,361**	**2,466**	**39,283**	**5,442,232**	**20,987,275**	**19,582,658**	**5,370**	**77,532,571**
Aboriginal Program															
Home Assistance Program	Homes	0	0	717	1,125	0	0	267	549	0	0	1,609,393	3,101,207	816	6,319,993
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**	**816**	**6,319,993**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,028	0	0	0	21,662	0	0	0	121,138,219	0	0	0	21,662	484,552,876
High Performance New Construction	Projects	182	73	19	3	5,098	3,251	772	134	26,185,591	11,901,944	3,522,240	688,738	9,255	148,181,415
Toronto Comprehensive	Projects	577	15	4	5	15,805	0	0	281	86,964,886	0	0	2,479,840	16,086	350,339,385
Multifamily Energy Efficiency Rebates	Projects	110	0	0	0	1,981	0	0	0	7,595,683	0	0	0	1,981	30,382,733
LDC Custom Programs	Projects	8	0	0	0	399	0	0	0	1,367,170	0	0	0	399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**	**772**	**415**	**243,251,550**	**11,901,944**	**3,522,240**	**3,168,578**	**49,382**	**1,018,925,088**
Other															
Program Enabled Savings	Projects	33	71	46	43	0	2,304	3,692	5,500	0	1,188,362	4,075,382	19,035,337	11,496	30,751,187
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	54,795	0	0	0	0	54,795	0
LDC Pilots	Projects	0	0	0	1,174	0	0	0	1,170	0	0	0	5,061,522	1,170	5,061,522
Other Total						**0**	**2,304**	**3,692**	**61,466**	**0**	**1,188,362**	**4,075,382**	**24,096,859**	**67,462**	**35,812,709**
Adjustments to 2011 Verified Results							**1,406**	**641**	**1,418**		**18,689,081**	**1,736,381**	**7,319,857**	**3,215**	**110,143,550**
Adjustments to 2012 Verified Results								**6,260**	**9,221**			**41,947,840**	**37,080,215**	**15,401**	**238,780,637**
Adjustments to 2013 Verified Results									**24,391**				**150,785,808**	**24,391**	**296,465,211**
Energy Efficiency Total						**136,610**	**109,191**	**117,536**	**224,457**	**603,144,419**	**482,474,435**	**554,528,447**	**975,639,300**	**575,647**	**5,896,382,612**
Demand Response Total (Scenario 1)						**79,733**	**142,670**	**280,099**	**309,091**	**3,739,185**	**2,427,011**	**5,046,495**	**8,698**	**309,091**	**11,221,389**
Adjustments to Previous Years' Verified Results Total						**0**	**1,406**	**6,901**	**35,030**	**0**	**18,689,081**	**43,684,221**	**195,185,880**	**43,006**	**645,389,397**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**	**404,536**	**568,578**	**606,883,604**	**503,590,526**	**603,259,163**	**1,170,833,878**	**927,745**	**6,552,993,397**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**70%**	**109%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 7: Adjustments to Province-Wide Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-18,839	2,319	4,705		-5,270	479	1,037		-9,707,002	955,512	1,838,408		-3,754	-32,284,656
Conservation Instant Coupon Booklet	Items	8,216	0	1,050		16	0	2		275,655	0	23,571		18	1,149,763
Bi-Annual Retailer Event	Items	81,817	0	0		108	0	0		2,183,391	0	0		108	8,733,563
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	20	2	193		1	1	72		14,667	985	441,938		74	945,497
Consumer Program Total						**-5,145**	**480**	**1,111**		**-7,233,290**	**956,497**	**2,303,917**		**-3,555**	**-21,664,975**
Business Program															
Retrofit	Projects	312	876	961		3,208	7,233	11,961		16,266,129	42,498,052	78,146,280		22,056	347,545,386
Direct Install Lighting	Projects	444	197	51		501	204	46		1,250,388	736,541	164,667		620	7,158,143
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	15	29	72		850	1,304	2,241		3,604,553	4,825,774	8,636,179		4,401	46,187,216
Energy Audit	Audits	119	77	270		604	439	2,383		2,945,189	2,145,367	13,100,635		3,426	44,418,129
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**5,162**	**9,181**	**16,631**		**24,066,259**	**50,205,734**	**100,047,761**		**30,503**	**385,148,444**
Industrial Program															
Process & System Upgrades	Projects	0	0	2		0	0	324		0	0	968,659		324	1,937,318
Monitoring & Targeting	Projects	0	1	3		0	0	54		0	528,000	639,348		54	2,862,696
Energy Manager	Projects	1	93	101		27	1,067	2,395		241,515	8,266,841	25,814,853		4,345	81,853,489
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**27**	**1,067**	**2,774**		**241,515**	**8,794,841**	**27,422,860**		**4,723**	**61,215,516**
Home Assistance Program															
Home Assistance Program	Homes	0	887	2,898		0	222	791		0	1,316,749	4,321,794		1,009	12,515,300
Home Assistance Program Total						**0**	**222**	**791**		**0**	**1,316,749**	**4,321,794**		**1,009**	**8,581,177**
Aboriginal Program															
Home Assistance Program	Homes	0	0	133		0	0	134		0	0	563,715		134	1,127,430
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**134**		**0**	**0**	**563,715**		**134**	**1,127,430**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12	0	0		138	0	0		545,536	0	0		138	2,182,145
High Performance New Construction	Projects	37	4	15		1,507	363	-184		2,398,941	2,832,533	-993,596		1,686	16,106,171
Toronto Comprehensive	Projects	0	15	4		0	672	185		0	4,523,517	1,324,388		857	16,219,327
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**1,645**	**1,035**	**2**		**2,944,477**	**7,356,050**	**330,792**		**2,682**	**11,104,528**
Other															
Program Enabled Savings	Projects	33	55	33		1,776	3,712	2,020		7,727,573	11,481,687	10,688,564		7,509	86,732,481
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
LDC Pilots	Projects	0	0	0		0	0	0		0	0	0		0	0
Other Total						**1,776**	**3,712**	**2,020**		**7,727,573**	**11,481,687**	**10,688,564**		**7,509**	**86,732,481**
Adjustments to 2011 Verified Results						**3,465**				**27,746,535**				**3,215**	**110,143,550**
Adjustments to 2012 Verified Results							**15,697**				**80,111,558**			**15,401**	**238,780,637**
Adjustments to 2013 Verified Results								**23,463**				**145,679,403**		**24,391**	**296,465,211**
Adjustments to Previous Years' Verified Results Total						**3,465**	**15,697**	**23,463**		**27,746,535**	**80,111,558**	**145,679,403**		**43,006**	**645,389,397**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	1.00	1.00	0.51	0.46	0.42	0.45	1.00	1.00	1.00	1.00	0.46	0.47	0.44	0.47
Appliance Exchange	1.00	1.00	1.00	1.00	0.51	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	1.00	1.00	0.60	0.50	0.48	0.48	1.00	1.00	1.00	1.00	0.50	0.49	0.48	0.48
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.00	1.05	1.13	1.73
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.12	0.91	1.04	1.74	1.00	1.00	1.00	1.00	0.91	0.92	1.04	1.75
Retailer Co-op	1.00	n/a	n/a	n/a	0.68	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	1.00	3.65	0.78	1.03	0.41	0.49	0.63	0.63	3.65	7.17	3.09	0.62	0.49	0.49	0.63	0.63
Business Program																
Retrofit	1.06	0.93	0.92	0.84	0.72	0.75	0.73	0.71	0.93	1.05	1.01	0.98	0.75	0.76	0.73	0.72
Direct Install Lighting	1.08	0.69	0.82	0.78	1.08	0.94	0.94	0.94	0.69	0.85	0.84	0.83	0.94	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	1.97	n/a	n/a	n/a	1.00	n/a	n/a	n/a	1.16	n/a	n/a	n/a	1.00
New Construction	0.50	0.98	0.68	0.71	0.50	0.49	0.54	0.54	0.98	0.99	0.76	0.79	0.49	0.49	0.54	0.54
Energy Audit	n/a	n/a	1.02	0.96	n/a	n/a	0.66	0.68	n/a	n/a	0.97	1.00	n/a	n/a	0.66	0.67
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	0.85	0.96	n/a	n/a	0.94	0.79	n/a	n/a	0.87	0.96	n/a	n/a	0.93	0.80
Monitoring & Targeting	n/a	n/a	n/a	0.59	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.36	n/a	n/a	n/a	1.00
Energy Manager	n/a	1.16	0.90	0.91	n/a	0.90	0.90	0.90	1.16	1.16	0.90	0.96	0.90	0.90	0.90	0.85
Retrofit	1.11	n/a	n/a	n/a	0.72	n/a	n/a	n/a	0.91	n/a	n/a	n/a	0.75	n/a	n/a	n/a
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	1.00	0.32	0.26	0.49	0.70	1.00	1.00	1.00	0.32	0.99	0.88	0.78	1.00	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	0.05	0.15	n/a	n/a	1.00	1.00	n/a	n/a	0.95	0.97	n/a	n/a	1.00	1.00
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a	n/a	0.54	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	n/a	0.49	0.50	0.50	0.50	1.00	1.00	1.00	n/a	0.50	0.50	0.50	0.50
Toronto Comprehensive	1.13	n/a	n/a	n/a	0.50	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	0.93	n/a	n/a	n/a	0.78	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	1.00	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	1.06	1.00	0.86	n/a	1.00	1.00	1.00	n/a	2.26	1.00	0.98	n/a	1.00	1.00	1.00
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Pilots	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Provincial Progress Towards CDM Targets

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012†	1.4	253.3	109.8	108.2
2013†	0.6	7.0	404.5	122.0
2014†	1.4	10.8	34.2	568.6
Verified Net Annual Peak Demand Savings in 2014:				**927.7**
2014 Annual CDM Capacity Target:				**1,330**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**69.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393.1
2012†	18.7	503.6	498.4	492.6	1,513.3
2013†	1.7	44.4	603.3	583.4	1,232.8
2014†	7.3	44.8	191.0	1,170.8	1,413.9
Verified Net Cumulative Energy Savings 2011-2014:					**6,553.0**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**109.2%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings = Activity * Per Unit Assumption** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Engineered and Custom Projects	**Gross Savings = Reported Savings * Realization Rate** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Demand Response	**Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio** **Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW** **All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)**
Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year that the exchange event occurred.	
HVAC Incentives	Results directly attributed to LDC based on customer postal code.	Savings are considered to begin in the year that the installation occurred.	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to IESO through project completion reports and continuing participant lists.	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system. Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to IESO through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program			
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Aboriginal Program			
Aboriginal Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014 assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported. A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation.		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation.		

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%
Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%

Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

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

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

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

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.

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

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

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

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

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

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

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

Table 11: Ottawa River Power Corporation Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	11	8	10	8	75,452	56,155	56,282	53,838
Appliance Exchange**	Appliances	3	1	4	5	3,679	1,251	7,721	8,423
HVAC Incentives	Equipment	83	50	52	69	162,687	90,917	96,942	132,501
Conservation Instant Coupon Booklet	Items	2	0	1	2	34,638	2,618	13,508	32,199
Bi-Annual Retailer Event	Items	3	3	2	9	53,105	57,691	32,459	138,698
Retailer Co-op	Items	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	0	0	6	32	0	0	0	0
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0
Consumer Program Total		**102**	**62**	**75**	**126**	**329,561**	**208,632**	**206,912**	**365,659**
Business Program									
Retrofit	Projects	55	65	53	142	346,394	203,807	252,541	742,183
Direct Install Lighting	Projects	103	151	96	103	305,337	507,526	339,820	392,057
Building Commissioning	Buildings	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	0	0	0	0	0	0
Energy Audit	Audits	0	0	0	0	0	0	0	0
Small Commercial Demand Response	Devices	0	0	0	0	0	0	0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Business Program Total		**158**	**215**	**149**	**245**	**651,731**	**711,333**	**592,361**	**1,134,240**
Industrial Program									
Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	0	0	0	0	0	0	0
Retrofit	Projects	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Industrial Program Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Home Assistance Program									
Home Assistance Program	Homes	0	0	0	6	0	0	0	66,458
Home Assistance Program Total		**0**	**0**	**0**	**6**	**0**	**0**	**0**	**66,458**
Aboriginal Program									
Home Assistance Program	Homes	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	6	0	0	0	26,276	0	0	0
High Performance New Construction	Projects	0	0	0	0	979	432	0	0
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total		**6**	**0**	**0**	**0**	**27,256**	**432**	**0**	**0**
Other									
Program Enabled Savings	Projects	0	0	0	0	0	0	0	0
Time-of-Use Savings	Homes	0	0	0	66	0	0	0	0
LDC Pilots	Projects	0	0	0	0	0	0	0	0
Other Total		**0**	**0**	**0**	**66**	**0**	**0**	**0**	**0**
Adjustments to 2011 Verified Results			**-21**	**0**	**0**		**-33,914**	**0**	**0**
Adjustments to 2012 Verified Results				**5**	**170**			**163,068**	**640,709**
Adjustments to 2013 Verified Results					**8**				**53,686**
Energy Efficiency Total		**266**	**278**	**218**	**411**	**1,008,547**	**920,397**	**799,273**	**1,566,358**
Demand Response Total		**0**	**0**	**6**	**32**	**0**	**0**	**0**	**0**
Adjustments to Previous Years' Verified Results Total		**0**	**-21**	**5**	**178**	**0**	**-33,914**	**163,068**	**694,395**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**266**	**257**	**228**	**621**	**1,008,547**	**886,483**	**962,341**	**2,260,753**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to Ottawa River Power Corporation Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-25	3	3		-47,746	4,798	5,448	
Conservation Instant Coupon Booklet	Items	0	0	0		505	0	41	
Bi-Annual Retailer Event	Items	0	0	0		4,686	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	0		0	0	0	
Consumer Program Total		**-25**	**3**	**3**		**-42,555**	**4,798**	**5,489**	
Business Program									
Retrofit	Projects	0	0	3		0	193,768	13,852	
Direct Install Lighting	Projects	4	2	2		8,641	5,354	8,195	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	0	0		0	596,426	0	
Energy Audit	Audits	0	0	0		0	0	0	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**4**	**2**	**5**		**8,641**	**795,548**	**22,047**	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	0	0		0	0	11,631	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**0**	**0**	**0**		**0**	**0**	**11,631**	
Home Assistance Program									
Home Assistance Program	Homes	0	0	2		0	3,431	14,598	
Home Assistance Program Total		**0**	**0**	**2**		**0**	**3,431**	**14,598**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0	
High Performance New Construction	Projects	0	0	0		0	0	0	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**0**	**0**	**0**		**0**	**0**	**0**	
Other									
Program Enabled Savings	Projects	0	0	0		0	0	0	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		**0**	**0**	**0**		**0**	**0**	**0**	
Adjustments to 2011 Verified Results		**-21**				**-33,914**			
Adjustments to 2012 Verified Results			**5**				**803,777**		
Adjustments to 2013 Verified Results				**10**				**53,764**	
Total Adjustments to Previous Years' Verified Results		**-21**	**5**	**10**		**-33,914**	**803,777**	**53,764**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	6,750	2,011	3,151	3,579	45,971,627	13,424,518	18,616,239	20,315,770
Appliance Exchange**	Appliances	719	556	2,101	2,238	873,531	974,621	3,746,106	3,990,372
HVAC Incentives	Equipment	53,209	38,346	40,418	48,467	99,413,430	66,929,213	71,225,037	90,274,814
Conservation Instant Coupon Booklet	Items	1,184	231	464	1,442	19,192,453	1,325,898	6,842,244	19,000,254
Bi-Annual Retailer Event	Items	1,504	1,622	1,142	4,626	26,899,265	29,222,072	16,441,329	70,254,471
Retailer Co-op	Items	0	0	0	0	3,917	0	0	0
Residential Demand Response	Devices	10,390	49,038	93,076	117,513	23,597	359,408	390,303	8,379
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	1	29	587	1,813	4,884	259,826	3,699,786
Consumer Program Total		**73,757**	**91,805**	**140,380**	**178,452**	**192,379,633**	**112,240,615**	**117,521,084**	**207,543,846**
Business Program									
Retrofit	Projects	34,201	78,965	82,896	98,849	184,070,265	387,817,248	478,410,896	642,515,421
Direct Install Lighting	Projects	22,155	20,469	19,807	24,794	65,777,197	68,896,046	68,140,249	89,528,509
Building Commissioning	Buildings	0	0	0	988	0	0	0	1,513,377
New Construction	Buildings	247	1,596	2,934	11,911	823,434	3,755,869	9,183,826	37,742,970
Energy Audit	Audits	0	1,450	4,283	9,367	0	7,049,351	23,386,108	46,012,517
Small Commercial Demand Response	Devices	55	187	773	2,116	131	1,068	373	319
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	21,390	19,389	23,706	23,380	633,421	281,823	346,659	0
Business Program Total		**78,048**	**122,056**	**134,399**	**171,405**	**251,304,448**	**467,801,406**	**579,468,111**	**817,313,113**
Industrial Program									
Process & System Upgrades	Projects	0	0	313	12,287	0	0	2,799,746	90,463,617
Monitoring & Targeting	Projects	0	0	0	102	0	0	0	502,517
Energy Manager	Projects	0	1,034	3,953	5,767	0	7,067,535	24,438,070	44,929,364
Retrofit	Projects	6,372	0	0	0	38,412,408	0	0	0
Demand Response 3	Facilities	176,180	74,056	162,543	166,082	4,243,958	1,784,712	4,309,160	0
Industrial Program Total		**182,552**	**75,090**	**166,809**	**184,238**	**42,656,366**	**8,852,247**	**31,546,976**	**135,895,498**
Home Assistance Program									
Home Assistance Program	Homes	4	1,777	2,361	2,466	56,119	5,524,230	20,987,275	19,582,658
Home Assistance Program Total		**4**	**1,777**	**2,361**	**2,466**	**56,119**	**5,524,230**	**20,987,275**	**19,582,658**
Aboriginal Program									
Home Assistance Program	Homes	0	0	267	549	0	0	1,609,393	3,101,207
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	40,418	0	0	0	223,956,390	0	0	0
High Performance New Construction	Projects	10,197	6,501	772	268	52,371,183	23,803,888	3,522,240	1,377,475
Toronto Comprehensive	Projects	33,467	0	0	802	174,070,574	0	0	7,085,257
Multifamily Energy Efficiency Rebates	Projects	2,553	0	0	0	9,774,792	0	0	0
LDC Custom Programs	Projects	534	0	0	0	649,140	0	0	0
Pre-2011 Programs completed in 2011 Total		**87,169**	**6,501**	**772**	**1,070**	**460,822,079**	**23,803,888**	**3,522,240**	**8,462,733**
Other									
Program Enabled Savings	Projects	0	2,177	3,692	5,500	0	525,011	4,075,382	19,035,337
Time-of-Use Savings	Homes	0	0	0	54,795	0	0	0	0
LDC Pilots	Projects	0	0	0	1,170	0	0	0	5,061,522
Other Total		**0**	**2,177**	**3,692**	**60,296**	**0**	**525,011**	**4,075,382**	**19,035,337**
Adjustments to 2011 Verified Results			**13,266**	**645**	**1,601**		**48,705,294**	**20,581**	**6,028**
Adjustments to 2012 Verified Results				**8,632**	**13,449**			**54,301,893**	**59,098,939**
Adjustments to 2013 Verified Results					**34,727**				**206,413,158**
Energy Efficiency Total		**213,515**	**156,735**	**168,583**	**289,384**	**942,317,539**	**616,320,385**	**753,683,966**	**1,210,925,694**
Demand Response Total		**208,015**	**142,670**	**280,099**	**309,091**	**4,901,107**	**2,427,011**	**5,046,495**	**8,698**
Adjustments to Previous Years' Verified Results Total		**0**	**13,266**	**9,277**	**49,777**	**0**	**48,705,294**	**54,322,474**	**265,518,125**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**421,530**	**312,671**	**457,958**	**648,252**	**947,218,646**	**667,452,690**	**813,052,934**	**1,476,452,516**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 14: Adjustments to Province-Wide Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-8,759	1,091	2,157		-16,241,086	1,952,473	3,873,449	
Conservation Instant Coupon Booklet	Items	15	0	1		255,975	0	20,668	
Bi-Annual Retailer Event	Items	117	0	0		2,373,616	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	1	1	115		330,093	2,009	701,488	
Consumer Program Total		**-8,628**	**1,092**	**2,273**		**-13,281,402**	**1,954,483**	**4,595,605**	
Business Program									
Retrofit	Projects	4,511	10,114	16,584		22,046,931	58,528,789	108,677,566	
Direct Install Lighting	Projects	541	217	49		1,346,618	781,858	174,460	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	3,287	2,673	4,151		11,323,593	9,884,305	15,992,924	
Energy Audit	Audits	656	488	3,631		2,391,744	2,386,374	19,822,524	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**8,996**	**13,491**	**24,414**		**37,108,886**	**71,581,326**	**144,667,473**	
Industrial Program									
Process & System Upgrades	Projects	0	0	426		0	0	1,232,785	
Monitoring & Targeting	Projects	0	0	54		0	528,000	639,348	
Energy Manager	Projects	29	1,071	2,687		0	8,968,007	28,893,596	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**29**	**1,071**	**3,168**		**0**	**9,496,007**	**30,765,729**	
Home Assistance Program									
Home Assistance Program	Homes	0	222	791		0	1,316,749	4,321,794	
Home Assistance Program Total		**0**	**222**	**791**		**0**	**1,316,749**	**4,321,794**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	134		0	0	563,715	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**134**		**0**	**0**	**563,715**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	266	0	0		1,049,108	0	0	
High Performance New Construction	Projects	13,072	727	405		23,905,663	5,665,066	1,535,048	
Toronto Comprehensive	Projects	0	1,920	529		0	12,924,335	3,783,965	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**13,337**	**2,647**	**934**		**24,954,771**	**18,589,400**	**5,319,013**	
Other									
Program Enabled Savings	Projects	1,776	3,712	2,020		1,673,712	11,481,687	10,688,564	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		**1,776**	**3,712**	**2,020**		**1,673,712**	**11,481,687**	**10,688,564**	
Adjustments to 2011 Verified Results		**15,511**				**50,455,967**			
Adjustments to 2012 Verified Results			**22,235**				**114,419,652**		
Adjustments to 2013 Verified Results				**33,734**				**200,921,892**	
Adjustments to Previous Years' Verified Results Total		**15,511**	**22,235**	**33,734**		**50,455,967**	**114,419,652**	**200,921,892**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

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2-Staff-39

Ref: Exhibit 2, p. 47 – DSP Section 5.2.3.6 b: Connection of Renewable Generation, *Anticipated Renewable Generation Connection Request [Table]*, p. 34.

At the reference, ORPC states: "Given the level of interest expressed by Ottawa River Power Corporation's customers' to-date, the forecasted of Micro-FIT applications is presented in the table below. These numbers provided are speculative in nature, but they are based on experience dealing with customers over the past several years. 2014 has been forecasted higher than the following years. This year the largest shareholding municipality put micro-Fit projects on a number of their facilities. This will not repeat itself in the future."

Application Type	2014	2015	2016	2017	2018
Forecast micro FIT Connections	7-10	4-5	4-5	4-5	4-5

a) Please provide the number of actual 2014 connections and the number of year to date 2015 connections.

Response:

During 2014 Ottawa River Power had seven additional MicroFit connections.
During 2015 Ottawa River Power also had seven new MicroFit connections

2-Staff-40

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *__Poles__*, p. 82.

At the reference, ORPC states: "ORPC would have to replace 685 poles installed in the 1960's to keep pace with the lifecycle of wood poles. ORPC has identified that at least 980 poles may need to be replaced due to a minimum height requirement of 40 feet to comply with new ESA guidelines."

a) Does the new Electrical Safety Authority (ESA) guideline mandate that existing poles less than 40 ft. tall must be replaced?

Response:

No the ESA does not mandate the replacement of poles less than 40 ft. ORPC must comply with current standards when rebuilding/replacing poles. As an example, when multiple circuits occupy the same pole and circuits are located above and below each other, each circuit placed above another shall be of equal or higher voltage. The minimum separation between circuits is specified below in the table 02-07. Other parameters to include; Pole buried depth is usually 6 ft 6 inches, Joint use conductors vertical distance to ground, etc.

Table 02-07

Minimum Separation of Conductors
of Different Circuits on Common Structures.
The Vertical requirement can be reduced by 0.5 meters
if the upper circuit's conductors are NOT an ASC type.

Voltages are Nominal Phase to Phase

(See USF Section 2.8, USF Drawing 02-103)

Voltage of Higher Voltage Circuit	**Minimum Vertical Clearance between Circuits** **(Based on CSA Table 21)**	**Minimum Horizontal Clearance between Circuits** **(Based on CSA Table 17)**
8.32 kV and lower*	200 (6'8")	70 (2'4")
12.48 kV and 13.8 kV	200 (6'8")	75 (2'6")
27.6 kV	200 (6'8")	90 (3')
34.5 kV	200 (6'8")	100 (3'4")
44 kV	200 (6'8")	110 (3'8")

b) Does ORPC consider that the 30 ft. and 35 ft. poles in its existing portfolio present safety risks to workers or the public?

Response:

There are no imminent safety concerns, however on occasions ORPC employees are required to isolate complete circuits to allow workers to repair/work on the affected equipment due to proximity of energized lines. On occasions large vehicles have contacted the low neutral circuit which is caused due to the vintage construction.

2-Staff-41

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *Pole Capital*, p. 84.

At the reference, ORPC states: "The age distribution of the population of 4,299 wood poles is fairly evenly distributed over one lifecycle period beginning in 2015. The population is therefore not skewed, and as such, approximately the same number of assets will require replacement over the first and second half of the lifecycle. ORPC adopted a UL of 45 years, and based on the average age of 17 years for the population."

a) The last sentence in the above paragraph appears to be incomplete. Please provide a full explanation or clarification of the evidence.

Response:

The ", and" should be removed from the statement to read as follows;

The age distribution of the population of 4,299 wood poles is fairly evenly distributed over one lifecycle period beginning in 2015. The population is therefore not skewed, and as such, approximately the same number of assets will require replacement over the first and second half of the lifecycle. ORPC adopted a UL of 45 years based on the average age of 17 years for the population.

2-Staff-42

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *Remote SCADA*, p. 101.

At the reference, ORPC states: "As underground cables cannot be inspected, ORPC plans on starting a cable condition testing program in 2015. The purpose of the program will be to determine the degree of cable jacket deterioration, from which replacement or sustainment activities will be identified and prioritized. ORPC plans on smoothing out the age profile of cable runs through the utilization of cable sustainment investments. ORPC must also be mindful that cable replacements cannot practically be performed during the winter months."

a) Has the cost of conversion from coaxial cable to fibre optic communications been included in this DSP?

Response:

The conversion, connection fees and ongoing rental fees are included in O&M expenses.

b) If yes to a), please provide the estimated cost by year of expenditure.

Response:

N/A.

c) Can underground cable condition be non-destructively tested?

Response:

The cable testing may involve injecting a higher than operating voltage to stress the cable. This testing is not intended to be destructive but cable failures have been known to occur.

2-Staff-43

Ref: Exhibit 2, p. 47 – DSP Section 5.3.2: Overview of Assets Managed, *Overhead Distribution Assets Optimization Policies and Practices*, *Fully Dressed Wood Poles*, p. 104.

At the reference, ORPC states: “As ORPC has experienced considerable premature failures of wood poles due to flaws in the manufacturer’s treatment process, ORPC has been able to avoid unnecessary expense through the reuse of “like new” components.”

a) Has ORPC taken action to avoid or minimize the risk of acquiring poles with flawed treatment? Please describe.

Response:

ORPC receives and accepts poles only if they are in compliance with the CSA Standard or other specification under which they were purchased and the poles must correspond to the order placed. This process complies with our USF standards and also complies with our mandated requirements outlined in the ESA 22/04 regulation as follows:

- Section 6.0, “Approval of electrical equipment” – the requirements distributors are to follow for approving equipment for use on new construction and on repairs to existing distribution systems
- Section 7.0, “Approval of plans, drawings and specifications for installation work” – the requirements distributors are to follow when designing installations that form part of their distribution systems.
- Section 8.0, “Inspection and approval of construction” – the requirements distributors are to follow prior to putting any new construction or repairs to distribution systems into use.

2.0 – VECC - 2
Reference: E2/T5/Sch.2/DSP/pg.123 (or 121)

a) Please update the total capital expenditure tables by category (Access/Renewal/System Service/General Plant) for the 2015 actual expenditures.

Response:

Please see the updated tables by category at Response to Staff question 2.7 above.

2.0 – VECC - 3
Reference: E1/pg.32

a) Are the OM&A costs of $97,383 with respect to the installation or the operation of smart meters?

Response:

The operations and maintenance costs of $97,383 are with respect to the operation of smart meters including operations, communication costs and brochures for customers.

2.0 – VECC - 4
Reference: E1/pgs. 43-45

Pre-amble: We are unable find the $2.6 million in stranded meters removed from rate base in the filed continuity schedules.

a) In what year were meters removed from rate base.

Response:

Ottawa River Power did not remove $2.6 million in stranded meters. This was an incorrect statement on page 44. Stranded meters of $944,000 were removed from the utility's asset base starting in 2010 but are still included in its rate base.

Response:

	2008 Ending Balance	2009 Additions	Retirements	osing Balance
1805-Land	130,499	0		130,499
1806-Land Rights	10,809			10,809
1808-Buildings and Fixtures	397,506	6,329		403,835
1810-Leasehold Improvements	49,714			49,714
1820-Distribution Station Equipment - Normally Primary below 50 kV	2,084,456	478,615		2,563,071
1830-Poles, Towers and Fixtures	8,029,668	78,052		8,107,720
1835-Overhead Conductors and Devices	2,217,699	213,146		2,430,845
1840-Underground Conduit	2,933,508			2,933,508
1845-Underground Conductors and Devices	252,656	77,683		330,339
1850-Line Transformers	3,403,296	119,476		3,522,772
1855-Services	748,088	127,263		875,351
1860-Meters	983,682	2,846	314,617	671,911
1908-Buildings and Fixtures	0			0
1915-Office Furniture and Equipment	122,774			122,774
1920-Computer Equipment - Hardware	312,587	7,423		320,010
1925-Computer Software	450,027	4,202	160,818	293,411
1930-Transportation Equipment	1,579,695	14,240		1,593,935
1935-Stores Equipment	1,761			1,761
1940-Tools, Shop and Garage Equipment	234,049			234,049
1955-Communication Equipment	29,544			29,544
1960-Miscellaneous Equipment	0			0
1970-Load Management Controls - Customer Premises	254,912			254,912
1975-Load Management Controls - Utility Premises	64,873			64,873
1980-System Supervisory Equipment	498,536	3,732		502,268
1995-Contributions and Grants - Credit	(1,159,255)	(119,236)		(1,278,491)
	23,631,085	**1,013,771**		**24,169,421**

b) Please explain the disposal of $588,700 (and $357,001 Disposal in accumulated depreciation in 2010).

Response:

The disposal of $588,700 was the gross asset value of meters that were removed from service in 2010 as part of the smart meter initiative.

c) Were the stranded meters included in the 2010 rate base approved by the Board in the last cost of service rate filing?

Response:

The disposal of Stranded Meters were not approved as part of the utility's 2010 Cost of Service

d) Please explain how the allocations (%share) of stranded meters costs in Table 2.30b have been determined.

Response:

The utility used the Board approved allocation of meter capital from the 2010 Cost of Service application.

e) Please clarify if the Applicant is seeking a 2 year recovery (as noted on Line 5/pg.45) or 3 years (as noted in Table 2.30b).

Response:

Ottawa River Power is seeking a 2 year recovery.

2.0 – VECC - 5
Reference: E2/T5/Sch.2/DSP

a) Are the authors of the Distribution System Plan (other than CHEC) employees of ORPC? If yes, was a third party review of the plan undertaken?

Response:

Denis Montgomery, President of ORPC, is the author of the DSP. Denis has extensive experience in developing Asset plans and participated in OEB workshops relating to RRFE, DSP. He also participated in two MEARIE workshops on DSP and Finance.

The third party review was completed by James Buckingham who is a consultant and P.Eng.

2.0 – VECC - 6

Reference: E2/T5/Sch.2/DSP/pg.7

b) Was the backup control room noted at page 7 completed in 2014? If yes, please provide a description and the year the costs were booked. If no, please explain when this project will be completed and the estimated cost.

Response:

The backup control room is located in Pembroke Substation #8 and was completed in 2014. The SCADA and Fibre Optic network have always existed in the Substation building. The documenting of the continuity plan was updated.

Enhancements may be completed in 2016 to include air conditioning and more suitable furniture for extended requirements to house multiple employees. The costs may be approximately $2,500.

2.0 – VECC -7
Reference: E2/T5/Sch.2/DSP/pg.29

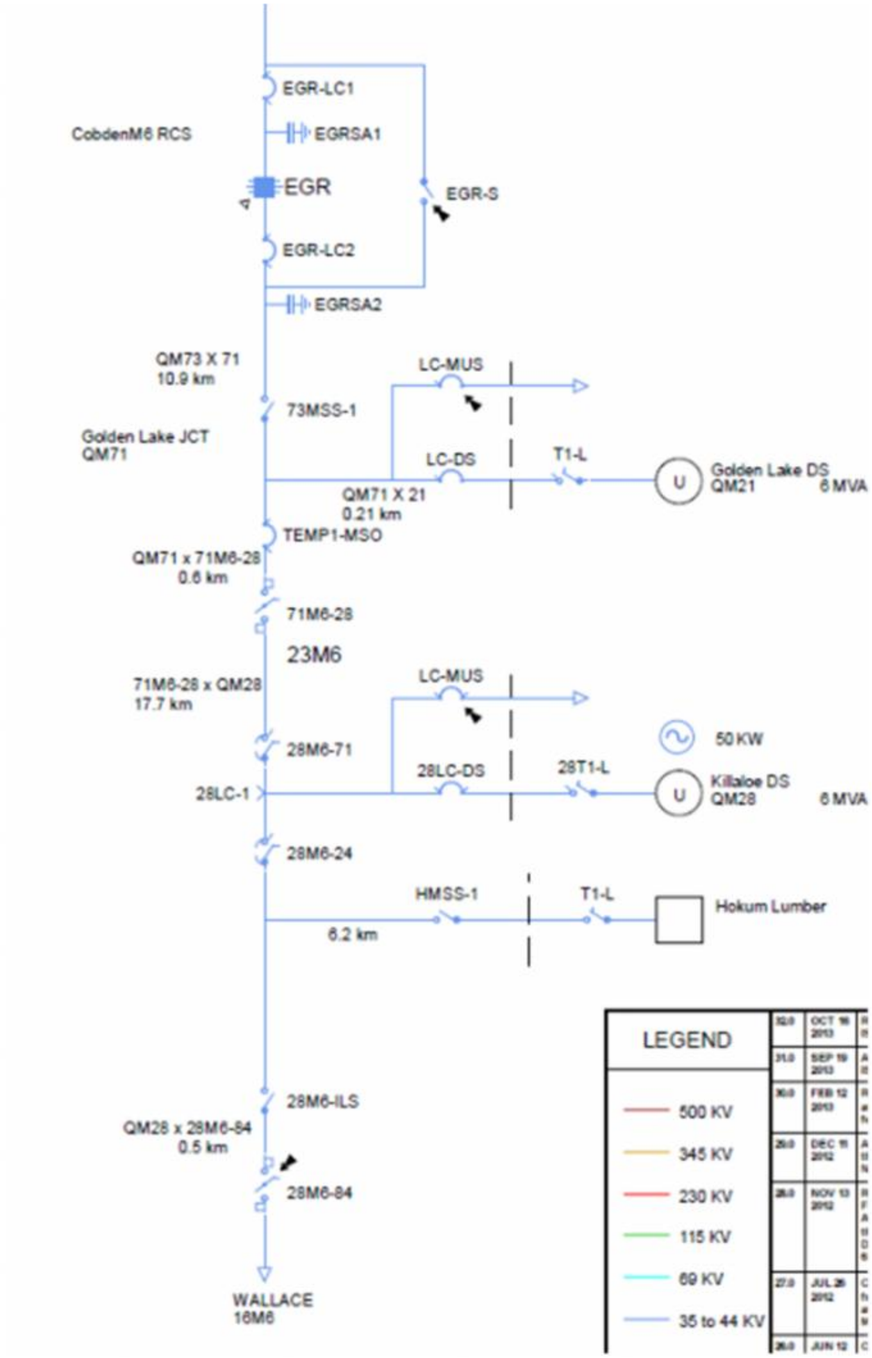
a) Please explain the nature of the service quality issues in the Killaloe service area described at page 29 of the DSP. How many customers were/are affected? What was/is the cost of remedial programs and how are the outcomes of any remedial program being measured?

Response:

Killaloe consist of circuits that is connected to the Hydro One Cobden DS. Killaloe is supplied by HONI with an M-class feeder supplying 44kV. The feeder is fed directly from HONI by 23M6 from Cobden TS. The Killaloe DS is connected and located between the Cobden TS approximately 50 km away and the Wallace TS. Due to the extreme travel distance compounded with no road access to the line, extended restoration time is normal. ORPC did not have any method of determining the power outage unless phone calls were received. ORPC decided to install a Smart reclosures that communicated not only the breaker status but also voltage and load.

The Killaloe DS may also be connected to the Wallace during extended power outages which means the Town of Killaloe has a redundant supply which can result in shorter power outages durations.

478 residential and 38 commercial customers are affected.
The re-closures project was completed over multiple years and totaled $53k.
The outcomes will be reflected in a lower SAIDI metric.


EGR-LC1
CobdenM6 RCS
EGRSA1
EGR
EGR-S
EGR-LC2
EGRSA2
QM73 X 71
10.9 km
LC-MUS
73MSS-1
Golden Lake JCT
QM71
LC-DS
T1-L
Golden Lake DS
QM21
6 MVA
QM71 X 21
0.21 km
TEMP1-MSO
QM71 x 71M6-28
0.6 km
71M6-28
23M6
71M6-28 x QM28
17.7 km
LC-MUS
50 KW
28M6-71
28LC-DS
28T1-L
Killaloe DS
QM28
6 MVA
28LC-1
28M6-24
HMSS-1
T1-L
Hokum Lumber
6.2 km
LEGEND
500 KV
345 KV
230 KV
115 KV
69 KV
35 to 44 KV
28M6-ILS
QM28 x 28M6-84
0.5 km
28M6-84
WALLACE
16M6

2.0 – VECC - 8
Reference: E2/T5/Sch.2/DSP/pg.98

a) ORPC explains it is currently gathering information on assets under the category of general plant. Please explain when this project will be completed and when ORPC expects to have completed a condition assessment on these assets.

Response:

- We will be completing a building assessments in 2016 to include furniture, computers, communication equipment and office equipment.
- Currently there are neither critical issues nor a priority before any considerable expenses.
- The phone system was replaced in 2015.
- The existing garage was assessed in 2014 and may require $150k remedial works.

2.0 – VECC - 9
Reference: E2/T5/Sch.2/DSP/pg.99

a) Has a condition assessment been done on the current fleet of vehicles? If yes please provide this assessment. If not please explain how the deviations in proposed replacements dates as between the Kinectrics replacement lives and the proposed (or actual) replacement dates was determined.

Response:

Testing Inspection and Maintenance are completed regularly including semi-annual hydraulics and high voltage testing and mechanical inspections.
Employee experience and feedback, TIM results, review of historical maintenance and repair costs, review analysis of major expenses as End of Useful Life nears and the age of the asset are drivers that determine the requirement for most replacements.
Finally, Pacing and Timing of all capital investments are analysed to smooth the total annual investment requirements.

ORPC's Fleet replacement plan lists all current vehicles and proposes future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Factors taken into consideration in establishing the replacement date of individual vehicles include:

- Vehicle age
- Mileage
- Engine hours
- Power take off hours
- Operating and maintenance costs
- Overall general condition of the vehicle

As the result of these evaluations, vehicles may be retained longer due to being in better than average condition and while others may be replaced earlier due to being in poorer condition.

Preventative scheduled maintenance on the entire Fleet is conducted regularly. Schedules are implemented per the manufacturers' recommendations, unless Fleet determines the condition of equipment is extreme or the equipment is lightly operated.
ORPC uses a local repair centre to maintain our fleet.
ORPC regularly inspects the aerial equipment on a 6-month basis, as well as monitors mileage and engine hours, which may trigger an earlier inspection. On light

duty equipment, ORPC performs regular scheduled maintenance every six months or 6,000 km.

2.0 – VECC - 10
Reference: E2/T5/Sch.2/DSP/5.4.5.2

a) Please describe how pole condition is assessed. Please provide an inventory of poles by condition (e.g. good, fair, and poor). If this is not available please explain how the pole replacement program is prioritized.

Response:

ORPC currently performs visual inspection and has completed drill testing on poles. Visual inspections record detailed information about the pole, the attached hardware and any other relevant information. This information is used in conjunction with the drill test to prioritize pole replacement, hardware replacement or to create new designs that will integrate with the present configuration. Drill assessment is a non-destructive testing method using an International Distribution Network (IML) Resistograph drill which measures the density or resistivity of the wood against the drill bit. The drill test provides an overall indication of rot, void, and solid wood thickness that can be used to calculate the remaining strength of the pole. The planned inspection schedule calls for the inspection of 1/3 of the poles annually. The OEB minimum inspection for poles requires that they be inspected in urban areas at a maximum interval of 3 years and in rural areas at a maximum interval of 6 years. In addition to the pole inspection program ORPC poles are being inspected during normal patrol to meet the OEB requirements. Currently, the inspections are being completed and the records are being stored in an ESRI database.

Pole Material Broken or Loose Guying, Max Pole Circumference Pole Age Ground Wire Missing or not Intact, Min Pole Circumference, Preservative Pole, Leaning or Twisting, External Damage Hole Width, Crossarm, Condition, Signs of Fire/Lighting/Arcing, External Damage Hole Depth, Transformer Standard, Comments, Insect Infestation, Drill Orientation, Porcelain Insulator, Vegetation Growth, Max External Decay, Width Pole Top, Condition Debris or Bird's Nesting, Max Internal Decay Width, Shell Condition, Cut-out Switch, Minimum Remaining Shell Width, Wood Pecker Damage, Sound Test, Interpretation of Test Result, Inline Switch, Overall Visual and Sound Remarks.

b) Please provide the same information for overhead and pad-mounted transformers.

Response:

ORPC visually inspects transformers every three years under the Overhead Visual Inspection and Underground Visual Inspection Programs and Record and follow-up on any complaints received from customers. The inspection of transformers includes: In addition to visual inspection OHL covers all of its transformers in its annual infra-red inspections. These inspections look for hot spots on transformers and their primary/secondary connections.

Polemount Transformers:

- Paint condition and corrosion
- Phase indicators and unit numbers match operating map
- Leaking oil
- Flashed or cracked insulators
- Contamination/discolouration of bushings
- Ground lead attachments
- Damaged disconnect switches or lightning arresters
- Ground wire on arresters unattached
- Padmount Transformers:
- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta bolt in place or damage
- Grading changes
- Access changes (Shrubs, trees etc.)
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Lid Damage, missing bolts, cabinet damage
- Cable connections
- Ground connections
- Nomenclature
- Animal nests/damage
- General Condition

Transformer Maintenance

ORPC performs maintenance on any transformers which are identified by either visual or infra-red inspection as needing work. This work may include replacement of connections if found to be hot, painting or replacement of unit if leaking.

2.0 – VECC - 11
Reference: E2/T5/Sch.2/DSP/5.4.4/pg.121

Pre-amble: The table at 5.4.4. (pages 121 and 123) does not appear to match the capital expenditure total shown on page 110 (expenditures by year under OEB defined categories). Similarly the expenditure totals on the first table on page 123 does not match the table which follow below it.

a) Please reconcile the tables on page 123.

Response:

The total of table match if the contributed capital is added to the last line item of the top table of Page 121 or conversely removed from the lower tables on page 121.

b) Please amend the table on page 121 to incorporate the projects (individually or by category) so as to equal the historic or proposed expenditures. Please also add the years 2010 to 2013 to this table.

Response:

ORPC does not understand the question as the tables do not address similar discussion items.

c) For both a) and c) please provide a new column showing 2015 actual expenditures.

Response:

Please see response to Staff Interrogatory 2-7.

2.0 – VECC - 12

Reference: E2/T5/Sch.2/DSP/pg.121& 135

a) Has ORPC had an independent assessment done of its transformer stations?

Response:

Yes, Hydro Ottawa completed the assessment of the Almonte Substations. We anticipate completing one assessment/year of the Pembroke substations with Hydro Ottawa.

b) Please identify the $139,000 in annual expenditures shown at page 135 for transformer stations with the amounts shown in the table at page 121.

Response:

The average annual expenditures (as per page 135) for Transformer Station is $139, 500.

IDNo	ItemNo	Investment Category	Investment Description	Capital Budget Year	Account	Lab	Matl	O/SCont	Truck	Total
553	224	System Renewal	Pembroke Substation Condition assesment	2015	1820	$2,500.00	$0.00	$10,000.00	$0.00	$12,500
526	218	System Renewal	Pembroke Substation testing	2015	1820	$4,000.00	$0.00	$8,000.00	$0.00	$12,000
405	103	System Service	Pembroke MS 3/7 Ground Grid	2015	1820	$11,500.00	$8,000.00	$8,000.00	$500.00	$28,000
407	103	System Service	Pembroke MS 6 Ground Grid	2015	1820	$0.00	$0.00	$12,000.00	$0.00	$12,000
206	103	System Service	Pembroke Substation MS 3/7 Fence	2015	1820	$2,000.00	$0.00	$16,000.00	$0.00	$18,000
520	217	System Service	Substation design and engineering	2015	1820	$2,500.00	$20,000.00	$0.00	$0.00	$22,500
552	223	System Service	Almonte MS- 3 fencing	2015	1820	$2,000.00	$0.00	$16,000.00	$0.00	$18,000
532	220	System Service	Electronic Protective relays	2015	1820	$3,000.00	$6,000.00	$7,500.00	$0.00	$16,500
									Total	$139,500.00

IDNo	ItemNo	Investment Category	Investment Description	Capital Budget Year	Account	Lab	Matl	O/SCont	Truck	Total
	219	System Service	Engineering Studies	2016	1820	$30,000.00	$0.00	$55,000.00	$1,000.00	$23,000
532	220	System Service	Electronic Protective relays	2016	1820	$3,000.00	$6,000.00	$7,500.00	$0.00	$16,500
281	105	System Service	Pembroke MS 6 Ground Grid	2016	1820	$2,000.00	$10,000.00		$0.00	$12,000
649	105	System Service	Pembroke MS 6 Ground Grid	2016	1820	$11,500.00	$8,000.00	$30,000.00	$500.00	$50,000
415	213	System Service	Pembroke Substation MS 2	2016	1808	$3,000.00	$15,000.00	$20,000.00	$0.00	$38,000
									Total	$139,500.00

IDNo	ItemNo	Investment Category	Investment Description	Capital Budget Year	Account	Lab	Matl	O/SCont	Truck	Total
609	104	System Service	Sub Battery	2017	1820	$950.00	$10,300.00	$0.00	$100.00	$11,350.00
635	130	System Service	Sub 8 Firewall	2017	1820	$0.00	$65,000.00	$0.00	$0.00	$65,000.00
398	214	System Service	SF6 Breaker	2017	1820	$3,500.00	$100,000.00	$4,000.00	$500.00	$108,000.00
622	220	System Service	Electronic Protective relays	2017	1820	$3,000.00	$6,000.00	$7,500.00	$0.00	$16,500.00
									Total	$200,850.00

IDNo	ItemNo	Investment Category	Investment Description	Capital Budget Year	Account	Lab	Matl	O/SCont	Truck	Total
610	104	System Service	Sub Battery	2018	1820	$950.00	$10,300.00	$0.00	$100.00	$11,350.00
170	130	System Service	Sub 3 Vector Correction	2018	1820	$4,000.00	$1,000.00	$0.00	$800.00	$5,800.00
631	130	System Service	Sub 4 PT	2018	1820	$4,000.00	$4,000.00	$0.00	$1,000.00	$9,000.00
287	213	System Service	Pem Sub 2 Switchgear HV Switch	2018	1820	$35,000.00	$180,000.00	$10,000.00	$3,000.00	$228,000.00
521	217	System Service	Substation design and engineering	2018	1820	$3,000.00	$70,000.00	$0.00	$0.00	$73,000.00
623	220	System Service	Electronic Protective relays	2018	1820	$3,000.00	$6,000.00	$7,500.00	$0.00	$16,500.00
620	223	System Service	Almonte MS-3 Rebuild	2018	1820	$25,000.00	$200,000.00	$55,000.00	$0.00	$280,000.00
	Total									$623,650.00

IDNo	ItemNo	Investment Category	Investment Description	Capital Budget Year	Account	Lab	Matl	O/SCont	Truck	Total
399	214	System Service	SF6 Breaker	2019	1820	$3,500.00	$100,000.00	$4,000.00	$500.00	$108,000.00
624	220	System Service	Electronic Protective relays	2019	1820	$3,000.00	$6,000.00	$7,500.00	$0.00	$16,500.00
	Total									$124,500.00

ORPC plans to smooth out expenditures over a seven year horizon for rate stability purposes not only for Stations, but System Service and even total Capital expenditures. ORPC believes that this approach aligns with the OEB's objective of "pacing and prioritizing capital investments to promote predictability in rates and affordability for customers." The installation of transformer station protection equipment (solid state protective relays) and engineering services (ground grid designs, etc.) requires the expertise of third-party service providers. ORPC has to rely on external service providers to perform this type of specialized work.

2.0 – VECC - 13

Reference: E2/T5/Sch.2/DSP/pg.141

a) Is the $108,000 shown at page 141 for station breakers an annual amount of capital expenditures?

Response:

Station Independent Breaker: ORPC owns five OCB's and performs annual inspections and oil condition testing on its station breakers that protects the transformer station and distribution system as a whole. The oil filled circuit breakers (OCB) have surpassed their typical useful life of 45 years, as they were manufactured in 1959. Recent inspections and condition test results (Pembroke Substation #4 2015) indicate that the OCB's are in good working condition relative to its age. Sourcing replacement parts for the OCBs is also a known issue. A failure of a bushing in 2008 was repaired by sourcing used parts from the local generating station. A recent catastrophic failure on July 10th,2015 in conjunction with our consultants advise that the OCBs should be replaced, and as such ORPC has assigned an adjusted end-of-life date of 2017 and 2019. ORPC plans to replace one of the OCBs in 2017 and one in 2019 at an estimated cost of $108,000. The replaced OCB will be refurbished and kept as a spare unit, if possible. The remaining breakers will be replaced within the next 10 to 15 years. The following picture depicts the oil filled circuit breaker.

b) Please identify this amount on the table at page 121.

Response:

The breaker replacement project is highlighted in yellow on the table below (from Page 121)

Capital Project Name	Investmment Category	2014	2015	2016	2017	2018	2019	Total
Fully Dressed Wood Pole Replacement Program	System Renewal	$34,000	$64,500	$64,500	$64,500	$64,500	$64,500	$322,500
Overhead & Pad-Mounted Transformer Replacement Program	System Renewal	$59,600	$59,500	$103,300	$103,300	$103,300	$103,300	$472,700
Conductors		$220,359	$60,200	$44,500	$14,000	$14,000	$14,000	$146,700
Fleet Vehicle Replacement Program	General Plant	$49,066	$61,000	$300,000	$60,000	$60,000	-	$481,000
Scada	System Service		$18,000	$45,000	$45,000		$45,000	$153,000
Transformer Station – Power Transformer Fire Barrier	System Service				$65,000			$65,000
Information System	General Plant	$35,425	$10,000			$26,000	$47,000	$83,000
Transformer Station - 44kV Breaker Replacement	System Service				$108,000		$108,000	$216,000
Engineering Studies	System Service			$86,000				$86,000
Outage Management System	System Service			$78,000				$78,000
44 KV tie Line Almonte	System Service				$100,000			$100,000
Substation upgrades	System Service	$84,000				$228,000		$228,000
Almonte Substation	System Service					$280,000		$280,000
Substation Design	System Service	$74,600				$73,000	$115,000	$188,000
Scattered Residential and Subdivisions	System Access	$203,500	$400,850	$400,850	$290,700	$290,700	$290,700	$1,673,800
Commercial	System Access	$108,370	$100,500	$100,500	$161,500	$91,500	$91,500	$545,500
2015 Misc. Small Capital Projects			$285,250					$285,250
2016 Misc. Small Capital Projects				$424,100				$424,100
2017 Misc. Small Capital Projects					$219,200			$219,200
2018 Misc. Small Capital Projects						$226,550		$226,550
2019 Misc. Small Capital Projects							$222,900	$222,900

2.0 – VECC - 14
Reference: E2/T5/Sch.2/DSP/pg.123

a) Why was there no spending under the category of system service between the years 2010 and 2013?

Response:

Previous management did not use the same interpretation of the definitions and trigger drivers for System Service in classifying the projects and most of the projects were included with System Renewal.

The trigger driver for the proposed investments correlates with triggers for System Service.

For example; Almonte MS3 upgrade could be classified System Renewal due to its trigger being age, but the recent condition assessment completed in 2014 did not highlight any deficiencies or concerns. The substation will need to be upgraded due to the existing load and future growth in the area. Therefore system service.
Another example is the electromechanical relays. ORPC plans to install new solid state relays under the System Service due to the trigger being Smart Grid and reclosures functionality and not due to the age of the relays.

1-SEC-11
[Ex. 2/5/2, unnumbered presentation] With respect to the Powerpoint presentation, please provide the date it was presented, the audience for the presentation, the purpose of the presentation, and the results of that meeting or other event, if any.

Response:

In preparation for this Cost of Service application Ottawa River Power held two community "town hall" meetings in an attempt to engage its customers. This was not done in prior applications.

The first town hall meeting was held October 16, 2014. ORPC advertised this meeting to discuss the application including its capital plans. A facility was secured and a presentation was prepared. The turnout was dismal with only one customer attending.

The second community meeting took place on November 23, 2015, coordinated by and with the Ontario Energy Board. Presentations were completed by both groups and one individual representing a greater than 50KW customer. Again the turnout was dismal with less than 20 customers attending representing a mere 0.2% of customers.

Ottawa River Power does not believe that this has enhanced the preparation of this application. It can only assume that its customers are satisfied with the customer service, reliability and rates that it provides.